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, 2024** 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 28, 2024, was $236,738,085, based on the closing price reported that date by the NASDAQ of $7.77 per share.

As of March 10, 2025, we had 42,619,347 shares outstanding. Our Annual Meeting of Shareholders will be held on May 29, 2025, in Denver, Colorado.

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 electricity or coal 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;
- legislation, regulations, administrative actions (e.g., Executive Orders), 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 the geopolitical environment in industries in which our customers operate;
- anticipated changes in the U.S. political environment, including those resulting from the change in Presidential Administration and control of Congress, and to regulatory agencies;
- changes in attitude toward environmental, social, and governance ("ESG") matters among regulators, investors and parties with which we do business;
- 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;
- supply chain disruptions and 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 ***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.

Hallador Energy Company is a vertically integrated power and coal company with operations primarily in Indiana. The Company operates across multiple stages of the energy supply chain, from coal extraction to electricity generation and mines coal from the rich, high-quality, lower sulfur reserves found in the Illinois Basin ("ILB").

Once the coal is mined by Sunrise Coal, LLC ("Sunrise"), the Company's wholly-owned mining subsidiary, the Company processes and transports it to power plants, where it is used as a primary fuel source for generating electricity. Through its wholly-owned subsidiary Hallador Power, LLC ("Hallador Power"), the Company owns and operates the Merom Power Plant ("Merom"), a 1,080 MW net coal fired power generating station, consisting of two 590 MW sub-critical water tube drum type steam turbine generators. Unit 1 entered commercial operations in 1982 and Unit 2 in 1983. The units are dispatched to the Midcontinental Independent System Operator ("MISO") interconnection. Hallador Power sells wholesale energy and accredited capacity to utilities within the MISO system through power purchase agreements ("PPA") and other bilateral transactions. Merom is located in Sullivan County, Indiana, about twenty miles from Sunrise's Oaktown Mining Complex. Sunrise also sells coal to other utilities in Indiana and throughout the southeast United States. In addition, it has a developed infrastructure for the transport of coal, including rail networks and truck loading systems, facilitating the efficient movement of the resource from the mine to its customers.

The vertically integrated structure allows the Company to control the entire process, from mining to power production, providing cost efficiencies, greater operational flexibility, and the ability to manage supply and demand within the energy market. Hallador Power has invested in technologies to reduce emissions and improve the environmental performance of coal-fired generation, particularly in response to regulatory pressures.

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 electric power generation and coal mining 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 electric power generation, mining or exploration;
- restricting the types, quantities, and concentration of materials that can be released into the environment in the performance of electric power generation, mining, exploration or production activities;
- discharge of materials;
- storage and handling of explosives;
- wetlands protection;
- surface subsidence from underground mining; and
- the effects, if any, that electric power generation or mining 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, that existing laws or regulations may be interpreted differently or more stringently enforced, that existing regulations may be repealed or that the authority of current regulators may be reduced or revoked, 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 *"Recent Regulatory Developments from the Presidential Transition"* in this section, below, and the risk factors described in *"Item 1A. Risk Factors"* below.

We are committed to conducting electric power generating and mining operations in compliance with applicable federal, state, and local laws and regulations. However, because of the extensive and detailed nature of these regulatory requirements, 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 electric power generating company or coal mining company to be free of citations. When we receive a citation, we attempt to remediate any identified condition immediately. While we have not quantified all of the costs of compliance with applicable federal and state laws and associated regulations, those costs have been and are expected to continue to be significant. Compliance with these laws and regulations has substantially increased the cost of electric power generation and the cost of coal mining for domestic coal producers.

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, power plant closing, and mine closings, including the cost of treating mine water discharge, when necessary. The accruals for asset retirement obligations, power plant closing and mine 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.

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, including greenhouse gas 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.

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.

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 and final 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.

On December 10, 2024, MSHA published a final rule to revise Testing, Evaluation, and Approval of Electric Motor-Driven Mine Equipment and Accessories within underground mining environments.

On December 20, 2023, MSHA published a final rule requiring that all mine operators 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).

It is uncertain whether MSHA will engage in further rulemaking regarding the above issues or any of the other various proposed rules or requests for information or whether any such rules 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 actuarial 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, 100% of our production involves underground room and pillar mining (no surface subsidence). 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, obtain emissions allowances, 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.
- The Cross-State Air Pollution Rule ("CSAPR") addresses the "good neighbor" provision in the Clean Air Act, which prohibits sources within each state from emitting any air pollutant in an amount which will contribute significantly to any other state's nonattainment of, or interference with maintenance of, any National Ambient Air Quality Standards ("NAAQS"). CSAPR requires power plants in certain states to reduce emission levels of sulfur dioxide and nitrogen oxide pursuant to a cap-and-trade program similar to the Acid Rain Program. In October 2016, the EPA published a final rule to update the CSAPR to address the 2008 ozone NAAQS ("CSAPR Update Rule"). Following legal challenges related to the CSAPR Update Rule, on April 30, 2021, the EPA issued the Revised CSAPR Update Rule. The Revised CSAPR Update Rule required affected electric generating units ("EGUs") within certain states (including Indiana) to participate in a new trading program. On June 5, 2023, the EPA published a final Federal Implementation Plan to address air quality impacts with respect to the 2015 Ozone NAAQS called the "Good Neighbor Plan." However, on June 27, 2024, the United States Supreme Court granted emergency applications seeking a stay of the Good Neighbor Plan pending judicial review. In response, on November 6, 2024, EPA issued an interim final rule, which effectively reinstated the Revised CSAPR Update Rule during the stay. While our CSAPR compliance costs to date have not been material, the future availability of and cost to purchase allowances to meet the emission reduction requirements is uncertain at this time, but it could be material.
- In February 2012, the EPA adopted the Mercury and Air Toxic Standards ("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, and in May 2024, EPA issued a final rule amending MATS and increasing the stringency of certain requirements. 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.

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 adopted 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.

On May 9, 2024, the EPA published a final rule that, among other things, repealed the ACE rule and also established emissions guidelines for GHG emissions for existing coal-fired and new or substantially modified gas-fired power plants. The rule divides coal-fired power plants into three categories. Those that will cease operation by 2032 are exempt from the rule. Those operating between 2032 and 2039 will be required to achieve emissions reductions equivalent to co-firing 40 percent by volume natural gas. Those intending to operate after 2039 will be required to achieve emissions reductions equivalent to 90 percent capture of CO2 through carbon capture and sequestration ("CCS"). While the rule has been challenged in court, the US Supreme Court declined to stay the rule while those challenges proceed. Additionally, the new Trump Administration has indicated its intention to revise the rule. The rule could potentially have a material adverse effect on our business, financial condition, and results of operations.

Future, additional regulation of GHG emissions in the U.S. could occur pursuant to future U.S. treaty commitments, new domestic legislation or regulation by the EPA. Congress has not currently adopted explicit 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 its authority to regulate carbon dioxide emissions from existing and modified power plants. However, we cannot predict whether such legislation will be signed into law in the future. 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, the Biden Administration 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. However, the new Trump administration has recently announced its intention to withdraw from the Paris Agreement, so these targets from the Biden Administration may change.

Since the 2021 Biden Administration targets were announced, the Parties of the UN Framework Convention on Climate Change have met on several occasions, including at the 28th Conference to the Parties on the UN Framework Convention on Climate Change ("COP28"). At the COP28, the Parties agreed to non-binding language calling on countries to transition away from fossil fuels in energy systems to achieve net zero emissions by 2050. 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.

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. 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 White House 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. However, in November 2024, the U.S. Court of Appeals for the D.C. Circuit held that CEQ has no authority to issue regulations implementing NEPA and that CEQ's NEPA regulations are, therefore, invalid and of no effect.

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 and stormwater 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 final rule for in May 2024, which established more stringent requirements for flue gas desulfurization ("FGD") wastewater, bottom ash transport water, and combustion residual leachate, among other measures. The new rule also established early shutdown alternatives for plants permanently ceasing coal combustion by certain target dates. These regulations may impact the market for our coal products and 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 requirements under CWA Section 316(a) for thermal discharges and Section 316(b) for cooling water intake structures. Section 316(a) standards allow thermal dischargers to have less stringent alternate thermal limits if they can demonstrate that the current effluent limitations, based on water quality standards, are more stringent than necessary to protect the aquatic organisms in the receiving water body. Merom Station is currently subject to a 316(a) variance and alternative thermal effluent limits. If Merom Station's 316(a) variance were revoked in the future, additional capital expenditures may be required that could be material.

Section 316(b) standards require affected facilities to choose among seven best technology available ("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.

Coal Combustion Residuals

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. 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. Further, in May 2024, EPA finalized changed to the CCR regulations for inactive surface impoundments at inactive electric utilities, referred to as “legacy CCR surface impoundments,” and also established certain requirements for a new subcategory of CCR areas called “CCR management units,” among other actions. 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 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 for our mining operations are mining equipment and replacement parts, steel-related (including roof control) products, belting products, lubricants, electricity, fuel, and tires. For our electric operations, we purchase coal, limestone, fuel oil, anhydrous ammonia, and other chemicals and items necessary to operate Merom Station. 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, 2024, Hallador and its subsidiaries employed 615 full-time employees and temporary miners, 582 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.

Recent Regulatory Developments from the Presidential Transition

On January 20, 2025, Donald J. Trump was inaugurated as the 47th President of the United States of America. Since President Trump's inauguration, the new Administration has rescinded various Biden Administration Executive Orders and has issued new Executive Orders and taken other related executive actions, which may impact the market for our coal products or our electric power generating operations. These new Executive Orders reflect policy objectives such as promoting the development of domestic energy resources, expedited permitting for energy projects, potential withdrawal from international climate change agreements, and the potential reconsideration of US EPA's 2009 endangerment finding for greenhouse gas emissions under the Clean Air Act, among other issues. Many of these policy objectives will require further rulemaking actions or other formal steps before they would become law. In addition, the new Administration has taken actions to reduce the number of federal employees and to eliminate certain federal agencies or reduce their authority. As a result, there is significant uncertainty regarding whether or how regulations and the agencies that administer and enforce these regulations may change as a result of the actions taken to date and possible future actions by the new Administration. Additionally, there may be litigation over such regulatory changes, and if public enforcement decreases as a result of such changes, private litigation over environmental matters may increase.

Other

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

Our corporate office, as well as Sunrise Coal and Hallador Power's 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 contracts or enter into new long-term contracts for electric power, capacity or coal.

In 2024, a significant portion of our electric power, capacity and coal 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 customers, and if supply exceeds demand in the electric power, capacity and coal 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 an increasing portion of our revenue stream to the increased volatility of the spot market.

Our financial performance may be impacted by price fluctuations in the electric power markets, as well as fluctuations in coal markets and other market factors that are beyond the Company’s control.

Market prices for power, capacity, coal and other ancillary services are unpredictable and tend to fluctuate substantially. Electric power generally must be produced concurrently with its use. As a result, power prices are subject to significant volatility due to supply and demand imbalances, especially in the day-ahead and spot markets. While we currently sell a significant portion of our electric power pursuant to long-term contracts (where we may be less susceptible to day-to-day fluctuations), we also sell a material amount of power in the competitive wholesale market including through MISO. A significant portion of the electricity we sell is used by residential and commercial customers for heating and air conditioning Long and short-term power prices may fluctuate substantially due to factors outside of the Company’s control, including:

- changes in generation capacity in the Company’s markets, including the addition of new supplies of power as a result of the development of new plants, expansion of existing plants, the continued operation of uneconomic power plants due to state subsidies, retirement of existing plants or addition of new transmission capacity;

- electric supply disruptions, including plant outages and transmission disruptions;

- changes in power transmission infrastructure;
- transportation capacity constraints or inefficiencies;
- weather conditions, including extreme weather conditions and seasonal fluctuations, including the effects of climate change;
- changes in commodity prices and the supply and available inventory of commodities, including but not limited to natural gas, coal and oil;
- changes in the demand for power, or in patterns of power usage, including the potential development of demand-side management tools and practices, distributed generation, and more efficient end-use technologies;
- development of new fuels, new technologies and new forms of competition for the production of power;
- economic and political conditions;
- changes in law, including judicial decisions, environmental regulations and environmental legislation; and
- federal, state and provincial power regulations and legislation, and regulations and actions of the ISO and RTOs.

Such factors and the associated fluctuations in power prices have affected the Company's profitability in the past and are expected to continue to do so in the future.

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

Several of our long-term electric power, capacity and coal contracts 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 force majeure, labor disputes, mechanical malfunctions and changes in government regulations, including, in the case of our coal contracts, 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 or similar terms, our business, financial condition and results of operations could be adversely affected.

Further, long-term coal sales contracts may contain provisions that allow for the purchase price to be renegotiated at periodic intervals, however, we had no coal contracts with price reopeners at December 31, 2024. 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.

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

In our Electric Operations, a material portion of our 2024 revenue was derived from a power purchase agreement with Hoosier ("PPA"), which we entered into as part of our acquisition of Hoosier Energy's Merom Generation Station ("Merom") in 2022. The PPA (as amended in August 2023) expires at the end of 2028. 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.

During 2024, we derived 89% of our delivered energy and 88% of our capacity sales revenue from three and four customers, respectively, each of which representing at least 10% of sales revenue. Additionally, we derived 96% of our third-party coal sales from four customers, each representing at least 10% of 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 recent efforts to sell our accredited capacity to long-term customers may not be successful.

In light of the fact that the Company believes it holds a considerable portion of the remaining unsold accredited capacity in MISO Zone 6, covering Indiana and parts of western Kentucky, the Company has recently focused its efforts on entering into one or more long-term contracts for the sale of its energy and capacity to large load end user(s) through a utility or cooperative, including through a data center targeted Request for Proposal (RFP) undertaken in 2024. This RFP resulted in a wholly owned subsidiary, Hallador Power Company, LLC, executing a Conversion Transaction Commitment Agreement with a leading global data center developer on January 2, 2025. The transaction contemplated thereby remains subject to a number of conditions, including negotiation of definitive documentation and the selection of a utility partner and there can be no assurance that definitive agreements will be entered into or that the proposed transaction will be consummated on the terms or timeframe currently contemplated, or at all. Failure to consummate the transaction contemplated by the Conversion Transaction Commitment Agreement and/or any other similar agreement(s) contemplated by the Company's recent RFP efforts may 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 electric power, capacity and coal sold and delivered depends on the continued creditworthiness of our customers. If the creditworthiness of our customers declines significantly, our business could be adversely affected. In addition, if a customer refuses to accept shipments of our coal for which they have an existing contractual obligation, our revenues will decrease, and we may have to reduce production at our mines until our customer's contractual obligations are honored.

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

At Merom, 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.

In our Coal Operations, 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.

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.

In October 2022, the Company, through its subsidiary Hallador Power, completed its acquisition of Merom, our one Gigawatt Generating Station located in Sullivan County, Indiana pursuant to an Asset Purchase Agreement ("APA") with Hoosier Energy. The operation and maintenance of generating facilities like Merom 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. From time to time, the Merom facilities may experience transformer failures that may cause one or more of its units to be offline for an extended period of time. We may 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. In connection with the APA, 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.

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 power, mining, 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. During the fourth quarter of 2024, we completed our annual impairment analysis, which was based upon the finalized operating plans of the Company, market driven pricing and cost trends. As part of that analysis, the Company determined the carrying amount of its long-lived assets were not recoverable and recorded a non-cash, long-lived asset impairment charge of $215.1 million in the fourth quarter of 2024. See "*Note 19 – Impairment of Coal Properties"* to the Consolidated Finance Statements in this Form 10-K for further information on the impairment analysis. The factors noted above 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 – Bank Debt"* to our consolidated financial statements, on September 27, 2024, we executed the First Amendment ("First Amendment") to the Fourth Amended and Restated Credit Agreement, dated as of August 2, 2023 (as amended, the "Credit Agreement"), in which we adjusted existing covenants and added new ones: (i) waived the Company's Leverage Ratio requirement for the third and fourth quarters of 2024, increased the threshold to 5.50 to 1.00 for the first quarter of 2025, and decreased the threshold back to 2.25 to 1.00 for each fiscal quarter thereafter, (ii) the Debt Service Coverage Ratio requirement (1.25 to 1.00) was waived from third quarter of 2024 through the first quarter of 2025, (iii) added a maximum First Lien Leverage Ratio for the first quarter of 2025, calculated as of the end of each fiscal quarter for the trailing twelve months, not to exceed 3.50 to 1.00; (iv) added a minimum liquidity requirement of $10.0 million, beginning on the First Amendment execution date and ending when the second quarter of 2025 compliance certificate is received, and (v) added a minimum quarterly EBITDA requirement, as defined in the First Amendment, of $5.0 million for the third quarter of 2024 through the first quarter of 2025.

As of December 31, 2024, our liquidity of $37.8 million and quarterly EBITDA of $6.2 million were in compliance with the requirements of the Credit Agreement.

Our ability to comply with the covenants in our credit agreement may be affected by changes in economic or business conditions or other events that are beyond our control. If we fail to comply with these covenants, we may be in default under our credit agreement, which may entitle the lenders to accelerate the debt obligations. In order to avoid defaulting on our indebtedness, we may be required to take actions such as reducing or delaying capital expenditures, reducing or eliminating dividends or share repurchases, selling assets, restructuring or refinancing all or part of our existing debt, or seeking additional equity capital, any of which may not be available on terms that are favorable to us, if at all. In the event of an event of default under 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.

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

As of December 31, 2024, our funded bank debt was $44.0 million and we held letters of credit totaling $19.4 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.

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, have faced increased scrutiny from stakeholders related to their ESG practices. Companies that do not adapt or comply with 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. Certain non-governmental organizations and other private actors have 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. Similarly, we could be criticized by ESG detractors for the scope and nature of any ESG policies or initiatives we implement. We could also be subjected to negative responses by governmental actors, such as state legislation, retaliatory legislative treatment or litigation by state or federal agencies, or face negative publicity campaigns that could adversely affect our reputation, business, financial performance and growth. 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.

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.

Consistent with the trend established by passage of the General Data Protection Regulation (the "GDPR"), the development and evolving nature of domestic and international privacy regulation and enforcement could impact and potentially limit how Hallador processes personal information. For example, California residents have certain privacy rights (including the right to limit the use and disclosure of sensitive personal information, and the right to request that a business delete personal information collected about them, among other rights), established by the California Consumer Privacy Act ("CCPA") and enforced by a 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 patterned after the standards set forth by CCPA, including broader data access rights, with some states even requiring businesses to perform data protection assessments for certain processing activities. In 2025, state privacy laws go into effect in a number of states, including Delaware, Maryland, Minnesota, Nebraska, and New Jersey, among others.

As new laws and regulations are enacted by legislators or adopted by regulators, 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 as many as 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.

Risks Related to our Industry

Substantial or extended volatility in coal prices could negatively impact our results of operations in both our Electric Operations and Coal Operations segments.

Our results of operations are primarily dependent upon the price we pay for our coal in the case of our Electric Operations, or the prices we receive for our coal in our Coal 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;
- 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. In addition, deregulation within the coal industry, including as a result of actions taken by the new Presidential Administration, may encourage new market entrants and could increase the number of competitors we face. 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.

Further, there is uncertainty surrounding tariffs and international trade relations, and it is difficult for us to predict future trade measures and the impact they will have on our business and operations. In early 2025, the new U.S. Presidential

Administration threatened and imposed tariffs on imports from various countries. In response, some of these countries threatened or imposed tariffs on imports from the U.S. How long current tariffs will remain in place, and whether the new Administration will enact the threatened tariffs or impose entirely new ones is uncertain.

These newly enacted tariffs, additional 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 and pollutants in wastewater 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, MATS, 316(a) and (b) rules, CCR rules, and ELGs 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. These rules could also lead to material capital expenditures for our electric generating operations.

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

Combustion of fossil fuels, such as the coal we produce in our mining operations and the energy we produce in our electric operations, 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. Many 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.

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, the U.S. rejoined the Agreement in 2021 and, in April 2021, established a goal of reducing economy-wide net GHG emissions 50-52% below levels by 2030. However, the new Trump Administration has recently announced its intention to withdraw from the Paris Agreement, so these targets from the Biden Administration may change.

Since the 2021 Biden Administration targets were announced, the Parties of the UN Framework Convention on Climate Change have met on several occasions, including at the 28th Conference to the Parties on the UN Framework Convention on Climate Change ("COP28"). At the COP28, the Parties agreed to non-binding language calling on countries to transition away from fossil fuels in energy systems to achieve net zero emissions by 2050. Although no legally binding commitment or timeline to phase out or phase down all fossil fuels was made, there can be no guarantees that countries will not seek to implement such a binding 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. 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. While the Biden executive order has now been rescinded by the new Trump Administration, the political dynamic could change yet again in the future. 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, 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. However, in January 2025 the Board of Governors of the US Federal Reserve System and Federal Deposit Insurance Corporation announced plans to withdrawing as members of the NGFS. 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 risks 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." Additionally, our electric power generating operations result in air emissions, wastewater effluent, and the generation of coal combustion residuals. 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 in our Coal Operations 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 Electric and Coal 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 and the electric generation 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. Many of these same risks apply to our electric operations and the operation of a coal-fired generating facility, including impacts on air, surface water, groundwater and the environment. 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 and electric operations, or indirect impacts that discourage or limit our customers' use of coal or purchase of coal-fired electricity. Federal and state laws addressing 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.

Anticipated changes in the U.S. political environment, including those resulting from the change in Presidential Administration and control of Congress, and to regulatory agencies, may result in significant changes to regulatory framework and enforcements.

As a result of the 2024 presidential election, changes in the Presidency and both houses of Congress may result in significant changes in, and have resulted in uncertainty with respect to, legislation, regulation, implementation or repeal of laws and rules related to our industry, our coal products, and our electric power operations. The new Presidential Administration has rescinded various prior Executive Orders and has issued new Executive Orders and taken other related executive actions. Many of these policy changes will require further rulemaking actions or other formal steps before they would become law. In addition, the new Administration has taken actions to reduce the number of federal employees and to eliminate certain federal agencies or reduce their authority. As a result, there is significant uncertainty regarding whether or how regulations and the agencies that administer and enforce these regulations may change as a result of the actions taken to date and possible future actions by the new Administration. Additionally, there may be litigation over such regulatory changes, and if public enforcement decreases as a result of such changes, private litigation over environmental matters may increase.

Changes to existing policies and rules regarding our industry, including those recently instituted, in addition to anticipated new rule proposals, may result in significant regulatory changes, increased penalties for non-compliance, increased competition, or increased private litigation. We also anticipate that there may be changes in legislative control and legislative priorities. As a result, future legislation may be proposed or passed that may adversely affect our business, operating results and financial condition.

We continually monitor these developments in order to respond to the changing regulatory environment impacting our business. While it is not possible to predict whether and when any such changes will occur, specific proposals discussed during and after the election, including the U.S. withdrawal from the Paris Agreement, could harm our business, operating results and financial condition. If we are slow or unable to adapt to any such changes, our business, operating results and financial condition could be adversely affected.

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

Mining and electricity generation companies must obtain numerous governmental permits or approvals that impose strict conditions and obligations relating to various environmental and safety matters in connection with our operations. 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, and conflicts in the Middle East. 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.

Although the Federal Reserve decreased the federal interest rate multiple times in 2024, the rate continues to be elevated and there can be no assurance that the rates will continue to decrease or that it will not be increased in 2025 or beyond. We have exposure to past increases in interest rates and may be affected further in the future. Based on our current variable debt level of $44.0 million as of December 31, 2024, 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 more than $0.4 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.

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 companies for attractive opportunities 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 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 estimates of our coal reserves could prove inaccurate and could result in decreased profitability in our Coal Operations.

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 in our Coal Operations.

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 operations are affected by commodity prices. In our Coal Operations, 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, limestone, 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.

Disruptions in supply chains could significantly impair our operating profitability.

We are dependent upon vendors to supply equipment within our power plant, mining equipment, 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, healthcare and labor. In addition to potential cost increases, inflation could cause a decline in global or regional economic conditions that reduce demand for our electric power, capacity or coal 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 the Merom Power Plant and our mines.

ITEM 3. LEGAL PROCEEDINGS.

The Company is subject to various legal proceedings and claims that arise in the ordinary course of business, including, but not limited to, environmental matters, contractual disputes, regulatory issues, personal injury, and employment claims. As of the filing date of this report, the Company does not have any active lawsuits or claims which are deemed material, but should facts or circumstances change, some or all of these alleged claims could have a material impact on the Company's financial results, results of operations and/or cash flows.

The Company accrues liabilities for legal matters when it is probable that a liability has been incurred and the amount can be reasonably estimated. While the Company believes that it has made appropriate provisions for all known legal matters, the outcome of legal proceedings is inherently uncertain, and there can be no assurance that the resolution of such matters will not have a material adverse effect on the Company's financial position, results of operations, or cash flows.

Subsequent to the end of the fourth quarter, the Company reached an agreement in principle to resolve a putative class action related to certain of its employment practices for an amount not material to its financial results. The liability related to this settlement was accrued during the fourth quarter, when settlement negotiations began. The resolution has not yet been finalized, but the Company expects the matter to be closed during the first half of 2025. See *"Note 22 – Contingencies"* to our Consolidated Financial Statements.

The Company will continue to monitor all proceedings and will update shareholders as necessary, in accordance with applicable legal and regulatory requirements.

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 40.9% is held by our officers, directors, and their affiliates.

On March 10, 2025, we had 193 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 – Stock Compensation Plans"* 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 mega-watt hour (MWh) and per ton and basis as derived from the 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. Our wholly owned subsidiary Hallador Power, operates our Merom Power Plant ("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 also mine coal in the State of Indiana through our wholly-owned subsidiary Sunrise Coal, LLC ("Sunrise"), serving the electric power generation industry. During the fourth quarter of 2024, we completed our review of the coal mining facilities and future mining plans. The impairment analysis was based upon our finalized coal mining operating plans, market driven pricing and cost trends. As part of that analysis, we determined the carrying amount of our coal mining long-lived asset group was not recoverable and recorded a non-cash, long-lived asset impairment charge of $215.1 million in the fourth quarter of 2024. See *"Note 19 – Impairment of Coal Properties"* to the Consolidated Financial Statements in this Form 10-K for further information on the impairment analysis.

Our business is organized based on the services and products we provide in two segments: (i) Electric Operations and (ii) Coal Operations. The Chief Operating Decision Maker ("CODM"), who is the Company's Chief Executive Officer, reviews and assesses operating performance measures related to our Electric Operations and our Coal Operations segments. In addition to these reportable segments, the Company has a "Corporate and Other and Eliminations" category, which is not significant enough, on a stand-alone basis, to be considered an operating segment. Corporate and Other and Eliminations primarily consist of unallocated corporate costs and activities, including a 50% interest in Sunrise Energy LLC and Oaktown Gas, LLC, which are accounted for using the equity method.

Throughout 2024, we made progress on transitioning Hallador Energy from a bituminous coal producer to an integrated independent power producer ("IPP"). This strategic transition has been a deliberate response to market signals and what we believe to be the superior economics of the IPP business model. As such, our focus remains on maximizing the value of Merom while actively seeking opportunities to acquire additional dispatchable generators. We have also prioritized building strong relationships with counterparties to secure favorable terms for collateral, enabling us to effectively leverage forward power sales in 2025 to offset pricing volatility in the spot market. This approach enhances our financial flexibility and strengthens our position in the evolving energy market.

In the fall of 2024, we reached a key milestone in our IPP transformation by signing a non-binding term sheet with a leading global data center developer for the supply of a significant portion of Merom's output of capacity and energy for well over a decade. As evidenced by our announcement of an exclusivity agreement with this development partner in January 2025, we are continuing to make progress as we seek to finalize a definitive agreement. As we have previously disclosed, the exclusivity period runs through the beginning of June 2025, in exchange for payments from the developer to Hallador Power of up to $5.0 million, depending on if and when a definitive agreement is finalized. This type of deal is complex and involves multiple parties, which adds time and challenges to negotiations. Despite these challenges, we remain encouraged by our partners and the steady progress that we continue to make. Our pursuit of this agreement further demonstrates our commitment towards forging a strategic partnership that we believe will create significant value for our shareholders for years to come. The completion of this proposed transaction is subject to, among other matters, the negotiation and execution of definitive agreements and there can be no assurance that definitive agreements will be entered into or that the proposed transaction will be consummated on the terms or timeframe currently contemplated, or at all.

We continue to witness the prevalent industry trend of retiring dispatchable generators, including coal, in favor of non-dispatchable resources such as wind and solar. We believe this transition from dispatchable to non-dispatchable generation made the attributes of our subsidiary, Hallador Power, much more valuable due to the enhanced reliability that we provide versus non-dispatchable generators. However, we believe the retirement of coal-based generation and lower natural gas prices could reduce the demand for coal supply, potentially lowering the value of Sunrise. During 2024, in response to declining coal demand, we reduced our coal production volume by approximately 40% and idled the higher cost surface mines. This optimization of coal production reduced our operational cash cost structure and better aligned our coal strategy to primarily support our internal electric generation.

Merom can produce up to 6.0 million Mega-Watthours (“MWh”) annually. The forward power price curves indicate that the margins earned on energy produced at Merom and the value of the accredited capacity sales assigned to the plant continues to increase. We are seeing strong indications for both energy and capacity sales in 2025 and beyond, especially considering our negotiations related to supporting data center development within the State of Indiana. In addition, while we largely held to our traditional approach of selling energy through bespoke bi-lateral agreements on a unit or plant contingent basis, during 2024 we sold a limited amount of power on a firm basis. While we continue to limit these types of firm sales to mitigate risk and wait for higher priced contracts to take effect, we will strategically utilize them to smooth our exposure to the spot market. This approach enables us to capture some of the episodic cash generation driven by demand from extreme weather and various other conditions stressing the power grid while limiting our exposure to periods of mild weather and lower demand.

In 2024, the ongoing surplus of natural gas in the market and mild weather patterns continued to moderate energy prices throughout the year and kept spot energy prices weak. We began to see favorable pricing signals at the end of the fourth quarter of 2024 and subsequent to year-end.

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 natural gas face transportation and storage challenges which increase price volatility. The limitations of storing viable energy, coupled with non-dispatchable generation gaining market share in an environment where there is unpredictability in the weather, indicates to us that energy's price volatility is likely to increase over the next decade. This volatility will keep the forward power price premium intact.

We are excited by the opportunity for Hallador Power to capture higher prices and energy volumes in 2025 and beyond compared to what we have historically achieved in our relatively short ownership tenure of Merom. In 2024, we sold 4.2 million MWh at an average sales price of approximately $48.62 per MWh. At the start of the year, we had 1.9 million MWh contracted, leaving us with significant exposure to the spot electricity market. Heading into 2025, we have contracted approximately 4.3 million MWh at an average price of $37.24 per MWh, which should help to smooth our exposure to the spot market. For 2026, we have already contracted 3.4 million MWh at $44.43 per MWh. Following 2026, we are optimistic that we can sell energy at higher prices in support of data center development and/or to traditional wholesale customers in line with the indicators of a higher forward curve. The tables included below highlight some of the revenue and margin improvements we have seen in our forward contracted power sales for 2025 and thereafter. These tables do not include the significantly higher prices that we are expecting if we are able to finalize our agreements in support of data center development.

In addition to the transaction we are negotiating with Merom, we continue to evaluate other strategic transactions that could add durability, scale, and geographic expansion opportunities to our electric operations. While these types of deals are limited and complex, we believe that Hallador is uniquely positioned to transform retiring and/or underperforming assets into future opportunities. This will enable us to supply high demand end users, such as data centers and on-shored industrial customers, with minimal impact to retail consumers, unlike a traditional utility siphoning off consumer power to serve these types of large load end-users. By continuing the operations of the dispatchable plants to support large load industrial users as the utilities transition to non-dispatchable generation, the new generation becomes additive to the already struggling grid rather than cannibalizing the overall reliability of what exists today. We are optimistic about the potential to add to our strategic portfolio and the long-term benefits that such a transaction could produce for the Company, its shareholders and its customers. This model for growth enables us to shift from transactional pricing related to plant acquisition, to traditional wholesale market pricing, and ultimately to the enhanced pricing associated with supporting data centers and other large load end users.

In the first quarter of 2024, we announced a restructuring of our Coal Operations to address the increase in costs we experienced at our mines. See *"Note 17 – Organizational Restructuring"* to the Consolidated Financial Statements in this Form 10-K for further information. We spent much of the year adjusting to this restructuring to optimize production, headcount, and strategy to best support our Electric Operations and our existing third-party coal contracts. By reducing headcount, focusing production on our most profitable mines and units within those mines, and improving our infrastructure and processes within those favored units, we were able to both slow the impact of rapidly increasing costs and reduce costs to better support the continued operations of our mines.

Historically, Sunrise has produced between four and six million tons annually. As we continue to optimize the mines in support of the plant, we expect to produce approximately 3.6 million tons of coal in 2025, with approximately 2.3 million tons produced directed to support our Electric Operations. We have also secured supplemental coal from third party suppliers at favorable prices to diversify self-production supply risk and to provide us additional flexibility in our sales portfolio and to fulfill future sales obligations to third-parties and Merom as shown in the table below. The optionality to obtain low-cost tons either internally or from third parties while capturing upward swings in the commodity markets for coal should further maximize margins while optimizing fuels costs at Merom.

We remain excited about the continued and deliberate transformation of Hallador from a commodity focused producer of coal to an IPP. We believe this transition provides significant opportunity to capture the expanding margins of the energy markets and capitalize on the soaring demand for electricity. We are pleased by the strong interest we continue to see from potential counterparties in our energy and capacity offerings, bolstered by Indiana's efforts to attract data centers and other high-density power users through its business-friendly climate and favorable tax policies. With the continued growth of our sales book, coupled with our ongoing focus to transition our operations to primarily electricity generation, we believe we are well positioned to materially strengthen our opportunities for growth and cash flow generation.

Solid Forward Sales Position - Segment Basis, Before Intercompany Eliminations

	2025	2026	2027	2028	2029	Total
Power						
Energy						
Contracted MWh (in millions)	4.25	3.36	1.78	1.09	0.27	10.75
Average contracted price per MWh	$ 37.24	$ 44.43	$ 54.66	$ 52.94	$ 51.33	
Contracted revenue (in millions)	$ 158.27	$ 149.28	$ 97.29	$ 57.70	$ 13.86	$ 476.40
Capacity						
Average daily contracted capacity MWh	773	727	623	454	100	
Average contracted capacity price per MWd	$ 201	$ 230	$ 226	$ 225	$ 230	
Contracted capacity revenue (in millions)	$ 55.95	$ 61.12	$ 51.40	$ 37.33	$ 3.47	$ 209.27
Total Energy & Capacity Revenue						
Contracted Power revenue (in millions)	$ 214.22	$ 210.40	$ 148.69	$ 95.03	$ 17.33	$ 685.67
Coal						
Priced tons - 3rd party (in millions)	2.95	2.50	2.50	0.50	—	8.45
Avg price per ton - 3rd party	$ 51.04	$ 55.49	$ 56.74	$ 59.00	$ —	
Contracted coal revenue - 3rd party (in millions)	$ 150.57	$ 138.73	$ 141.85	$ 29.50	$ —	$ 460.65
TOTAL CONTRACTED REVENUE (IN MILLIONS) - CONSOLIDATED	$ 364.79	$ 349.13	$ 290.54	$ 124.53	$ 17.33	$ 1,146.32
Priced tons - Intercompany (in millions)	2.30	2.30	2.30	2.30	—	9.20
Avg price per ton - Intercompany	$ 51.00	$ 51.00	$ 51.00	$ 51.00	$ —	
Contracted coal revenue - Intercompany (in millions)	$ 117.30	$ 117.30	$ 117.30	$ 117.30	$ —	$ 469.20
TOTAL CONTRACTED REVENUE (IN MILLIONS) - SEGMENT	$ 482.09	$ 466.43	$ 407.84	$ 241.83	$ 17.33	$ 1,615.52

* Actual revenue related to solid forward sales positions may differ materially for various reasons, including price adjustment features for coal quality and cost escalations, volume optionality provisions and potential force majeure events.

Electric Operations

Internal Controls Disclosure

Our electric operations employ third party service providers for the day-to-day operations and maintenance of Merom as well as managing market transactions and optimizing plant dispatch. We contract with Consolidated Asset Management Services ("CAMS") to manage ongoing operations, maintenance and asset management functions at Merom. CAMS provides an operations and maintenance program which includes daily management of plant performance, safety protocols and workforce management. CAMS develops and implements predictive and preventative maintenance schedules designed to maximize plant availability and maintain compliance with environmental and regulatory standards. In coordination with our engineering teams, CAMS identifies and manages capital projects that aim to improve operational efficiency and reduce long-term costs. CAMS also provides performance monitoring and reporting. CAMS provides regular reports on key performance indicators ("KPIs") such as heat rates and forced outage rates to help us assess plant efficiency. CAMS assists in ensuring adherence to local, state and federal regulations including environmental rules and safety mandates. We maintain oversight of CAMS through regular audits and performance reviews, confirming all procedures align with our company policies and best practices.

We engage with Alliance for Cooperative Energy Services Power Marketing, LLC (“ACES”), as our agent to manage our wholesale power market activities and risk management strategies related to electric operations. Through this relationship, ACES manages the dispatch and scheduling on the real-time and day-ahead markets. ACES manages bidding strategies, scheduling our generation in the relevant regional transmission organizations (“RTOs”) or independent system operators (“ISOs”). To optimize our sales portfolio, ACES analyzes energy market dynamics, identifies opportunities to optimize plant dispatch, and recommends operational adjustments to capture favorable margins. ACES assists in risk management by executing short-term trades on our behalf to mitigate price volatility and lock in predictable revenues as well as ensures that our participation in the energy markets adheres to relevant market rules and regulations. We receive regular risk reports and settlement statements, which our internal teams review to confirm accuracy and compliance with our company policies.

We regularly review the performance and controls of CAMS and ACES. Our formal review processes include monthly performance reviews through joint meetings with CAMS and ACES to evaluate KPI trends, discuss operational challenges, and plan market strategies. Periodic internal and external audits examine environmental, safety, and financial compliance, ensuring third-party activities align with regulatory standards and Company objectives. We also have a risk committee that evaluates all marketing activities and exposures.

Merom operates under permits issued by various agencies. CAMS provides support and expertise to ensure compliance with emissions requirements, water use regulations, and waste disposal guidelines. The power markets we operate in periodically update their rules and tariffs, which may affect how we dispatch our plants or manage financial positions. ACES continuously monitors changes, recommending updates to our strategies as needed.

Volatility in wholesale power prices can impact revenue. ACES provides strategies to mitigate price risk.
Equipment failures or unexpected downtime at coal plants can lead to missed market opportunities or contractual liabilities. Our relationship with CAMS is designed to minimize these risks through comprehensive operations and maintenance practices. Future environmental or market regulations may require capital investments or shift market behavior. Our teams, in conjunction with CAMS and ACES, monitor emerging policies to proactively plan operational or strategic adjustments.

Property

Through Hallador Power, the Company owns and operates Merom, a 1,080 MW net coal fired power generating station, consisting of two 590 MW sub-critical water tube drum type steam turbine generators. Unit 1 entered commercial operations in 1982 and Unit 2 in 1983. The units are dispatched to the MISO interconnection. Hallador Power sells wholesale energy and accredited capacity to utilities within the MISO system through PPA’s and other bilateral transactions. Merom is located in Sullivan County, Indiana, on approximately 691 acres, which also holds a 112-acre landfill. Hallador Power has two tracts under option for approximately 72 acres for expansion and future development at Merom. Merom is about twenty miles from Sunrise’s Oaktown Mining Complex and has rail and truck access. The Company acquired Merom from Hoosier Energy Rural Electric Cooperative, Inc. in 2022.

	Year Ended December 31,	
	2024	2023
Power Capacity and Utilization		
Nameplate capacity (MW)(i)	1,080	1,080
Accredited capacity for the period (MW)(ii)	823	860
Accredited capacity utilization(iii)	49 %	45 %

i. Nameplate capacity for the Merom Power Plant refers to the maximum electric output generated by the plant in the period presented and may not reflect actual production. Actual production each period varies based on weather conditions, operational conditions, and other factors.

ii. Accredited capacity is based on MISO's average seasonal accreditations for the year. Average seasonal accreditations were 808 MW and 838 MW per day for 2024 and 2023, respectively. Accreditations are weighted and adjusted annually based on 3-year rolling performance metrics.

iii. Accredited capacity utilization is measured as power produced (MWh) divided by accredited capacity for the period (MW) multiplied by 24 times the number of days for the period.

Permits are required by federal and state law for Merom's facilities and landfill. Merom holds several construction and environmental permits for air, wastewater and solids waste disposal. All necessary permits to support current operations are in place. New permits or permit revisions may be necessary from time to time to facilitate future operations or to keep pace with the changing regulatory landscape. 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. Merom continually excels in environmental excellence and compliance.

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 is properly mitigated, and (2) assure that all regulation requirements of the permit are fully satisfied. We hold surety bonds of $9.7 million to cover obligations relating to reclamation at Merom.

Coal Operations

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.

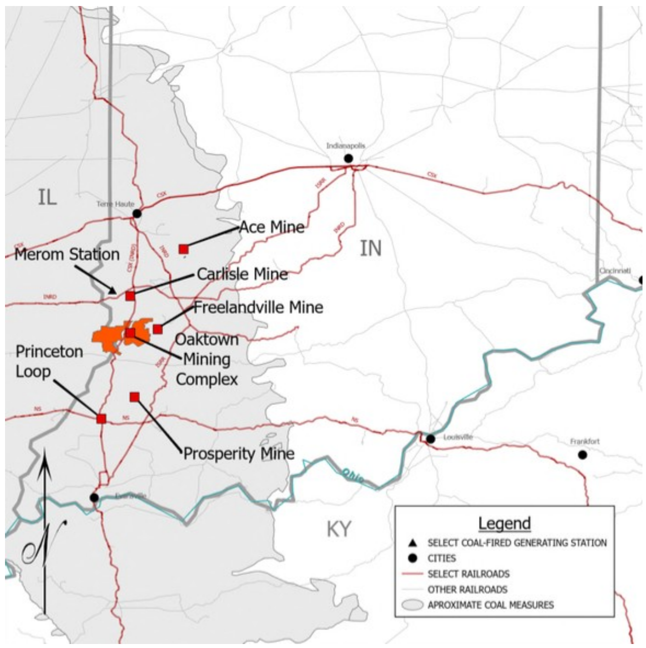
Summary of All Mining Properties

The Company has seven total mining properties. These properties are the Oaktown Mining Complex ("Oaktown"), 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, Freelandville and Carlisle. Oaktown Fuels No. 2, Prosperity and Freelandville were temporarily idled in February of 2024 as part of the Organizational Restructuring in "*Note 17 – Organizational Restructuring*" to the Consolidated Financial Statements below. Ace in the Hole Mine and Carlisle are fully depleted.

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 (“ILB”) 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 Oaktown 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 and other Sunrise Coal logistic facilities where it is blended with coal from the Oaktown Mines.

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 March 2025 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 Merom and our 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 March 2025 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 March 7, 2025, from John T. Boyd Company providing an update of estimated coal reserves at the Oaktown Mining Complex as of December 31, 2024, 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 March 7, 2025, 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, 2024 and including a comparison of the Company's mineral reserves at the Oaktown Mining Complex as of December 31, 2024 and as of December 31, 2023. 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, 2024:

SUMMARY MINERAL RESERVES AT END OF THE FISCAL YEAR ENDED DECEMBER 31, 2024

	Mineral Reserves (tons in millions)		
	Proven	Probable	Total
Oaktown			
Oaktown Fuels No. 1 Mine	25.7	2.7	28.4
Oaktown Fuels No. 2 Mine	5.9	0.2	6.1
Total	31.6	2.9	34.5

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.

Oaktown is an underground Room-and-Pillar ("R&P") coal mining complex. It is comprised of 83 square miles within the ILB coal-producing region of the mid-western U.S. Oaktown operations currently consists of one active underground mine - Oaktown Fuels No. 1 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 area and its immediate vicinity, our Company controls approximately 64,000 acres of mineral rights. We have a complex collection of leases that apply to more than 1,000 tracts. Leased tracts 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. The Company controls surface rights through fee simple ownership for over 1,700 permitted acres, holding mine accesses, processing, storing, shipping, and refuse disposal facilities (i.e., refuse impoundment site and fine refuse injection sites). We acquired Oaktown Fuels No. 1 and No. 2 Mines from Vectren Fuels in 2014.

Oaktown 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 has utilized this mining method since the inception of each operation. To date, Oaktown has produced a combined 75.0 million tons of clean coal. Oaktown is configured to operate up to 6 CM sections (currently operating 4 CM sections), with an annual production target of approximately 3.6 million tons. The Oaktown Preparation Plant serves as the coal washing and shipment facility for Oaktown’s two R&P mines. The plant was commissioned in 2009 to wash coal by the Oaktown Fuels No. 1 Mine. The Oaktown Preparation Plant’s processing capacity was upgraded to 1,800 raw tons-per-hour (TPH) from its previous 1,600 raw TPH in 2023. Coal from Oaktown is transported to customers via rail and truck. The Oaktown 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 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 $10.0 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 Oaktown’s mineral reserves:

OAKTOWN
Recoverable Coal Reserves as of December 31, 2024 and 2023

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	12/31/2024	12/31/2023
Oaktown Mining Complex								
Oaktown Fuels No. 1 Mine	11,630	6.0	—	100.0	25.7	2.7	28.4	34.1
Oaktown Fuels No. 2 Mine	11,576	5.0	—	100.0	5.9	0.2	6.1	26.6
Total					31.6	2.9	34.5	60.7

Oaktown Fuels No. 1 Mine

As of December 31, 2024, the assigned and accessible reserve base for the Oaktown Fuels No. 1 Mine contains 28.4 million tons of recoverable Indiana V seam coal, of which 28.4 million tons are currently permitted. The reserve contains saleable tons which average heating content of approximately 11,630 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, 2024, the assigned and accessible reserve base for the Oaktown Fuels No. 2 Mine contains 6.1 million tons of recoverable Indiana V seam coal, of which 5.4 million tons are currently permitted. The reserve contains saleable tons which average heating content of approximately 11,576 Btu per pound with approximately 5.0 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. In 2021, an additional mine access (elevator) was constructed for employee and supply ingress/egress closer to the active production faces. Oaktown Fuels No. 2 was temporarily idled in February of 2024.

Coal tons 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 2024, with the coal sales price estimated over the life of the reserve averaging approximately $49 (ranging from $47.25 to $51.47 per 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 March 7, 2025, 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 Oaktown as of December 31, 2024 and including a comparison of the Company's mineral reserves at Oaktown as of December 31, 2024 and as of December 31, 2023.

Historical production for Oaktown during the years ended December 31, 2024, 2023, and 2022 are provided in the following table:

	Annual Saleable Production Tons (Million Tons)		
Mine/Reserve	**2024**	**2023**	**2022**
Oaktown Mining Complex			
Oaktown Fuels No. 1 Mine	3.5	3.9	3.9
Oaktown Fuels No. 2 Mine	0.4	2.5	2.5
Total Oaktown Mining Complex Production	3.9	6.4	6.4

Other Properties

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

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

Ace Mine is now depleted. Remaining inventory of coal and base was moved to our Oaktown wash plant in early 2023. Reclamation resumed in the Spring of 2023. There are four phases of reclamation that extend through 2029, of which, Phase 1 and 2 were completed as of December 31, 2024.

Prosperity (surface) – Assigned

The Prosperity mine contains approximately 0.2 million tons of low sulfur coal. 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.

Freelandville (surface) – Assigned

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. That option was extended from May 2023 until May 2026. Mining started in the fall of 2022 and continued through April 2023 with limited production in 2024. Remaining reserves under the permit are 0.4 million tons. There are additional reserves of 1.2 million tons available with the completion and approval of an Army Corps of Engineers permit. In February 2024, this mine was idled.

Carlisle

The Carlisle mine is located near the town of Carlisle, Indiana in Sullivan County. It became operational in January 2007 for both surface and underground mining. The mine was permanently closed for mining operations in 2020. A wash plant was relocated to the Carlisle mine in 2022 and was sold in 2024.

Our Coal Contracts

In 2024, on a segment basis Sunrise sold 3.9 million tons of coal to 6 power plants in four different states across five different customers.

During 2024, on a segment basis we derived 96% of our revenue from four customers (5 power plants), with each of the four customers representing at least 10% of our coal sales. 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.

Significant third-party customers in 2024 include Vectren Corporation, a wholly-owned subsidiary of CenterPoint Energy (NYSE: CNP), Orlando Utility Commission (OUC), and Duke Energy Corporation (NYSE: DUK).

Of our 2024 sales, on a segment basis 43%, excluding Merom, 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
2025	3.0	2.3	5.3	$ 51.03
2026 - 2028 (total)	5.5	6.9	12.4	53.38
Total	8.5	9.2	17.7	

* 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, 2024, we are committed to supplying third-party customers a base amount of 8.5 million tons of coal through 2028 of which 8.5 million tons are priced. We are committed to supplying coal to Merom a base amount of 9.2 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 3.6 million ton annualized pace for the foreseeable future to meet Merom and third-party market demand. We also have contracts in place to purchase coal through March of 2026, and anticipate similar contracts in the future.

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 $65.9 million and $59.4 million for the years ended December 31, 2024 and 2023 respectively. Operating cash flow increased mainly due to prepaid physically delivered power contracts entered into during 2024.

Our capital expenditure budget for 2025 is $66.0 million. Of the $66.0 million, the electric operations budget is $31.0 million for maintenance capex and $14.0 million for ELG. The coal operations budget is $14.8 million plus an additional $5.8 million for discretionary items.

As of December 31, 2024, our bank debt was $44.0 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 term debt to March 31, 2026, and our revolver to July 31, 2026.

On September 27, 2024, the Company executed the First Amendment ("First Amendment") to the Fourth Amended and Restated Credit Agreement, dated as of August 2, 2023 (as amended, the "Credit Agreement"), with PNC. The primary purpose of the First Amendment was to provide the Company with short-term covenant relief to pursue additional liquidity. The First Amendment provides for additional flexibility for the Company to enter into prepaid forward power sale contracts, provided that the Company repays outstanding term loans under the Credit Agreement ("Term Loan") with proceeds received from certain eligible power purchase agreements, up to a maximum of $20.0 million. These required prepaid forward power sale Term Loan repayments, if any, will take the place of the $6.5 million quarterly Term Loan payments.

We expect cash from operations generated primarily by our expected higher Electric Operation margins in 2025 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 $16.9 million, including $5.7 million at Merom, presented as asset retirement obligations (ARO) in our accompanying consolidated balance sheets. In the event we are not able to perform reclamation, we have surety bonds in place totaling $30.8 million to cover ARO.

Capital Expenditures ("Capex")

For the year ended December 31, 2024, our Capex was $53.4 million allocated as follows (in millions):

Oaktown – maintenance capex	$	22.5
Oaktown – investment		11.3
Merom Plant		18.7
Other		0.9
Capex per the Condensed Consolidated Statements of Cash Flows	$	53.4

Results of Operations

Presentation of Segment Information

Our business is organized based on the services and products we provide in two segments: (i) Electric Operations and (ii) Coal Operations. The Chief Operating Decision Maker ("CODM"), who is the Company's Chief Executive Officer, reviews and assesses operating performance measures related to our Electric Operations and our Coal Operations segments.

In addition to these reportable segments, the Company has a "Corporate and Other and Eliminations" category, which is not significant enough, on a stand-alone basis, to be considered an operating segment. Corporate and Other and Eliminations primarily consist of unallocated corporate costs and activities, including a 50.0% interest in Sunrise Energy, which is accounted for using the equity method.

Electric Operations

	Year Ended December 31,			
	2024		2023	
	(in thousands)			
Delivered Energy	$	203,434	$	211,772
Capacity Revenue		58,093		56,155
Electric Sales	$	261,527	$	267,927
Fuel	$	(111,768)	$	(139,496)
Other Operating Costs (1)		(19)		(32)
Other Operating and Maintenance Costs (2)		(28,622)		(33,777)
Cost of Purchased Power		(10,888)		—
Utilities		(2,070)		(429)
Labor		(30,842)		(31,245)
General and Administrative		(5,311)		(4,914)
EBITDA Margin		72,007		58,034
Other Operating Revenue		982		414
Amortization of Contract Asset		—		(26,581)
Depreciation, Depletion and Amortization		(19,290)		(18,739)
Asset Retirement Obligations Accretion		(457)		(576)
Interest expense		(1,875)		(322)
Income (Loss) before Income Taxes	$	51,367	$	12,230

1) Other operating costs include costs for limestone, dibasic acid, ammonia, lime dust and soda ash.
2) Other operating and maintenance costs include all other operating and maintenance costs with the exceptions of those costs considered variable as discussed above in 1).

	Year Ended December 31,	
	2024	2023
	(per MWh)	
MWh Generated (in thousands)	3,830	4,224
MWh Purchased (in thousands)	354	—
MWh Sold (in thousands)	4,184	4,224
Delivered Energy	$ 48.62	$ 50.14
Capacity Revenue	13.88	13.29
Electric Sales	$ 62.50	$ 63.43
Fuel	$ (26.71)	$ (33.02)
Other Operating Costs (1)	—	(0.01)
Other Operating and Maintenance Costs (2)	(6.84)	(8.00)
Cost of Purchased Power	(2.60)	—
Utilities	(0.49)	(0.10)
Labor	(7.37)	(7.40)
General and Administrative	(1.27)	(1.16)
EBITDA Margin	17.22	13.74
Other Operating Revenue	0.23	0.10
Amortization of Contract Asset	—	(6.29)
Depreciation, Depletion and Amortization	(4.61)	(4.44)
Asset Retirement Obligations Accretion	(0.11)	(0.14)
Interest expense	(0.45)	(0.08)
Income (Loss) before Income Taxes	$ 12.28	$ 2.89

1) Other operating costs include costs for limestone, dibasic acid, ammonia, lime dust and soda ash.
2) Other operating and maintenance costs include all other operating and maintenance costs with the exceptions of those costs considered variable as discussed above in 1).

Fuel decreased $27.7 million, or 19.9%, from 2023 due to production decreasing by 394 MWh, or 9.3%, and the expiration of a purchased coal contract in 2023 reducing our average coal pricing by $8.61 per ton, or 14%, on a segment basis. We used 189,000 tons, or 9.2%, less in production compared to the prior year. The decrease in demand for electric power was related to mild weather throughout 2024 and the associated higher demand for natural gas as natural gas inventories remained high causing a decline in the average spot prices for natural gas which changed $0.34 per mbtu, or 13.5% from 2023.

Other operating and maintenance costs decreased $5.2 million, or 15.3%, from 2023 primarily due to 2023 year-to-date planned maintenance of $13.0 million compared to $9.1 million in 2024.

Cost of purchased power increased $10.9 million, or 100.0%, from 2023. When energy hours at the Merom Hub are priced below our production cost at our Merom Facility, we make net hourly purchases of power in the MISO market.

Amortization of the contract asset decreased by $26.6 million, or 100.0%, from 2023 due to the expiration of our coal purchase contract.

Income (loss) before income taxes increased $39.1 million, or 320.0%, and increased $9.39 per MWh, from 2023 due to the items described in the discussion above.

Coal Operations

	Year Ended December 31, 2024	2023
	(in thousands)	
Coal Sales	$ 202,525	$ 432,888
Fuel	$ 2,851	$ 7,089
Other Operating and Maintenance Costs	89,283	165,479
Utilities	13,844	17,301
Labor	85,322	121,172
General and Administrative	9,877	10,287
EBITDA Margin	1,348	111,560
Other Operating Revenue	2,756	2,936
Depreciation, Depletion and Amortization	(46,245)	(48,365)
Asset Impairment	(215,136)	—
Asset Retirement Obligations Accretion	(1,171)	(1,228)
Exploration Costs	(260)	(904)
Gain (loss) on disposal or abandonment of assets, net	(1,629)	(398)
Interest expense	(11,033)	(11,869)
Loss on Extinguishment of Debt	—	(1,491)
Settlement of Litigation	(2,750)	—
Income (Loss) before Income Taxes	$ (274,120)	$ 50,241

	Year Ended December 31, 2024	2023
	(per ton)	
Tons Sold	3,864	6,922
Coal Sales	$ 52.41	$ 62.54
Fuel	$ 0.74	$ 1.02
Other Operating and Maintenance Costs	23.11	23.91
Utilities	3.58	2.50
Labor	22.08	17.51
General and Administrative	2.56	1.49
EBITDA Margin	0.34	16.11
Other Operating Revenue		
Depreciation, Depletion and Amortization	(11.97)	(6.99)
Asset Impairment	(55.68)	—
Asset Retirement Obligations Accretion	(0.30)	(0.18)
Exploration Costs	(0.07)	(0.13)
Gain (loss) on disposal or abandonment of assets, net	(0.42)	(0.06)
Interest expense	(2.86)	(1.71)
Loss on Extinguishment of Debt	—	(0.22)
Settlement of Litigation	(0.71)	—
Income (Loss) before Income Taxes	$ (71.67)	$ 6.82

During 2024, we undertook an Organizational Restructuring of our Coal Operations. See "*Note 17 – Organizational Restructuring*" in the Consolidated Financial Statements for further information.

Segment operating revenues from coal operations decreased $230.4 million, or 53.2%, from 2023. Consolidated operating revenues from coal operations decreased $224.5 million, or 62.0%, from 2023. These declines were due to reductions in volume and average sales price for our coal. Our average sales price, on a segment basis, decreased $10.13 per ton and we sold 3.1 million tons less compared to 2023. Our average sales price, on a consolidated basis, for 2024 decreased $7.58 per ton and we sold 3.3 million tons less compared to 2023.

Other operating and maintenance costs decreased $76.2 million, or 46.0%. Labor decreased $35.9 million, or 29.6%, from 2023, however labor cost per ton sold increased $4.57 per ton sold. These changes were driven by the Reorganization Plan disclosed in *"Note 17 — Organizational Restructuring"* to the Consolidated Financial Statements. As part of the Organizational Restructuring, we incurred aggregate expenses of $1.9 million ($1.1 million in the first quarter of 2024 and $0.8 million in the second quarter of 2024) that were included in coal operations *"Labor"*. These charges related to compensation, tax, professional, and insurance related expenses and are considered one-time charges paid during 2024. During 2024, we produced 2.7 million tons less on a segment basis than 2023. Additionally, we went from 5 mines producing to 1 mine producing and reduced our coal employee headcount by 305 employees.

We recorded an asset impairment of $215.1 million during 2024. During the fourth quarter of 2024, we began our annual business plan review. We evaluated core hole samples at several of our mines, reviewing the quality of the mine seam and density of the coal. Based upon market price trends, we believe that the required course of action is to only produce those reserves that will allow us the lowest possible cost, and therefore capture the highest possible margins. The core hole samples at our Oaktown 2 mine were of a lower quality and density than that of the Oaktown 1 mine. As such, at the conclusion our annual business plan review during the fourth quarter of 2024, we decided to temporarily seal the Oaktown 2 mine, and to focus coal production at the Oaktown 1 mine, which has lower recovery costs. Due to that decision, we determined a triggering event had occurred and completed an impairment review to determine if the carrying value of our coal properties were impaired by comparing the net book value of our coal properties to estimated undiscounted future net cash flows. The result of this undiscounted cash flow test indicated the carrying amount of our coal properties may not be recoverable. As a result, the Company prepared a discounted cash flow model (Level 3 fair value measurement under the fair value hierarchy) to estimate fair value.

Income (loss) before income taxes decreased $324.4 million, or 645.6%, and decreased $78.49 per ton, from 2023. The main drivers of this change in income from operations are described in the discussion above.

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, 2024, 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. In the fourth quarter of 2024, the Company made certain reclassifications that reduced "other operating and maintenance costs" and increased "depreciation, depletion and amortization" for certain assets with a useful life of one to three years. The entire adjustment is reflected in the fourth quarter of 2024. Previous interim periods and prior year periods were not adjusted as the amounts were not material. The amounts recognized in the fourth quarter of 2024 that are related to the first, second and third quarters of 2024 were $2.1 million, $2.6 million and $1.7 million, respectively.

	Mar-31 2024	Jun-30 2024	Sep-30 2024	Dec-31 2024	Total 2024
	(in thousands, except per share information)				
SALES AND OPERATING REVENUES:					
Electric sales	$ 60,681	$ 59,465	$ 71,715	$ 69,666	$ 261,527
Coal sales	49,630	32,801	31,662	23,355	137,448
Other revenues	1,263	1,045	1,377	1,734	5,419
Total revenue	111,574	93,311	104,754	94,755	404,394
EXPENSES:					
Fuel	8,059	10,439	13,176	17,669	49,343
Other operating and maintenance costs	37,482	35,912	33,320	11,650	118,364
Cost of purchased power	1,926	2,619	3,149	3,194	10,888
Utilities	4,374	3,396	3,185	4,959	15,914
Labor	35,168	26,555	26,721	27,720	116,164
Depreciation, depletion and amortization	15,443	13,649	13,838	22,696	65,626
Asset retirement obligations accretion	399	399	410	420	1,628
Exploration costs	70	47	62	81	260
General and administrative	5,944	7,803	6,471	6,309	26,527
Asset impairment	—	—	—	215,136	215,136
(Gain) loss on disposal or abandonment of assets, net	(24)	(222)	(290)	486	(50)
Settlement of litigation	—	—	—	2,750	2,750
Total operating expenses	108,841	100,597	100,042	313,070	622,550
INCOME (LOSS) FROM OPERATIONS	2,733	(7,286)	4,712	(218,315)	(218,156)
Interest expense (1)	(3,937)	(3,735)	(2,692)	(3,486)	(13,850)
Loss on extinguishment of debt	(853)	(1,937)	—	—	(2,790)
Equity method investment income (loss)	(249)	(257)	(234)	(6)	(746)
INCOME (LOSS) BEFORE INCOME TAXES	(2,306)	(13,215)	1,786	(221,807)	(235,542)
INCOME TAX EXPENSE (BENEFIT):					
Current	—	—	—	(169)	(169)
Deferred	(610)	(3,011)	232	(5,846)	(9,235)
Total income tax expense (benefit)	(610)	(3,011)	232	(6,015)	(9,404)
NET INCOME (LOSS)	$ (1,696)	$ (10,204)	$ 1,554	$ (215,792)	$ (226,138)
NET INCOME (LOSS) PER SHARE:					
Basic	$ (0.05)	$ (0.27)	$ 0.04	$ (5.06)	$ (5.72)
Diluted	$ (0.05)	$ (0.27)	$ 0.04	$ (5.06)	$ (5.72)
WEIGHTED AVERAGE SHARES OUTSTANDING:					
Basic	34,816	37,879	42,598	42,617	39,504
Diluted	34,816	37,879	43,018	42,617	39,504

	Mar-31 2023	Jun-30 2023	Sep-30 2023	Dec-31 2023	Total 2023
	(in thousands, except per share information)				
SALES AND OPERATING REVENUES:					
Electric sales	$ 92,392	$ 71,017	$ 67,403	$ 37,115	$ 267,927
Coal sales	94,602	88,574	97,420	81,330	361,926
Other revenues	1,361	1,640	965	1,059	5,025
Total revenue	188,355	161,231	165,788	119,504	634,878
EXPENSES:					
Fuel	55,973	32,641	11,345	3,429	103,388
Other operating and maintenance costs	32,520	41,908	65,551	59,876	199,855
Cost of purchased power	—	—	—	—	—
Utilities	4,497	4,343	4,507	4,383	17,730
Labor	40,531	36,528	37,639	37,719	152,417
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
(Gain) loss on disposal or abandonment of assets, net	21	37	20	320	398
Total operating expenses	159,122	138,987	141,985	129,772	569,866
INCOME (LOSS) FROM OPERATIONS	29,233	22,244	23,803	(10,268)	65,012
Interest expense (1)	(3,899)	(3,541)	(3,030)	(3,241)	(13,711)
Loss on extinguishment of debt	—	—	(1,491)	—	(1,491)
Equity method investment income (loss)	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

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 2024**	**2nd 2024**	**3rd 2024**	**4th 2024**	**T4Qs**
Tons produced	1,271	889	873	971	4,004
Tons sold	1,214	849	926	875	3,864
Wash plant recovery in %	60 %	59 %	60 %	62 %	
Capex (Coal Operations)	$ 8,632	$ 7,560	$ 6,810	$ 11,079	$ 34,081
Maintenance capex (Coal Operations)	$ 8,085	$ 6,014	$ 4,208	$ 4,492	$ 22,799
Maintenance capex per ton sold (Coal Operations)	$ 6.66	$ 7.08	$ 4.54	$ 5.13	$ 5.90
Average cost per ton sold(i)	$ 51.65	$ 49.94	$ 52.22	$ 43.25	$ 49.51

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
Wash plant recovery in %	70 %	67 %	65 %	62 %	
Capex (Coal Operations)	$ 12,639	$ 14,445	$ 11,570	$ 17,867	$ 56,521
Maintenance capex (Coal Operations)	$ 7,778	$ 9,754	$ 7,938	$ 13,567	$ 39,037
Maintenance capex per ton sold (Coal Operations)	$ 4.59	$ 5.69	$ 3.86	$ 9.29	$ 5.64
Average cost per ton sold(i)	$ 38.81	$ 41.52	$ 46.54	$ 53.78	$ 44.94

i) Average cost per ton sold is calculated as the sum of the Coal Operation's "Fuel", "Other Operating and Maintenance Costs", "Utilities" and "Labor" costs as adjusted for the fourth quarter 2024 reclassification adjustments previously described, divided by tons sold for the respective period in this table. Coal Operations costs are presented in the "Presentation of Segment Information" above.

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). 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. As of December 31, 2024, and December 31, 2023, coal inventory includes NRV adjustments of $0.3 million and $2.0 million, respectively.

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. This cash flow analysis is largely dependent upon the operating plans of the Company, which are reviewed by the Company and its Board of Directors no less than annually, normally during the 4th quarter of each year. Changes in anticipated activity levels, pricing or operating expenses can have significant effects on the ultimate value of the undiscounted cash flow analysis.

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, 2024 and 2023, the related consolidated statements of operations, cash flows and stockholders' equity for each of the two years in the period ended December 31, 2024, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2024, 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, 2024, 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 17, 2025 expressed an unqualified opinion.

Change in accounting principle

As discussed in Notes 1 and 20 to the consolidated financial statements, the Company has adopted new accounting guidance in 2024 related to the disclosure of segment information in accordance with ASU 2023-07, *Segment Reporting (Topic 280)*. The adoption was retrospectively applied to 2023.

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 matters

The critical audit matters communicated below are matters 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) relate 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 matters below, providing a separate opinion on the critical audit matters or on the accounts or disclosures to which they relate.

Asset retirement obligations

As of December 31, 2024, the Company's asset retirement obligations totaled $16.9 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 judgment 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 uncertain future 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 judgments.

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 judgments 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.

Impairment of coal properties

As described further in Notes 1 and 19 to the consolidated financial statements, long-lived assets are evaluated for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. When performing the impairment assessments, the Company projects undiscounted cash flows at the asset group level. If the asset group is determined not to be recoverable, the Company, with the assistance of third-party valuation specialists, performs an analysis of the fair value of the asset group and recognizes an impairment loss when the fair value of the asset group is less than the carrying value. As of December 31, 2024, the Company recorded asset impairment charges of $215.1 million associated with its coal properties. The identification of impairment indicators and the calculation of the amount of impairment requires significant management judgment. We identified the long-lived asset impairment assessment of coal properties as a critical audit matter.

The principal consideration for our determination that the long-lived asset impairment assessment of coal properties is a critical audit matter is due to the uncertainties and significant management judgment when estimating the fair value of the coal properties. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to management's forecasted future revenues and cash flows and evaluation of the reasonableness of the valuation model used. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing these procedures and evaluating the audit evidence obtained.

Our audit procedures related to the long-lived asset impairment assessment of coal properties included the following, among others:

- We tested the design and operating effectiveness of internal controls over the identification of impairment indicators, estimation of fair value, and recognition processes.
- With the assistance of professionals with specialized skill and knowledge, we tested management's process for calculating the asset impairment of coal properties, including evaluating the reasonableness of the valuation methodology and certain significant assumptions used in the calculations including the discount rate applied to the estimated future cash flows.
- We evaluated the qualifications of the third-party specialist engaged by the Company based on their credentials and experience.

- We evaluated the reasonableness of significant judgments including forecasted revenue and operating expenses. We tested whether these forecasts were reasonable and consistent with historical performance and industry projections and conditions found in industry reports, as applicable.

/s/ GRANT THORNTON LLP

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

Tulsa, Oklahoma
March 17, 2025

PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

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

	2024	2023
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,232	$ 2,842
Restricted cash	4,921	4,281
Accounts receivable	15,438	19,937
Inventory	36,685	23,075
Parts and supplies	39,104	38,877
Prepaid expenses	1,478	2,262
Assets held-for-sale	—	1,540
Total current assets	104,858	92,814
Property, plant and equipment:		
Land and mineral rights	70,307	115,486
Buildings and equipment	429,857	537,131
Mine development	92,458	158,642
Finance lease right-of-use assets	13,034	12,346
Total property, plant and equipment	605,656	823,605
Less - accumulated depreciation, depletion and amortization	(347,952)	(334,971)
Total property, plant and equipment, net	257,704	488,634
Equity method investments	2,607	2,811
Other assets	3,951	5,521
Total assets	$ 369,120	$ 589,780
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of bank debt, net	$ 4,095	$ 24,438
Accounts payable and accrued liabilities	44,298	62,908
Current portion of lease financing	6,912	3,933
Contract liabilities - current	97,598	66,316
Total current liabilities	152,903	157,595
Long-term liabilities:		
Bank debt, net	37,394	63,453
Convertible notes payable	—	10,000
Convertible notes payable - related party	—	9,000
Long-term lease financing	8,749	8,157
Deferred income taxes	—	9,235
Asset retirement obligations	14,957	14,538
Contract liabilities - long-term	49,121	47,425
Other	1,711	1,789
Total long-term liabilities	111,932	163,597
Total liabilities	264,835	321,192
Commitments and contingencies (Note 22)		
Stockholders' equity:		
Preferred stock, $.10 par value, 10,000 shares authorized; none issued	—	—
Common stock, $.01 par value, 100,000 shares authorized; 42,621 and 34,052 issued and outstanding, as of December 31, 2024 and December 31, 2023, respectively	426	341
Additional paid-in capital	189,298	127,548
Retained earnings (deficit)	(85,439)	140,699
Total stockholders' equity	104,285	268,588
Total liabilities and stockholders' equity	$ 369,120	$ 589,780

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)

	2024	2023
SALES AND OPERATING REVENUES:		
Electric sales	$ 261,527	$ 267,927
Coal sales	137,448	361,926
Other revenues	5,419	5,025
Total sales and operating revenues	404,394	634,878
EXPENSES:		
Fuel	49,343	103,388
Other operating and maintenance costs	118,364	199,855
Cost of purchased power	10,888	—
Utilities	15,914	17,730
Labor	116,164	152,417
Depreciation, depletion and amortization	65,626	67,211
Asset retirement obligations accretion	1,628	1,804
Exploration costs	260	904
General and administrative	26,527	26,159
Asset impairment	215,136	—
(Gain) loss on disposal or abandonment of assets, net	(50)	398
Settlement of litigation	2,750	—
Total operating expenses	622,550	569,866
INCOME (LOSS) FROM OPERATIONS	(218,156)	65,012
Interest expense (1)	(13,850)	(13,711)
Loss on extinguishment of debt	(2,790)	(1,491)
Equity method investment (loss)	(746)	(552)
NET INCOME (LOSS) BEFORE INCOME TAXES	(235,542)	49,258
INCOME TAX EXPENSE (BENEFIT):		
Current	(169)	(164)
Deferred	(9,235)	4,629
Total income tax expense (benefit)	(9,404)	4,465
NET INCOME (LOSS)	$ (226,138)	$ 44,793
NET INCOME (LOSS) PER SHARE:		
Basic	$ (5.72)	$ 1.35
Diluted	$ (5.72)	$ 1.25
WEIGHTED AVERAGE SHARES OUTSTANDING		
Basic	39,504	33,133
Diluted	39,504	36,827
(1) Interest Expense:		
Interest on bank debt	$ 9,286	$ 8,636
Other interest	2,817	1,842
Amortization:		
Amortization of debt issuance costs	1,747	3,233
Total amortization	1,747	3,233
Total interest expense	$ 13,850	$ 13,711

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)

	2024	2023
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (226,138)	$ 44,793
Adjustments to reconcile net income to net cash provided by operating activities:		
Deferred income tax (benefit)	(9,235)	4,629
Equity method investment (loss)	746	552
Cash distribution - equity method investment	—	625
Depreciation, depletion and amortization	65,626	67,211
Asset impairment	215,136	—
Loss on extinguishment of debt	2,790	1,491
(Gain) loss on disposal or abandonment of assets, net	(50)	398
Amortization of debt issuance costs	1,747	3,233
Asset retirement obligations accretion	1,628	1,804
Cash paid on asset retirement obligation reclamation	(1,407)	(3,384)
Stock-based compensation	4,454	3,554
Amortization of contract asset and contract liabilities	(70,203)	(97,018)
Director fees paid in stock	150	—
Change in current assets and liabilities:		
Accounts receivable	4,499	9,952
Inventory	(13,610)	15,548
Parts and supplies	(227)	(10,582)
Prepaid expenses	784	1,186
Accounts payable and accrued liabilities	(14,580)	(18,992)
Contract liabilities	103,181	33,804
Other	643	610
Net cash provided by operating activities	$ 65,934	$ 59,414

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

	2024	2023
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	$ (53,367)	$ (75,352)
Proceeds from sale of equipment	4,239	62
Proceeds from held-for-sale assets	3,200	—
Investment in equity method investments	(542)	—
Net cash used in investing activities	(46,470)	(75,290)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payments on bank debt	(147,000)	(59,713)
Borrowings of bank debt	99,500	66,000
Payments on lease financing	(5,633)	—
Proceeds from sale and leaseback arrangement	5,134	11,082
Issuance of related party notes payable	5,000	—
Payments on related party notes payable	(5,000)	—
Debt issuance costs	(673)	(6,013)
ATM offering	34,515	7,318
Taxes paid on vesting of RSUs	(277)	(2,101)
Net cash provided by (used in) financing activities	(14,434)	16,573
Increase in cash, cash equivalents, and restricted cash	5,030	697
Cash, cash equivalents, and restricted cash, beginning of year	7,123	6,426
Cash, cash equivalents, and restricted cash, end of year	$ 12,153	$ 7,123
CASH, CASH EQUIVALENTS, AND RESTRICTED CASH:		
Cash and cash equivalents	$ 7,232	$ 2,842
Restricted cash	4,921	4,281
	$ 12,153	$ 7,123
SUPPLEMENTAL CASH FLOW INFORMATION:		
Cash paid for interest	$ 10,511	$ 9,966
SUPPLEMENTAL NON-CASH FLOW INFORMATION:		
Change in capital expenditures included in accounts payable and prepaid expense	$ 356	$ 1,882

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 Shares	Common Stock Issued Amount	Additional Paid-in Capital	Retained Earnings (Deficit)	Total Stockholders' Equity
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
Stock-based compensation	—	—	4,454	—	4,454
Stock issued on vesting of RSUs	380	4	(4)	—	—
Taxes paid on vesting of RSUs	(159)	(2)	(275)	—	(277)
Stock issued on redemption of convertible notes	3,672	36	22,957	—	22,993
Stock issued in ATM offering	4,655	47	34,468	—	34,515
Stock issued for director fees	21	—	150	—	150
Net loss	—	—	—	(226,138)	(226,138)
BALANCE, DECEMBER 31, 2024	42,621	$ 426	$ 189,298	$ (85,439)	$ 104,285

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

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

Segment Information

Our business is organized based on the services and products we provide in two segments: (i) Electric Operations and (ii) Coal Operations. The Chief Operating Decision Maker ("CODM"), who is the Company's Chief Executive Officer, reviews and assesses operating performance measures related to our Electric Operations and our Coal Operations segments.

In addition to these reportable segments, the Company has a "Corporate and Other and Eliminations" category, which is not significant enough, on a stand-alone basis, to be considered an operating segment. Corporate and Other and Eliminations primarily consist 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 and Oaktown Gas, LLC, which we account for using the equity method.

During the fourth quarter of 2024, we sold our held-for-sale wholly-owned subsidiary Summit Terminal LLC, a logistics transport facility located on the Ohio River. For further information, see "*Note 21 – Assets Held For Sale*" below.

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

The Coal Operations reportable segment includes our currently operating underground mining complex Oaktown 1 among other mining complexes and locations which operated throughout the year ended December 31, 2023 and were subsequently idled during the year ended December 31, 2024.

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.

In the fourth quarter of 2024, the Company made certain reclassifications that reduced "other operating and maintenance costs" and increased "depreciation, depletion and amortization" on the Consolidated Statements of Operations for certain assets with a useful life of one to three years. The entire adjustment is reflected in the fourth quarter of 2024. Previous interim periods and prior year were not adjusted as the amounts were not material. The amounts recognized in the fourth quarter of 2024 that are related to the first, second and third quarters of 2024 were $2.1 million, $2.6 million and $1.7 million, respectively.

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.

Restricted Cash

Restricted cash represents cash held by third parties primarily for future workers' compensation claims and MISO escrow payments. Workers' compensation is based estimated claim liabilities and MISO escrow payments are based on power purchased or sold related to power demand and our power purchase agreements ("PPA").

Accounts Receivable

The timing of revenue recognition, billings and cash collections results in accounts receivable from customers. Customers are invoiced as power is delivered or as coal is shipped or at periodic intervals in accordance with contractual terms. Coal 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, 2024 or 2023.

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, 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 our 2022 acquisition of Merom. 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, $19.6 million was amortized, of which $30.7 million 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.

Plant Equipment and Mining Properties

The values of our Hallador Power property, plant and equipment were initially recorded at relative fair value based on the consideration paid upon closing of the acquisition of Merom in 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 over the remaining estimated useful life of the Merom at the time of equipment acquisition, or seven to nine years.

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 fifteen years.

The Company reviews long-lived assets for impairment whenever events or changes in circumstances, known as triggering events, indicate that the carrying amount of a long-lived asset or asset group, may not be recoverable. Management considers various factors when determining if long-lived assets should be evaluated for impairment, including a significant adverse change in the business climate or industry conditions (such as sustained decreases in commodity prices, volatility in energy costs, and the global economy), a current period operating or cash flow loss combined with a history of losses, a significant adverse change in the extent or manner in which an asset is used, or a current expectation that the asset will be sold or otherwise disposed of before the end of its useful life.

During the fourth quarter of 2024, the Company completed a review of its coal mining facilities and future mining plans. The impairment analysis was based upon our coal mining operating plans, market driven pricing and cost trends. As part of that analysis, the Company determined the carrying amount of its coal mining long-lived asset group was not recoverable and recorded a non-cash, long-lived asset impairment charge of $215.1 million in 2024. See "*Note 19 – Impairment of Coal Properties*" below related to our 2024 impairment. There were no long-lived asset impairments during the year ended December 31, 2023.

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.

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 the Company commences 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. The Company reflects 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. The Company uses the 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.

The Company reviews its ARO at least annually and reflects 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 Merom. There was no change in estimate for the year ended December 31, 2024. In the event the Company is not able to perform reclamation, it has surety bonds at December 31, 2024 totaling $30.8 million to cover ARO. The undiscounted asset retirement obligation was $26.1 million and $26.6 million at December 31, 2024 and 2023, respectively.

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

	Year Ended December 31, 2024	Year Ended December 31, 2023
Balance, beginning of year	$ 16,688	$ 20,834
Accretion	1,628	1,804
Change in estimate	—	(2,566)
Payments	(1,407)	(3,384)
Balance, end of year	16,909	16,688
Less current portion	(1,952)	(2,150)
Long-term balance, end of year	$ 14,957	$ 14,538

Contract Liabilities

Contract Liabilities include the PPA 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 for the acquisition of Merom in 2022. The agreement was amended August 31, 2023 to extend through 2028. The amendment included additional obligations to Hoosier of $186.6 million, or $56.00 per MWh, as of December 31, 2024. 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, 2024 and 2023, amortization of the power purchase agreement contract liability totaled $47.1 million and $70.5 million, respectively. The Power Purchase Agreement term is from October 21, 2022 to May 31, 2028. The Capacity Payment Reductions occurred on May 31, 2023 and November 30, 2023 in the amount of $7.5 million each. The contract liability relating to this contract totaled $43.5 million as of December 31, 2024.

We also have contract liabilities arising from PPA's for capacity and physically delivered power entered into whereas the customers made advance payments to Hallador Power. These contracts that have delivery periods through the Spring shoulder season ending May 31, 2025. The liability will be amortized to electric sales revenue over the remaining term of the agreement as the contract is fulfilled. The contract liability relating to these contracts totaled $42.0 million as of December 31, 2024.

During the year ended December 31, 2024, the Company entered into a $60.0 million prepaid physically delivered power contract. The power purchase agreement term is from June 1, 2025 through December 31, 2026. The power purchase agreement liability will be amortized to electric sales revenue pro-rata over the term of the agreement as the contract is fulfilled. The contract liability, including $1.2 million of implied interest relating to this contract totaled $61.2 million as of December 31, 2024.

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. See *"Note 22 – Contingencies"* related to our decision to settle certain litigation in February of 2025.

Fuel Costs

Fuel costs in our Electric Operations include coal purchased from Sunrise Coal and third parties to operate Merom. Fuel costs in our Coal Operations include mainly diesel, as well as natural gas and petroleum to operate our coal mines. These fuel costs are expensed as the fuel is used. The difference between Sunrise Coal's cost to produce coal and the contracted sales price to Hallador Power is eliminated from fuel costs on the Consolidated Statements of Operations.

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) SMCRA and other state statutes, (iv) depreciation, depletion, and amortization, (v) the lower of cost or net realizable value for our inventory (vi) estimates used in our impairment analysis, and (vii) estimates used in the calculation of ARO.

Long-term Contracts

Power Operations

As of December 31, 2024, we are committed to supply the following long-term delivered energy and capacity related to Hoosier and third-party customers:

	2025	2026	2027	2028	2029
Annual plant energy generation (in MWh) (in millions)	6.0	6.0	6.0	6.0	6.0
Hoosier PPA delivered energy (in MWh) (in millions)	1.7	1.6	1.3	0.4	-
Percentage of annual plant energy generation	28%	27%	22%	7%	0%
Other customers delivered energy (in MWh) (in millions)	0.6	1.8	0.5	0.7	0.3
Percentage of annual plant energy generation	10%	30%	8%	12%	5%
Plant capacity (in MW)	775	800	800	800	800
Hoosier PPA Capacity (in MW)	97	105	110	46	-
Percentage of annual plant capacity	13%	13%	14%	6%	0%
Other customers capacity (in MW)	68	89	118	120	15
Percentage of annual plant capacity	9%	11%	15%	15%	2%

For 2024, we derived 89% of our delivered energy and 88% of our capacity sales revenue from three and four customers, respectively, each of which representing at least 10% of sales revenue. At December 31, 2024, 100% of our accounts receivable were with three customers.

For 2023, we derived 100% of our electric delivered energy generation from Hoosier and 91% of our capacity sales revenue from three customers, each representing at least 10% of capacity sales revenue. For the year ended December 31, 2023, 100% of our electric sales and accounts receivable were with two customers.

Coal Operations

As of December 31, 2024, we are committed to supplying third-party customers 8.4 million tons of coal through 2028. There are no coal contracts with price reopeners at December 31, 2024. In addition, we are committed to supplying 9.2 million tons of coal to Merom through 2028. All committed tons to Merom are priced based upon the terms of the intercompany sales transactions.

For 2024, we derived 94% of our third-party coal sales from three customers, each representing at least 10% of coal sales. At December 31, 2024, 98% of our coal operations accounts receivable was from four customers, each representing more than 10%.

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%.

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 - Adopted

The Company has adopted Accounting Standards Update ("ASU") 2023-07, Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures ("ASU 2023-07"), which is effective retrospectively for the year end December 31, 2024. ASU 2023-07 primarily enhances 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. The Company updated the "*Segment of Business*" footnote below to reflect changes for what the CODM reviews on a regular basis. The Company updated its prior year information to conform to the current year presentation. See "*Note 20 – Segments of Business*" for enhanced disclosures associated with the adoption of ASU 2023-07.

Recent Accounting Pronouncements Not Yet Adopted

In December 2023, the Financial Accounting Standards Board ("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.

In November 2024, the FASB issued ASU 2024-04, Debt - Debt With Conversion and Other Options (Subtopic 470-20): Induced Conversion of Convertible Debt Instruments. The objective of the standard is to improve the relevance and consistency in application of the induced conversion guidance in Subtopic 470-20, Debt with Conversion and Other

Options. This standard will affect entities that settle convertible debt instruments for which the conversion privileges are changed to induce conversion. The guidance will be effective for annual reporting periods beginning after December 15, 2025, and interim reporting periods within those annual reporting periods. The Company is currently evaluating the impact of the new standard on its financial statements and related disclosures.

In November 2024, the FASB issued ASU 2024-03, Income Statement Reporting-Comprehensive Income-Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses. The standard update improves the disclosures about a public business entity's expenses by requiring more detailed information about the types of expenses (including purchases of inventory, employee compensation, depreciation and amortization) included within income statement expense captions. The guidance will be effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. Early adoption is permitted. The standard will be applied on a prospective basis, with retrospective application permitted. The Company is currently evaluating the impact of adoption of the standard on its financial statement disclosures.

(2) INVENTORY

Inventory is valued at lower of cost or net realizable value ("NRV"). As of December 31, 2024 and 2023, coal inventory includes NRV adjustments of $0.3 million and $2.0 million, respectively.

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

	December 31,	
	2024	2023
Advanced coal royalties	$ 3,906	$ 5,521
Other	45	—
Total other assets	$ 3,951	$ 5,521

(4) BANK DEBT

On March 13, 2023, we executed an amendment ("March 13th Amendment") to our credit agreement with PNC Bank, National Association (in its capacity as administrative agent, "PNC"). The primary purpose of the March 13th Amendment was to convert $35.0 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 March 13th Amendment also reduced the total capacity under the revolver to $85.0 million and waived the maximum annual capital expenditure covenant for 2022 and increased the covenant for 2023 to $75.0 million. Subsequent to December 31, 2022, and prior to the effective date of the March 13th Amendment, we had borrowed an additional $17.0 million under the revolver. Additionally, the March 13th 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 ("August 2nd Amendment") to our credit agreement with PNC, which was accounted for as a debt extinguishment. The primary purpose of the August 2nd Amendment was to convert $65.0 million of the outstanding funded debt into a new term loan with a maturity of March 31, 2026, and enter into a revolver of $75.0 million with a maturity of July 31, 2026. The August 2nd Amendment increased the maximum annual capital expenditure limit to $100.0 million.

Prior to the March 13th 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 13th Amendment, bank debt was comprised of term debt ($35.0 million as of March 13, 2023) and an $85.0 million revolver ($40.2 million borrowed as of March 13, 2023). The term debt required payment of $10.0 million in June 2023 each quarter thereafter in 2023 and $5.0 million by March 31, 2024. Under the August 2nd Amendment, bank debt was comprised of term debt ($58.5 million borrowed as of December 31, 2023) and a $75.0

million revolver ($33.0 million borrowed as of December 31, 2023). The term debt requires quarterly payments of $6.5 million beginning April 2024 through March 2026.

On September 27, 2024, the Company executed the First Amendment (“First Amendment”) to the Fourth Amended and Restated Credit Agreement, dated as of August 2, 2023 (as amended, the “Credit Agreement”), with PNC which was accounted for as a debt modification. The primary purpose of the First Amendment was to provide the Company with short-term covenant relief to pursue additional liquidity. The First Amendment provides for additional flexibility for the Company to enter into prepaid forward power sale contracts, provided that the Company repays outstanding term loans under the Credit Agreement (“Term Loan”) with proceeds received from certain eligible power purchase agreements, up to a maximum of $20.0 million. These required prepaid forward power sale Term Loan repayments, if any, will take the place of the $6.5 million quarterly Term Loan payments. During the fourth quarter of 2024, the Company entered into a prepaid forward power sales contract in which $20.0 million of the proceeds were used to pay our required $6.5 million quarterly loan payments through the third quarter of 2025 and also reduced our fourth quarter 2025 payment to $6.0 million. Furthermore, the First Amendment defines certain administrative changes which include, among other things, added requirements related to reporting, third party financial advisors, and appraisals on coal and power assets.

Bank debt was reduced by $47.5 million and increased by $6.3 million during the years ended December 31, 2024 and 2023, 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, 2024, we had additional borrowing capacity of $30.6 million under the revolver and total liquidity of $37.8 million. Our additional borrowing capacity is net of $19.4 million in outstanding letters of credit as of December 31, 2024 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 our initial facility totaled $4.3 million. Additional costs incurred with the First Amendment totaled $0.6 million. These unamortized bank fees were deferred and are being amortized over the term of the loan.

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 2nd 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 bank fees as of December 31, 2024 and 2023, were $2.5 million and $3.6 million, respectively.

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

	December 31, 2024	December 31, 2023
Current bank debt	$ 6,000	$ 26,000
Less unamortized debt issuance cost	(1,905)	(1,562)
Net current portion	$ 4,095	$ 24,438
Long-term bank debt	$ 38,000	$ 65,500
Less unamortized debt issuance cost	(606)	(2,047)
Net long-term portion	$ 37,394	$ 63,453
Total bank debt	$ 44,000	$ 91,500
Less total unamortized debt issuance cost	(2,511)	(3,609)
Net bank debt	$ 41,489	$ 87,891

Covenants

The First Amendment, among other things, provided the Company with short-term covenant relief to pursue additional liquidity. The First Amendment waived the Company's Leverage Ratio requirement for the third and fourth quarters of 2024, increased the threshold to 5.50 to 1.00 for the first quarter of 2025, and decreased the threshold back to 2.25 to 1.00 for each fiscal quarter thereafter. Additionally, the Debt Service Coverage Ratio requirement (1.25 to 1.00) was waived from third quarter of 2024 through the first quarter of 2025. The First Amendment also added additional financial covenants which include: (i) a maximum First Lien Leverage Ratio for the first quarter of 2025, calculated as of the end of each fiscal quarter for the trailing twelve months, not to exceed 3.50 to 1.00; (ii) a minimum liquidity requirement of $10.0 million, beginning on the First Amendment execution date and ending when the second quarter of 2025 compliance certificate is received; and (iii) a minimum quarterly EBITDA requirement, as defined in the First Amendment, of $5.0 million for the third quarter of 2024 through the first quarter of 2025.

As of December 31, 2024, our liquidity of $37.8 million and quarterly EBITDA of $6.2 million were 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, 2024, we were paying SOFR plus 5.00% on the outstanding bank debt which equates to an all-in rate of 9.48%.

Future Maturities (in thousands):	
2025	$ 6,000
2026	38,000
2027	—
Total	$ 44,000

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

	December 31,	
	2024	2023
Accounts payable	$ 24,291	$ 43,636
Accrued property taxes	4,185	2,987
Accrued payroll	3,258	6,575
Workers' compensation reserve	4,321	3,629
Group health insurance	1,700	2,300
Asset retirement obligation - current portion	1,952	2,150
Other	4,591	1,631
Total accounts payable and accrued liabilities	$ 44,298	$ 62,908

(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.

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.

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.

Disaggregation of Revenue

Revenue is disaggregated by revenue source for our electric operations and primary geographic markets for our coal 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.

Electric operations

	December 31,	
	2024	2023
Delivered energy (including contract liability amortization)	$ 203,434	$ 211,772
Capacity	58,093	56,155
Total Electric Operations sales	$ 261,527	$ 267,927

Coal operations

	December 31,	
	2024	2023
Outside third-party Indiana customers	$ 59,045	$ 144,942
Customers in Florida, North Carolina, Alabama and Georgia	78,403	216,984
Total Coal Operations sales	$ 137,448	$ 361,926

Performance Obligations

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 our Asset Purchase Agreement ("Hoosier APA") with Hoosier in which Hallador Power shall sell, and Hoosier shall buy, delivered energy quantities through 2025 at the contract price, which is $34.00 per MWh. We have remaining delivered energy obligations to Hoosier totaling $59.0 million through 2025 as of December 31, 2024. The agreement was amended August 31, 2023 to extend through 2028. The amendment included additional obligations to Hoosier of $186.6 million, or $56.00 per MWh, as of December 31, 2024.

In addition to delivered energy, under the Hoosier APA, Hallador Power shall provide a stand-ready obligation to provide electricity to MISO, also known as contract capacity. The contract capacity that Hallador Power shall provide to Hoosier is 917 megawatts ("MW") for contract year one, and on average 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 $18.6 million as of December 31, 2024. The agreement was amended August 31, 2023, to extend through 2028, with additional capacity obligation to Hoosier of $59.5 million as of December 31, 2024, at a price of $7.02 per kilowatt month for the contract capacity.

During the second quarter of 2024, the Company entered into an 11-month, $45.0 million prepaid physically delivered power contract in which Hallador will provide a total of 1,302,480 MWh. Since the period between customer payment and the transfer of promised services is less than one year, we have elected the practical expedient which allows us to not assess whether a customer contract has a significant financing component.

During the fourth quarter of 2024, we entered into a 19-month, $60.0 million prepaid physically delivered power contract in which Hallador will provide a total of 1,918,200 MWh. As the total amount paid up-front by the customer differs from the stand-alone selling price of the transferred power, the Company concluded the contract contains a significant financing component. The contract liability associated with the $60.0 million prepayment will be accreted over the agreement term based upon the Company's incremental borrowing rate which approximates 10.3%, and the accretion will be separately recognized as interest expense.

The Company also has additional PPA's with customers for capacity whereas the customers made advance payments to Hallador Power in the amounts of $35.4 million and $35.3 million during the years ended December 31, 2024 and 2023, respectively. The delivery periods related to these prepayments are June 1 through May 31. The liability will be amortized to electric sales revenue as the contract is fulfilled.

Additionally, during the fourth quarter of 2024, we entered into three contracts in the amount of $52.1 million to provide a total of 1,389,600 MWh from December 2024 through December 2025. We have energy and capacity obligations to customers, excluding the Hoosier APA, through 2029 totaling $230.8 million and $131.3 million, respectively, as of December 31, 2024.

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 $460.4 million, which represent the average fixed prices on our committed contracts as of December 31, 2024. We expect to recognize approximately 32.7% of this coal sales revenue in 2025, with the remainder recognized through 2028.

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.

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.

	December 31,		
	2024	2023	2022
Accounts receivable from contracts with customers	$ 15,438	$ 19,937	$ 29,889
Contract assets	—	—	19,567
Contract liabilities - current	97,598	66,316	123,599
Contract liabilities - long-term	49,121	47,425	84,096
Total contract liabilities	146,719	113,741	207,695

We received payments related to advanced capacity and advanced physically delivered energy of $160.0 million and $41.2 million for the years ending December 31, 2024 and 2023, respectively. Of the amount of contract liabilities that we recorded as of the beginning of the period, we recognized $70.2 million and $123.6 million of electric revenue related to these advance contract liability payments for the years ended December 31, 2024 and 2023, respectively. 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 31st are below (in thousands):

	2024	2023
Expected amount	$ (49,464)	$ 10,344
State income taxes, net of federal benefit	(9,059)	1,246
Percentage depletion	—	(3,348)
Change in valuation allowance	49,695	(3,681)
Stock-based compensation	121	(844)
Return to provision adjustments	(722)	159
Nondeductible items	175	—
Other	(150)	589
Total income tax expense	$ (9,404)	$ 4,465

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

	2024	2023
Deferred tax assets:		
Net operating loss	$ 32,725	$ 20,029
Power contracts	10,828	23,302
Compensation	1,955	2,287
Accrued liabilities	423	570
ARO liabilities	2,293	2,798
Lease liabilities	3,938	3,044
Coal properties	26,191	—
Other	5,215	2,016
Total deferred tax assets	83,568	54,046
Valuation allowance	(49,695)	—
Deferred tax assets, net of valuation allowance	33,873	54,046
Deferred tax liabilities:		
Coal properties	—	(28,535)
Power properties	(27,960)	(31,126)
Investment partnerships	(531)	(549)
ROU assets	(5,382)	(3,071)
Total deferred tax liabilities	(33,873)	(63,281)
Net deferred tax liability	$ —	$ (9,235)

Our effective tax rate (“ETR”) for 2024 and 2023 was approximately 4% and 9% respectively. The tax rate for the years ended December 31, 2024 and 2023 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 losses over the prior three years as well as projected losses over the next year, we believe that it is not more likely than not that the benefit from certain federal and state deferred tax assets will be realized. As such, we have recorded a full valuation allowance as of December 31, 2024.

The remaining federal NOLs generated in pre-2018 years of $19.5 million can offset 100% of future years’ taxable income. The federal NOLs generated in post 2017 years of $104.9 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, which total $168.0 million, have a 20-year carryforward period and will expire in the years 2034 to 2044 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, 2024:

Total authorized RSUs in Plan approved by shareholders	4,850,000
Stock issued out of the Plan from vested grants	(3,761,430)
Non-vested grants	(1,034,486)
RSUs available for future issuance	54,084

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 as of December 31, 2023	858,363
Awarded - weighted average share price on award date was $5.69	599,013
Vested	(380,390)
Forfeited	(42,500)
Non-vested grants as of December 31, 2024	1,034,486

RSU Vesting Schedule

Vesting Year	RSUs Vesting
2025	682,068
2026	176,210
2027	176,208
	1,034,486

Shares vested in 2024 had a value of $2.0 million based on the share price of $5.33 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 $8.9 million based on the March 10, 2025 closing stock price of $8.60.

For the years ended December 31, 2024 and 2023, stock-based compensation was $4.5 million and $3.6 million, respectively.

As of December 31, 2024, unrecognized stock compensation expense to be recognized over the remaining 3-year vesting period was $2.7 million, and we had 54,084 RSUs available for future issuance. RSUs are not allocated earnings and losses as they are considered non-participating securities. Forfeitures are recognized as they occur.

Stock Options

We have no stock options outstanding.

(9) EMPLOYEE BENEFITS

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

	2024	2023
Health benefits, including premiums	$ 13,796	$ 18,483
401(k) matching	1,851	2,910
Deferred bonus plan	553	687
Total	$ 16,200	$ 22,080

Of the amounts in the above table, $15.2 million and $21.5 million are recorded in "*labor*" in the consolidated statements of operations for the years ended December 31, 2024 and 2023, respectively, with the remainder in general and administrative.

Our mine employees are also covered by workers' compensation and such costs were approximately $4.0 million and $4.9 million for 2024 and 2023, respectively, and are recorded in "*labor*" 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 operating leases for office space with remaining lease terms ranging from one month to approximately eight 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. Imputed interest on our operating leases was $0.3 million as of December 31, 2024. At December 31, 2024 and 2023, respectively, we had approximately $0.7 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 and five finance leases during 2024, 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 $5.2 million and $2.3 million for the years ended December 31, 2024 and 2023, respectively. Interest expense on our finance lease liability was $1.5 million during the year ended December 31, 2024. Imputed interest expense on our future remaining finance lease liability was $1.7 million for the year ended December 31, 2024. We had deferred financing fees of $0.2 million and $0.1 million at December 31, 2024 and 2023, respectively, 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.

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

	December 31, 2024	December 31, 2023
Operating lease information:		
Operating cash outflows from operating leases	$ 169	$ 208
Weighted average remaining lease term in years	8.0	8.5
Weighted average discount rate	9.5 %	9.5 %
Finance lease information:		
Financing cash outflows from finance leases	$ 5,633	$ —
Proceeds from sale and leaseback arrangement	5,134	11,082
Weighted average remaining lease term in years	2.18	3.00
Weighted average discount rate	9.0 %	8.5 %

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

		For the Year Ended December 31, 2024	For the Year Ended December 31, 2023
		(In thousands)	
Operating lease assets	Buildings and equipment	$ 664	$ 712
Operating lease liabilities:			
Current operating lease liabilities	Accounts payable and accrued liabilities	$ 99	$ 58
Non-current operating lease liabilities	Other long-term liabilities	565	654
Total operating lease liability		$ 664	$ 712
Finance lease assets	Finance lease right-of-use assets	$ 13,034	$ 12,346
Finance lease liabilities:			
Current finance lease liabilities	Current portion of lease financing	$ 6,912	$ 3,933
Non-current finance lease liabilities	Long-term lease financing	8,749	8,157
Total finance lease liabilities		$ 15,661	$ 12,090

Future minimum lease payments under non-cancellable leases as of December 31, 2024, were as follows:

	Operating Leases	Finance Leases
	(In thousands)	
2025	$ 108	$ 8,147
2026	121	7,972
2027	125	1,391
2028	129	—
2029	133	—
Thereafter	361	—
Total minimum lease payments	$ 977	$ 17,510
Less imputed interest and deferred finance fees	(313)	(1,849)
Total lease liability	$ 664	$ 15,661

(11) SELF INSURANCE

We self-insure non-leased underground mining equipment. Such equipment is allocated among four mining units dispersed over seven miles and seven mining units dispersed over eleven miles, at December 31, 2024 and 2023, respectively. The historical cost of such equipment was approximately $227.8 million and $262.0 million as of December 31, 2024 and 2023, respectively.

We also self-insure for workers' compensation claims under a guaranteed cost program. Under this program, we are responsible for the first $1.0 million per claim up to an aggregate of $4.0 million annually. Restricted cash of $3.4 million and $3.8 million as of December 31, 2024 and 2023, respectively, represents cash held and controlled by a third party and is restricted for future workers' compensation claim payments. The Company had $4.3 million and $3.6 million of workers' compensation reserve as of December 31, 2024 and 2023, respectively in "Accounts payable and accrued liabilities" on the Consolidated Balance Sheets.

(12) NET INCOME (LOSS) 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,	
	2024	2023
Basic earnings per common share:		
Net income (loss) - basic	$ (226,138)	$ 44,793
Weighted average shares outstanding - basic	39,504	33,133
Basic earnings (loss) per common share	$ (5.72)	$ 1.35

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

	Year Ended December 31,	
	2024	2023
Diluted earnings per common share:		
Net income (loss) - basic	$ (226,138)	$ 44,793
Add: Convertible Notes interest expense, net of tax	—	1,201
Net income (loss) - diluted	$ (226,138)	$ 45,994
Weighted average shares outstanding - basic	39,504	33,133
Add: Dilutive effects of if converted Convertible Notes	—	3,164
Add: Dilutive effects of Restricted Stock Units	—	530
Weighted average shares outstanding - diluted	39,504	36,827
Diluted net income (loss) per share	$ (5.72)	$ 1.25

(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. See asset impairment discussion below in Nonrecurring Fair Value Measurements sections below.

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 – Summary of Significant Accounting Policies*".

Nonrecurring Fair Value Measurements

During the fourth quarter of 2024, the Company completed its review of the coal mining facilities and future mining plans. The impairment analysis was based upon the coal mining operating plans of the Company, market driven pricing and cost trends. As part of that analysis, the Company determined the carrying amount of its coal mining long-lived asset group was not recoverable and recorded a non-cash, long-lived asset impairment charge of $215.1 million in 2024.

The discounted cash flow model was calculated using projected economics for the Coal Operations assets, using the Company's mining plan and reserve estimates to be mined and sold at prevailing commodity prices, operating expenses, and production cost levels, which are classified as Level 3 inputs.

(14) EQUITY METHOD INVESTMENTS

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, 2024 and 2023 was $2.1 million and $2.8 million, respectively.

The Company also owns a 50% interest in Oaktown Gas, LLC. Oaktown Gas, LLC operates an emission abatement project through the destruction of gases extracted from the Oaktown mines to generate carbon credits and other emissions offset credits. The carrying value of the investment included in the consolidated balance sheets as of December 31, 2024 was $0.5 million.

(15) CONVERTIBLE NOTES

On July 29, 2022, we issued a $5.0 million senior unsecured convertible note (the "July 29th Note") to a related party affiliated with an independent member of our board of directors. The July 29th Note carried 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 had the option to convert the July 29th Note into shares of the Company's common stock at a conversion price of $6.254. During the first quarter of 2024, the holders of the July 29th Note converted them into 799,488 shares of common stock of the Company, and in connection with such early conversion, we elected to pay interest through August 2025 with 112,570 shares of common stock on the conversion date. We recorded inducement expense which is reported in loss on extinguishment of debt in the condensed consolidated statements of operations in the amount of $0.6 million during the three months ended March 31, 2024. As of December 31, 2024, the entire July 29th Note had been converted to shares of common stock of the Company.

On August 8, 2022, we issued an additional $4.0 million of senior unsecured convertible notes (the "August 8th Notes") to related parties affiliated with independent members of our board of directors. The August 8th Notes carried 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 had the option to convert the Notes into shares of the Company's common stock at a conversion price of $6.254. Beginning August 8, 2025, we could elect to redeem the August 8th Notes and the holder was obligated to surrender them at 100% of the outstanding principal balance together with any accrued unpaid interest. Upon receipt of the redemption notice from the Company, the holder could have elected to convert the principal balance and accrued interest into the Company's common stock. During the first quarter of 2024, the holders converted $3.0 million of the August 8th Notes into 479,693 shares of common stock of the Company, and in connection with such early conversion, we elected to pay interest through August 2025 with 67,542 shares of common stock on the conversion date. During the same period, the holders also converted accrued interest into 57,564 shares of the Company's common stock.

We recorded inducement expense which is reported in loss on extinguishment of debt during the first quarter of 2024 in the condensed consolidated statements of operations in the amount of $0.3 million. During the second quarter of 2024, the holder converted the remaining $1.0 million of August 8th Notes into 159,898 shares of common stock of the Company, and in connection with such early conversion, we paid accrued interest and additional shares of common stock of 5,099 and 25,003, respectively, on the conversion date. We recorded inducement expense which is reported in loss on extinguishment of debt during the second quarter of 2024 in the condensed consolidated statements of operations in the amount of $0.2 million. As of December 31, 2024, the entire August 8th Note had been converted to shares of common stock of the Company.

On August 12, 2022, we issued an additional $10.0 million senior unsecured convertible note (the "August 12th Note") to an unrelated party. The August 12th Note carried 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 had the option to convert the August 12th Note into shares of the Company's common stock at a conversion price of $6.15. Beginning August 12, 2025, we could elect to redeem the August 12th Note and the holder would have been obligated to surrender at 100% of the outstanding principal balance together with any accrued unpaid interest. Upon receipt of the redemption notice from the Company, the holder could elect to convert the principal balance and accrued interest into the Company's common stock. During the three months ended March 31, 2024, the holder converted accrued interest into 65,041 shares of the Company's common stock. During the second quarter of 2024, the holder converted the $10.0 million August 12th Note into 1,626,016 shares of common stock of the Company, and in connection with such early conversion, we paid accrued interest and additional shares of common stock of 49,716 and 224,268, respectively, on the conversion date. We recorded inducement expense which is reported in loss on extinguishment of debt in the condensed consolidated statements of operations in the amount of $1.7 million during the second quarter of 2024. As of December 31, 2024, the entire August 12th Note had been converted to shares of common stock of the Company.

The funds received from the issuance of the various notes described above 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.

(16) NOTES PAYABLE – RELATED PARTIES

In March 2024, we issued unsecured promissory notes, having a 12-month maturity date and 12% per annum interest rate, to (i) Charles R. Wesley IV Revocable Trust (in which our director Charles R. Wesley IV has a pecuniary interest) in the principal amount of $2,000,000, (ii) Lubar Opportunities Fund I, LLC (in which are our director David J. Lubar has a pecuniary interest) in the principal amount of $2,500,000, and (iii) Hallador Alternative Investment Advisors LLC (in which our director David C. Hardie has a pecuniary interest) in the principal amount of $500,000. The related party notes were paid off in June 2024 with proceeds from the prepaid physically delivered power contract mentioned above in "*Note 6 – Revenue*".

(17) ORGANIZATIONAL RESTRUCTURING

On February 23, 2024, (the "Effective Date"), we committed to a reorganization effort in the Coal Operations Segment (the "Reorganization Plan") that included a workforce reduction of approximately 110 employees, or approximately 12% of the workforce. The reduction in workforce was communicated to employees on the Effective Date and implemented immediately, subject to certain administrative procedures. The Reorganization Plan is designed to strengthen our financial and operational efficiency and create significant operational savings and higher margins in our coal segment. This step will help to advance our transition from a company primarily focused on coal production to a more resilient and diversified integrated independent power producer ("IPP"). As part of this initiative, we substantially idled production at our higher cost surface mines, Prosperity Mine, and Freelandville Mine, with minimal ongoing production. We also focused our seven units of underground equipment on four units of our lowest cost production at our Oaktown Mine. In connection with the Reorganization Plan, we incurred aggregate expenses of $1.9 million ($1.1 million in the first quarter of 2024 and $0.8 million in the second quarter of 2024) that were included in *"Labor"* in the consolidated statements of operations. These charges related to compensation, tax, professional, and insurance related expenses and are considered one-time charges paid during 2024. The coal mining properties asset group was tested for impairment as result of the organizational restructuring passing the undiscounted recoverability test. See "*Note 19* – Impairment of Coal Properties" for additional changes to the Company's mining plans that occurred during the fourth quarter of 2024.

(18) 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 $50.0 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, we or the Agent have the right, by giving five (5) days' notice, to terminate the Sales Agreement in our and the Agents 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. During the year ended December 31, 2024, we issued 4,654,430 shares of Common Stock under the ATM Program for net proceeds of $34.5 million.

(19) IMPAIRMENT OF COAL PROPERTIES

Annually, the Company reviews its business plans for the next several years, with specific emphasis on the upcoming year. This business plan review involves updates to its mining plans that take into account many factors, such as changes in market price trends, cost trends, expected demand trends, its latest engineering studies and current year operational and financial results. During the fourth quarter of 2024, the Company began its annual business plan review. The Company evaluated core hole samples at several of its mines, reviewing the quality of the mine seam and density of the coal. Based upon market price trends, the Company believes the required course of action is to only produce those reserves that will allow it the lowest possible cost, and therefore capture the highest possible margins. The core hole samples at the Oaktown 2 mine were of a lower quality and density than that of the Oaktown 1 mine. As such, at the conclusion of the Company's annual business plan review during the fourth quarter of 2024, it decided to temporarily seal the Oaktown 2 mine, and to focus coal production at the Oaktown 1 mine, which has lower recovery costs.

As a result of the Company's decision to temporarily seal the Oaktown 2 mine, the Company determined a triggering event had occurred. The Company then completed an impairment review to determine if the carrying value of its coal properties were impaired. The Company compared the net book value of its coal properties to estimated undiscounted future net cash flows. The result of this undiscounted cash flow test indicated the carrying amount of its coal properties may not be recoverable. As a result, the Company prepared a discounted cash flow model (Level 3 fair value measurement under the fair value hierarchy) to estimate fair value. Significant inputs used to determine fair value include estimates of future cash flows from coal sales and minimum payments, an appropriate discount rate and the useful economic life. The estimated cash flows are the product of a process that began with current realized pricing as of the measurement date and included an adjustment for risk related to the realization of such future cash flows.

The discounted cash flow model used assumptions regarding the projected economics of the Coal Operations assets, given prevailing commodity prices and operating expense levels, which are classified as Level 3 inputs. Coal Operations assets include all of our coal mining properties as these properties are all within the same asset group given the near proximity to one another and their sharing of personnel and assets used to fulfill customer contracts. The Company utilized an estimated market participant discount rate of 11.5% and assumed production that is consistent with our current mining plans and reserve estimates that equate to approximately 3.6 million tons per year until all reserves are produced as part of the analysis.

The result of the discounted cash flow analysis confirmed that fourth quarter of 2024 changes to the mining plans caused the carrying amount of its coal properties to not be recoverable. As a result, the Company recorded an impairment expense during the fourth quarter of 2024 of $215.1 million. The Company did not record an impairment during the year ended December 31, 2023.

(20) SEGMENTS OF BUSINESS

Our business is organized based on the services and products we provide in two segments: (i) Electric Operations and (ii) Coal Operations. The Chief Operating Decision Maker ("CODM"), who is the Company's Chief Executive Officer, reviews and assesses operating performance measures related to our Electric Operations and our Coal Operations segments.

Our Electric Operations segment includes the electric power generation facilities of our Merom power plant, which is a two unit, 1080-megawatt rated coal fired power plant located in Sullivan County, Indiana. Our sales region is in MISO Zone 6, which includes Indiana and a portion of western Kentucky. Revenues from our Electric Operations segment consist primarily of delivered energy and capacity revenues. Fuel costs included in our Electric Operations segment include the cost of coal purchased from our Coal Operations segment, which are based on multi-year contracts which approximate market prices at the time the contracts are entered into.

Our Coal Operations segment includes the Oaktown 1 and 2 underground mining complexes, as well as other currently idled mining facilities, which produce high-quality bituminous coal from the Illinois Basin. Revenues from our Coal Operations segment consist of sales of coal to various third-parties and to Merom. Coal sales to our Electric Operations are based on multi-year contracts which approximate market prices at the time the contracts are entered into. Intercompany coal sales and amounts above actual costs to produce the coal are eliminated in the consolidated statements of operations.

In addition to these reportable segments, the Company has a "Corporate and Other and Eliminations" category, which is not significant enough, on a stand-alone basis, to be considered an operating segment. Corporate and Other and Eliminations primarily consist of unallocated corporate costs and activities, including our equity method investments.

The CODM evaluates segment performance based upon EBITDA margin for each business segment. EBITDA margin is calculated for each segment as follows:

1. For our Electric Operations segment, EBITDA margin is comprised of delivered energy revenues less certain significant segment expenses, which include (i) variable costs, (ii) other operating and maintenance costs, (iii) costs of purchased power, (iv) utilities, (v) labor and (vi) general and administrative costs. Variable operating costs are comprised of fuel costs and certain other operating costs, such as limestone and soda ash.
2. For our Coal Operations segment, EBITDA margin is comprised of coal sales less certain significant segment expenses, which include (i) fuel, (ii) other operating and maintenance costs, (iii) utilities, (iv) labor and (v) general and administrative costs.

EBITDA margin for each segment is a key measure used by our CODM and provides information about our core operating performance, significant expenses and ability to generate cash flow. Additionally, EBITDA margin provides investors with the financial analytical framework upon which our CODM bases financial, operational, compensation and planning decisions and presents a measurement that investors, rating agencies and debt holders have indicated is useful in assessing us and our results of operations. Our CODM reviews variable costs, as defined above, in our Electric Operations segment in order to evaluate the efficiency of that segments operations.

Presented below are the Electric and Coal Operations key metrics reviewed by the CODM at December 31, 2024 (in thousands):

	Electric Operations		Coal Operations
Delivered Energy	$ 203,434	Coal Sales	$ 202,525
Capacity Revenue	58,093		
Electric Sales	$ 261,527		
Fuel	$ (111,768)		
Other Operating Costs (1)	(19)		
Total Variable Costs	$ (111,787)		
Other Operating and Maintenance Costs (2)	$ (28,622)	Fuel	$ (2,851)
Cost of Purchased Power	(10,888)	Other Operating and Maintenance Costs	(89,283)
Utilities	(2,070)	Utilities	(13,844)
Labor	(30,842)	Labor	(85,322)
Power Margin Without General and Administrative	77,318	Coal Margin Without General and Administrative	11,225
General and Administrative	(5,311)	General and Administrative	(9,877)
Electric Operations — EBITDA Margin	$ 72,007	Coal Operations — EBITDA Margin	$ 1,348

(1) Other operating costs include costs for limestone, dibasic acid, ammonia, lime dust and soda ash.
(2) Other operating and maintenance costs include all other operating and maintenance costs with the exceptions of those costs considered variable as discussed above in (1).

Presented below are the Electric and Coal Operations key metrics reviewed by the CODM at December 31, 2023 (in thousands):

	Electric Operations		Coal Operations
Delivered Energy	$ 211,772	Coal Sales	$ 432,888
Capacity Revenue	56,155		
Electric Sales	$ 267,927		
Fuel	$ (139,496)		
Other Operating Costs (1)	(32)		
Total Variable Costs	$ (139,528)		
Other Operating and Maintenance Costs (2)	$ (33,777)	Fuel	$ (7,089)
Cost of Purchased Power	—	Other Operating and Maintenance Costs	(165,479)
Utilities	(429)	Utilities	(17,301)
Labor	(31,245)	Labor	(121,172)
Power Margin Without General and Administrative	62,948	Coal Margin Without General and Administrative	121,847
General and Administrative	(4,914)	General and Administrative	(10,287)
Electric Operations — EBITDA Margin	$ 58,034	Coal Operations — EBITDA Margin	$ 111,560

(1) Other operating costs include costs for limestone, dibasic acid, ammonia, lime dust and soda ash.
(2) Other operating and maintenance costs include all other operating and maintenance costs with the exceptions of those costs considered variable as discussed above in (1).

Presented below are the Electric and Coal Operations revenues reconciled to our consolidated operating revenues at December 31, 2024 (in thousands):

Reconciliation of Revenue:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Delivered Energy	$ 203,434	$ —	$ —	$ 203,434
Capacity Revenue	58,093	—	—	58,093
Other Operating Revenue	982	2,756	1,681	5,419
Coal Sales (Third-Party)	—	137,448	—	137,448
Coal Sales (Intercompany)	—	65,077	(65,077)	—
Operating Revenues	$ 262,509	$ 205,281	$ (63,396)	$ 404,394

Presented below are the Electric and Coal Operations revenues reconciled to our consolidated operating revenues at December 31, 2023 (in thousands):

Reconciliation of Revenue:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Delivered Energy	$ 211,772	$ —	$ —	$ 211,772
Capacity Revenue	56,155	—	—	56,155
Other Operating Revenue	414	2,936	1,675	5,025
Coal Sales (Third-Party)	—	361,926	—	361,926
Coal Sales (Intercompany)	—	70,962	(70,962)	—
Operating Revenues	$ 268,341	$ 435,824	$ (69,287)	$ 634,878

Presented below is our reconciliation of EBITDA Margin to the most comparable GAAP account, income (loss) before income taxes at December 31, 2024 (in thousands):

Reconciliation of Income (Loss) before Income Taxes:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Electric Operations — EBITDA Margin	$ 72,007	$ —	$ 65,276	$ 137,283
Coal Operations — EBITDA Margin	—	1,348	(65,077)	(63,729)
Other Operating Revenue	982	2,756	1,681	5,419
Depreciation, Depletion and Amortization	(19,290)	(46,245)	(91)	(65,626)
Asset Impairment	—	(215,136)	—	(215,136)
Asset Retirement Obligations Accretion	(457)	(1,171)	—	(1,628)
Exploration Costs	—	(260)	—	(260)
Gain (loss) on disposal or abandonment of assets, net	—	(1,629)	1,679	50
Interest Expense	(1,875)	(11,033)	(942)	(13,850)
Loss on Extinguishment of Debt	—	—	(2,790)	(2,790)
Equity Method Investment (Loss)	—	—	(746)	(746)
Settlement of litigation	—	(2,750)	—	(2,750)
Corporate — General and Administrative	—	—	(11,339)	(11,339)
Corporate — Other Operating and Maintenance Costs	—	—	(440)	(440)
Income (Loss) before Income Taxes	$ 51,367	$ (274,120)	$ (12,789)	$ (235,542)

Presented below is our reconciliation of EBITDA Margin to the most comparable GAAP account, income (loss) before income taxes at December 31, 2023 (in thousands):

Reconciliation of Income (Loss) before Income Taxes:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Electric Operations — EBITDA Margin	$ 58,034	$ —	$ 69,778	$ 127,812
Coal Operations — EBITDA Margin	—	111,560	(70,961)	40,599
Other Operating Revenue	414	2,936	1,675	5,025
Amortization of Contract Asset	(26,581)	—	—	(26,581)
Depreciation, Depletion and Amortization	(18,739)	(48,365)	(107)	(67,211)
Asset Retirement Obligations Accretion	(576)	(1,228)	—	(1,804)
Exploration Costs	—	(904)	—	(904)
Gain (loss) on disposal or abandonment of assets, net	—	(398)	—	(398)
Interest Expense	(322)	(11,869)	(1,520)	(13,711)
Loss on Extinguishment of Debt		(1,491)	—	(1,491)
Equity Method Investment (Loss)	—	—	(552)	(552)
Corporate — General and Administrative	—	—	(10,958)	(10,958)
Corporate — Other Operating and Maintenance Costs	—	—	(568)	(568)
Income (Loss) before Income Taxes	$ 12,230	$ 50,241	$ (13,213)	$ 49,258

Presented below are our Electric and Coal Operations assets and capital expenditures at December 31, 2024 (in thousands):

Other Reconciliations:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Assets	$ 220,477	$ 144,519	$ 4,124	$ 369,120
Capital Expenditures	$ 18,699	$ 34,081	$ 587	$ 53,367

Presented below are our Electric and Coal Operations assets and capital expenditures at December 31, 2023 (in thousands):

Other Reconciliations:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Assets	$ 208,331	$ 376,387	$ 5,062	$ 589,780
Capital Expenditures	$ 18,831	$ 56,521	$ —	$ 75,352

(21) ASSETS HELD FOR SALE

During the third quarter of 2024, the Company considered strategic alternatives with respect to its wholly-owned subsidiary Summit. Summit primarily held property, plant and equipment. On July 29, 2024, the Company entered into a ninety day right of first refusal ("ROFR") with a potential buyer of Summit for $3.2 million. As of July 29, 2024, Summit met the held-for-sale criteria, and its assets were included in "assets held-for-sale" in the current assets section of the consolidated balance sheets. The Company recorded the Summit assets, once held for sale, at the lower of their carrying value or their estimated fair value less cost to sell. The Company also did not record depreciation and amortization of $0.1 million ($0.1 million after-tax) on assets held-for-sale and continued to do so while held-for-sale criteria was met.

Fair value is the amount at which an asset, liability or business could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques or may be observable using quoted market prices. The Company used a market approach consisting of the contractual ROFR sales price, subject to prorations for property taxes and utilities, to determine the fair value, and subtracted estimated costs to sell from that calculated fair value.

The sale of Summit did not represent a strategic shift that has or will have a major effect on the Company, and as such, did not qualify for treatment as a discontinued operation.

The Company sold Summit on December 23, 2024 for $3.2 million. The Company recorded a $1.7 million gain in *"(Gain) loss on disposal or abandonment of assets, net"* in its consolidated statements of operations.

(22) CONTINGENCIES

Our Coal Operations subsidiary is party to litigation in which the plaintiffs allege violations of the Fair Labor Standards Act and state law due to alleged failure to compensate for time "donning" and "doffing" equipment and to account for certain bonuses in the calculation of overtime rates and pay. In January 2025, we agreed to settle with the plaintiffs such litigation for $2.8 million, which is recorded in "accounts payable and accrued liabilities" on our consolidated balance sheets at December 31, 2024.

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, 2024. Based on that evaluation, our management concluded that our ICFR was effective at December 31, 2024.

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, 2024, 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, 2024, 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, 2024, 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, 2024, 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, 2024, and our report dated March 17, 2025 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 17, 2025

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, 2024.

The Company has adopted a Code of Ethics for Senior Officers that applies to its chief executive officer, chief financial officer, and other financial executives. A copy of the Company's Code of Ethics for Senior Officers is filed as Exhibit 14.1 to this Annual Report on Form 10-K.

The Company's Insider Trading Policy governing, among other things, the purchase, sale, and/or other disposition of its securities by directors, officers and employees of the Company is reasonably designed to promote compliance with insider trading laws, rules and regulations, and Nasdaq listing standards. This policy is included as Exhibit 19.1 to this Annual Report on Form 10-K.

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. (4)
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)
10.1	Fourth Amended and Restated Loan Agreement dated August 2, 2023(5)
10.2	First Amendment to Fourth Amended and Restated Loan Agreement dated as of September 27, 2024 (6)
10.3	Second Amendment to Fourth Amended and Restated Loan Agreement dated as of October 23, 2024 (7)
10.4	Amended and Restated Hallador Energy Company 2008 Restricted Stock Unit Plan (8)
10.5	Form of Hallador Energy Company Restricted Stock Unit Issuance Agreement (8)
10.6	2022 Executive Officer Compensation Plan++(9)
10.7	2024 Executive Officer Compensation Plan * ++
10.8	Asset and Purchase Agreement dated February 14, 2022 (10)
14.1	Code of Ethics for Senior Executive Officers*
19.1	Insider Trading Policy *
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*
32.1	SOX 906 Certification*
95.1	Mine Safety Disclosure*
96.1	Technical Report Summary (Coal Resources and Coal Reserves, Oaktown Mining Complex), dated March 2025*
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 8-K filed December 18, 2023
(5) IBR to Form 10-Q filed on August 7, 2023
(6) IBR to Form 8-K filed on October 3, 2024
(7) IBR to Form 10-Q filed on November 11, 2024
(8) IBR to Form DEF 14A dated April 12, 2017
(9) IRB to Form 10-Q filed November 14, 2022
(10) IBR to Form 8-K/A filed March 11, 2022
(11) IBR to Form 10-K filed March 14, 2024

* 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 17, 2025	/s/MARJORIE HARGRAVE
	Marjorie Hargrave, 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 17, 2025
/s/BRYAN LAWRENCE		
Bryan Lawrence	Director	March 17, 2025
/s/BRENT BILSLAND		
Brent Bilsland	Board Chairman, President and CEO	March 17, 2025
/s/DAVID J. LUBAR		
David J. Lubar	Director	March 17, 2025
/s/ZARRELL GRAY		
Zarrell Gray	Director	March 17, 2025
/s/CHARLES WESLEY, IV		
Charles Wesley, IV	Director	March 17, 2025

Exhibit 10.7

HALLADOR ENERGY COMPANY
2024 EXECUTIVE OFFICER PLAN

Definitions

The following definitions shall apply for purposes of this Hallador Energy Company 2024 Executive Officer Plan (this "2024 EO Plan"):

"Cause" means, as determined in the Board's discretion:

(v) The Covered Person's willful and continued material failure to perform the reasonable duties and responsibilities of his or her position after the Corporation has provided the Covered Person with a written demand for performance that describes the basis for the Corporation's belief that the Covered Person has not substantially performed his or her duties and the Covered Person has not corrected the failure within thirty (30) days of the written demand;

(vi) Any act of personal dishonesty taken by the Covered Person in connection with his or her responsibilities as an employee of the Corporation or its subsidiary and intended to result in his or her substantial personal enrichment;

(vii) The Covered Person's conviction of, or plea of nolo contendere to, a felony that the Board reasonably believes has had or will have a material detrimental effect on the Corporation's reputation or business; or

(viii) The Covered Person's breach of any fiduciary duty owed to the Corporation or a subsidiary of the Corporation by the Covered Person that has a material detrimental effect on the Corporation's or such subsidiary's reputation or business.

"Change of Control" means the first to occur, following the Effective Date, of the following events:

(iii) the acquisition by any person or group of related persons (as determined pursuant to section 13(d)(3) of the Securities Exchange Act of 1934) of beneficial ownership of securities of the Corporation representing fifty percent (50%) or more of the total number of votes that may be cast for the election of Board members; or

(iv) stockholder approval of (A) any agreement for a merger or consolidation in which the Corporation will not survive as an independent corporation or other entity, or (B) any sale, exchange or other disposition of all or substantially all of the Corporation's assets, including, without limitation, the sale, exchange or other disposition of the equity securities or assets of Sunrise Coal, LLC or of Hallador Power Company, LLC.

Definitions

Definitions

Notwithstanding anything herein to the contrary, with respect to any amounts that constitute nonqualified deferred compensation under Code Section 409A and that would be payable in connection with a Change of Control, to the extent required to avoid accelerated or additional taxation under such section, no Change of Control will be deemed to have occurred unless such Change of Control also constitutes a change in the ownership or effective control of the Corporation or a change in the ownership of a substantial portion of the Corporation's assets within the meaning of Code Section 409A(a)(2)(A)(v).

"Closing" means the closing date of a transaction that results in a Change of Control, as set forth in the definitive agreement governing such transaction.

"Code" means the Internal Revenue Code of 1986, as amended.

"Covered Person" means each of the Corporation's (i) Chief Executive Officer (also currently serving as the President, Corporate Secretary and Chairman of the Board of the Corporation), (ii) the Chief Financial Officer of the Corporation, and (iii) the President of Hallador Power Company, LLC, a wholly-owned subsidiary of the Corporation.

"Effective Date" means April 1, 2024, the effective date of this 2024 EO Plan.

"Good Reason" with respect to a Covered Person, means the occurrence of one or more of the following without the Covered Person's written consent:

(iv) A fifteen percent (15%) or more reduction in the Covered Person's total annual cash compensation opportunity (base salary and target bonus opportunity collectively), as compared to the Covered Person's total annual cash compensation opportunity immediately prior to the reduction in compensation;

(v) A change in the Covered Person's principal work location resulting in a new one-way commute that is more than fifty (50) miles greater than the Covered Person's one-way commute prior to the change in the Covered Person's principal work location without allowing alternate accommodation (such as remote work), regardless of whether the Covered Person receives an offer of relocation benefits; or

(vi) (A) A material reduction in the Covered Person's authority, duties and/or responsibilities, or (B) in connection with a proposed Change of Control, a proposed material reduction in the Covered Person's authority, duties and/or responsibility by the acquiring company as compared to the Executive's authority, duties and/or responsibilities in effect immediately prior to the Closing (for example, but not by way of limitation, this determination will include an analysis of whether the Covered Person will maintain at least the same level, scope and type of duties and responsibilities with respect to the management, strategy, operations and business of the combined entity resulting from such transaction, taking the Corporation, any acquirer and their respective parent corporations, subsidiaries and other affiliates, together as a whole).

With respect to any termination for Good Reason, the Covered Person shall give the Corporation written notice, which shall identify with reasonable specificity the grounds for the Covered Person's resignation, and provide the Corporation a period of thirty (30) days from the day such notice is given to cure the alleged grounds for termination for Good Reason contained in the notice. A termination will not be for Good Reason if such notice is given by the Covered Person to the Corporation more than ninety (90) days after the occurrence of the event that the Covered Person alleges is Good Reason for her or her termination.

Any event or condition shall cease to constitute "Good Reason" if the Corporation cures the event or condition within the thirty (30) day cure period, or, if the Corporation fails to cure the event or condition within such thirty (30) day period, the Covered Person fails to terminate employment within ninety (90) days following the expiration of the thirty (30) day cure period.

"<u>Payment Date</u>" means the date on which the Corporation pays the Retention Bonus to the Covered Persons, which shall be on the date of the Closing.

"<u>Release</u>" means a general release, in the form provided by the Corporation, of any and all claims against the Corporation and all related parties with respect to all matters arising out of the Covered Person's employment by the Corporation and its affiliates and (if applicable) the termination thereof (other than claims for any entitlements under the terms of this 2024 EO Plan or for vested benefits under any employee benefit plans or programs of the Corporation made available to employees of the Corporation and its affiliates generally under which the Covered Person has accrued and is due a benefit), subject to applicable law.

"<u>RSU Plan</u>" means that certain Amended and Restated 2008 Restricted Stock Unit Plan as adopted by the Corporation in May 2017, as amended and in effect from time to time.

"<u>Section 280G</u>" means Section 280G of the Code and the final regulations and any guidance promulgated thereunder.

"<u>Section 409A</u>" means Section 409A of the Code and the final regulations and any guidance promulgated thereunder.

"Section 4999" means Section 4999 of the Code and the final regulations and any guidance promulgated thereunder.

Participation in 2024 EO Plan

Each of the Covered Persons, along with other employees of the Corporation as determined by the Compensation Committee of the Board, shall be eligible to participate in this 2024 EO Plan, provided that the Covered Person is employed by the Corporation on the date this 2024 EO Plan is adopted by the Board, and is not excluded from this 2024 EO Plan as provided below.

Retention Bonus Eligibility and Payment Date

Each Covered Person who is employed by the Corporation (or a subsidiary) upon a Change of Control and remains employed by the Corporation through the Closing, shall receive a retention bonus under this 2024 EO Plan (the "Retention Bonus") and, provided that the conditions for payment of any Retention Bonus set forth in this 2024 EO Plan are satisfied, one-hundred percent (100%) of the Retention Bonus, as specified with respect to the Covered Person in Schedule 1 attached hereto, shall be paid in a lump-sum payment on the Payment Date.

Ineligibility to Receive Retention Bonuses

If, prior to the date of the Closing of a Change of Control, a Covered Person (i) voluntarily terminates his or her employment, or (ii) is terminated for Cause, he or she will not receive a Retention Bonus, and any funds that would have been utilized for that Covered Person's Retention Bonus will revert to the Corporation and will not be reallocated to any other person, including any person that is a Covered Person under this or a similar compensation plan.

Termination Without Cause or Termination for Good Reason

In the event that, following an announcement by the Corporation of a transaction that would result in a Change of Control, or upon the occurrence of a Change of Control as described in clause (ii) of the definition of Change in Control above, but prior to the Closing relating to such Change of Control, a Covered Person's employment with the Corporation is terminated without Cause or the Covered Person terminates his or her employment with the Corporation for Good Reason, that Covered Person shall be eligible to receive the Retention Bonus that he or she would otherwise have been entitled to receive had he or she remained employed with the Corporation through the Closing; provided, however, that any Retention Bonus payable to the Covered Person shall be reduced on a dollar for dollar basis, but not below zero, by the amount paid or payable to the Covered Person upon such termination pursuant to any severance agreement between the Covered Person and the Corporation.

This 2024 EO Plan shall provide benefits to each Covered Person and his or her respective heirs, representatives, successors, and assigns, and will be binding on all successors and assigns of the Corporation and any acquirer of the Corporation.

Benefits to Covered Persons and Their Respective Heirs

Participation in this 2024 EO Plan will not provide any guarantee or promise of employment or continued service of any Covered Person or any employee of the Corporation or its subsidiaries with the Corporation or any of its subsidiaries, and the Corporation shall retain the right, and its subsidiaries shall retain the right, to terminate the employment of any Covered Person or any other employee of the Corporation or its subsidiaries, as applicable, at any time.

No Guarantee of Continued Service

Notwithstanding anything to the contrary herein, it is a condition to a Covered Person's entitlement to receive a Retention Bonus under this 2024 EO Plan that a Covered Person shall have executed and delivered to the Corporation a written Release and shall not revoke such Release, such that the Release becomes irrevocable by its terms on or before the date on which such compensation is due to be paid by the Corporation. If a Covered Person fails to execute and deliver a Release, or revokes the Release before it becomes irrevocable, the Covered Person shall have no right to receive any Retention Bonus hereunder.

Release

The Corporation will withhold from any payments under this 2024 EO Plan (including to a beneficiary or estate) any amount required to satisfy all applicable federal, state, local, or foreign income, employment, and other tax withholding obligations.

Withholding

It is intended that Retention Bonuses under this 2024 EO Plan meet the short-term deferral exception under Section 409A (accordingly, notwithstanding anything herein to the contrary, no payments to be made hereunder shall be made later than the fifteenth (15th) day of the third (3rd) month following the last day of the taxable year in which the Closing of a Change of Control is effectuated or otherwise in which the payment right vests) and, if not exempt, the Retention Bonuses payable pursuant to this 2024 EO Plan are intended to comply with Section 409A, to the extent the requirements of Section 409A are applicable hereto. The provisions of this 2024 EO Plan shall be construed and administered in a manner consistent with that intention.

Section 409A

409A Payment Adjustments

If payment of any amount under this 2024 EO Plan that is subject to Section 409A at the time specified therein would subject such amount to any additional tax under Section 409A, the payment of such amount shall be postponed to the earliest commencement date on which the payment of such amount could be made without incurring such additional tax. In addition, to the extent that any guidance issued under Section 409A would result in the Covered Person being subject to the payment of interest or any additional tax under Section 409A, the Corporation shall, to the extent reasonably possible and as allowed by applicable treasury regulations, amend this 2024 EO Plan in order to avoid the imposition of any such interest or additional tax under Section 409A, which amendment shall have the minimum economic effect necessary and be reasonably determined in good faith by the Corporation.

No Representation Regarding 409A

Notwithstanding the foregoing, the Corporation makes no representations that the payments and benefits provided under this 2024 EO Plan comply with Section 409A and in no event will the Corporation be liable or be required to reimburse a Covered Person for all or any portion of any taxes, penalties, interest or other expenses that may be imposed on or incurred by him or her as a result of this 2024 EO Plan being subject to, but not compliant with, Section 409A.

409A Delay Payments

If a Covered Person is deemed to be a "specified employee" within the meaning of that term under Code Section 409A(a)(2)(B), then with regard to any payment or the provisions of any benefit that is required to be delayed pursuant to Code Section 409A(a)(2)(B)(i), such payment or benefit shall not be made or provided prior to the earlier of:

(i) the expiration of the six (6) month period measured from the date of the Covered Person's "separation from service" (as such term is defined in Treasury Regulation Section 1.409A-1(h)); or

(ii) the date of the Covered Person's death (the "Delay Period");

and all payments and benefits delayed pursuant to the foregoing (whether they would have otherwise been payable in a single sum or in installments in the absence of such delay) shall be paid to the Covered Person in a lump sum within ten (10) days following the expiration of the Delay Period.

No Trust Assets

No provision of this 2024 EO Plan will require the Corporation, for the purpose of satisfying any obligations under this 2024 EO Plan, to purchase assets or place any assets in a trust or other entity to which contributions are made or otherwise to segregate any assets, nor will the Corporation maintain separate bank accounts, books, records or other evidence of the existence of a segregated or separately maintained or administered fund for such purposes.

No Trust

Nothing contained in this 2024 EO Plan and no action taken pursuant to the provisions of this 2024 EO Plan will create or be construed to create a trust of any kind.

No Property Will Constitute Security

No property that may be acquired or invested by the Corporation in connection with this 2024 EO Plan will be deemed security for the obligations to the Covered Persons hereunder, but will be, and continue for all purposes to be, part of the general funds of the Corporation, and the Covered Persons will have no rights under this 2024 EO Plan other than as unsecured general creditors of the Corporation.

Bonus Program

This 2024 EO Plan is intended to be a "bonus program" as defined under U.S. Department of Labor Regulation Section 2510.3-2(c) and will be construed and administered in accordance with such intention.

Choice of Law

All questions concerning the construction, validation, and interpretation of this 2024 EO Plan will be governed by the laws of the State of Colorado without regard to its conflict of laws provisions.

Amendment

The Corporation reserves the right to amend or terminate this 2024 EO Plan at any time; provided, however, that (i) any such amendment or termination shall be made in writing and approved by resolution of the Compensation Committee or the Board, and (ii) following the Effective Date, the Corporation may not, without a Covered Person's written consent, amend or terminate this 2024 EO Plan in any way that (x) prevents the Covered Person from becoming eligible for his or her Retention Bonus under this 2024 EO Plan, or (y) reduces the amount of Retention Bonuses payable, or potentially payable to a Covered Person under this 2024 EO Plan.

2024 EO Plan Annual Base Salaries

Under this 2024 EO Plan, effective as of April 1, 2024, the salaries (the "2024 EO Plan Annual Base Salary") of the Covered Persons shall be as specified with respect to each such Covered Person in Schedule 1 attached hereto.

Change of Control Salaries

If a Change of Control occurs before March 31, 2026, for purposes of calculating the Retention Bonuses in Schedule 1, the 2024 EO Plan Annual Base Salaries shall be as set forth immediately above.

As promptly as practical after the adoption of this 2024 EO Plan, the Covered Persons shall be granted restricted stock units in accordance with the RSU Plan and pursuant to award agreements under said RSU Plan approved by the Compensation Committee as specified with respect to each such Covered Person in Schedule 1 attached hereto.

2024 EO Plan Restricted Stock Units

Such restricted stock units shall vest in amounts and at times as set forth in Schedule 1 attached hereto and in accordance with the terms of the RSU Plan and applicable award agreement with respect thereto.

2024 and 2025 EO Bonus Performance Plans

The Covered Persons shall be entitled to annual performance bonuses for each of the Corporation's 2024 and 2025 fiscal years, in amounts as the Compensation Committee shall determine in its discretion with respect to each such Covered Person in accordance with the 2024 and 2025 Executive Officer Bonus Performance Plans ("EO Bonus Plans") as described in Schedule 2 attached hereto, provided that such Covered Person continues in the service of the Corporation (or its subsidiary) through December 31, 2024 (with respect to the performance bonus for the 2024 fiscal year), or December 31, 2025 (with respect to the performance bonus for the 2025 fiscal year).

Service Agreements

To the maximum extent allowed by law, the right of each of the Covered Persons to receive the Retention Bonus due pursuant to this 2024 EO Plan in the event of a Change of Control shall be subject to that Covered Person having entered into an agreement with the party that acquires the Corporation upon such Change of Control whereby that Covered Person shall agree to continue to work for the acquirer or its affiliate or the Corporation, as applicable, for a period of 3 months following the Closing of the Change of Control or such lesser period as determined by the acquirer (the "Post Change of Control Employment Period"); *provided*, that the foregoing shall not apply to a Covered Person unless: (a) the acquiror desires to engage that Covered Person to continue to work for the acquirer (or its affiliate or the Corporation or its affiliate); (b) the agreement between such Covered Person and the acquiror requires the acquiror to pay the Covered Person a monthly salary equivalent to or greater than the per month amount of the Covered Person's 2024 EO Plan Annual Base Salary for each month during the Post Change of Control Employment Period; and (c) the agreement between such Covered Person and the acquiror requires the acquiror to pay such Covered Person a retention bonus equivalent to one quarter of the Covered Person's performance bonus for the most recent completed fiscal year, which payment shall be due and payable within thirty (30) days after the end of the Post Change of Control Employment Period as long as such Covered Person continued to work for the acquirer, its affiliate or the Corporation until the last day of the Post Change of Control Employment Period or the acquirer, its affiliate or the Corporation terminates such agreement with such Covered Person prior to such date; and (d) the Covered Person having been employed by the Corporation or a subsidiary through the Closing of the Change of Control.

Schedule 1

The Covered Person's total compensation under the 2024 EO Plan shall be as follows:

Covered Person Title	**2024 EO Plan Annual Base Salary for Period April 1, 2024 through March 31, 2026**
Chief Executive Officer	$675,000 per year
Chief Financial Officer	$400,000 per year
President (Hallador Power Company, LLC)	$450,000 per year
	Retention Bonus Amount
Chief Executive Officer	An amount equal to the sum of: (1) $1,350,000 in the event the acquiring company following the Closing of a Change of Control does not engage such Covered Person to continue to work for the acquirer, or $1,181,250 in the event the acquiring company does engage such Covered Person to continue to work for the acquirer pursuant to the requirements of the provisions in the 2024 EO Plan titled "Service Agreements;" plus (2) an amount equal to the Covered Person's annualized performance bonus for the prior fiscal year, *pro rated* for the period served in the fiscal year in which the Closing occurs through to the date of the Closing.
Chief Financial Officer	An amount equal to the sum of: (1) $800,000 in the event the acquiring company following the Closing of a Change of Control does not engage such Covered Person to continue to work for the acquirer, or $700,000 in the event the acquiring company does engage such Covered Person to continue to work for the acquirer pursuant to the requirements of the provisions in the 2024 EO Plan titled "Service Agreements;" plus (2) an amount equal to the Covered Person's annualized performance bonus for the prior fiscal year, *pro rated* for the period served in the fiscal year in which the Closing occurs through to the date of the Closing.
President (Hallador Power Company, LLC)	An amount equal to the sum of: (1) $900,000 in the event the acquiring company following the Closing of a Change of Control does not engage such Covered Person to continue to work for the acquirer, or $787,500 in the event the acquiring company does engage such Covered Person to continue to work for the acquirer pursuant to the requirements of the provisions in the 2024 EO Plan titled "Service Agreements;" plus (2) an amount equal to the Covered Person's annualized performance bonus for the prior fiscal year, *pro rated* for the period served in the fiscal year in which the Closing occurs through to the date of the Closing.

	Restricted Stock Units
Chief Executive Officer	A one-time grant of a total of 315,236 restricted stock units, to be granted under the RSU Plan as promptly as practical after the adoption of this 2024 EO Plan, which shall vest in the amount of 105,079 restricted stock units on March 31st of each of 2025 and 2026, and 105,078 restricted stock units on March 31, 2027, subject to the Covered Person's continued Service, as defined in the RSU Plan, through the applicable vesting date, and shall vest in full subject to the Covered Person's continued Service through to the date of a Change in Control, as defined in the RSU Plan, and otherwise in accordance with the terms of the RSU Plan and the applicable award agreement.
Chief Financial Officer	A one-time grant of a total of 70,053 restricted stock units, to be granted under the RSU Plan as promptly as practical after the adoption of this 2024 EO Plan, which shall vest in the amount of 23,351 restricted stock units on March 31st of each of 2025, 2026 and 2027, subject to the Covered Person's continued Service through the applicable vesting date, and shall vest in full subject to the Covered Person's continued Service through to the date of a Change in Control, and otherwise in accordance with the terms of the RSU Plan and the applicable award agreement.
President (Hallador Power Company, LLC)	A one-time grant of a total of 122,592 restricted stock units, to be granted under the RSU Plan as promptly as practical after the adoption of this 2024 EO Plan, which shall vest in the amount of 40,864 restricted stock units on March 31st of each of 2025, 2026 and 2027, subject to the Covered Person's continued Service through the applicable vesting date, and shall vest in full subject to the Covered Person's continued Service through to the date of a Change in Control, and otherwise in accordance with the terms of the RSU Plan and the applicable award agreement.
	Signing Bonus
Chief Financial Officer	In addition to the bonuses otherwise described under the 2024 Plan which the Chief Financial Officer is eligible for in accordance with the terms of the 2024 Plan, the Chief Financial Officer shall be granted a one-time grant of a total of 17,513 restricted stock units, to be granted under the RSU Plan as promptly as practical after the Chief Financial Officer becomes an employee of the Corporation, which shall vest in the amount of 5,838 restricted stock units on March 31st of each of 2025 and 2026, and 5,837 restricted stock units on March 31, 2027, subject to the Covered Person's continued Service through the applicable vesting date, and shall vest in full subject to the Covered Person's continued Service through to the date of a Change in Control, and otherwise in accordance with the terms of the RSU Plan and the applicable award agreement.

Executive Officer Bonus Performance Plan
Performance Goals and Payouts

Chief Executive Officer

The chart below sets forth the applicable goals and payouts for the Chief Executive Officer:

Area	Goals	Base Points	Threshold Goal	Target Goal	Maximum Goal	Payout Does Not Meet Threshold	Payout at Target	Payout at Maximum
Safety (Sunrise) Note 1	Severity Measure (National Average)	5	100.00%	89%	78.00%	$0	$23,100	$46,200
	Violations Per Inspection Day (National Average)	5	0.50	0.42	0.34	$0	$23,100	$46,200
Safety (Power) Note 2	Incident Rate	5	5.40	4.50	3.60	$0	$23,100	$46,200
	Safety Inspection Rate	5	1	1.25	1.50	$0	$23,100	$46,200
Financial	Adjusted EBITDA ($ million)	60	34.3	49.0	63.7	$0	$277,200	$554,400
Discretionary		20				$0	$92,400	$184,800

Chief Financial Officer

The chart below sets forth the applicable goals and payouts for the Chief Financial Officer:

Area	Goals	Base Points	Threshold Goal	Target Goal	Maximum Goal	Payout Does Not Meet Threshold	Payout at Target	Payout at Maximum
Safety (Sunrise) Note 1	Severity Measure (National Average)	5	100.00%	89%	78.00%	$0	$10,000	$20,000
	Violations Per Inspection Day (National Average)	5	0.50	0.42	0.34	$0	$10,000	$20,000
Safety (Power) Note 2	Incident Rate	5	5.40	4.50	3.60	$0	$10,000	$20,000
	Safety Inspection Rate	5	1	1.25	1.50	$0	$10,000	$20,000
Financial	Adjusted EBITDA ($ million)	60	34.3	49.0	63.7	$0	$120,000	$240,000
Discretionary		20				$0	$40,000	$80,000

President (Hallador Power Company, LLC)

The chart below sets forth the applicable goals and payouts for the President of Hallador Power Company, LLC:

Area	Goals	Base Points	Threshold Goal	Target Goal	Maximum Goal	Payout Does Not Meet Threshold	Payout at Target	Payout at Maximum
Safety (Sunrise) Note 1	Severity Measure (National Average)	5	100.00%	89%	78.00%	$0	$15,000	$30,000
	Violations Per Inspection Day (National Average)	5	0.50	0.42	0.34	$0	$15,000	$30,000
Safety (Power) Note 2	Incident Rate	5	5.40	4.50	3.60	$0	$15,000	$30,000
	Safety Inspection Rate	5	1	1.25	1.50	$0	$15,000	$30,000
Financial	Adjusted EBITDA ($ million)	60	34.3	49.0	63.7	$0	$180,000	$360,000
Discretionary		20				$0	$60,000	$120,000

Note 1: Safety (Sunrise) is based on Sunrise Coal's performance percentage relative to the national average for underground coal mines over the preceding 4 years. For the 2024 Performance Period, safety will be determined relative to the 2020 – 2023 period. For the 2025 Performance Period, safety will be determined relative to the 2021 – 2024 period. Actual results for each safety measure will be calculated by Sunrise Coal management with final results available.

Note 2: Safety (Power) is based on Hallador Power's performance percentage relative to the national average for coal-fired power generating facilities over the preceding 4 years. For the 2024 Performance Period, safety will be determined relative to the

2020 – 2023 period. For the 2025 Performance Period, safety will be determined relative to the 2021 – 2024 period. Actual results for each safety measure will be calculated by Hallador Power management with final results available.

The charts above set forth the Performance Goals for each performance measure for each of the 2024 and 2025 Performance Periods and the associated payouts for the Chief Executive Officer and Chief Financial Officer of the Corporation and the President of Hallador Power Company, LLC (each, a “Covered Person”).

For the Chief Executive Officer, the target bonus is $462,000 for each of the 2024 and the 2025 Performance Periods. For the Chief Financial Officer, the target bonus is $200,000 for each of the 2024 and the 2025 Performance Periods. For the President of Hallador Power Company, LLC, the target bonus is $300,000 for each of the 2024 and the 2025 Performance Periods. A portion of the target bonus is allocated to each performance measure in proportion to the base points allocated to the performance measure. Performance against each Performance Goal and the corresponding payout are measured separately. The attained performance against a Performance Goal shall not affect the performance bonus amount payable with respect to any other Performance Goal.

No payout is available with respect to a performance measure if performance is at or below the threshold level.

The payout for performance above the threshold level but below the target level shall be determined by straight line interpolation between zero and the target payout amount.

The payout for performance above the target level but below the maximum level shall be determined by straight line interpolation between the target payout amount and the maximum payout amount.

Performance in excess of the maximum Performance Goal does not result in a payout in excess of the maximum payout amount.

Performance bonus amounts, if any, will be paid in a lump sum net of applicable withholding, after audit completion, in March 2025 with respect to the 2024 Performance Period and in March 2026 with respect to the 2025 Performance Period, contingent on the Covered Person’s continued service with the Corporation or its affiliates through to December 31, 2024, with respect to the 2024 Performance Period, and through to December 31, 2025, with respect to the 2025 Performance Period.

Example - CEO:

By way of example, if, for the 2024 Performance Period, Severity Measure (National Average) is 99%, the threshold Performance Goal for Violations per Inspection Day, Incident Rate and Safety Inspection Rate are not exceeded, and the adjusted EBITDA is $50.0 million, the Chief Executive Officer shall be entitled to a receive a performance bonus for the 2024 Performance Period calculated as follows:

Severity Measure (National Average): $23,100 * (100 - 99)/(100 - 89) = $2,100
EBITDA: $277,200 + ($277,200 * (50 - 45)/(54 - 45)) = $277,200 + $154,000 = $431,200

TOTAL: $433,300

In addition to the safety and financial performance goals described in the above chart: (i) the Chief Executive Officer may also be entitled to receive a discretionary bonus amount for each of the 2024 Performance Period and 2025 Performance Period, as determined by the Board or the Committee, as applicable, of up to $184,800; (ii) the Chief Financial Officer may also be entitled to receive a discretionary bonus amount for each of the 2024 Performance Period and 2025 Performance Period, as determined by the Board or the Committee, as applicable, of up to $80,000; and (iii) the President of Hallador Power Company, LLC may also be entitled to receive a discretionary bonus amount for each of the 2024 Performance Period and 2025 Performance Period, as determined by the Board or the Committee, as applicable, of up to $120,000.

EXHIBIT 14.1

CODE OF CONDUCT AND ETHICS

1. **Introduction.** This Code of Conduct and Ethics (the Code) covers a wide range of business practices and procedures. It does not cover every issue that may arise, but it sets out basic principles to guide all employees, officers, and directors of the company, its subsidiaries and affiliates (the Company). All of our employees, officers, and directors must conduct themselves accordingly and seek to avoid even the appearance of improper behavior. The Code should also be provided to and followed by the Company's agents and representatives.

   If a law, rule, or court order conflicts with a policy in this Code, you must comply with the law, rule, or court order. If you have any questions about these conflicts, you should immediately ask your supervisor or Human Resources how to handle the situation. Employees, officers, and directors are responsible for understanding the legal and policy requirements that apply to their jobs and report any suspected violations of law, this Code, or Company policy to their supervisor or Human Resources. You may report any concerns or potential violations to your supervisor, Human Resources, or the legal/compliance department.

   Acting with integrity and doing the right thing are driving forces behind the Company's success. From the very beginning, our Company has been committed to conducting its business in an ethical manner - doing right by our employees, customers, vendors, suppliers, communities and stockholders. The Company requires its employees, officers, and directors to conduct themselves and the Company's business in the most ethical manner possible. We share the responsibility for protecting and advancing the Company's reputation, and ethics and values must drive our business strategies and activities. This Code provides you with the guidelines for meeting your ethical and legal obligations at the Company.

2. **Compliance with Laws, Rules, and Regulations.** Obeying the law, both in letter and in spirit, is the foundation on which this Company's ethical standards are built. All employees, officers, and directors must respect and obey the laws, rules, and regulations of all relevant jurisdictions, including but not limited to, the cities, counties, states, and countries in which we operate. Although employees, officers, and directors are not expected to know the details of each of these laws, rules and regulations, it is important to know enough to determine when to seek advice from supervisors, managers or other appropriate personnel. If you are uncertain about any law, rule, or regulation, you should contact your supervisor, Human Resources, or the legal or compliance department.

3. **Conflicts of Interest.** A conflict of interest exists when a person's private interest interferes in any way, or even appears to interfere, with the interests of the Company. A conflict situation can arise when an employee, officer or director takes actions or has interests that may make it difficult to objectively and effectively perform his or her Company work. It is immaterial whether the employee was originally aware of the conflict. An employee that discovers a conflict during or after-the-fact must report it and discontinue the arrangement or activity.

   Conflicts of interest may also arise when an employee, officer or director (or a member of his or her family) receives improper personal benefits due to his or her position in the Company. Loans to, or guarantees of obligations to, employees, officers, and directors and their family members by the Company may create conflicts of interest.

   It is a conflict of interest for a Company employee, officer, or director to work for a competitor, customer, or supplier. You should avoid any direct or indirect business connection with our customers, suppliers or competitors; except as required on our behalf. Such work and/or activities shall include, but is not limited to, directly or indirectly competing with Company in any way, or acting as an officer, director, employee, consultant, stockholder, volunteer, lender, or agent of any business enterprise of the same nature as, or which is in direct competition with, the business in which Company is now engaged or in which Company becomes engaged during the term of your employment with Company, as may be determined by Company in its sole discretion.

   Conflicts of interest are prohibited as a matter of Company policy, except as approved by Marjorie Hargrave, our Chief Financial Officer. Conflicts of interest may not always be clear-cut, so if you have a question, you should consult with your supervisor or Human Resources. Any employee, officer, or director who becomes aware of a conflict or potential conflict must report it immediately to a supervisor or Human Resources.

   Nothing in this Code is intended to interfere with your rights under federal and state laws, including the National Labor Relations Act (NLRA), nor will the Company construe this Code in a way that limits such rights. Employees have the right to engage in or refrain from activities protected by the NLRA.

4. **Confidentiality.** Employees, officers, and directors must maintain the confidentiality of proprietary information entrusted to them by the Company or its customers or suppliers, except when disclosure is authorized in writing by the chief financial officer or required by laws or regulations. Proprietary information includes all non-public information of the Company and intellectual property such as trade secrets, patents, trademarks and copyrights, as well as business, marketing and service plans, engineering and manufacturing ideas, designs, databases, records, and any unpublished financial data and reports. Disclosing such information might be of use to competitors or harmful to the Company or its customers or suppliers if disclosed. This includes information that suppliers and customers have entrusted to us.

Information that has been made public by the Company, such as press releases, news articles, or advertisements, is not considered confidential and does not require protection.

It is the responsibility of each of us to use discretion in handling Company information so that we do not inadvertently reveal confidential information to competitors, vendors, suppliers, friends and/or family members. If you are unsure about whether certain information is confidential, presume that it is. The obligation to preserve proprietary information continues even after employment ends.

5. **Insider Trading.** All non-public information about the Company should be considered confidential information. Employees, officers, and directors who have access to confidential information about the Company or any other entity are not permitted to use or share that information for trading purposes or for any other purpose except to conduct Company business as described in the Company's Insider Trading Policy. To use non-public information for personal financial benefit or to "tip" others who might make an investment decision based on this information is unethical and illegal. If you have any questions, please consult with the Company's legal department or your personal legal counsel when appropriate.

6. **Corporate Opportunities.** Employees, officers, and directors are prohibited from taking opportunities that are discovered through the use of corporate property or information for themselves without the consent of the Board. No employee, officer, or director may use corporate property or information for personal gain and no employee, officer, or director may compete directly or indirectly with the Company. Employees, officers, and directors owe a duty to the Company to advance the Company's interests when the opportunity to do so arises.

7. **Competition and Fair Dealing.** We seek to fairly and honestly outperform our competition. We seek competitive advantages through superior work effort—never through unethical or illegal business practices. Stealing proprietary information, possessing trade secret information that was obtained without the owner's consent, or inducing such disclosures by past or present employees of other companies is prohibited and potentially illegal. Each employee, officer and director should endeavor to respect the rights of and deal fairly with the Company's customers, suppliers, competitors and employees. No employee, officer or director should take unfair advantage of anyone through manipulation, concealment, abuse of privileged information, misrepresentation of material facts, or any other illegal trade practice.

   No employee, officer or director is permitted to engage in price fixing, bid rigging, allocation of markets or customers, or similar illegal activities. The Company will fully cooperate with law enforcement and other agencies to pursue anyone engaged in illegal activities to protect the Company's good name.

The purpose of business entertainment and gifts in a commercial setting is to create goodwill and sound working relationships, not to gain unfair advantage with customers or suppliers and against competitors. No gift or entertainment should ever be offered, given, requested, provided or accepted by any Company employee, officer or director, family member of an employee, officer or director, or agent unless it (1) is not a cash gift; (2) is consistent with customary business practices; (3) is reasonable in fair market value under the given circumstances; (4) cannot be construed as a bribe or payoff; and (5) does not violate any laws, regulations or applicable policies of the other party's organization. Please discuss with your supervisor, Human Resources, Marjorie Hargrave or the legal department any gifts or proposed gifts if you are not certain whether they are appropriate or legal.

8. **Antitrust.** Antitrust laws in the United States and other countries are intended to preserve a free and competitive marketplace. The Company requires full compliance with these laws. Employees, officers, and directors must not discuss with competitors how the Company prices, markets, services or otherwise competes. Employees, officers, and directors must not share confidential business information with our competitors and must not engage in any conduct that could unreasonably restrict our competitors' access to the market. Antitrust laws are complex and can be difficult to understand. Employees, officers, and directors should seek advice from the legal or compliance department when dealing with antitrust issues.

9. **Political Contributions.** Except as approved in advance by the Chief Executive Officer or Chief Financial Officer, the Company prohibits political contributions (directly or through trade associations) by the Company. This includes (1) any contributions of Company funds or other assets for political purposes, (2) encouraging individual employees to make any such contribution, or (3) reimbursing an employee for any contribution. Individual employees are free to make personal political contributions as they see fit or to participate in the Company's Political Action Committee.

10. **Payments to Government Personnel.** From time to time, the Company's business obligates it to interact with officials and employees of (1) foreign government; (2) U.S. federal, state, and local governments; and (3) U.S. and foreign political parties.

    The Foreign Corrupt Practices Act (the FCPA) prohibits the making of a payment and/or the promising or offering of anything of value to any foreign government official, government agency, political party, or political candidate (collectively, Government Personnel) in exchange for a business favor or when otherwise intended to influence the action taken by any such individual or agency or to gain or retain any competitive or improper business advantage. It is very important to know that the prohibitions of the FCPA apply to actions taken by all employees and by all outside parties engaged directly or indirectly by the Company (e.g., consultants, professional advisers, etc.). While the FCPA does, in certain limited circumstances, allow nominal "facilitating payments" to be made, given the complexity of the FCPA and the severe penalties associated with its violation, all employees and outside parties engaged by the company must comply with the Company's FCPA policy and contact the legal department with any questions concerning the Company's and their obligations under the FCPA or concerning any transaction which may be in violation of the FCPA; any other federal, state, local, or foreign law or regulation; or this Code.

No employee of the Company may retain a consultant, agent, or other outside party which will have contact with any foreign or U.S. Government Personnel until the employee, the legal department and the Chief Financial Officer have reasonably concluded that such retained party understands and will fully abide by the FCPA, the Company's FCPA policy, and this Code.

In addition, the U.S. government has a number of laws and regulations regarding business gratuities, which may be accepted by U.S. Government Personnel. The promise, offer, or delivery to an official or employee of the U.S. government of a gift, favor, or other gratuity in violation of these rules would not only violate Company policy but could also be deemed a civil or criminal offense. State and local governments, as well as foreign governments, often have similar rules.

11. **Discrimination, Retaliation, and Harassment.** The diversity of the Company's employees is a tremendous asset. We are firmly committed to providing equal opportunity in all aspects of employment and will not tolerate any illegal discrimination or harassment based on race, color, religion, sex, national origin, age, disability, or any other protected class under applicable federal, state, and local laws. Employees must comply with all anti-discrimination, anti-retaliation, and anti-harassment laws whether local, state or federal.

    If any employee, officer, or director believes he or she has been harassed by anyone at the Company, he or she should immediately report the incident to his or her supervisor or Human Resources. Similarly, supervisors and managers who learn of any such incident should immediately report it to Human Resources. Human Resources will promptly and thoroughly investigate any complaints and take appropriate action.

12. **Health and Safety.** The Company strives to provide each employee, officer and director, as well as customers, vendors, or other visitors, with a safe and healthy work environment. Each employee, officer, and director has the responsibility for maintaining a safe and healthy workplace for all employees, officers, and directors by following environmental, safety, and health rules and practices and by reporting accidents, injuries and unsafe equipment, practices or conditions.

    All Company locations must remain in compliance with the Occupational Safety and Health Act (OSH Act), the Mine Safety and Health Act (MSH Act) and other regulatory requirements. Safety issues and violations of regulatory requirements will be promptly addressed. In addition to meeting our obligations, the Company will take proactive initiatives to make safety a top priority. Employees, officers, and directors are charged with the responsibility for maintaining safe practices and conditions in everything they do and report anything that threatens anyone's safety.

    Employees, officers, and directors are expected to perform their Company related work in a safe manner, free of the influences of alcohol, illegal drugs or controlled substances. The use of illegal drugs in the workplace will not be tolerated.

13. **Environmental.** The Company expects its employees, officers, and directors to follow all applicable environmental laws and regulations. If you are uncertain about your responsibility or obligation, you should check with your supervisor or the legal or compliance department for guidance. You should immediately report to management any emergency situations involving any types of potential environmental harm to persons or property.

14. **Record-Keeping, Financial Controls and Disclosures.** The Company requires honest, accurate and timely recording and reporting of information to make responsible business decisions.

    All business expense accounts must be documented and recorded accurately in a timely manner. If you are not sure whether a certain expense is legitimate, ask your controller. Policy guidelines are available from your controller.

    All of the Company's books, records, accounts and financial statements must be maintained in detail; must appropriately reflect the Company's transactions; must be made promptly without false or misleading information; must be promptly disclosed in accordance with any applicable laws or regulations; and must conform both to applicable legal requirements and to the Company's system of internal controls. Any employee who becomes aware of any inadvertent or unauthorized disclosure of information discussed in this Section must notify the legal or compliance department immediately.

    If any employee, officer, or director has concerns or complaints regarding accounting or auditing matters of the Company, then he or she is encouraged to submit those concerns by one of the methods described in the "Compliance Procedures" section below.

    Business records and communications often become public and we should avoid exaggeration, derogatory remarks, guesswork or inappropriate characterizations of people and companies that may be misunderstood. This applies equally to e-mail, internal memos and formal reports. Records should always be retained or destroyed according to the Company's record retention policies. In accordance with those policies, in the event of litigation or governmental investigation, please consult with the legal or compliance department.

15. **Protection and Proper Use of Company Assets.** All employees, officers, and directors should protect the Company's assets and ensure their efficient use. Theft, carelessness, and waste have a direct impact on the Company's profitability. All Company assets are to be used for legitimate or authorized Company purposes. Any suspected incident of fraud or theft, including theft of time, should be immediately reported for investigation. Unless approved by [insert party to approve use], Company assets should not be used for non-Company business.

    The obligation of employees, officers, and directors to protect the Company's assets includes the Company's proprietary information. Proprietary information includes intellectual property such as trade secrets, patents, trademarks and copyrights, as well as business, marketing and service plans, engineering and manufacturing ideas, designs, databases, records, and any unpublished financial data and reports. Nothing in this Code is intended to interfere with your rights under federal and state laws, including the National Labor Relations Act, nor will the Company construe this Code in a way that limits such rights.

Employees have the right to engage in or refrain from activities protected by the National Labor Relations Act.

Unauthorized use or distribution of this information is a violation of Company policy. It could also be illegal and result in civil or criminal penalties.

16. **Trade Issues.** From time to time, the United States, foreign governments, and the United Nations have imposed boycotts and trading sanctions against various governments and regions, which must be obeyed. Advice regarding the current status of these matters must be obtained from the legal department.

17. **Waivers of the Code of Business Conduct and Ethics.** Any waiver of this Code for employees, executive officers or directors may be made only by the Board and will be promptly disclosed as required by law or regulation.

18. **Reporting Any Illegal or Unethical Behavior.** Employees are encouraged to talk to supervisors or other appropriate personnel such as the legal or compliance department or Human Resources about observed behavior that they believe may be illegal or a violation of this Code or Company policy or when in doubt about the best course of action in a particular situation. The Company will immediately and thoroughly investigate all such concerns and take appropriate action. The Company will not allow retaliation for reports made in good faith by employees of misconduct by others. Employees are expected to cooperate in internal investigations of misconduct.

19. **Improper Influence on Conduct of Auditors.** It is prohibited to directly or indirectly take any action to coerce, manipulate, mislead or fraudulently influence the Company’s independent auditors for rendering the financial statements of the Company materially misleading. Prohibited actions include, but are not limited to, those actions taken to coerce, manipulate, mislead or fraudulently influence an auditor (1) to issue or reissue a report on the Company’s financial statements that is not warranted in the circumstances (due to material violations of generally accepted accounting principles, generally accepted auditing standards, or other professional or regulatory standards); (2) not to perform an audit, review or other procedures required by generally accepted auditing standards or other professional standards; or (3) not to communicate matters to the Company’s Audit Committee.

20. **Compliance Procedures.** All employees, officers, and directors have the responsibility to report observed or suspected violations of law, this Code and any activity that might constitute financial fraud or financial misconduct. We must all work to ensure prompt and consistent action against violations. However, not all situations are clear-cut. Since we cannot anticipate every situation that will arise, it is important that we have a way to approach a new question or problem. These are the steps to keep in mind:

    (a) **Make Sure You Have All the Facts.** To reach the right solutions, we must be as fully informed as possible.

(b) **Ask Yourself: What Specifically Am I Being Asked to Do? Does It Seem Unethical or Improper?** This will enable you to focus on the specific question you are faced with and the alternatives you have. Use your judgment and common sense; if something seems unethical or improper, it probably is.

(c) **Discuss the Problem with Your Supervisor, Human Resources, or, for Compliance Issues, with the Legal Department.** This is the basic guidance for all situations. In many cases, your supervisor will be more knowledgeable about the question and will appreciate being brought into the decision-making process. Remember that it is your supervisor's responsibility to help solve problems. If you are uncomfortable discussing the problem with your supervisor, you can talk to Human Resources. If your question relates to any compliance issues addressed in this Code, you can talk to the Company's legal or compliance department.

(d) **Seek Help from Company Resources.** In a case where it may not be appropriate to discuss an issue with your supervisor or local management, call **303-746-7036** which will put you in direct contact with the legal department at Company headquarters. If you prefer to write, address your concerns to the legal department or the Audit Committee of the Board. Anonymous reports can be made through the internet at **https://www.whistleblowerservices.com/hpco** or by phone at **866-229-6923.**

(e) **You May Report Violations in Confidence and without Fear of Retaliation.** If your situation requires that your identity be kept secret, your anonymity will be protected. The Company does not permit retaliation of any kind against employees, officers or directors for good faith reports of suspected violations.

(f) **Always Ask First, Act Later.** If you are unsure of what to do in any situation, seek guidance before you act.

(g) **All Employees, Officers, and Directors Are Subject to the Company's Code, Which Describes Procedures for the Internal Reporting of Violations of the Code.** All employees, officers, and directors must comply with those reporting requirements and promote compliance with them by others. Failure to adhere to this Code by any employee, officer, or director will result in disciplinary action up to and including termination.

'Adopted March 11, 2025

Exhibit 19.1

HALLADOR ENERGY COMPANY

Insider Trading Policy

Updated March 11, 2025

As a public company, Hallador Energy Company ("Hallador") is subject to various federal and state laws and regulations governing trading in its securities. It is our policy, (hereinafter referred to as the "Policy"), and that of our subsidiaries, to comply fully, and to assist our employees in complying fully, with these laws and regulations.

Who is subject to this Policy?

All directors, officers, employees, consultants, customers, suppliers and any other person who may come into possession of material, nonpublic information about Hallador Energy and its subsidiaries are subject to this Policy. In addition, special trading restrictions apply to all directors, executive officers, and additional employees designated by the CFO from time to time (collectively, "Covered Persons").

Family members who reside with you (including a spouse, a child, a child away at college, stepchildren, grandchildren, parents, stepparents, grandparents, siblings, in-laws and domestic partners), or anyone else who lives in your household, and any family members who do not live in your household but whose transactions in Hallador securities are directed by you or are subject to your influence or control (such as parents or children who consult with you before they trade in Hallador securities) (collectively, "Family Members").

> *This Policy **does not**, however, **apply** to personal securities transactions of Family Members where the purchase or sale decision is made solely by an independent third party and not controlled by, influenced by or related to you or your Family Members.*

Entities that you influence or control, including any corporations, partnerships, trusts, and custodial accounts, (collectively, "Controlled Entities").

You are responsible for the compliance with this Policy, and therefore should make your Family Members and Controlled Entities aware of the need to confer with you before they trade in Hallador securities. **Who is the Administrator of the Policy?** The Chief Financial Officer (CFO) or another employee designated by the CFO shall be responsible for the administration of this Policy. All determinations and interpretations of this Policy shall be final and not subject to further review. **Hallador' s CFO, Marjie Hargrave, can be reached at 303-917-0777 or by email at mhargrave@HalladorEnergy.com.**

What is Insider Trading?

Insider trading restrictions prohibit trading in the securities of a company on the basis of material, nonpublic information gained through involvement with the company or providing that information to others outside the company. The prohibition against such trading generally prohibits:

- Trading in Hallador securities while in possession of material, nonpublic information about Hallador and its subsidiaries and affiliates.
- Passing (or "tipping") material, nonpublic information about Hallador or its subsidiaries and affiliates to others, including family and friends.
- Trading in the securities of another company based on material, nonpublic information about that company learned in the course of working for Hallador or its subsidiaries and affiliates.
- Participating in transactions related to Hallador securities that are short-term or speculative in nature.

Actions prohibited while in possession of material, nonpublic information include, but are not limited to:

- Buying and selling of Hallador securities (except when trading under an approved 10b5-1 plan, see below).
- Selling Hallador securities acquired upon exercise of a stock option or engaging in a "cashless" exercise of an option through a broker. (Hallador does not have any issued stock options.)

What is Materiality?

It is not possible to define all categories of material information. Information should be considered material if there is a reasonable likelihood that an investor would consider it to be an important factor when making an investment decision. In this regard, there are various categories of information (positive and negative) that are particularly sensitive and, as a general rule, should always be considered material.

Examples of such information include, but are not limited to:

- Financial results
- Changes in earnings estimates or unusual gains or losses in major operations
- Projections of future earnings or losses
- Changes its dividend policy
- Material impairment, write-off or restructuring
- Stock splits
- New equity or debt offerings
- Extraordinary borrowings
- Changes in debt ratings

- Impending bankruptcy or financial liquidity problems
- Pending or proposed plans or agreements, even if preliminary in nature, involving mergers, acquisitions, divestitures, recapitalizations, strategic alliances, licensing agreements, or purchases or sales of significant assets
- The disposition or acquisition of significant assets
- Gain or loss of a substantial customer or vendor
- Termination or reduction of business relationship with a significant customer
- Material sales contracts
- Significant litigation exposure due to actual or threatened litigation, or developments regarding government agency investigations
- Major changes in Executive Management

The determination of whether information is material is subjective and made based on the facts and circumstances of each particular situation. Either positive or negative information may be material. When in doubt about whether particular nonpublic information is material, you should presume it is material. The CFO shall make the final determination as to the materiality of nonpublic information. When in doubt, Insiders should presume information to be material and consult the CFO before initiating transactions in Hallador securities.

<u>When can information be considered “Public"?</u>

Insider trading prohibitions come into play when you possess information that is both material and nonpublic. Normally, information is considered to be “public” if it has been widely disseminated to the general public through press releases, news tickers, widely available publication or newspaper, or in a Form 8-K, 10-Q or 10-K filed with the Securities and Exchange Commission (“SEC”).

If you are aware of material, nonpublic information, you may not trade until the information has been disclosed to the public, and the investing public has had time to fully absorb it. You are required to wait two full trading days after the information has been released to the public before treating the information as public and trading in Hallador securities. Therefore, if an announcement is made before the markets open on a Monday, you may trade in Hallador securities starting at the open of trading on Wednesday of that week, because two full trading days would have elapsed by then (all of Monday and Tuesday). If the announcement is made after the close of the trading markets on Monday, you may not trade until the open of trading on Thursday.

Hallador stock trades on the NASDAQ under the symbol: HNRG. For purposes of this Policy, a “trading day” shall be a day in which the NASDAQ is open for trading.

As with questions of materiality, if you are not sure whether information is considered public, you should either consult with the CFO or assume that the information is nonpublic and treat it as confidential.

Tipping is prohibited!

You are required to maintain the confidentiality of Hallador's material nonpublic information until it is publicly disclosed and generally known or available to the public. Such information may not be disclosed, or "tipped," to others such as Controlled Entities, Family Members or other relatives, or business or social acquaintances. Similarly, you may not recommend trades or assist in the trading of Hallador securities by another individual on the basis of material, nonpublic information.

Do not discuss material nonpublic information where it may be overheard, such as in restaurants, elevators, restrooms, and other public places. Remember that cellular phone conversations are often overheard and that voice mail and e-mail messages may be retrieved by persons other than their intended recipients.

This Policy applies to material, nonpublic information of Hallador's business partners.

Employees who, in the course of their work for Hallador come into possession of material, nonpublic information about any of our business partners (customer, vendor or supplier) are required to treat such material nonpublic information as if it was about Hallador, and are prohibited from trading in securities of that company until the information is publicly disclosed and generally known or available to the public.

This Policy remains applicable after employment or services terminate with Hallador.

This Policy continues to apply to transactions in Hallador securities even after the termination of employment or contractual or other business relationship. Persons in possession of material nonpublic information when their employment or other business relationship has been terminated may not trade in Hallador securities until that information has become public or is no longer material.

What is the "pre-clearance" policy?

Covered Persons must obtain pre-clearance of any planned transactions in Hallador securities from the CFO to confirm that the Covered Person is not in possession or aware of any material, non-public information. In addition, the Controlled Entities, Family Members, and other persons living in the household of each Covered Person must obtain pre-clearance of any such transactions.

If a proposed transaction is not approved under the pre-clearance policy, the Covered Person must refrain from engaging in the transaction and should not inform or "tip" any other individual within or outside of Hallador of the material nonpublic information.

Once Covered Person has received pre-clearance for the planned transaction, it is effective for one week, unless the Covered Person becomes aware of any material nonpublic information during that time, in which case the pre-clearance expires immediately.

Failure to obtain pre-clearance before making a transaction of company stock is a violation of this Policy and will increase risks of being liable for insider trading.

The Covered Person should notify the CFO or his designate immediately upon completion the transaction and request that their broker immediately provide the information about the trades to the CFO such that any required Section 16 filing may be made on a timely basis.

Additionally, except for the exercise of options that does not involve the sale of Hallador securities or transactions pursuant to a valid 10b5-1 Plan, no Covered Persons shall purchase or sell any security of Hallador during the period beginning on 15th day of the month following the last day of any calendar quarter and ending two full trading days after the public release of the disclosure of Hallador's financial results in an earnings release, Form 10-K or Form 10-Q for such fiscal quarter.

Approval by the CFO of any transaction does not constitute legal advice, nor is it a guarantee that a transaction will not be subject to challenge by third parties.

When does the trading window open and close?

Covered Persons may purchase or sell Hallador securities during the trading window associated with the quarterly earnings releases. The quarterly trading window shall open following the conclusion of the second trading day after the earnings call and will end no later than the 15th day of the month after the completion of the fiscal quarter. For example: Earnings Call on Monday after market close; trading window opens at the open of trading on Thursday; and trading window closes on the fifteenth day of the month after the completion of the fiscal quarter. During these open trading windows, Covered Persons are still required to obtain pre-clearance of the transaction from the CFO.

There are no guarantees that material, nonpublic information won't develop at any time during the trading window and cause it to close early. If an event occurs that causes the CFO to close the trading window early, Covered Persons will be notified by e-mail of the closure.

If Covered Persons are aware of material, nonpublic information, they must not trade, even during the trading windows.

When are Blackout Periods?

From time-to-time, and on a case-by-case basis, the CFO may declare blackout periods, as deemed appropriate in the CFO's discretion, to help protect Hallador from insider trading on the basis of material, nonpublic information. Covered Persons subject to a blackout period are prohibited from trading in Hallador securities for the duration of the blackout period. The CFO will notify Covered Persons at the beginning of the blackout period, and again when it concludes.

Is trading under Rule 10b5-1 allowed?

Pursuant to SEC Rule 10b5-1, Covered Persons may adopt a written trading plan. Any such plan must be approved by the CFO. The trading plan must be entered into during an open trading window and when the Covered Person is not in possession of material, nonpublic information. The preferred period for entering into a trading plan is generally the ten trading days immediately following the second full trading day after the quarterly earnings have been released. The plan must either specify the amount, price and timing of transactions in advance or delegate authority to an independent third party. Once the trading plan is adopted, the Covered Person must not exercise any influence over the transaction.

Transactions Pursuant to 10b5-1 Plans and Pre-Clearance of 10b5-1 Plans

Notwithstanding the trading preclearance requirement stated above in the “What is the ‘pre-clearance’ policy” section, a Covered Person shall not be required to preclear a transaction in Hallador securities if such transaction is executed pursuant to a valid contract, instruction or plan that provides an affirmative defense (a 10b5-1 Plan) pursuant to Rule 10b5-1 under the 1934 Act and such transaction is lawful under any applicable state securities laws and complies with the Rule 10b5-1 requirements set forth on Appendix A .

However, a 10b5-1 Plan cannot be entered into or adopted by a Covered Person when the Covered Person is in possession of material, non-public information related to the security, whether the issuer of such security is Hallador’s or any other company. To provide assistance in preventing inadvertent violations of applicable securities laws and to avoid the appearance of impropriety in connection with the adoption of a 10b5-1 Plan, the adoption of any 10b5-1 Plan providing for transactions in the securities of Hallador (including without limitation, acquisitions and dispositions of Hallador common stock, the exercise of options and the sale of Hallador common stock issued upon exercise of options) must comply with Rule 10b5-1 requirements attached as Appendix A and be precleared by the CFO to confirm the absence of material non-public information at the time of such adoption. The CFO will not otherwise pass upon the conformity of the 10b5-1 Plan or its execution to the requirements of Rule 10b5-1 or any applicable state law, which shall be solely the responsibility of the Covered Person. In addition, any proposed amendment to, alteration of or deviation from an established 10b5-1 Plan will be treated as the adoption of a new 10b5-1 Plan, which must be precleared by the CFO. In connection with this preclearance, the Covered Person shall provide the CFO with a copy of the 10b5-1 Plan proposed to be entered into or adopted by the Covered Person, which must comply with the Rule 10b5-1 requirements attached as Appendix A. If after consultation with the CFO it is determined that Hallador and/or such Covered Person is in possession of material, non-public information, the Covered Person may not enter into, amend, modify or adopt the 10b5-1 Plan at such time.

Short-term or speculative transactions are restricted!

Covered Persons, and any Covered Person’s Controlled Entities or Family Members, may not engage in short-term or speculative transactions in Hallador securities as there is heightened legal risk or the appearance of improper or inappropriate conduct. Such transactions include but are not limited to:

- **Short-term trading** – Covered Persons who purchase Hallador securities in the open market may not sell any Hallador securities of the same class during the six months following the purchase (or vice versa).
- **Short sales** – Covered Persons may not sell Hallador securities they do not own.
- **Margin accounts and pledges** – Covered Persons may not margin or pledge Hallador securities (including due to that fact that the sales of the securities can occur when the Covered Person is aware of Material Nonpublic Information).
- **Standing and limit orders outside of an approved trading plan** – Standing and limit orders are discouraged since there is no control over the timing of purchases or sales resulting from instructions to the broker. The broker may execute the order when the Covered Person is aware of material nonpublic information**. If a Covered Person must use a standing or limit order, a "pre-clearance" must be obtained and the order should be limited to a seven (7) day duration.**
  - *If the CFO issues a Trading Window Blackout during the seven (7) day pre-clearance approval period, it is the responsibility of the Covered Person to cancel the standing and limit orders to maintain compliance with the Policy.*
- **Hedging:** Covered Persons may not purchase financial instruments that are designed hedge or offset any decrease in the market value of Hallador's equity securities, whether granted as compensation or held directly or indirectly by the Covered Person. Financial instruments include prepaid variable forward contracts, equity swaps, collars and exchange funds, but the term is not limited to these instruments**.**

Are there restrictions on gifting or charitable donations of Hallador securities?

Covered Persons must comply with the trading windows and blackout periods for gifting and charitable contributions and obtain a "pre-clearance" from the CFO for such transactions and immediately provide the details of any such gift or charitable contribution once completed to ensure timely Section 16 reporting.

What if I am a Section 16 filer?

Persons who are subject to Section 16 of the Securities and Exchange Act of 1934, as amended ("Section 16"), are required to report acquisitions and dispositions of Hallador securities within two business days after any transaction. Such persons may be required to disgorge any profits realized from a short-swing transaction, which is any purchase and sale, or sale and purchase, of Hallador's equity securities within a period of less than six months, whether or not such person possessed any material, non-public information at the time of the transaction.

All persons subject to Section 16 must obtain pre-clearance from the CFO two business days prior to conducting any transaction in order to confirm that compliance with Section 16 is maintained and request that their broker immediately provide the information about the trades to the CFO such that any required Section 16 filing may be made on a timely basis.

Transactions by Family Members and Controlled Entities of persons subject to Section 16 must be reported on the Form 4 of such person. **When in doubt about the reporting of a transaction, please contact the CFO.**

<u>Are there consequences for violating this Policy?</u>

Each person covered by the Policy is responsible for making sure that he or she complies with the Policy, and ensuring compliance with the Policy by his or her Controlled Entities and Family Members. Due to the severity and potentially significant adverse consequences of an insider trading violation, persons who violate the Policy may be subject to disciplinary action by the company, which may include termination or other appropriate action. Disciplinary action may also result due to violations of the Policy by a person's Covered Entities or Family Members.

Under applicable U.S. law, individuals who trade on inside information (or tip information to others who trade) can be liable for sanctions that include:

- a civil penalty of up to three times the profit gained or loss avoided;
- a criminal fine (no matter how small the profit) of up to $5 million; and
- a prison term of up to 20 years.

In addition, employers (as well as possibly any supervisory person) that fail to take appropriate steps to prevent insider trading can be subject to penalties including:

- a civil penalty of the greater of (a) $1,978,690, and (b) three times the profit gained or loss avoided by the person as a result of the violation; and
- a criminal fine of up to $25 million.

Under very limited circumstances, the CFO may provide a waiver of the provisions of this Policy.

<u>Acknowledgment</u>

The undersigned does hereby acknowledge receipt of Hallador Energy Company's Insider Trading Policy. The undersigned has read and understands (or has had explained) such Policy and agrees to be governed by such Policy at all times in connection with the purchase and sale of securities and the confidentiality of nonpublic information.

Signature

Print Name

Date:

APPENDIX A

10b5-1 Plan Requirements

Covered Persons are permitted to effect transactions in the company's securities pursuant to approved 10b5-1 Plans. In order to qualify as an approved "10b5-1 Plan" for purposes of this policy, the trading plan must meet all of the following requirements:

1. The 10b5-1 Plan must be established in writing, signed and dated by the person establishing the plan, approved and signed by the company (with respect to the issuer certificate thereto), and filed with Office of the Chief Legal Officer.
2. The 10b5-1 Plan must be in a form that meets the requirements of Rule 10b5-1 and include certifications from the person establishing the plan that:
   - he, she or it was not aware of any material non-public information about the company or its securities when he, she or it established the 10b5-1 Plan; and
   - the 10b5-1 Plan is entered into in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b5 under the Exchange Act.
3. The 10b5-1 Plan may not be established during any closed trading window to which the person establishing the plan is subject.
4. For any 10b5-1 Plan adopted by any "officer" or "director" (as defined under Rule 10b5-1), trading under such 10b5-1 Plan may not commence until the later of: (a) ninety (90) days after the adoption of the 10b5-1 Plan or (b) two business days following the public disclosure of the company's financial results for the fiscal quarter during which the 10b5-1 Plan was adopted (but, in any event, this required cooling-off period is subject to a maximum of 120 days after adoption of the 10b5-1 Plan).
5. Subject to the exceptions enumerated in Rule 10b5-1, Covered Persons may not have more than one operative 10b5-1 Plan at a time.
6. Each person establishing a 10b5-1 Plan must act in good faith with respect to the 10b5-1 Plan at all times during which it remains outstanding.
7. Any changes or modifications to an existing 10b5-1 Plan with regard to the amount, price, or timing of the purchase or sale of securities underlying the 10b5-1 Plan, or a modification or change to a written formula or algorithm, or computer program that affects the amount, price, or timing of the purchase or sale of such securities, will be deemed to be a termination of the original 10b5-1 Plan and the adoption of a new 10b5-1 Plan, which must comply with the same requirements above, including the cooling-off period set forth in paragraph 4 of this Appendix A.
8. Any form of 10b5-1 Plan must be reviewed and approved by the Office of the Chief Legal Officer prior to entry into the 10b5-1 Plan. The Office of the Chief Legal Officer shall be notified in advance of any proposed amendments to the 10b5-1 Plan or the termination of the 10b5-1 Plan.

Exhibit 21.1

List of Subsidiaries

Edwardsport Construction Company, LLC

Gibson County Logistics, LLC

Hallador Renewables, LLC

Hallador Sands, LLC

Hallador Power Company

Hourglass Sands, LLC

HR Beam One, LLC

Oaktown Fuels Mine No. 1, LLC

Oaktown Fuels Mine No. 2, LLC

Oaktown Gas, LLC

Phoenix 820, LLC

Phoenix 500, LLC

Prosperity Mine, LLC

SFI Coal Sales, LLC

Sunrise Administrative Services, LLC

Sunrise Coal LLC

Sunrise Energy, LLC

Sunrise Land Holdings, LLC

Sycamore Coal, Inc.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 17, 2025, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Hallador Energy Company on Form 10-K for the year ended December 31, 2024. We consent to the incorporation by reference of said reports in the Registration Statements of Hallador Energy Company on Forms S-3 (File No. 333-273325 and File No. 333-273327) and Forms S-8 (File No. 333-261930, File No. 333-163431 and File No. 333-171778).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

March 17, 2025

Exhibit 23.2

John T. Boyd Company

Mining and Geological Consultants

March 7, 2025
File: 3467.008

Subject: CONSENT OF JOHN T. BOYD COMPANY TO BE NAMED IN REGISTRATION STATEMENT

Ladies and Gentlemen:

The undersigned hereby consents to the references to our firm in the form and context in which they appear in this Annual Report on Form 10-K for the year ended December 31, 2024 (as may be amended, the “Annual Report”). We hereby further consent to (i) the use in the Annual Report of information relating to our Technical Report Summary (Coal Resources and Coal Reserves, Oaktown Mining Complex), dated March 2025 (the “Report”), providing an update of estimated coal reserves at the Oaktown Mining Complex as of December 31, 2024 and (ii) the incorporation by reference of the Report in the Registration Statements on Form S-3 (Nos. 333-273325 and 333-273327) and the Registration Statements on Form S-8 (Forms S-8 (Nos. 333-163431, 333-171778 and 333-261930) of Hallador Energy Company, including any amendment thereto, any related prospectus and any related prospectus supplement of such information.

Respectfully submitted,

JOHN T. BOYD COMPANY
By:

Ronald L Lewis

Ronald Lewis
Managing Director and COO

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Chairman
James W. Boyd

President and CEO
John T. Boyd II

Managing Director and COO
Ronald L. Lewis

Vice Presidents
Robert J. Farmer
Jisheng (Jason) Han
John L. Weiss
Michael F. Wick
William P. Wolf

Managing Director - Australia
Jacques G. Steenekamp

Managing Director - China
Rongjie (Jeff) Li

Managing Director – South America
Carlos F. B[illegible]

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jtboydcol@jtboyd.com

www.jtboyd.com

Exhibit 31.1

CERTIFICATION

I, Brent K. Bilsland, certify that:

1. I have reviewed this annual report on Form 10-K of Hallador Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant’s other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 17, 2025

/s/BRENT K. BILSLAND
Brent K. Bilsland, Chairman, President and CEO

Exhibit 31.2

CERTIFICATION

I, Marjorie Hargrave, certify that:

1. I have reviewed this annual report on Form 10-K of Hallador Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 17, 2025 /s/MARJORIE HARGRAVE
Marjorie Hargrave - CFO

Exhibit 32.1

CERTIFICATION PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with this Annual Report (the "Report"), of Hallador Energy Company (the "Company"), on Form 10-K for the period ended December 31, 2024 as filed with the Securities and Exchange Commission on the date hereof the undersigned, in the capacities and date indicated below, each hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 17, 2025	By:	/s/BRENT K. BILSLAND Brent K. Bilsland, Chairman, President and CEO
March 17, 2025	By:	/s/MARJORIE HARGRAVE Marjorie Hargrave, CFO

EXHIBIT 95.1

Our principles at Sunrise Coal LLC are safety, honesty, and compliance. We firmly believe that these values compose a dedicated workforce and with that, come high production. The core to this is our strong training programs that include accident prevention, workplace inspection and examination, emergency response and compliance. We work with the Federal and State regulatory agencies to help eliminate safety and health hazards from our workplace and increase safety and compliance awareness throughout the mining industry.

We are regulated by the Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 ("Mine Act"). MSHA inspects our mines on a regular basis and issues various citations and orders when it believes a violation has occurred under the Mine Act. We present information below regarding certain violations which MSHA has issued with respect to our mines. While assessing this information please consider that the number and cost of violations will vary depending on the MSHA inspector and can be contested and appealed, and in that process, are often reduced in severity and amount, and are sometimes dismissed.

The disclosures listed below are provided pursuant to the Dodd-Frank Act. We believe that the following disclosures comply with the requirements of the Dodd-Frank Act; however, it is possible that future SEC rule making may require disclosures to be filed in a different format than the following.

The table that follows outlines required disclosures and citations/orders issued to us by MSHA during 2024. The citations and orders outlined below may differ from MSHA`s data retrieval system due to timing, special assessed citations, and other factors.

Definitions:

Section 104(a) Significant and Substantial Citations "S&S": An alleged violation of a mining safety or health standard or regulation where there exists a reasonable likelihood that the hazard outlined will result in an injury or illness of a serious nature.

Section 104(b) Orders: Failure to abate a 104(a) citation within the period of time prescribed by MSHA. The result of which is an order of immediate withdraw of non-essential persons from the affected area until MSHA determines the violation has been corrected.

Section 104(d) Citations and Orders: An alleged unwarrantable failure to comply with mandatory health and safety standards.

Section 107(a) Orders: An order of withdrawal for situations where MSHA has determined that an imminent danger exists.

Section 110(b)(2) Violations: An alleged flagrant violation issued by MSHA under section 110(b)(2) of the Mine Act.

Pattern or Potential Pattern of Violations: A pattern of violations of mandatory health or safety standards that are of such a nature as could have significantly and substantially contributed to the cause and effect of coal mine health or safety hazards under section 104(e) of the Mine Act or a potential to have such a pattern.

Contest of Citations, Orders, or Proposed Penalties: A contest proceeding may be filed with the Commission by the operator or miners/miner's representative to challenge the issuance or penalty of a citation or order issued by MSHA.

MSHA Federal Mine ID#`s:
(12-02465 – Carlisle Preparation Plant) (12-02394 – Oaktown Fuels No. 1) (12-02418 – Oaktown Fuels No. 2) (12-02462 – Oaktown Fuels Preparation Plant) (12-02249 – Prosperity Mine)
(12-02339 Freelandville East, Center Pit Mine)

Year Ending 2024

Mine ID#	Section 104(a) Citations	Section 104(b) Orders	Section 104(d) Citations/Orders	Section 107(a) Orders	Section 110(b)(2) Violations	Proposed MSHA Assessments (In thousands)
12-02465	0	0	0	0	0	$0.00
12-02394	92	0	4	0	0	$148.00
12-02418	7	0	0	0	0	$15.00
12-02462	0	0	0	0	0	$0.30
12-02249	0	0	0	0	0	$0.00
12-02339	0	0	0	0	0	$0.00

Mine ID#	Section 104(e) Notice Yes/No	Section 104(e) POV Yes/No	Mining Related Fatalities	Legal Actions Pending	Legal Actions Initiated	Legal Actions Resolved
12-02465	No	No	0	0	0	0
12-02394	No	No	0	0	0	0
12-02418	No	No	0	1	0	3
12-02462	No	No	0	0	0	0
12-02249	No	No	0	0	0	0
12-02339	No	No	0	0	0	0

Mine ID#	Contest of Citations/ Orders	Contest of Penalties	Complaints of Compensation	Complaints of Discharge/ Discrimination	Applications of Temp. Relief	Appeals of Decisions/ Orders
12-02465	0	0	0	0	0	0
12-02460	0	0	0	0	0	0
12-02394	0	0	0	0	0	0
12-02418	0	0	0	0	0	0
12-02462	0	0	0	0	0	0
12-02249	0	0	0	0	0	0
12-02339	0	0	0	0	0	0

Exhibit 96.1

TECHNICAL REPORT SUMMARY

COAL RESOURCES AND COAL RESERVES OAKTOWN MINING COMPLEX

Indiana and Illinois

Prepared For

SUNRISE COAL, LLC

By

John T. Boyd Company

Mining and Geological Consultants

Pittsburgh, Pennsylvania, USA

Report No. 3467.008

MARCH 2025

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1.0 EXECUTIVE SUMMARY

1.1 Introduction

Sunrise's Oaktown Mining Complex is a mining complex that includes two underground room-and-pillar (R&P) mines—the active Oaktown Fuels No. 1 Mine and the idled Oaktown Fuels No. 2 Mine, respectively —and the Oaktown Complex Coal Preparation Plant (CPP). BOYD was retained by Sunrise to complete an independent technical assessment of coal resource and coal reserve estimates for the Oaktown Mining Complex.

BOYD's findings as a result of the audit of Oaktown Mining Complex's coal resource and coal reserve estimates are based on our detailed examination of the supporting geologic, technical, and economic information obtained from: (1) Sunrise files, (2) discussions with Sunrise personnel, (3) records on file with regulatory agencies, (4) public sources, and (5) nonconfidential BOYD files.

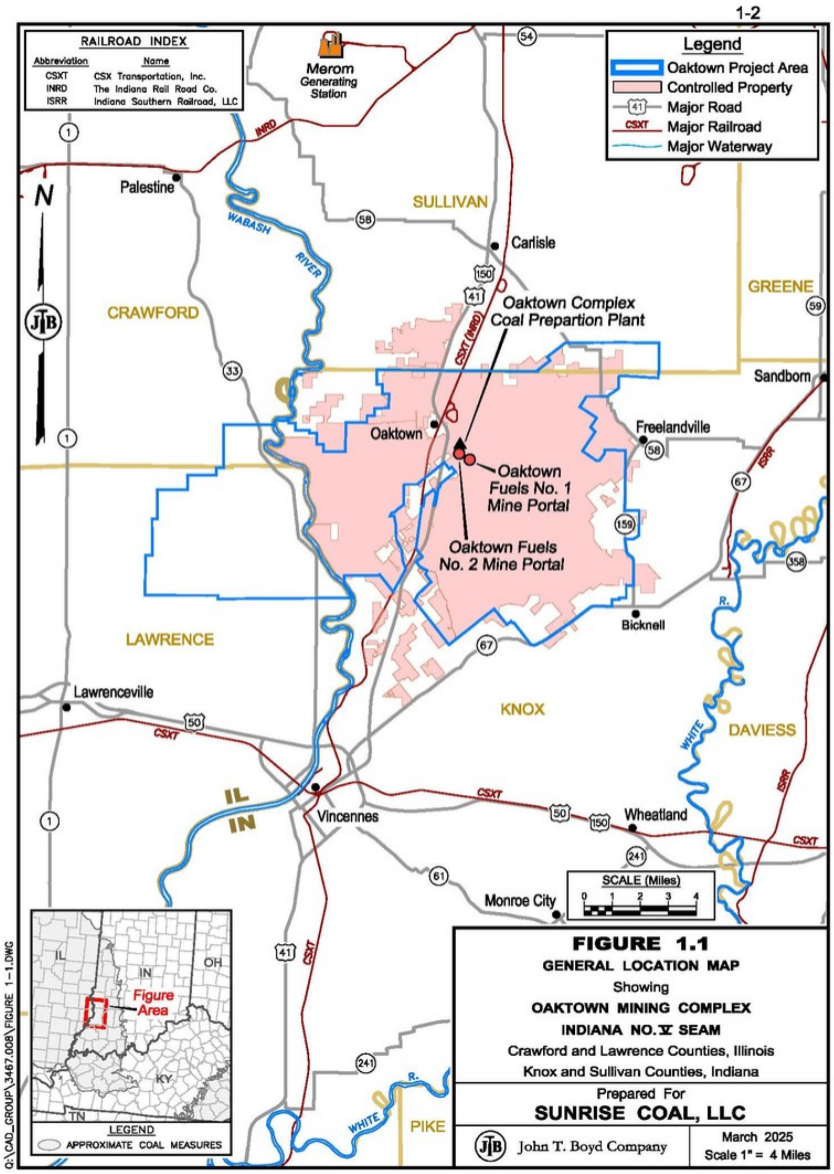
This technical report identifies and summarizes the results of our audit of the Oaktown Mining Complex coal reserves and independent assessment of the economic viability of extracts of the Oaktown Mining Complex coal reserves over the life of the mine and satisfies the requirements for Sunrise's disclosure of coal reserves set forth in Subpart 1300 and Item 601(b)(96) of the SEC's Regulation S-K (S-K 1300). This is the second technical report summary for the Oaktown Mining Complex. BOYD is a qualified person as defined in Regulation S-K 1300.

Weights and measurements are expressed in U.S. customary units. Unless noted, the effective date of the information, including estimates of coal reserves, is December 31, 2024.

1.2 Property Description

The Oaktown Mining Complex is an active underground coal mining and processing operation located in Knox and Sullivan counties, Indiana, and Lawrence County, Illinois. The general location of the Oaktown Mining Complex is provided in Figure 1.1, following this page. The project lies in a well-developed region with a robust infrastructure.

Figure 1.1


1-2
RAILROAD INDEX
Abbreviation Name
CSXT CSX Transportation, Inc.
INRD The Indiana Rail Road Co.
ISRR Indiana Southern Railroad, LLC
Legend
Oaktown Project Area
Controlled Property
Major Road
Major Railroad
Major Waterway
Merom Generating Station
Palestine
SULLIVAN
Carlisle
WABASH RIVER
GREENE
CRAWFORD
Oaktown Complex Coal Prepartion Plant
Sandborn
Oaktown
Freelandville
Oaktown Fuels No. 1 Mine Portal
Oaktown Fuels No. 2 Mine Portal
LAWRENCE
Bicknell
Lawrenceville
KNOX
DAVIESS
IL
IN
Vincennes
Wheatland
Monroe City
SCALE (Miles)
PIKE
Figure Area
LEGEND
APPROXIMATE COAL MEASURES
FIGURE 1.1
GENERAL LOCATION MAP
Showing
OAKTOWN MINING COMPLEX
INDIANA NO. V SEAM
Crawford and Lawrence Counties, Illinois
Knox and Sullivan Counties, Indiana
Prepared For
SUNRISE COAL, LLC
John T. Boyd Company
March 2025
Scale 1" = 4 Miles

Located within the ILB coal-producing region of the midwestern U.S., the Oaktown Mining Complex is one of the largest underground R&P coal mining complexes in North America.

The Oaktown Mining Complex mines coal exclusively from the Indiana V Seam (Illinois No. 5 Springfield Seam). Within the Oaktown Mining Complex mine plan boundaries, Sunrise currently maintains the right to mine and remove approximately 95% of the Indiana V Seam through lease agreements. Several small adverse (uncontrolled) tracts exist within the proposed life-of-mine (LOM) plan; however, Sunrise has demonstrated success in acquiring these as required during the ordinary course of business. BOYD is not aware of any encumbrances, litigation, or orders that would hinder the continued development of the property.

The Indiana V Seam has been extensively mined in the ILB region and is one of two predominant coal seams of economic interest. Sunrise has demonstrated a history of successfully mining the Indiana V Seam at the Oaktown Mining Complex, with initial mining at the complex dating to 2009.

1.3 Geology

The Oaktown Mining Complex is situated in the Carbondale Group (Formation) of the Pennsylvania System. Near-surface geology of this area primarily consists of the overlying Quarternary System. Coal seams mined in this region are generally classified as medium- to high-sulfur content and moderate ash thermal coal products.

The Indiana V Seam is the only coal seam of economic interest on the property. Structurally, the Indiana V Seam consists of a singular and relatively consistent horizon averaging between 4 ft to 8 ft thick containing little in-seam parting. The Indiana V Seam globally dips in the general westerly direction and experiences localized areas where the seam elevations vary. Pronounced gradients can occur periodically in the form of rolls in the seam. Depths for the Indiana V Seam range from approximately 300 ft to 450 ft below ground surface within the Oaktown Mining Complex area.

The Indiana V Seam coal bed is characterized as high sulfur and moderate ash coal that is used for steam purposes.

1.4 Exploration

The Indiana V Seam has been extensively explored and mined in the region, with drilling records dating prior to the inception of the Oaktown Mining Complex. Sunrise provided data for 1,935 drill holes that have intercepted the Indiana V Seam and have been complied for defining the lateral extent, thickness, and qualities (both raw and clean) of the Indiana V Seam in the immediate Oaktown Mining Complex project area.

BOYD's audit indicates that in general: (1) Sunrise has performed extensive drilling and sampling work on the subject property, (2) the work completed has been done by competent personnel, and (3) the amount of data available combined with wide-spread knowledge of the Indiana V Seam, is sufficient to confirm the thickness, lateral extents, and quality characteristics of the Indiana V Seam.

1.5 Coal Resources/Reserves

Sunrise's estimated underground mineable coal reserves for the Oaktown Mining Complex total 34.4 million recoverable (clean) product tons remaining as of December 31, 2024. The coal reserves controlled by Sunrise are summarized in Table 1.1.

Table 1.1: Coal Reserves Summary

	Product Tons (000)			Average Product Quality (As Received Basis)				
		By Permit Status		%			Heating	SO_2
			Not	Total			Value	(lbs per
Classification	Total	Permitted	Permitted	Moisture	Ash	Sulfur	(Btu/lb)	MMBtu)
Oaktown Fuels No. 1 Mine								
Proven	25,660	25,660	-	13.0	7.5	3.5	11,504	6.0
Probable	2,675	2,675	-	13.0	7.3	3.5	11,533	6.0
Total	28,335	28,335	-	13.0	7.5	3.5	11,506	6.0
Oaktown Fuels No. 2 Mine								
Proven	5,887	5,214	673	13.0	7.5	2.9	11,580	5.0
Probable	215	207	8	13.0	8.1	2.5	11,465	4.4
Total	6,102	5,421	681	13.0	7.5	2.9	11,576	5.0
Total - Oaktown Mining Complex								
Proven	31,547	30,874	673	13.0	7.5	3.3	11,518	5.8
Probable	2,890	2,882	8	13.0	7.4	3.4	11,528	5.9
Total	34,437	33,756	681	13.0	7.5	3.4	11,519	5.8

It is BOYD’s opinion that extraction of the reported coal reserves is technically achievable and economically viable after the consideration of potentially material modifying factors. Periodic amendments to existing mining permits to add additional acreage (reserve tonnage) in order to sustain coal production is common practice. We are not aware of any issues that would impact or prevent the present “Not Permitted” reserves to be permitted as future mining needs dictate. We are also not aware of any prohibition against the proposed mining and processing activities.

There are no reportable coal resources excluding those converted to coal reserves for the Oaktown Mining Complex.

1.6 Operations

1.6.1 Mining

The Oaktown Mining Complex is comprised of the Oaktown Fuels No. 1 and Oaktown Fuels No. 2 underground mines. Each mine utilizes R&P mining (employing continuous miners [CMs]) for primary production. This mining method is highly productive and commercially demonstrated; it has been one of the primary approaches to 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 58.3 million tons of clean coal. The complex is configured to operate up to six CM sections, with an annual production target of approximately 6 million product tons. The Oaktown Mining Complex is generally considered an industry leader in terms of mining productivity and mining costs when compared to other R&P underground operations.

It is BOYD’s opinion that the forecasted production levels for the Oaktown Mining Complex operations are reasonable, logical, and consistent with typical R&P mining practices in the Indiana V Seam and historical practices utilized by Sunrise. The Oaktown Mining Complex LOM plans developed by BOYD show a relatively stable production output until individual production sections are retired corresponding to reserve exhaustion. In the aggregate, the Oaktown Mining Complex LOM plan projects the complex will produce approximately 57.1 million tons of run-of-mine (ROM) coal (34.4 million saleable tons after processing) during the next 11 years (through 2035).

1.6.2 Processing

The Oaktown Complex CPP serves as the coal washing facility for the Oaktown Mining Complex’s two R&P mines. The plant was commissioned in 2009 to wash coal produced by the Oaktown Fuels No. 1 Mine. The Oaktown Complex CPP has a current processing capacity of 1,600 raw tons-per-hour (TPH).

The beneficiation process utilized at the Oaktown Mining Complex has a proven performance record and has remained relatively unchanged for decades. The plant's ability to blend raw coal production from the two underground mines into a singular plant feed allows for both more consistent plant operation and the ability to achieve differing clean coal qualities for various customer specifications.

1.6.3 Other Infrastructure

The Oaktown Mining Complex underground mines and CPP are supported by several surface infrastructure sites. Major surface infrastructure includes ancillary buildings, high-voltage power distribution stations, ROM coal conveyor belts, CPP refuse facilities, underground access and ventilation structures, and truck/rail loading systems.

Product coal from the Oaktown Mining Complex is transported to its customer base via rail, truck, or a combination of both. The Oaktown Complex CPP 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 CPP can facilitate the loading of trucks for direct transport to select customers, or to Sunrise's transload facility in Princeton, Indiana serviced by the Norfolk Southern (NS) Railroad.

The Oaktown Complex refuse facility serves as the disposal location for all waste rock (coarse coal refuse) and portions of the fine coal slurry (fine coal refuse) produced during the processing of coal. The majority of the fine coal slurry is transported overland via a network of pumps and pipelines for underground disposal within mined-out void areas of the Oaktown Fuels No. 1 and No. 2 mines.

1.7 Financial Analysis

1.7.1 Market Analysis

The Oaktown Mining Complex's product is thermal coal that is directed into the U.S. coal-fired generation market. Historically, this market accounts for all of the Oaktown Mining Complex annual sales.

Coal use among domestic power generators has fallen out of favor in several of the individual states of the U.S. and is being replaced by natural gas and renewable forms of generation. However, several states are positioned to remain largely reliant upon coal for power generation, such as Indiana. Sunrise anticipates its geographical location, reputation for sustained production, and well-capitalized infrastructure well position the complex to continue supplying coal into the Indiana market and other domestic coal markets when opportunities present.

1.7.2 Capital and Operating Costs

The ILB is widely recognized as being ideally suited for commercial scale mining through R&P mining methods. The region's Indiana V Seam is conducive to efficient, low-cost production R&P operations. In terms of total dollars expended per year, cash operating costs for R&P mines contain a mixture of variable and fixed costs. Unit costs, therefore, will vary mostly due to changes in production and less so with regard to general inflation and major mine site changes.

During the historical review period of 2020 through 2024, total cash operating costs per saleable ton for the Oaktown Mining Complex were within the range of $30 to $47 per saleable ton. Cash operating costs for the complex were approximately $8.45 per ton higher in 2024 than 2023, primarily due to significant increases in direct labor and direct operating costs due to one-time reduction in workforce expenses.

While each of the individual mines may have realized higher or lower operating costs annually, their operation in parallel aids in the complex's ability to minimize short-term periods of individual mine coal production decreases and/or increases in operating costs.

The Oaktown Mining Complex is regarded as being well-capitalized comparatively to industry peers. Continual capital expenditures have been ongoing by Sunrise in recent years to support mine infrastructure expansions, maintenance of production equipment, refuse placement, etc. Notwithstanding the significant capital expenditures of 2022 and 2023 for major equipment rebuilds, Oaktown Mining Complex's aggregate capital expenditure level was relatively consistent and generally within the range of $4.00 to $5.00 per clean ton.

BOYD found Sunrise's forecasted operating and capital costs to be indicative of the complex's historical performance and in general agreement with BOYD's independent LOM forecasts.

1.7.3 Economic Analysis

The results of our indicative economic analysis for Oaktown Mining Complex over the 11-year period (2025 to 2035) shows an after-tax net present value (NPV) of $70.7 million for the expected case at a 12% discount rate. The coal sales price estimated over the life of the reserves averages approximately $48.72 (ranging from $47.25 to $51.47).

The NPV estimate was made for purposes of confirming the economic viability of the reported coal reserves and not for purposes of valuing Sunrise or its assets. Internal rate-of-return (IRR) and project payback were not calculated, as there was no initial investment considered in the financial model.

While BOYD concludes that the stated coal reserves are economically viable under reasonable financial assumptions and market price expectations, we note that the project is sensitive to fluctuations in coal sales prices and/or operating costs and is marginal or uneconomic under some scenarios.

1.8 Regulation and Liabilities

Multiple permits are required by federal and state law for underground mining, coal preparation and related facilities, and other incidental activities. Sunrise reports that 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, Sunrise should be able to secure new permits, as required, to maintain its planned operations within the context of the current regulations.

Permits generally require that Sunrise 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. Sunrise reports holding surety bonds to cover its current obligations relating to mining and reclamation, road repair, etc. Those obligations currently equate to $6.7 million.

1.9 Conclusions

It is BOYD's overall conclusion that Sunrise's estimates of coal reserves, as reported herein: (1) were prepared in conformance with accepted industry standards and practices, and (2) are reasonably and appropriately supported by technical evaluations, which consider all relevant modifying factors. We do not believe there is other relevant data or information material to the Oaktown Mining Complex that would render this technical report summary misleading. Our conclusions represent only informed professional judgment.

Given the operating history and status of evolution, residual uncertainty for this project is considered minor under the current and foreseeable operating environment. A general assessment of risk is presented in the relevant sections of this report.

The ability of Sunrise, or any mine operator, to recover all of the reported coal reserves is dependent on numerous factors that are beyond the control of, and cannot be anticipated by, BOYD. These factors include mining and geologic conditions, the capabilities of management and employees, the securing of required approvals and permits in a timely manner, future coal prices, etc. Unforeseen changes in regulations could also impact performance. Opinions presented in this report apply to the site conditions and features as they existed at the time of BOYD's investigations and those reasonably foreseeable.

2.0 INTRODUCTION

2.1 Registrant and Purpose

This technical report summary was prepared for Hallador Energy (Hallador) in support of their disclosure of their subsidiary, Sunrise's, coal resources and coal reserves for the Oaktown Mining Complex.

Hallador is a US-based energy solutions company headquartered in Terre Haute, Indiana, and is listed on the National Association of Securities Dealers Automated Quotations (NASDAQ:HNRG) stock exchange. A large portion of Hallador's business focuses upon coal mining through their subsidiary Sunrise. Sunrise is actively engaged in the production and export of thermal coal from mines located in the ILB. The company also owns and operates the Princeton Rail Loop, which is located near Princeton, Indiana on the NS Railroad. Additional information regarding Hallador (and Sunrise) can be found on their website at www.halladorenergy.com.

2.2 Terms of Reference

Sunrise retained BOYD to complete an independent technical assessment of mineral resource and mineral reserve estimates and supporting information for the Oaktown Mining Complex. Our objective was to obtain reasonable assurance that the coal resource and coal reserve statements for Oaktown Mining Complex are free from material misstatement.

The results of our third-party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in Subpart 1300 and Item 601(b)(96) of the SEC's Regulation S-K. The purpose of this report is: (1) to summarize available information for the subject mining properties, (2) to provide the conclusions of our technical assessment, (3) to provide a statement of coal resources and/or coal reserves for the Oaktown Mining Complex, and (4) provide our conclusion of the economic viability of the Oaktown Mining Complex's coal reserves. This is the second technical report summary filed by Sunrise for the Oaktown Mining Complex.

BOYD's findings are based on our detailed examination of the supporting geologic and other scientific, technical, and economic information provided by Sunrise, as well as our assessment of the methodology and practices applied by Sunrise in formulating the estimates of coal resources and coal reserves disclosed in this report. We did not independently estimate coal resources or coal reserves from first principles.

We used standard engineering and geoscience methods, or a combination of methods, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of mining property evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The ability of Sunrise, or any mine operator, to recover all of the estimated coal reserves presented in this report is dependent on numerous factors that are beyond the control of, and cannot be anticipated by, BOYD. These factors include mining and geologic conditions, the capabilities of management and employees, the securing of required approvals and permits in a timely manner, future coal prices, etc. Unforeseen changes in regulations could also impact performance. Opinions presented in this report apply to the site conditions and features as they existed at the time of BOYD's investigations and those reasonably foreseeable.

This report is intended for use by Sunrise subject to the terms and conditions of its professional services agreement with BOYD. The agreement permits Sunrise to file this report as a technical report summary with the SEC pursuant to Subpart 1300 and Item 601(b)(96) of Regulation S-K. Except for the purposes legislated under U.S. securities law, any other uses of our reliance on this report by any third party is at that party's sole risk. The responsibility for this disclosure remains with Sunrise. The user of this document should ensure that this is the most recent disclosure of coal resources and coal reserves for the subject property as it is no longer valid if more recent estimates have been issued.

2.3 Expert Qualifications

BOYD is an independent consulting firm specializing in mining-related engineering and financial consulting services. Since 1943, BOYD has completed over 4,000 projects in the United States and more than 60 other countries. Our full-time staff comprises mining experts in: civil, environmental, geotechnical, and mining engineering; geology; mineral economics; and market analysis. Our extensive experience in coal resources/reserve estimation and our knowledge of the subject coal properties, provides BOYD an informed basis on which to opine on the reasonableness of the estimates provided by Sunrise. An overview of BOYD can be found on our website at www.jtboyd.com.

The individuals primarily responsible for this independent technical assessment and the preparation of this report are by virtue of their education, experience, and professional association considered qualified persons as defined in Subpart 1300 of Regulation S-K.

Neither BOYD nor its staff employed in the preparation of this report have any beneficial interest in Sunrise, and are not insiders, associates, or affiliates of Sunrise. The results of our audit were not dependent upon any prior agreements concerning the conclusions to be reached, nor were there any undisclosed understandings concerning any future business dealings between Sunrise and BOYD. This report was prepared in return for fees based upon agreed commercial rates, and the payment for our services was not contingent upon our opinions regarding the project or approval of our work by Sunrise and its representatives.

2.4 Principal Sources of Information

Information used in this assignment was obtained from: (1) Sunrise files, (2) discussions with Sunrise personnel, (3) records on file with regulatory agencies, (4) public sources, and (5) nonconfidential BOYD files.

The following information was provided by Sunrise:

- Year-end reserve statements and reports for 2024.
- Exploration records (e.g., drilling logs, lab sheets).
- Geologic databases of lithology and coal quality.
- Computerized geologic models.
- Mapping data, with:
  - Mineral tenure boundaries.
  - Permit boundaries.
  - Limits of previous mining.
- LOM plans and supporting documentation.
- Financial forecasting models.
- Historical information, including:
  - Production reports and reconciliation statements.
  - Financial statements.
  - Product sales and pricing.

Information from sources external to BOYD and/or Sunrise are referenced accordingly.

The data and work papers used in the preparation of this report are on file in our offices.

2.4.1 Site Visits

A personal inspection of the Oaktown Fuels No. 1 and No. 2 mines was made by two of BOYD's senior mining engineers—qualified persons and co-authors of this report—on December 2, 2021.

The site visit included: (1) observation of both mine's active underground workings, belt lines, outby areas, and portal (mine access) locations; (2) a tour of the mine site's surface infrastructure; and (3) a tour of the Oaktown Complex CPP, truck and rail loadout, and refuse disposal facility. BOYD's representatives were accompanied by senior Sunrise management personnel who openly and cooperatively answered questions regarding, but not limited to: site geology, mining conditions and operations, equipment usage, labor relations, operating and capital costs, current coal washing operations, and coal marketing.

2.4.2 Reliance on Information Provided by the Registrant

In the preparation of this report we have relied, without independent verification, upon information furnished by Sunrise with respect to: property interests; exploration results; current and historical production from such properties; current and historical costs of operation and production; and agreements relating to current and future operations and sale of production.

BOYD exercised due care in reviewing the information provided by Sunrise within the scope of our expertise and experience (which is in technical and financial mining issues) and concluded the data are valid and appropriate considering the status of the subject properties and the purpose for which this report was prepared. BOYD is not qualified to provide findings of a legal or accounting nature. We have no reason to believe that any material facts have been withheld, or that further analysis may reveal additional material information. However, the accuracy of the results and conclusions of this report are reliant on the accuracy of the information provided by Sunrise.

While we are not responsible for any material omissions in the information provided for use in this report, we do not disclaim responsibility for the disclosure of information contained herein which is within the realm of our expertise.

2.5 Effective Date

The effective (i.e., "as of") date of this report is December 31, 2024. The estimates of coal resources and coal reserves and supporting information presented in this report are effective as of December 31, 2024.

2.6 Units of Measure

The U.S. customary measurement system has been used throughout this report. Tons are short tons of 2,000 pounds-mass. Unless otherwise stated, currency is expressed in U.S. Dollars ($). Historic prices and costs are presented in nominal (unadjusted) dollars. Future dollar values are expressed on a constant (unescalated) basis as of the effective date of this report.

3.0 PROPERTY OVERVIEW

3.1 Description and Location

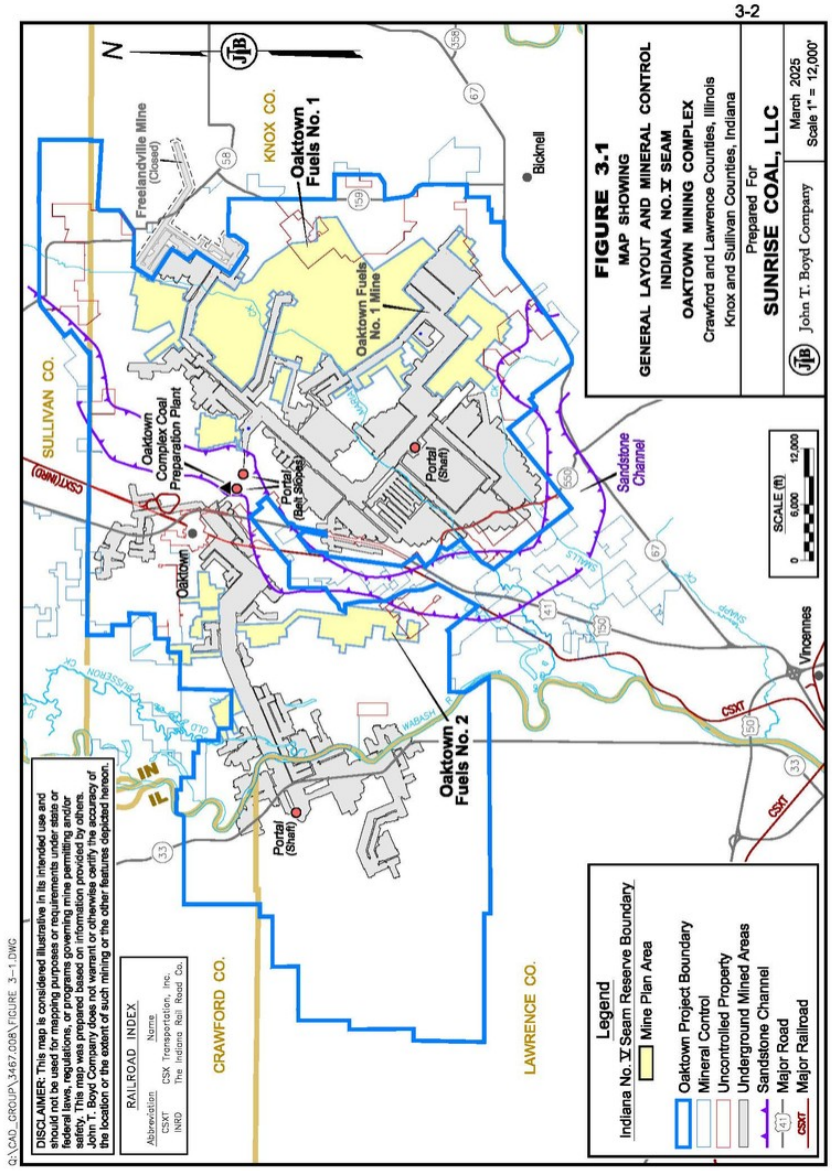
The Oaktown Mining Complex is a coal mining and processing operation located in Knox and Sullivan counties, Indiana, and Crawford and Lawrence counties, Illinois. Comprising almost 118 square miles within the ILB coal-producing region of the midwestern U.S., the Oaktown Mining Complex is one of the largest underground R&P coal mining complexes in North America. The Oaktown Mining Complex operations currently consist of the active Oaktown Fuels No. 1 underground mine, the recently idled Oaktown Fuels No. 2 underground mine, and related coal processing facilities and other infrastructure.

While each of the two mines have a unique Mine Safety and Health Administration (MSHA) mine identification number and has a separate direct management team, the Oaktown Mining Complex is commercially operated as a single entity. All mine output is delivered by belt conveyors to a central coal processing facility, the Oaktown Complex CPP, that is rated at 1,600 raw TPH and reports to MSHA under its own identification number. The ROM coal is segregated by mine, and refined analysis and processing systems are utilized to meet customer specifications. Plant reject-material reports to the coarse and fine refuse disposal facilities or is placed into abandoned mine void areas through slurry (fine refuse) injection. Saleable output is shipped to a diverse customer base via truck or rail facilitated by the rail load-out on a dedicated rail spur serviced by CSX and INRD.

The Oaktown Mining Complex is located approximately 44 miles south of Terre Haute, Indiana near the town of Oaktown, Indiana. The city of Vincennes, Indiana lies about 14 miles to the southwest. The project area is essentially bisected by U.S. Route 41.

Geographically, the Oaktown Complex CPP is located at approximately 38°51’24.7” N latitude and 87°25’30.9” W longitude. Figures 1.1 (page 1-2) and 3.1, following this page, illustrate the location and general layout of the Oaktown Mining Complex.

Figure 3.1


3-2
FIGURE 3.1
MAP SHOWING
GENERAL LAYOUT AND MINERAL CONTROL
INDIANA NO. V SEAM
OAKTOWN MINING COMPLEX
Crawford and Lawrence Counties, Illinois
Knox and Sullivan Counties, Indiana
Prepared For
SUNRISE COAL, LLC
John T. Boyd Company
March 2025
Scale 1" = 12,000'
SCALE (ft)
0 6,000 12,000
Legend
Indiana No. V Seam Reserve Boundary
Mine Plan Area
Oaktown Project Boundary
Mineral Control
Uncontrolled Property
Underground Mined Areas
Sandstone Channel
Major Road
Major Railroad
DISCLAIMER: This map is considered illustrative in its intended use and should not be used for mapping purposes or requirements under state or federal laws, regulations, or programs governing mine permitting and/or safety. This map was prepared based on information provided by others. John T. Boyd Company does not warrant or otherwise certify the accuracy of the location or the extent of such mining or the other features depicted hereon.
RAILROAD INDEX
Abbreviation Name
CSXT CSX Transportation, Inc.
INRD The Indiana Rail Road Co.
Q:\CAD_GROUP\3467.008\FIGURE 3-1.DWG
N
SULLIVAN CO.
KNOX CO.
CRAWFORD CO.
LAWRENCE CO.
IN
IL
Freelandville Mine (Closed)
Oaktown Fuels No. 1
Oaktown Fuels No. 1 Mine
Oaktown Complex Coal Preparation Plant
Portal (Belt Slope)
Portal (Shaft)
Oaktown
Oaktown Fuels No. 2
Sandstone Channel
Bicknell
Vincennes
CSXT (INRD)
CSXT

3.2 History

Vectren Fuels was the original developer of the property. Construction of the Oaktown Fuels No. 1 Mine slope, surface mine infrastructure, and CPP began in 2008. Following development of the slope, commercial coal production began in 2009. Processing of the Oaktown Fuels No. 1 Mine coals was facilitated by the then 800 raw feed TPH capacity CPP. Development of Oaktown Fuels No. 2 Mine followed shortly after, with commercial coal production beginning in 2013. The commercial production status of Oaktown Fuels No. 2 Mine coincided with the expansion of the CPP's 800 TPH capacity to its present 1,600 TPH capacity.

Sunrise's involvement with the Oaktown Mining Complex dates to 2014 with the acquisition of Oaktown Fuels No. 1 and No. 2 mines from Vectren Fuels. Sunrise steadily increased annual production from the Oaktown Mining Complex—averaging between 6 to 7 million product tons annually between 2017 and 2023. The mine workings have substantially grown since 2014, and both mines have installed new shafts (mine accesses) for employee ingress/egress from the active production faces. The new Oaktown Fuels No. 1 Mine portal location is approximately 4.5 miles southeast of the town of Oaktown, Indiana while the new Oaktown Fuels No. 2 Mine portal location is approximately 1.5 miles northwest of the village of Russellville, Illinois. The Oaktown Fuels No. 2 Mine was idled in February 2024 as part of a restructuring to strengthen financial and operational efficiency.

There are no significant Indiana V Seam mining activities known to have occurred within the Oaktown Mining Complex boundarys preceding Vectren Fuel's and Sunrise's involvement.

3.3 Property Control

Within the Oaktown Mining Complex area and immediate vicinity, Sunrise controls approximately 59,000 acres of mineral rights. This control exists as a complex collection of leases that apply to thousands of individual 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 fractional, in which mineral rights are split between several owners. Sunrise and its predecessors have acquired the necessary rights to support development and operations through purchase or lease agreements with predominantly private owners or entities.

BOYD has not independently verified ownership of the Oaktown Mining Complex area and the underlying property agreements. Ownership data provided to BOYD, including maps and summaries of lease agreements, have been accepted as being true and accurate for the purpose of this report.

3.3.1 Coal Ownership

Sunrise currently controls approximately 95% of the coal within projected mine plan boundaries through lease agreements with the balance currently reported as adverse. Reportedly, lease terms generally extend until all the coal is removed from the subject tract. Where applicable, royalty rates are typically based upon a percentage of the gross sales price of the coal. No material amounts of mineral within the Oaktown Mining Complex mine plan boundaries is owned in fee.

Adverse (uncontrolled) tracts within the project limits are common; however, it is generally reasonable to assume that such tracts can be acquired or leased in the ordinary course of business as has been demonstrated historically by Sunrise. It is BOYD's opinion that adverse coal control does not pose a material risk to the estimate of coal reserves reported herein.

3.3.2 Surface Ownership

As part of the Oaktown Mining Complex, Sunrise 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).

Sunrise reports it controls adequate surface rights to sustain current mining operations in the near term. Additional surface property will likely be required during the life of the mine for the placement of additional infrastructure. It is generally reasonable to assume the required property can be acquired or leased in the ordinary course of business; as such, we do not believe there is any undue risk associated with surface ownership to the estimated reserves reported herein.

3.4 Adjacent Properties

As illustrated in Figures 1.1 and 3.1, there are no other operating mines or mines/properties controlled by Sunrise adjacent to the Oaktown Mining Complex. As shown, some existence of Indiana V Seam mining has taken place near the Oaktown Mining Complex to the northeast. Sunrise's mine plans include sufficient barrier zones to mitigate any risk associated with prior mining activities of the adjacent properties.

3.5 Regulation and Liabilities

Mining and related activities on the Oaktown Mining Complex properties are regulated by both federal and state laws. The relevant federal laws include:

- Clean Air Act of 1970/1977.
- Clean Air Act Amendments of 1990.
- Clean Water Act of 1977.
- Surface Mining Control and Reclamation Act of 1977.
- Resource Conservation and Recovery Act of 1976.

In Indiana and Illinois, responsibility for enforcing these acts, with the aid of numerous state laws and legislative rules, lies with Illinois's Environmental Protection Agency (IL-EPA) and Indiana's Department of Natural Resources (IN-DNR).

As mandated by these laws and regulations, numerous permits are required for underground mining, coal preparation and related facilities, and other incidental activities. Sunrise reports that necessary permits are in place or applied for to support current operations. New permits or permit revisions may be necessary from time to time to facilitate future operations. Given sufficient time and planning, Sunrise should be able to secure new permits, as required, to maintain its planned operations within the context of the current regulations.

Permits generally require that the permittee 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 regulations requirements of the permit are fully satisfied. Sunrise reports holding surety bonds to cover its current obligations relating to mining and reclamation, road repair, etc. Those obligations currently equate to $6.7 million.

Regular inspection of the mines and related facilities are conducted by MSHA for health and safety compliance. On finding any violation of a health or safety standard, an inspector will issue a citation that specifies the standard violated and evaluates the gravity of the violation by several factors, including likelihood of injury. Any infraction that is reasonably likely to result in a serious injury or illness or is caused by the operator's unwarrantable failure to comply with regulatory requirements will carry additional fines and could result in temporary closure. Typically, the civil penalties for regular assessments are not considered material.

BOYD is not aware of any prohibition of mining and processing activities for the Oaktown Mining Complex. However, the reported coal reserves may be materially impacted by: Sunrise's failure to comply with permit conditions and rules; delays in obtaining required government or other regulatory approvals or permits; Sunrise's inability to obtain such required approvals or permits; or changes in governmental regulations.

3.6 Accessibility, Local Resources, and Infrastructure

The Oaktown Mining Complex lies within a rural but well-developed region of southwestern Indiana and southeastern Illinois, with an extensive history related not only to coal mining, processing, and transportation, but also many other industries and services. A reported 1.4 million people live within 75 miles of the Oaktown Mining Complex, according to the U.S. Census of 2020.

General access to the Oaktown Mining Complex is via a well-developed network of primary and secondary roads serviced by state and local governments. These roads offer direct access to the mine and processing facilities and are generally open year-round.

Coal produced at the Oaktown Mining Complex is transported primarily by rail, truck, or a combination of both. A rail load-out facility and dedicated rail spur loop facilitate transportation of the coal on the INRD and CSX railroads. Additionally, Oaktown Mining Complex can facilitate the loading of trucks for direct transport to select customers, or to Sunrise's transload facility in Princeton, Indiana serviced by the NS Railroad.

Several regional airports are located near the Oaktown Mining Complex and the Indianapolis International Airport is located approximately 100 miles northeast of the complex.

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.

3.7 Physiography

The Oaktown Mining Complex lies within the Southern Hills and Lowland areas of the Southwest Indiana region. This region is characterized by relatively flat topography possessing gentle gradients associated with drainages. Surface elevations within the Oaktown Mining Complex area range from approximately 410 ft to 590 ft above mean sea-level. The region possesses a network of overlying tributaries and waterways flowing to the Wabash River; all of which overlay the complex area.

Land cover within the area consists predominantly of mixed crop/pastureland and forest dotted with medium- to low-density (rural) residential areas.

3.8 Climate

Climate in and around the Oaktown Mining Complex is typical of southwestern Indiana, with four distinct seasons: cold winters; hot and humid summers; and mild falls and springs.

Over the course of the year, the temperature typically varies from 24°F to 87°F and is rarely below 7°F or above 94°F. The hot season lasts from late-May to late-September, with an average daily high temperature above 78°F. The hottest month of the year is July, with an average high of 87°F and low of 68°F. The cold season lasts from early-December to late-February, with an average daily high temperature below 49°F. The coldest month of the year is January, with an average low of 25°F and high of 40°F.

The area experiences on average 46 in. of rain and 9 in. of snowfall per year. Adverse weather conditions seldom limit the Oaktown Mining Complex coal mining, processing, and loading operations; however, extreme weather conditions may temporarily impact operations.

4.0 GEOLOGY

4.1 Regional Geology

The Oaktown Mining Complex is located within the eastern portion of the ILB region, a sedimentary basin which coal-bearing areas cover approximately 50,000 square miles across the majority of Illinois, southwestern Indiana and portions of western Kentucky. The coal bearing members of the ILB consist of Pennsylvanian rocks, formed approximately 290 – 330 million years ago. The Indiana VI (Herrin) and Indiana V (Springfield) seams are accredited with the vast majority of the economically mineable coals within the ILB.

The ILB has informally been subdivided into eight mining regions—Northern Illinois, Western Illinois, West-central Illinois, East-central Illinois, Southwestern Illinois, Southeastern Illinois, Southwestern Indiana, and Western Kentucky. The majority of current coal mining from the ILB occurs within the West-central Illinois, Southeastern Illinois, Southwestern Illinois, Southwestern Indiana, and Western Kentucky regions. The Oaktown Mining Complex is located within the Southwestern Indiana region of the ILB.

There are three predominant structural features within the ILB which include the DuQuoin monocline, La Salle anticlinal belt, and the Cottage Grove-Rough Creek fault system. The features surround the Fairfield Basin area which contain the deepest extents of the ILB. The DuQuoin monocline on the west, the La Salle anticlinal belt on the north, and the Cottage Grove-Rough Creek fault system on the south, all flank the Fairfield Basin. In general, the Illinois and Indiana portions of the ILB dip gently towards the interior, Fairfield Basin. The Southwestern Indiana mining region, in which the Oaktown Mining Complex is located, experiences localized rolling of the coal seams but predominately dips in a westerly direction.

The Carbondale Formation is the primary coal-bearing formation containing the majority of the ILB economically mineable bituminous coals. The Indiana VI (Herrin) and Indiana V (Springfield) seams that are heavily exploited within the ILB, are typically between 2 ft and 6 ft in thickness. Coal in the region is classified as high-volatile bituminous with rank increasing to the south. Sulfur content is generally related to the overlying strata of the coals within the ILB. Generally, coals possess sulfur contents ranging from 3% to 5% and heating values above 11,000 Btu/lb.

4.2 Local Stratigraphy

Pennsylvanian sedimentary strata comprise the uppermost stratigraphic units of bedrock in and around the Oaktown Mining Complex. These units primarily include bedrock of, in descending stratigraphic order, the McLeansboro, Carbondale, and Racoon Creek Group.

The strata of the Pennsylvanian system are predominantly clastic and contain subordinate amounts of coal and limestone. The Indiana V (Springfield) coal seam resides within the Carbondale Group, specifically the Petersburg formation. The stratigraphic relationship between these groups is presented in Figure 4.1 as follows.

System	Group	Formation
Pennsylvanian	McLeansboro	Mattoon
		Bond
		Patoka
		Shelburn
	Carbondale	Dugger
		Petersburg
		Linton
	Raccoon Creek	Staunton
		Brazil
		Mansfield

Figure 4.1
Generalized Stratigraphic Chart,
Southwestern Indiana

4.2.1 McLeansboro Group

The McLeansboro Group ranges in thickness of approximately 150 to 750 ft; beginning with the Mattoon Formation. The uppermost Mattoon Formation is predominately formed of sandstone and/or conglomerate type rocks. The remaining Bond, Patoka, and Shelburn formations, in descending stratigraphic order, are characterized by sequences of shale, mudstone, and siltstone with interspersed limestones. The predominant limestones of presence are the Livingston, Carthage, Vigo, and West Franklin. There are no bituminous coal beds present possessing economic value.

4.2.2 Carbondale Group

The Carbondale Group extends from the Indiana VII (Danville) coal seam to the base of the Indiana III (Seelyville) coal seam. The unit is divided into the Dugger, Petersburg, and Linton formations. The Carbondale Group is a sedimentary sequence of non-marine rocks (sandstone, siltstone, mudstone, shale, limestone, and coal) ranging in thickness from approximately 300 ft to 450 ft. Regionally, the Carbondale Group contains several commercial coal beds, including the Indiana VII (Danville), Indiana VI (Herrin), Indiana V (Springfield) and others; however, within the vicinity of the Oaktown Mining Complex, only the Indiana V Seam is of economic interest. The Indiana V coal seam possesses moderate continuity (instances of sandstone paleochannel erosion) and ideal mining thickness (4 ft to 8 ft).

4.2.3 Raccoon Creek Group

The Raccoon Group includes all strata below the base of the Indiana III (Seelyville) coal bed. It is made up of Staunton, Brazil, and Mansfield formations. The Raccoon Group reaches a maximum thickness of about 1,000 ft in southwestern Indiana. Strata of the group are very similar to those of the overlying Carbondale Group, except that the Raccoon Creek Group contains coal beds of little or no commercial value.

4.3 Coal Seam Geology

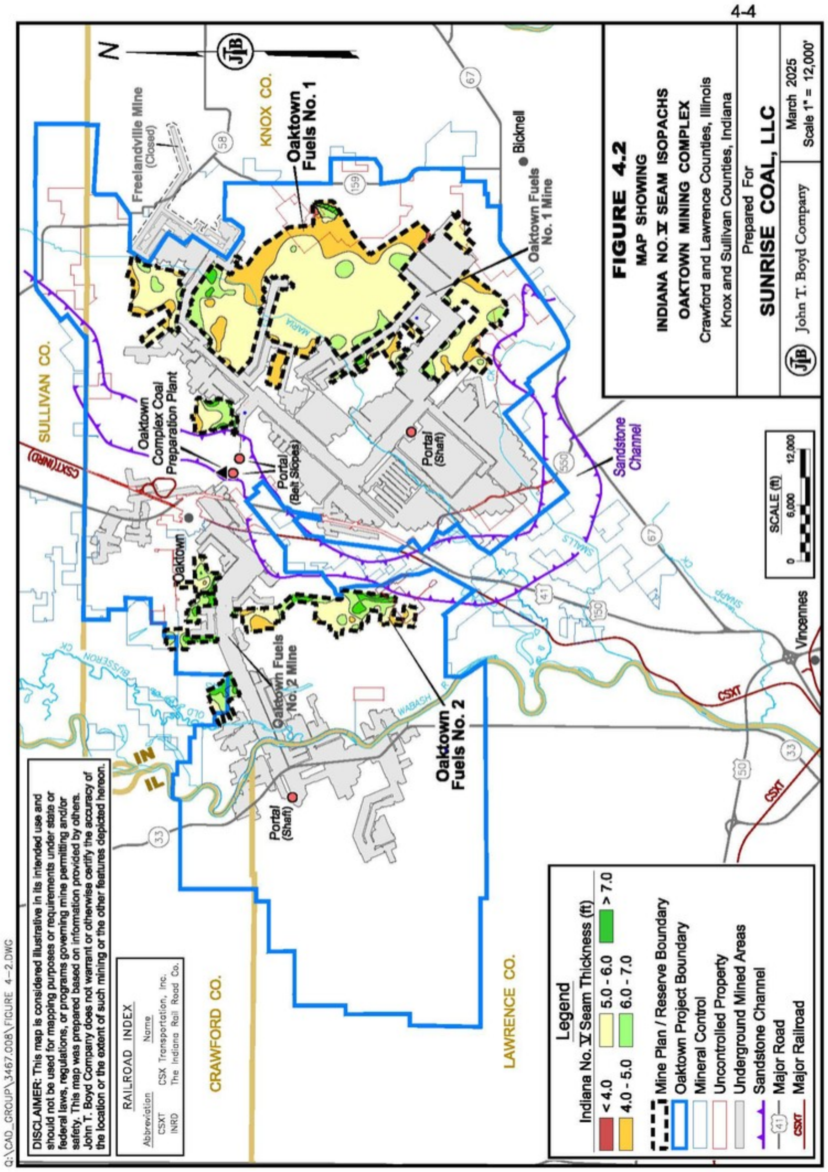
The Indiana V Seam is the only coal seam of economic interest within the Oaktown Mining Complex. The Indiana V Seam is fairly uniform in depositional nature (typically 4 ft to 8 ft thickness) and continuity throughout much of the project’s surrounding area.

4.3.1 Lithology

The Indiana V Seam coal bed is relatively consistent containing a singular interval of coal within minimal in-seam partings. Mining methods employed at the Oaktown Mining Complex generally extract the entirety of the coal seam with minimal out-of-seam (OSD) dilution.

The coal thickness across the Oaktown Mining Complex area is generally between the 4.0 ft to 8.0 ft range, averaging 4.8 ft over the extents of mine plan areas. Isolated pockets of both thinner and thicker coal do exist, and extreme but generally isolated occurrences may range from less than a foot to above 12 ft thick. Figure 4.2, following this page, provides a map of the Indiana V Seam thickness. The locations of thinner coal occurrences are generally well-defined by the extensive exploration performed in and around the study area, and mine plans have been developed to avoid these low coal occurrences.

Figure 4.2


4-4
FIGURE 4.2
MAP SHOWING
INDIANA NO. V SEAM ISOPACHS
OAKTOWN MINING COMPLEX
Crawford and Lawrence Counties, Illinois
Knox and Sullivan Counties, Indiana
Prepared For
SUNRISE COAL, LLC
John T. Boyd Company
March 2025
Scale 1" = 12,000'
SCALE (ft)
0
6,000
12,000
Legend
Indiana No. V Seam Thickness (ft)
< 4.0
4.0 - 5.0
5.0 - 6.0
6.0 - 7.0
> 7.0
Mine Plan / Reserve Boundary
Oaktown Project Boundary
Mineral Control
Uncontrolled Property
Underground Mined Areas
Sandstone Channel
Major Road
Major Railroad
DISCLAIMER: This map is considered illustrative in its intended use and should not be used for mapping purposes or requirements under state or federal laws, regulations, or programs governing mine permitting and/or safety. This map was prepared based on information provided by others. John T. Boyd Company does not warrant or otherwise certify the accuracy of the location or the extent of such mining or the other features depicted hereon.
RAILROAD INDEX
Abbreviation
Name
CSXT
CSX Transportation, Inc.
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The Indiana Rail Road Co.
Q:\CAD_GROUP\3467.008\FIGURE 4-2.DWG
N
SULLIVAN CO.
KNOX CO.
CRAWFORD CO.
LAWRENCE CO.
IN
IL
Freelandville Mine
(Closed)
Oaktown
Fuels No. 1
Oaktown Fuels
No. 1 Mine
Bicknell
Oaktown
Complex Coal
Preparation Plant
Portal
(Belt Slopes)
Portal
(Shaft)
Sandstone
Channel
Oaktown
Oaktown Fuels
No. 2 Mine
Oaktown
Fuels No. 2
Portal
(Shaft)
Vincennes
CSXT (INRD)
CSXT

The immediate roof overlying the Indiana V Seam coal bed generally consists of interbedded shales and sandy shales. Occasional instances of sandstone roof can occur within the project area, where paleochannel sandstone fill has scoured and replaced part or all the normal roof strata. The most prominent existence of paleochannel sandstone fill resides within the sandstone channel that divides the Oaktown Fuels No. 1 and No. 2 mines mineable reserves. Other, less prominent, localized paleochannelization eroding of the typical roof strata and possibly portions of the Indiana V Seam are likely to be found within the Oaktown Mining Complex mineable reserves. Areas of the deposit with sandstone channels in close proximity to the Indiana V Seam commonly exhibit discontinuities and rolls in the coal bed. Poor roof conditions are also common along margins of the channels, where the roof type transitions between the sandstone roof and normal shale roof. Sunrise has implemented various programs to identify and mitigate, where possible, problems associated with poor roof conditions.

The immediate floor beneath the Indiana V Seam coal bed consists of an interval of underclay. The underclay provides a generally competent floor, however poor floor conditions can develop when the underclay is exposed to water.

4.3.2 Structure

The Indiana V Seam coal bed is located at depths ranging from approximately 150 ft to over 600 ft below ground surface, averaging 350 ft within the Oaktown Mining Complex area. Seam structure shows a general seam dip of less than 2 degrees in a westerly direction. There are not any major structural faulting or tectonic features known to occur in the deposit. Small-displacement faults and compaction-related faults may be present, but are not expected to materially affect mine plans.

The structural setting for the deposit is generally considered to be simple in terms of geological complexity. Some areas exhibit evidence of localized channelization; as such, isolated areas of the deposit may be considered moderate in geological complexity.
Having been widely studied and extensively mined, the Indiana V Seam is well-known and widely-accepted to be a uniform deposit.

4.3.3 Coal Quality

Overall, the Indiana V Seam coal bed is a high-sulfur moderate ash coal that is used for steam purposes.

5.0 EXPLORATION DATA

5.1 Background

The Indiana V Seam has been the subject of extensive exploration drilling and sampling by Sunrise and other parties, over a timespan of decades. Records from exploration drilling comprise the primary data used in the evaluation of coal resources on the property. A database compiling the results of 1,935 drill holes—covering Oaktown Mining Complex and surrounding area Indiana V Seam—along with electronic copies of original drilling and sampling logs for a representative sample (approximately 42%), was provided for our review.

Additionally, discussions were held between BOYD and Sunrise concerning their standard exploration and sampling methodologies. Topics covered standard procedures ranging from site safety and mapping, to how to select proper drilling equipment, recording accurate and detailed geological logs, performing coal sampling, supervising geophysical logging, and plugging drill holes once work was complete. Sunrise's provided explanation of exploration standards highlight their focus on obtaining the highest accuracy of data possible from the various exploration campaigns they completed.

Due to archival storage of some physical records of drill holes and detailed information on the drilling and sampling methodologies utilized, some documents were not provided for our review. While this limits the ability to provide a completely transparent and detailed overview of the work completed in developing the Oaktown Mining Complex, Sunrise has also demonstrated that they have been very thorough in exploring and sampling, and the complex has been able to consistently and economically mine coal from this deposit for more than a decade.

5.2 Procedures

5.2.1 Drilling

Drill holes on the subject property were completed using various drilling procedures based on specific goals and data needs at various stages of planning and developing the Oaktown Mining Complex. Some drill holes were rotary drilled for purposes of completing geophysical logging, while others were completed using continuous core drilling methods to provide more detailed geologic records and sampling opportunities.

Sunrise technical staff were able to summarize the standard types of equipment and procedures they generally utilized in exploration work completed on the property. This information, combined with information BOYD was able to gather from our review of drilling records are as follows:

- Frequently used drilling equipment that is utilized during exploration is typical of the ILB region. Typical drilling equipment that Sunrise uses for exploration, depending on the goal of a specific drilling and sampling program, may consist of one or both of:
  - Continuous NQ-sized (3.0 in. outside diameter) diamond core rigs.
  - Water rotary with 4.875 in. diameter barrels.
- Presently, core logging activities are completed in the field. Reportedly, current practices for Sunrise are for cored intervals to be photographed, with special attention paid to the coal interval. Cored coal is initially photographed in its entirety.
- Select intervals of coal roof rock and floor rock are photographed and then boxed for archival purposes.
- Geophysical logging has been performed for some drill holes, while others may or may not have been completed/recorded. Sunrise has noted that geophysical logging is currently completed on all holes drilled.

Due to the large extent of historic exploration work, any recent drilling is generally for infilling areas with lower geologic assurance or for establishing confidence of sandstone channel locations. In such instances, nearby drill hole records are referenced prior to commencing any new drill holes, to show the anticipated depth to the coal horizons.

Geophysical logs obtained from newly drilled holes are correlated by Sunrise geologists by aligning known “marker beds”, and then checking coal seam depths, elevations, and thicknesses to ensure seam continuity. These data are formatted and then imported into Sunrise’s geologic modeling programs.

BOYD’s review of the methodologies and procedures indicate the data obtained and utilized by Sunrise for the Oaktown Mining Complex project area were carefully and professionally collected, prepared, and documented, conforming with general industry standards, and are appropriate for use of evaluating and estimating coal resources and reserves.

5.2.2 Coal Quality Sampling

The Oaktown Mining Complex coal quality testing was performed on a large number of coal samples obtained from the Indiana V Seam, in and around the project area. The relatively dense core drilling coverage, combined with channel samples being taken regularly from underground development areas, provides a thorough understanding of the clean coal product that could be produced from the Oaktown Mining Complex.

All coal intercepts of Oaktown Mining Complex exploration were geologically logged, photographed, and sampled in the field by competent geologists. Sampling methodologies consist of first pushing the cored intervals of coal out of the core barrel, directly into a clean single-row wooden core box. Prior to removing coal core from the drilling barrel, the core box is lined with durable plastic sheeting, which helps retain moisture content and minimize coal core oxidation. Once the coal core is fully extruded from the core barrel, it is then inspected, photographed, and logged by the on-site geologist, and cardboard inserts are installed in the wooden core box to maintain coal core integrity.

Upon completing detailed recording (geologic logging and photographing) of the coal interval, coal cores are split into the desired intervals to be analyzed and bagged. An order sheet is placed inside the sample bag, which specifies drill hole information, split information, and testing to be completed on the bagged sample. Sample bags are then zip tied closed, labeled, and then double bagged to eliminate incidental core loss due to potential damage during transportation to the testing lab.

Sunrise maintains all control of coal core samples, up to the point that samples are handed over to the lab performing testing. Once logging and sampling are complete, the sampled coal core intervals are transported to the selected lab that will perform the required analyses. Typically, washability analysis is performed on the majority of drillhole samples with select drillholes being expanded to include full proximate or other analyses (i.e., ultimate, ash content, etc.). The lab manager signs off on the return analysis sheet, indicating that testing results are accurate and that the sample provided was sufficient for testing purposes.

Past programs utilized various accredited coal testing laboratories, again depending on what testing needed to be completed on the coal core at a given time. All analytical work was conducted to International Organization of Standardization (ISO) or American Society for Testing and Materials (ASTM) standards, and various available laboratory sample sheets were provided for review with drilling log data.

Available testing sheets were reviewed by BOYD during our drill hole data audit, and our review of the discussed field and sampling procedures noted above indicated that the general description and sampling work were conducted to appropriate standards. Based on the stated standards and laboratory used, BOYD considers the sample preparation and analytical procedures were adequate for the coal quality results for inclusion in geological modelling and coal resource estimation.

5.2.3 Coal Washability Testing

Coal washability tests (proximate analysis) were conducted at various specific gravities, generally ranging from 1.45 specific gravity float (SGF) through 1.55 SGF. Estimated coal reserves for the Oaktown Mining Complex are currently reported using 1.55 SGF testing results over the entire Oaktown Mining Complex project area. Proximate analysis test results were completed on 723 drill core samples, which were used in estimating quantity and quality of the remaining Oaktown Mining Complex coal reserves.

Although it was noted that Sunrise generally does not perform any randomized sample verification in order to conduct quality control testing of individual coal analyses, Sunrise will typically perform channel sampling and quality analyses throughout mine workings. The channel sample data are then utilized to update quality models.

5.2.4 Other Exploration Methods

Numerous coal samples and surveyed coal thickness measurements have been collected throughout the mine workings. There is no known ore reported via other methods of exploration (such as airborne or ground geophysical surveys) completed for the project area.

5.3 Results

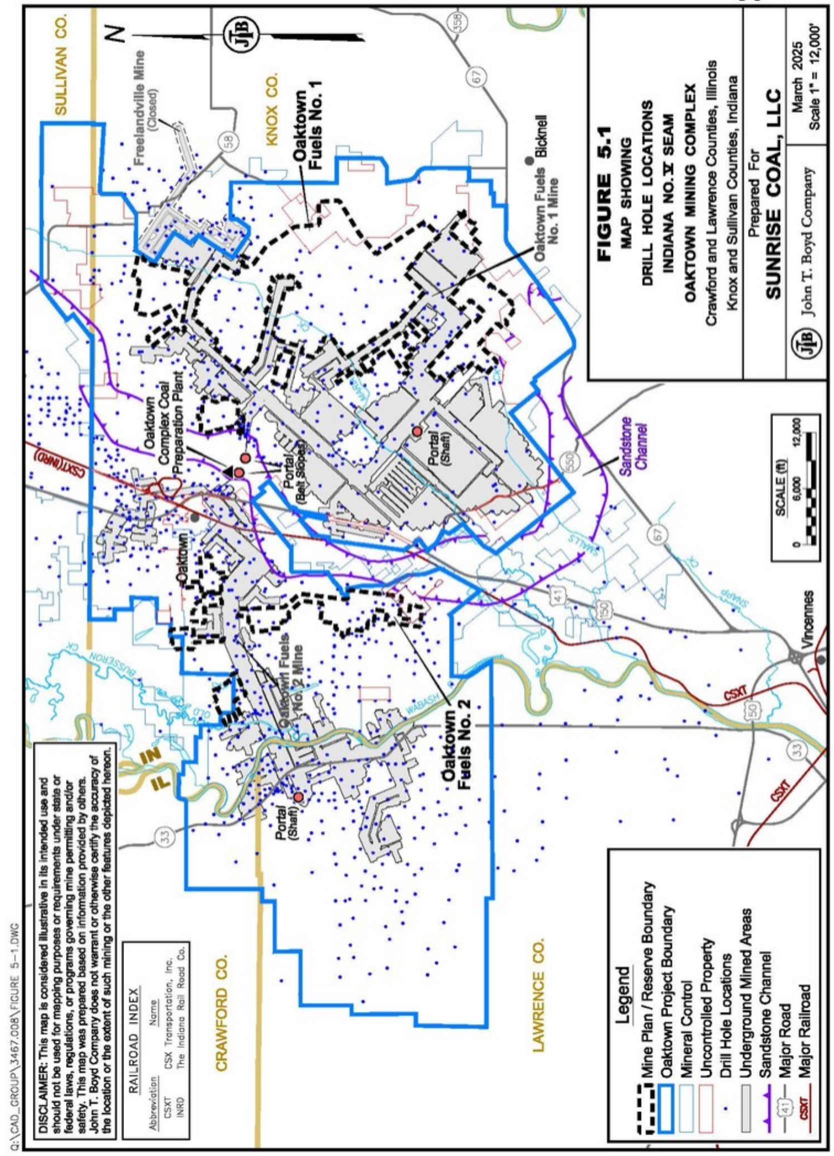
A total of 1,962 drill holes and in-mine samples are in and around the Oaktown Mining Complex area. The distribution of these drill holes is shown on Figure 5.1. Lithologic and coal quality data from these holes were used only for geologic modeling and coal resource assessment for the property.

General descriptive statistics for the Indiana V Seam thickness are provided in Table 5.1 below.

Table 5.1: Indiana V Seam Thickness (feet) Statisitcs

	Oaktown Fuels No. 1 Mine	Oaktown Fuels No. 2 Mine
Mean	5.2	4.8
Minimum	0.5	2.1
Maximum	8.7	12.1
Standard Deviation	0.8	0.9

Figure 5.1


5-5
FIGURE 5.1
MAP SHOWING
DRILL HOLE LOCATIONS
INDIANA NO. V SEAM
OAKTOWN MINING COMPLEX
Crawford and Lawrence Counties, Illinois
Knox and Sullivan Counties, Indiana
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Q:\CAD_GROUP\3467.008\FIGURE 5-1.DWG
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KNOX CO.
CRAWFORD CO.
LAWRENCE CO.
IN
IL
N
Freelandville Mine
(Closed)
Oaktown Fuels No. 1
Oaktown Fuels No. 1 Mine
Bicknell
Oaktown Complex Coal Preparation Plant
Portal
(Belt Slope)
Portal
(Shaft)
Oaktown
Oaktown Fuels No. 2 Mine
Oaktown Fuels No. 2
Sandstone Channel
Vincennes
CSXT
CSXT (INRD)
WABASH

As shown, the thickness of the seam can range from less than a foot to over 12 ft across the Oaktown Mining Complex area. Average thickness of the Indiana V Seam for the project area is approximately 5.2 ft for the Oaktown Fuels No. 1 Mine area and 4.8 ft for the Oaktown Fuels No. 2 Mine area.

The results of the coal quality analyses from 723 samples are summarized in Table 5.2.

Table 5.2: Descriptive Statistics, Indiana V Seam Coal Quality

			Oaktown Fuels No. 1 Mine		Oaktown Fuels No. 2 Mine	
		Units	Raw	Clean	Raw	Clean
Float (i.e., Yield)	Mean	%		88.7		87.9
	Minimum	%		59.1		51.6
	Maximum	%		98.3		97.9
	Standard Deviation			3.1		4.0
Ash	Mean	%	14.5	8.5	14.5	8.9
	Minimum	%	4.0	6.8	4.0	6.7
	Maximum	%	62.5	13.8	62.5	12.5
	Standard Deviation			0.8		0.6
Sulfur	Mean	%	4.9	3.5	4.9	3.1
	Minimum	%	0.6	2.3	0.6	1.0
	Maximum	%	14.0	5.0	14.0	5.6
	Standard Deviation			0.3		0.4
Heating Value	Mean	Btu/lb	11,961	13,246	11,961	13,283
	Minimum	Btu/lb	4,904	12,510	4,904	12,625
	Maximum	Btu/lb	13,389	13,656	13,389	14,564
	Standard Deviation			106		120

Note: Raw and Clean coal qualities are provided on a dry basis.

Raw and clean (washed) coal quality data demonstrate the consistency of the Indiana V Seam as a high-sulfur, moderate ash coal.

5.4 Data Verification

For purposes of this report, BOYD did not verify historic drill hole data by conducting independent drilling in areas already explored. It is customary in preparing coal resource and reserve estimates to accept basic drilling and coal quality data as provided by the client subject to the reported results being judged representative and reasonable.

BOYD's efforts to judge the appropriateness and reasonability of the source exploration data included reviewing a representative sample of drilling logs and coal quality test results for holes located in unmined portions of the Oaktown Mining Complex area. These records were compared with their corresponding database records for transcription errors, noting the vast majority of the information being consistent. Lithologic and coal quality data points were compared via visual and statistical inspection with geologic mapping.

BOYD's review indicates that in general, Sunrise has performed extensive drilling and sampling work on the subject property, the work completed has been done so by competent personnel, and the amount of data available from exploration and mining operations, combined with wide-spread knowledge of the Indiana V Seam, is sufficient to confirm seam uniformity and continuity throughout the Oaktown Mining Complex deposit.

6.0 COAL RESOURCES AND RESERVES

6.1 Applicable Standards and Definitions

Unless noted, coal resource and coal reserve estimates disclosed herein are done so in accordance with the standards and definitions provided by S-K 1300. It should be noted that BOYD considers the terms “mineral” and “coal” to be generally interchangeable within the relevant sections of S-K 1300.

Estimates of coal resources and reserves 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; the geological complexity of the deposit; and economic, legal, social, and environmental factors associated with mining the resource/reserve. By assignment, BOYD used the definitions provided in S-K 1300 to describe the varying degree of certainty associated with the estimates reported herein.

The definition of mineral (coal) resource provided by S-K 1300 is:

> *Mineral resource is a concentration or occurrence of material of economic interest in or on the Earth's crust in such form, grade or quality, and quantity that there are reasonable prospects for economic extraction. A mineral resource is a reasonable estimate of mineralization, taking into account relevant factors such as cut-off grade, likely mining dimensions, location or continuity, that, with the assumed and justifiable technical and economic conditions, is likely to, in whole or in part, become economically extractable. It is not merely an inventory of all mineralization drilled or sampled.*

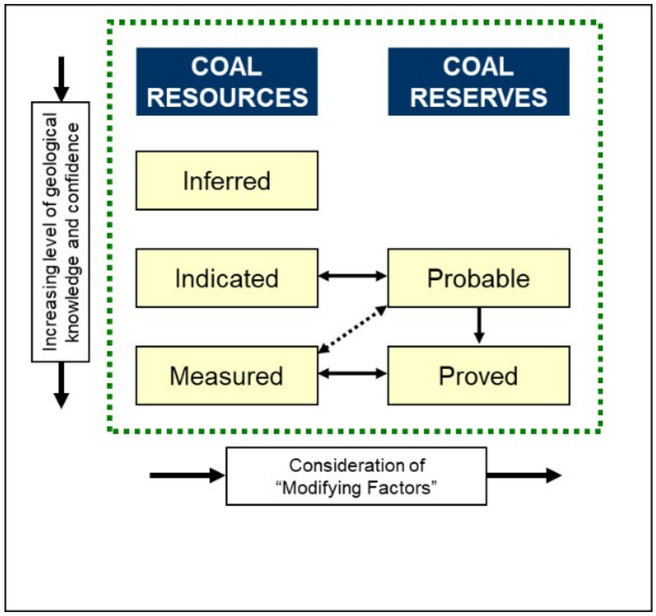
Estimates of coal resources are subdivided to reflect different levels of geological confidence into measured (highest geologic assurance), indicated, and inferred (lowest geologic assurance). See Glossary of Abbreviations and Definitions.

The definition of mineral (coal) reserve provided by S-K 1300 is:

> *Mineral reserve is an estimate of tonnage and grade or quality of indicated and measured mineral resources that, in the opinion of the qualified person, can be the basis of an economically viable project. More specifically, it is the economically mineable part of a measured or indicated mineral resource, which includes diluting materials and allowances for losses that may occur when the material is mined or extracted.*

Estimates of coal reserves are subdivided to reflect geologic confidence, and potential uncertainties in the modifying factors, into proven (highest assurance) and probable. See Glossary of Abbreviations and Definitions.

Figure 6.1 shows the relationship between coal resources and coal reserves.



In this report, the term "coal reserves" represents the tonnage and coal quality of product coal that will be available for sale after beneficiation of the ROM coal.

6.2 Coal Resources

6.2.1 Methodology

Based on provided information, Sunrise's coal resources (and coal reserves) estimation and modeling techniques consists of:

1. Interpreted and correlated coal seam intercepts are compiled and validated. Seam thickness is aggregated and coal qualities are composited, based on assumed mining methods, for each data point.
2. Boundaries of the respective resource classification regions are developed using the data points.
3. ROM coal thickness and coal qualities for each data point are derived from the application of dilution parameters.

4. Clean product qualities for each data point are derived from coal washability analysis and plant efficiency factors.
5. The approved LOM design is subdivided into small mining blocks and sequenced using mine planning software.
6. In-place, ROM, and clean product estimates of coal volume and qualities for each mining block are estimated within the mine planning software by linear least squares interpolation of the data points developed in Steps 1 and 2.
7. The mining blocks (and associated volumetric data) are further subdivided by resource classification and property tract polygons.
8. Relevant and periodic summaries are prepared by Sunrise to support planning and coal resource/reserve reporting.

6.2.2 Criteria

Development of the coal resource estimate for the Oaktown Mining Complex assumes mining using standard underground R&P methods and equipment, which have been utilized successfully at the Oaktown Mining Complex for over a decade.

Within the area of study, the Indiana V Seam exhibits consistent and well-characterized clean (i.e., washed) coal qualities which are within existing marketable limits for ILB coal products. BOYD did not discover any areas within the property where clean coal quality was deficient relative to Sunrise's historical coal sales and current sales contract specifications for high-sulfur thermal coal. As such, no reductions have been made to the coal resources due to coal quality.

A minimum mineable seam thickness of 4 ft was used to limit the coal resources of the Indiana V Seam. This cut-off is a function of the employed mining techniques and equipment. Mining heights less than 4 ft result in operational difficulties and increase OSD, thereby reducing productivity and increasing costs.

There were not any other cut-offs applied.

6.2.3 Classification

Geologic assuredness is established by the availability of both structural (thickness and elevation) and quality information for the Indiana V Seam. Classification is generally based on the concentration or spacing of exploration data, which can be used to demonstrate the geologic continuity of the deposit. Table 6.1 provides the general criteria employed in the classification of the coal resources.

Table 6.1: Coal Resource Classification Criteria

Classification (Geologic Confidence)	Data Point Spacing Feet			Miles		
Measured	0	–	2,640	0	–	0.5
Indicated	2,640	–	7,920	0.5	–	1.5
Inferred	7,920	–	15,840	1.5	–	3.0

Extrapolation or projection of resources in any category beyond any data point does not exceed half the point spacing distance.

BOYD reviewed the classification criteria employed by Sunrise with regards to data density, data quality, geological continuity and/or complexity, and estimation quality. The Indiana V Seam is well-known and of low complexity. We believe these criteria appropriately reflect the interpreted geology and the estimation constraints of the deposit. Coal resources in the Oaktown Mining Complex area are well-defined throughout nearly all areas of the mine plan. Observed drill hole spacing averages approximately 1,995 ft and generally ranges between 440 ft and 8,000 ft.

6.2.4 Coal Resource Estimate

There are no reportable coal resources excluding those converted to coal reserves for the Oaktown Mining Complex. Quantities of coal controlled by Sunrise within the defined boundaries of the Oaktown Mining Complex which are not reported as coal reserves, are not considered to have potential economic viability; as such, they are not reportable as coal resources.

6.3 Coal Reserves

6.3.1 Methodology

Estimates of coal reserves are derived contemporaneously with estimates of coal resources for the LOM plans through the application of appropriate modifying factors. Economic viability of the coal reserves is subsequently confirmed via a LOM financial forecast.

The coal reserve estimates have been prepared using generally accepted industry methodology to provide reasonable assurance that the coal reserves are economic and recoverable at the time of evaluation.

6.3.2 Parameters and Assumptions

The following parameters and assumptions were relied upon to determine the coal reserves:

- The underground operation is mined using R&P methods.
- The mine plans were developed to address anticipated geologic, geotechnical, and hydrogeologic conditions.
- Mining and processing parameters are revised periodically, to assure that the conversion of in-place coal to saleable product are: (1) in reasonable conformity with present and recent historical operational performance, and (2) reflective of expected mining and processing operations.

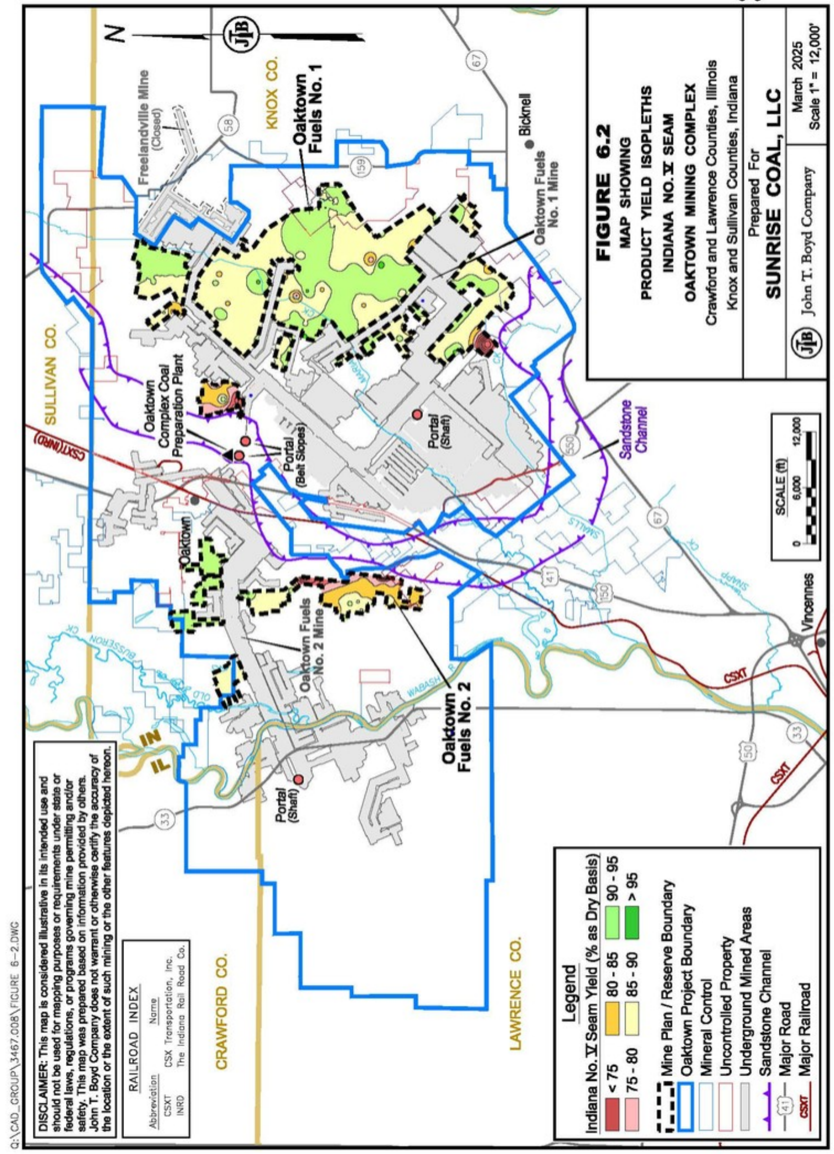
Mining recovery, which is dependent on numerous factors associated with R&P mining, historically ranges between 40 and 50% (averaging 44.4%) for the Indiana V Seam. Within the Oaktown Mining Complex's LOM plan areas, the estimated average mining recovery is 48% for the Oaktown Fuels No. 1 Mine and 45% for the Oaktown Fuels No. 2 Mine. Theses recoveries are considered reasonable.

Clean coal estimates are based on coal washability data. These estimates have been conservatively adjusted downward to reflect practical yields achieved by the preparation plant. Salient coal preparation factors used to estimate the coal reserves include:

- Product yields are derated by 8 percentage points to account for preparation plant efficiency.
- The average product yield for the coal reserves is 80% before accounting for OSD or approximately 60.4% after the inclusion of OSD.
- Sulfur content within clean coal estimates is adjusted upward by approximately 15% above washability data (consistent with historical clean coal processing results).
- Product moisture was estimated at 13.0% (as-received basis).

Figure 6.2, on the following page, depicts the estimated unadjusted (i.e., excluding OSD and plant preparation efficiencies) product yield for the Indiana V Seam across the Oaktown Mining Complex deposit.

Figure 6.2



6-6
FIGURE 6.2
MAP SHOWING
PRODUCT YIELD ISOPLETHS
INDIANA NO. V SEAM
OAKTOWN MINING COMPLEX
Crawford and Lawrence Counties, Illinois
Knox and Sullivan Counties, Indiana
Prepared For
SUNRISE COAL, LLC
John T. Boyd Company
March 2025
Scale 1" = 12,000'
Legend
Indiana No. V Seam Yield (% as Dry Basis)
< 75
75 - 80
80 - 85
85 - 90
90 - 95
> 95
Mine Plan / Reserve Boundary
Oaktown Project Boundary
Mineral Control
Uncontrolled Property
Underground Mined Areas
Sandstone Channel
Major Road
Major Railroad
RAILROAD INDEX
Abbreviation
Name
CSXT
CSX Transportation, Inc.
INRD
The Indiana Rail Road Co.
DISCLAIMER: This map is considered illustrative in its intended use and should not be used for mapping purposes or requirements under state or federal laws, regulations, or programs governing mine permitting and/or safety. This map was prepared based on information provided by others. John T. Boyd Company does not warrant or otherwise certify the accuracy of the location or the extent of such mining or the other features depicted hereon.
SCALE (ft)
0
6,000
12,000
Oaktown Fuels No. 1
Oaktown Fuels No. 2
Oaktown Fuels No. 1 Mine
Oaktown Fuels No. 2 Mine
Oaktown Complex Coal Preparation Plant
Portal (Belt Slopes)
Portal (Shaft)
Freelandville Mine (Closed)
Sandstone Channel
Bicknell
Oaktown
Vincennes
SULLIVAN CO.
KNOX CO.
CRAWFORD CO.
LAWRENCE CO.
IN
IL

The Indiana V Seam across the Oaktown Mining Complex property exhibits clean coal quality which is consistent with Sunrise's historical production and current sales contract specifications. Furthermore, the projected coal quality over the life of the coal reserves is consistent with coals produced by other ILB operators (please refer to Chapter 10 for further information). As such, BOYD does foresee any quality deviations that would adversely affect the marketability of future coal production from the Oaktown Mining Complex.

The economic viability of the stated coal reserves is demonstrated by the production and financial projections presented in Chapters 10 through 12 of this report. The forecasted sales prices (FOB CPP) used in the estimation of coal reserves for the Oaktown Mining Complex vary by year, ranging from $47.25 to $51.47 and averaging $48.72 per clean ton (refer to Section 10.2.5 for further details).

6.3.3 Classification

Proven and probable coal reserves are derived from measured and indicated coal resources, respectively, in accordance with S-K 1300. BOYD is satisfied that the stated coal reserve classification reflects the outcome of technical and economic studies. Figure 6.3, on the following page, illustrates the reserve classification of the Indiana V Seam within the Oaktown Mining Complex.

6.3.4 Coal Reserve Estimate

Sunrise's estimated underground mineable coal reserves for the Oaktown Mining Complex total 34.4 million recoverable (clean) product tons remaining as of December 31, 2024. The coal reserves reported in Table 6.2 (page 6-9) are based on the approved LOM plan which, in BOYD's opinion, is technically achievable and economically viable after the consideration of all material modifying factors.

Figure 6.3

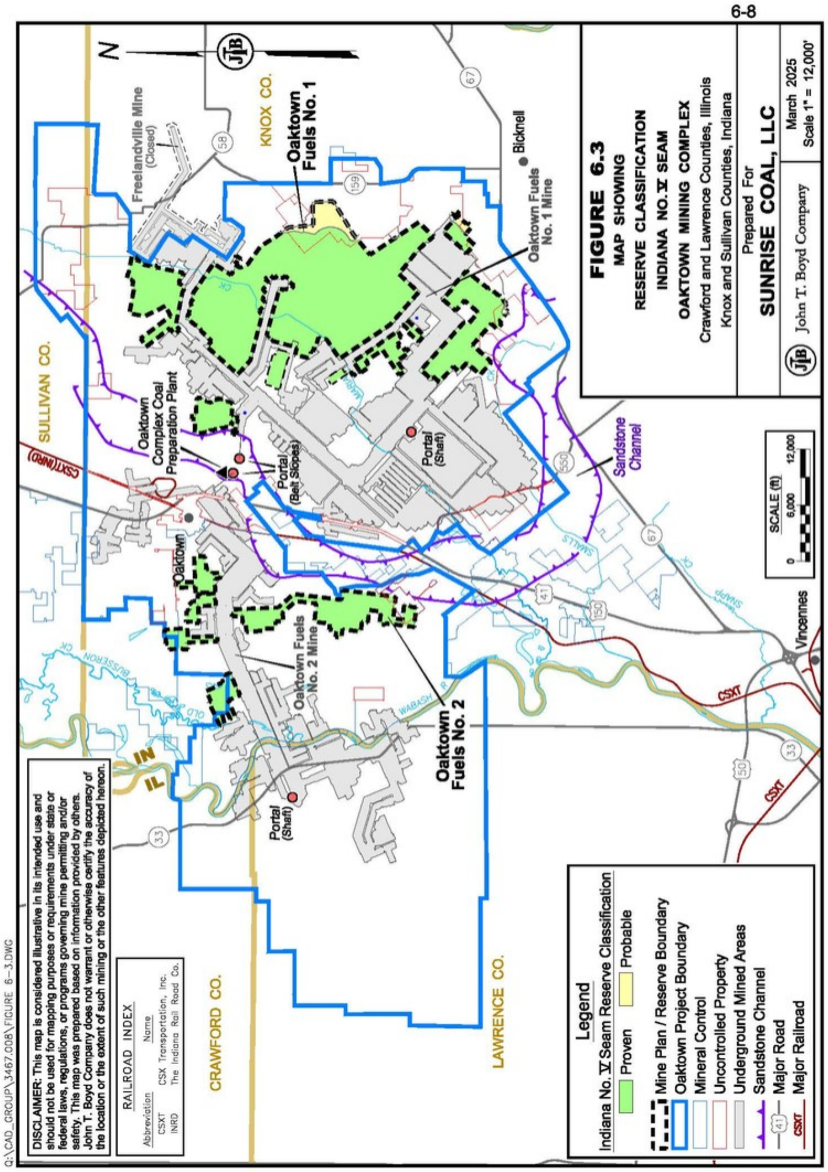

6-8
FIGURE 6.3
MAP SHOWING
RESERVE CLASSIFICATION
INDIANA NO. V SEAM
OAKTOWN MINING COMPLEX
Crawford and Lawrence Counties, Illinois
Knox and Sullivan Counties, Indiana
Prepared For
SUNRISE COAL, LLC
John T. Boyd Company
March 2025
Scale 1" = 12,000'
SCALE (ft)
0
6,000
12,000
Legend
Indiana No. V Seam Reserve Classification
Proven
Probable
Mine Plan / Reserve Boundary
Oaktown Project Boundary
Mineral Control
Uncontrolled Property
Underground Mined Areas
Sandstone Channel
Major Road
Major Railroad
DISCLAIMER: This map is considered illustrative in its intended use and should not be used for mapping purposes or requirements under state or federal laws, regulations, or programs governing mine permitting and/or safety. This map was prepared based on information provided by others. John T. Boyd Company does not warrant or otherwise certify the accuracy of the location or the extent of such mining or the other features depicted hereon.
RAILROAD INDEX
Abbreviation
Name
CSXT
CSX Transportation, Inc.
INRD
The Indiana Rail Road Co.
Q:\CAD_GROUP\3467.008\FIGURE 6-3.DWG
N
SULLIVAN CO.
KNOX CO.
CRAWFORD CO.
LAWRENCE CO.
IN
IL
Freelandville Mine
(Closed)
Oaktown
Fuels No. 1
Oaktown Fuels
No. 1 Mine
Bicknell
Oaktown
Complex Coal
Preparation Plant
Portal
(Belt Slopes)
Portal
(Shaft)
Oaktown
Oaktown Fuels
No. 2 Mine
Oaktown
Fuels No. 2
Sandstone
Channel
Vincennes
CSXT
CSXT(INRD)

TABLE 6.2

ESTIMATED COAL RESERVES BY MINE
AS OF 31 DECEMBER 2024
OAKTOWN MINING COMPLEX
Indiana and Illinois
Prepared For
SUNRISE COAL, LLC
By
John T. Boyd Company
Mining and Geological Consultants
February 2025

	Product Tons (000)			Average Product Quality (As Received Basis)				
		By Permit Status		%			Heating	SO_2
			Not	Total			Value	(lbs per
Classification	Total	Permitted	Permitted	Moisture	Ash	Sulfur	(Btu/lb)	MMBtu)
Oaktown Fuels No. 1 Mine								
Proven	25,660	25,660	-	13.0	7.5	3.5	11,504	6.0
Probable	2,675	2,675	-	13.0	7.3	3.5	11,533	6.0
Total	28,335	28,335	-	13.0	7.5	3.5	11,506	6.0
Oaktown Fuels No. 2 Mine								
Proven	5,887	5,214	673	13.0	7.5	2.9	11,580	5.0
Probable	215	207	8	13.0	8.1	2.5	11,465	4.4
Total	6,102	5,421	681	13.0	7.5	2.9	11,576	5.0
Total - Oaktown Mining Complex								
Proven	31,547	30,874	673	13.0	7.5	3.3	11,518	5.8
Probable	2,890	2,882	8	13.0	7.4	3.4	11,528	5.9
Total	34,437	33,756	681	13.0	7.5	3.4	11,519	5.8

Coal reserves for the Oaktown Mining Complex are summarized by mine in Table 6.3, below.

Table 6.3: Coal Reserves Summary

Mine	Product Tons (000) by Classification		
	Proven	Probable	Total
Oaktown Fuels No. 1	25,660	2,675	28,335
Oaktown Fuels No. 2	5,887	215	6,102
Total	31,547	2,890	34,437

The reported coal reserves include only coal that is controlled by the company under lease agreement as of December 31, 2024. It should be noted that the Oaktown Mining Complex's permitted underground mining area includes approximately 1.9 million product tons which are currently uncontrolled (i.e., owned by other parties). Sunrise anticipates gaining control of the mineral rights to this uncontrolled coal in due time and adjusting its mine plans accordingly. BOYD is not aware of any encumbrances, litigation, or orders that would hinder the continued development of the property.

At the time of reporting, approximately 33.8 million product tons, or 98% of the reported reserves, are permitted for mining by appropriate federal and state regulatory authorities. The remaining 681 thousand product tons are not permitted. It is typical for mining permits to be periodically amended as mining progresses to add acreage (tonnage) in order to sustain coal production. It is reasonable to expect that all necessary permits to recover the coal will be successfully obtained in advance of mining.

The coal reserves of the Oaktown Mining Complex are well-explored and defined. It is our conclusion that nearly 92% of the stated reserves can be classified in the proven reliability category (the highest level of assurance) with the remainder classified as probable. Given the uniformity of the Indiana V Seam in and around the Oaktown Mining Complex, it is reasonable to assume that further exploration and testing will confirm the occurrence of coal reserves, resulting in an increase in the percentage of coal reported in the proven category.

Table 6.4, below, summarizes the washed coal quality for each mine of the Oaktown Mining Complex. The reported coal reserves generally consist of high-sulfur moderate ash coal that may be used for steam purposes.

Table 6.4: Coal Reserves Product Quality Summary

	Average Product Quality (As Received Basis)				
	%			Heating	SO_2
Mine	Total Moisture	Ash	Sulfur	Value (Btu/lb)	(lbs per MMBtu)
Oaktown Fuels No. 1	13.0	7.5	3.5	11,506	6.0
Oaktown Fuels No. 2	13.0	7.5	2.9	11,576	5.0
Average	13.0	7.5	3.4	11,519	5.8

Figures 6.4 and 6.5, respectively, illustrate the product ash and product sulfur content over the Oaktown Mining Complex area. As shown, there are slight increases in both ash and sulfur content from southeast to northwest across the property.

The Oaktown Mining Complex is an established underground coal mining and processing complex with a consistent operating history. BOYD has assessed that sufficient studies have been undertaken to enable the coal resources to be converted to coal reserves based on current operating methods and practices. Changes in the factors and assumptions employed in these studies may materially affect the coal reserve estimate.

The extent to which the coal reserves may be affected by any known geological, operational, environmental, permitting, legal, title, variation, socio-economic, marketing, political, or other relevant issues has been reviewed as warranted. It is BOYD's opinion that Sunrise has appropriately mitigated, or has the operational acumen to mitigate, the risks associated with these factors. BOYD is not aware of any additional risks that could materially affect the development of the reserves.

Based on our audit review, we have a high degree of confidence that the estimates shown in this report accurately represent the available coal reserves controlled by Sunrise, as of December 31, 2024.

Figure 6.4

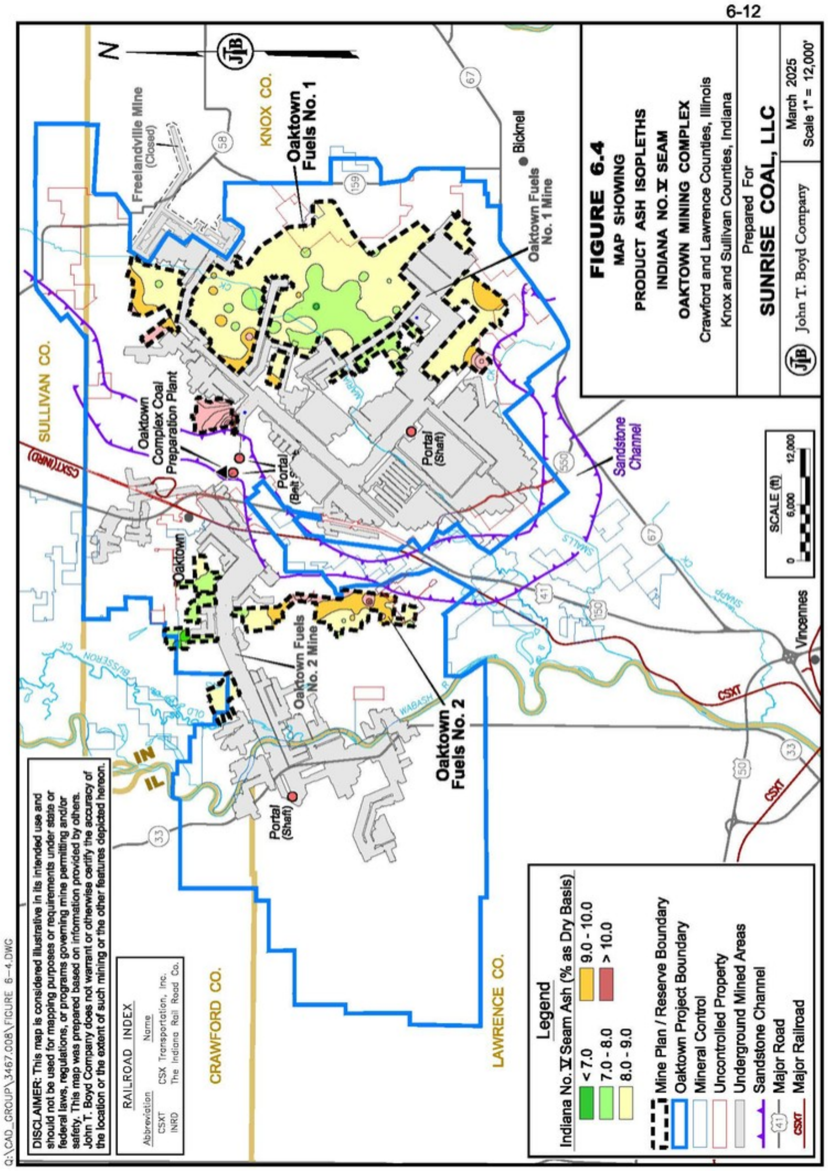
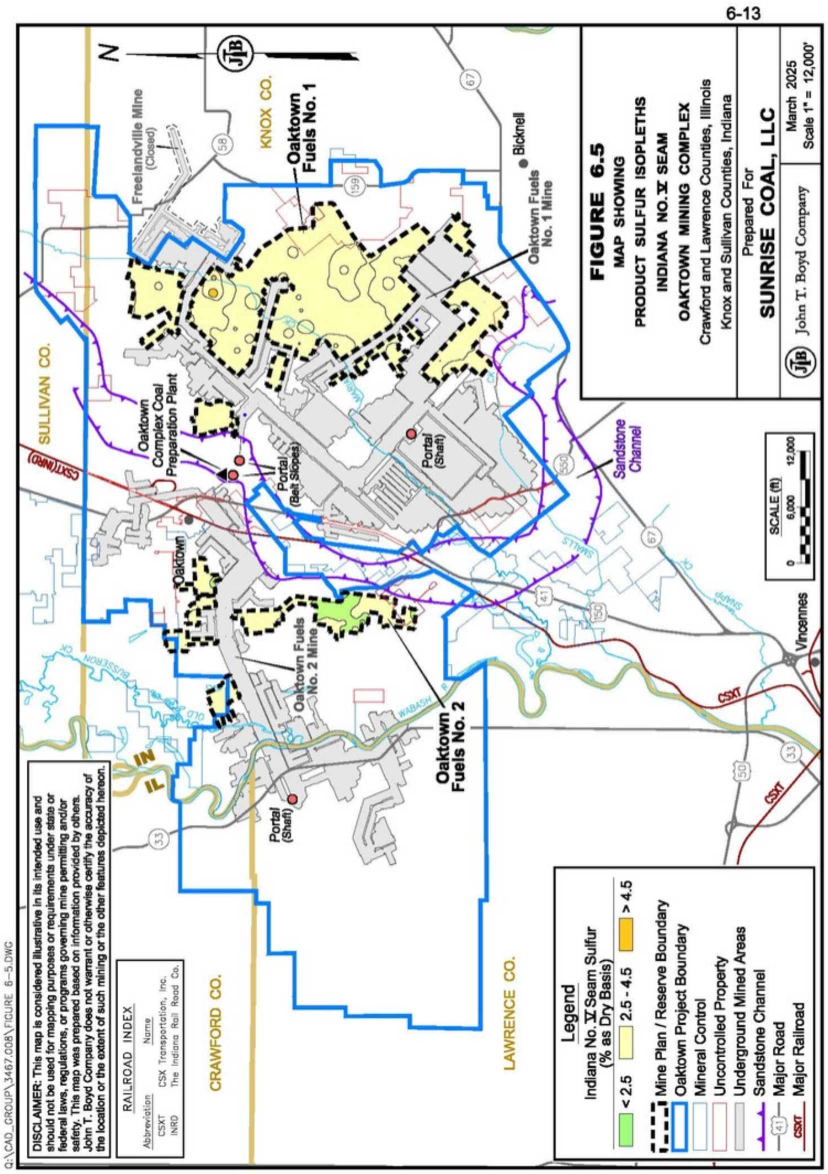

6-12
FIGURE 6.4
MAP SHOWING
PRODUCT ASH ISOPLETHS
INDIANA NO. V SEAM
OAKTOWN MINING COMPLEX
Crawford and Lawrence Counties, Illinois
Knox and Sullivan Counties, Indiana
Prepared For
SUNRISE COAL, LLC
John T. Boyd Company
March 2025
Scale 1" = 12,000'
Legend
Indiana No. V Seam Ash (% as Dry Basis)
< 7.0
7.0 - 8.0
8.0 - 9.0
9.0 - 10.0
> 10.0
Mine Plan / Reserve Boundary
Oaktown Project Boundary
Mineral Control
Uncontrolled Property
Underground Mined Areas
Sandstone Channel
Major Road
Major Railroad
DISCLAIMER: This map is considered illustrative in its intended use and should not be used for mapping purposes or requirements under state or federal laws, regulations, or programs governing mine permitting and/or safety. This map was prepared based on information provided by others. John T. Boyd Company does not warrant or otherwise certify the accuracy of the location or the extent of such mining or the other features depicted hereon.
RAILROAD INDEX
Abbreviation Name
CSXT CSX Transportation, Inc.
INRD The Indiana Rail Road Co.
SCALE (ft)
0 6,000 12,000
Oaktown Fuels No. 1
Oaktown Fuels No. 1 Mine
Oaktown Fuels No. 2
Oaktown Fuels No. 2 Mine
Oaktown Complex Coal Preparation Plant
Portal (Shaft)
Freelandville Mine (Closed)
Sandstone Channel
SULLIVAN CO.
KNOX CO.
CRAWFORD CO.
LAWRENCE CO.
Oaktown
Bicknell
Vincennes
IN
IL
N

Figure 6.5


6-13
FIGURE 6.5
MAP SHOWING
PRODUCT SULFUR ISOPLETHS
INDIANA NO. V SEAM
OAKTOWN MINING COMPLEX
Crawford and Lawrence Counties, Illinois
Knox and Sullivan Counties, Indiana
Prepared For
SUNRISE COAL, LLC
John T. Boyd Company
March 2025
Scale 1" = 12,000'
SULLIVAN CO.
KNOX CO.
CRAWFORD CO.
LAWRENCE CO.
Oaktown Fuels No. 1
Oaktown Fuels No. 2
Oaktown Fuels No. 1 Mine
Oaktown Fuels No. 2 Mine
Oaktown Complex Coal Preparation Plant
Freelandville Mine (Closed)
Portal (Belt Slopes)
Portal (Shaft)
Oaktown
Bicknell
Vincennes
Sandstone Channel
SCALE (ft)
0 6,000 12,000
IN
IL
Legend
Indiana No. V Seam Sulfur (% as Dry Basis)
< 2.5
2.5 - 4.5
> 4.5
Mine Plan / Reserve Boundary
Oaktown Project Boundary
Mineral Control
Uncontrolled Property
Underground Mined Areas
Sandstone Channel
Major Road
Major Railroad
RAILROAD INDEX
Abbreviation Name
CSXT CSX Transportation, Inc.
INRD The Indiana Rail Road Co.
DISCLAIMER: This map is considered illustrative in its intended use and should not be used for mapping purposes or requirements under state or federal laws, regulations, or programs governing mine permitting and/or safety. This map was prepared based on information provided by others. John T. Boyd Company does not warrant or otherwise certify the accuracy of the location or the extent of such mining or the other features depicted hereon.
Q:\CAD_GROUP\3467.008\FIGURE 6-5.DWG

6.3.5 Validation

BOYD independently estimated coal reserves for the Oaktown Mining Complex mine plan from geologic data and models provided by Sunrise. Based on our review of Sunrise's well-documented geologic modeling and estimation techniques and the results of our data validation efforts (described earlier), we are of the opinion that Sunrises' modeling procedures are reasonable and appropriate. We consider the LOM plan and economic forecast sufficiently detailed to support the estimate of coal reserves reported herein. Furthermore, it is BOYD's opinion that there is a high degree of assurance associated with the stated coal reserves due to the current amount of exploration and sampling, mine planning, and economic analyses that have been completed on the Indiana V Seam within the Oaktown Mining Complex area.

6.3.6 Reconciliation with Previous Estimates

Figure 6.6, below, illustrates the comparison of Sunrise's coal reserve estimates as of December 31, 2024, with those reported of December 31, 2023.

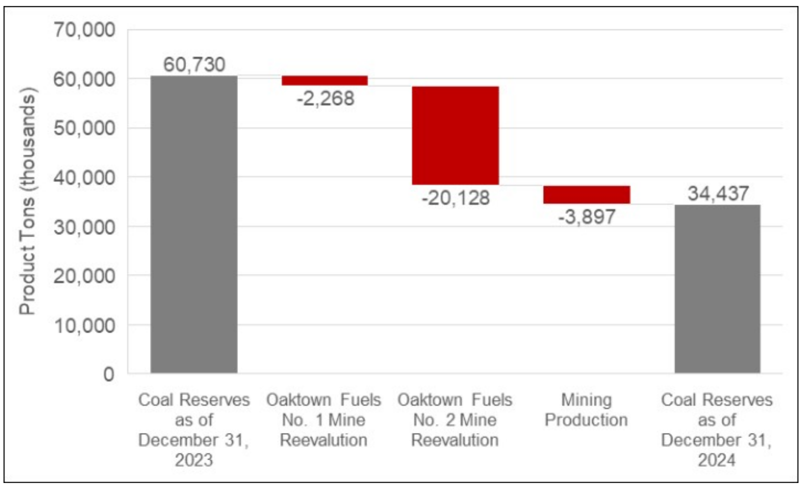


Figure 6.6
Reconciliation with Previous Coal Reserves Estimate

The net decrease in reserves reflects: (1) reevaluation of the life-of-mine plans for both underground operations, including substantial revisions to the Oaktown Fuels No.2 Mine; and (2) depletion through ordinary mining operations and inventory sales.

7.0 MINING OPERATIONS

7.1 Mining Method Description

Coal is produced by the Oaktown Fuels No. 1 and No. 2 underground mines using the R&P mining method. R&P mining is a partial extraction technique that recovers a portion of a coal seam. An illustration of a typical R&P mining operation is provided in Figure 7.1.

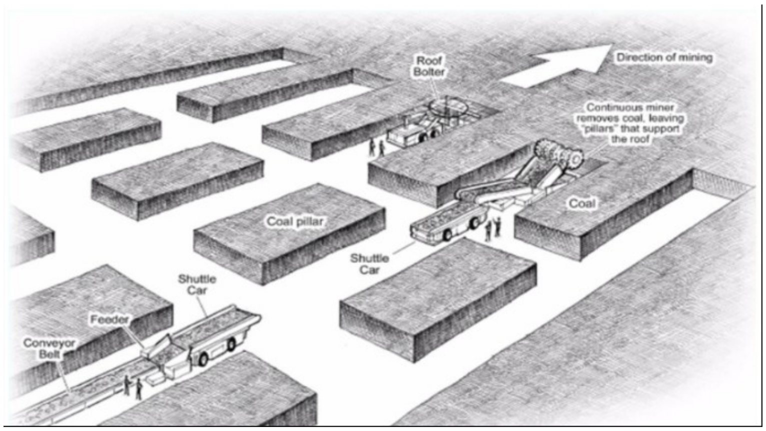


Figure 7.1
Room-and-Pillar Mining Method
Source: Pennsylvania State University (Arch Coal, Inc.).

R&P mining utilizes the systematic development of interconnected underground entries or openings with rectangular roadways that are driven in the coal seam and are typically supported by roof bolts installed in the immediate roof. The parallel mine entries are connected by crosscuts which result in a series of mine openings separated by solid coal pillars that support the main roof. R&P mining systems, which generally utilize CMs, can be used for coal production (like the underground mines of the Oaktown Mining Complex) or as a development technique to support longwall (LW) production. This flexible mining system is widely used across the U.S. coal industry, at large and small mines with varying seam thicknesses and mining conditions.

A typical R&P production section will include one or two CM units, one to three roof bolting machines, and between two and three coal haulage machines (most commonly either ram cars [RC] or shuttle cars [SC]) per CM. The main piece of equipment is the CM, which is a heavy, steel framed machine (often over 40 tons) mounted on cat tracks, that operates on AC power. Key components of a CM include:

- Electric and hydraulic motors that power the CM's operation.
- A tram mechanism that propels the machine.
- A horizontally mounted, cylindrical cutting head used to cut the coal seam.
- A pair of gathering arms that pick-up/clear away the mined material.
- An internal conveyor system used to load the mined product into a haulage vehicle.

Although there have been ongoing advances in CM equipment technology, the basic R&P mining process has been utilized for decades and has remained largely unchanged over that time. The CM is used to extract the coal seam by mining a rectangular opening or "cut". The cut typically ranges from 18 ft to 20 ft in width and extends the height[1] of the coal seam plus some increment of extraneous non-coal roof and floor material extracted during the mining process (known as OSD). The depth that the CM cuts into the coal seam (i.e., the cut length) is dependent upon mining conditions, regulations, operating practices, etc. but is generally in the range of 15 ft to 40 ft. Shorter cuts are taken in areas where there are difficult roof conditions.

A critical element of R&P mining is the interaction between the CM, the roof-bolting machine and supporting haulage units. Known as "place-changing", the following steps will typically occur during mining cycle:

1. The CM penetrates the cut. As the coal and associated OSD are extracted, the CM unit loads the broken material into one of the haulage vehicles/RC.
2. Once fully loaded, the RC carries the product from the CM to a "feeder," where the coal is discharged from the car and gradually metered onto a conveyor belt for transport out of the mine. The empty RC then trams back to the CM to be reloaded. While this is taking place, the second RC is subsequently loaded. If additional RCs are utilized, these units follow in sequence. This operating pattern continues until the coal volume within the cut is fully extracted.
3. The CM then backs out of the cut and trams to the next location where the mining process is continued.
4. After a cut is completed, the exposed roof in the cut (just completed by the CM) must be supported. A roof bolting machine trams into the freshly mined area, drills holes into the roof and installs roof bolts—steel rods that strengthen the integrity of the roof. The principle of

[1] In instances where a CM is operating in thick seam conditions (i.e., the coal thickness is greater than 8 ft), the height of the cut may be less than the full thickness of the seam.

roof bolting is to physically tie together the weaker individual layers of roof strata to create a single "laminated" unit of rock that is stronger than the unsupported strata.

Place-change mining is an efficient form of R&P mining, although the process will routinely incur delays during a production shift (perhaps 5 to 20 minutes per occurrence, depending upon site-specific considerations). Where roof conditions permit (and approval is granted by regulatory agencies), mine operators will employ "deep cut" mining plans to reduce the impact of place-changing delays. Longer cuts (usually 30 ft to 40 ft in length) enable the CM to spend a greater portion of available shift time in cutting and loading activities.

Place-changing CM equipment has steadily evolved over the years via technological breakthroughs to become sophisticated, productive, and durable. Today's state-of-the-art CM units are equipped with efficient motors, computer diagnostics, solid-state electronics, advanced remote-control systems, and scrubbing mechanisms (which preserve underground air quality by capturing a significant percentage of respirable dust that is generated by the breaking/grinding of coal and rock during the mining process). Ever-improving technological gains have resulted in dramatic improvements in productivity, machine availability, employee safety, and unit operating costs over the past four decades.

An R&P mine may operate a single production section, or multiple sections (like the mines of the Oaktown Mining Complex). This is dependent upon the size of the reserve, supporting infrastructure, capitalization, markets, etc. A variation of the traditional R&P place-changing method is the "super-section". Under this system, the CM production section is equipped with two CM machines, two sets of haulage vehicles, and multiple roof bolters. Under this variation, each "super-section" essentially operates two production units per belt dumping point enhancing the productive output of the mine section. This variation of traditional R&P mining is employed at both Oaktown Fuels No. 1 and No. 2 mines.

R&P extraction may be performed as either "first mining" or "secondary extraction". First or "advance-only" mining is where a system of entries or openings are driven/advanced and the remaining coal pillars are left intact. Under this system, after a section has reached its intended advance distance, the section equipment is recovered and relocated to a new area, leaving the developed pillars untouched (i.e., no secondary mining of the pillars occurs). Reasons for employing this type of R&P mining may include equipment specifications, geological conditions, subsidence restrictions, operator preferences, etc.

Secondary extraction or "retreat mining" is the process whereby, after the mine workings have reached the end of the advance stage of mining, the direction of mining is reversed (i.e., the mine operator retreats towards the mouth of the production section, employing a prescribed series of cuts to sequentially recover coal from the pillars). Retreat mining systems can be complex and may include partial or full pillar extraction (which allows the roof to systematically collapse and subsequently results in subsidence of the overlying surface).

Reserve recovery (extraction ratio) varies at R&P mines. Generally, 40% to 50% extraction of the in-place coal is typical, with extraction ratios ranging from 30% to 70%. Retreat mining may or may not offer higher extraction ratios than advance only mining; actual recoveries are dependent upon pillar dimensions and a variety of operational considerations.

Historically, the Oaktown Fuels No. 1 Mine has employed three or four super-sections in its mining operations, and Oaktown Fuels No. 2 Mine has employed two or three super-sections. Some secondary extraction whereby small portions (or “fender cuts”) of some pillars are removed has been utilized at both operations and will likely be utilized in future operations. Sunrise has no plans for full pillar extraction secondary mining in its LOM plan.

R&P mining has been one of the predominant approaches to mining the Indiana V Seam (within which Oaktown Mining Complex operates) for decades. Mining in the Oaktown Fuels No. 1 Mine, which first began production in 2009 and is the oldest of the Oaktown Mining Complex’s two operations, is largely identical to the practices used at the Oaktown Fuels No. 2 Mine. In terms of mining methodology, the application of R&P mining techniques at the Oaktown Fuels No. 1 and No. 2 mines is viewed as a prudent operating decision based on: (1) the extent of the complex’s overall coal reserve base, (2) Sunrise’s targeted annual production levels, (3) the mines’ historic and expected mining conditions and seam orientation, and (4) the successful application of R&P technology at nearby historical and active mining operations. The use of R&P mining at the Oaktown Mining Complex is further justified based on Sunrise’s experience operating R&P mines and their reputation for having refined the technical, operational, and financial elements of this mining technique for site specific conditions over the years.

7.2 Mine Equipment and Staffing

7.2.1 Mine Equipment

The equipment utilized at the two Oaktown Mining Complex underground R&P mines is nearly identical to one another. This allows for synergies between the operations, including the sharing of equipment and critical spare parts. Additionally, mining equipment utilized by Oaktown Mining Complex is not unique to the ILB region (i.e., Oaktown Mining Complex's mining equipment is similar to the equipment commonly used by competitor underground mines in the region).

Table 7.1, below, presents Oaktown Mining Complex's projected number of CM super-sections for 2025 through 2035 according to BOYD's conceptual LOM:

Table 7.1: Projected Number of Operating CM Sections

	Year(s)			
Mine	2025 to 2029	2030 to 2032	2033	2034 to 2035
Oaktown Fuels No. 1	4	2	1	1
Oaktown Fuels No. 2	0	2	2	1

A listing of equipment typically employed by the two mines' CM super-sections is shown in Table 7.2, below.

Table 7.2: Summary of Production Unit Equipment

Section Type	Equipment Type	Manufacturer	Quantity
CM Sections	Continuous Miner	Joy	2
	Shuttle Car/Ram Car	Joy, Stamler	2–3
	Bolter	Fletcher	1–3
	Scoop	Fairchild	1–3
	Power Center	Line Power	1–2
	Feeder	Joy, Stamler	1

Based on BOYD's review of the Oaktown Mining Complex's equipment and asset listings, the operations' current complement of equipment is sufficient to meet the production levels projected for each of the operations over their conceptual LOM plans. Additionally, capital projections prepared by Sunrise have accounted for future equipment related expenditures to maintain production at forecasted levels. In BOYD's opinion, all mining equipment utilized on the Oaktown Mining Complex's CM super-sections is suitable for the mining conditions anticipated, as well as for the future proposed rates of production.

7.2.2 Staffing

Oaktown Mining Complex's underground mines and coal preparation facility are staffed by a workforce primarily from the surrounding southwestern Indiana and southeastern Illinois areas. The workforce, which is comprised of both hourly and salary employees, has no labor affiliation (i.e., the Oaktown Mining Complex is union-free). Table 7.3, below, provides recent historical employment as reported by MHSA for each operational site.

Table 7.3: Historical Employment

Operational Site	Employee Classifcation	Employee Count by Year				
		2020	2021	2022	2023	2024
Oaktown Fuels No. 1 Mine	Underground	300	286	359	399	451
	Surface	33	32	37	41	36
	Office	11	10	10	9	16
	Subtotal	344	328	406	449	503
Oaktown Fuels No. 2 Mine	Underground	215	263	296	315	70
	Surface	4	8	11	12	3
	Office	5	3	4	3	1
	Subtotal	224	274	311	330	74
Oaktown Complex CPP	Surface	61	68	73	87	57
Total - Oaktown Mining Complex		629	670	790	866	634

Future employment levels are expected to resemble historical levels. Given Sunrise's ability to hire and retain employees, staffing is not expected to hinder the Oaktown Mining Complex operations' ability to achieve forecasted production levels.

7.3 Mine Production

7.3.1 Historical Mine Production

Historical mine production data for the two Oaktown Mining Complex underground R&P mines, based on publicly available information reported by MSHA, are detailed in Table 7.4, below.

Table 7.4: Historical Mine Production

	Oaktown Fuels No. 1 Mine			Oaktown Fuels No. 2 Mine			Total - Oaktown Mining Complex		
Year	Tons (000)	Hours (000)	TPEH	Tons (000)	Hours (000)	TPEH	Tons (000)	Hours (000)	TPEH
2008	-	33	-	-	-	-	-	33	-
2009	47	145	0.3	-	-	-	47	145	0.3
2010	1,015	333	3.0	-	11	-	1,015	344	2.9
2011	2,668	715	3.7	-	26	-	2,668	741	3.6
2012	2,754	709	3.9	-	50	-	2,754	759	3.6
2013	3,376	741	4.6	1,039	176	5.9	4,415	1,036	4.3
2014	3,341	739	4.5	2,092	378	5.5	5,433	1,277	4.3
2015	3,519	780	4.5	2,180	480	4.5	5,699	1,399	4.1
2016	3,828	844	4.5	1,947	553	3.5	5,775	1,502	3.8
2017	3,684	784	4.7	2,547	608	4.2	6,231	1,469	4.2
2018	4,072	779	5.2	2,867	680	4.2	6,939	1,576	4.4
2019	4,167	816	5.1	2,298	637	3.6	6,464	1,600	4.0
2020	3,433	718	4.8	1,810	495	3.7	5,243	1,333	3.9
2021	3,489	732	4.8	2,147	626	3.4	5,636	1,487	3.8
2022	3,860	974	4.0	2,500	753	3.3	6,360	1,873	3.4
2023	3,934	1,060	3.7	2,451	773	3.2	6,385	2,003	3.2
2024	3,534	1,106	3.2	363	182	2.0	3,897	1,391	2.8
Total/Average	50,720	12,007	4.2	24,241	6,427	3.8	74,961	19,969	3.8

Notes:
(1) Employee Hours for each operation includes Underground, Surface at Underground, and Office Workers employees as listed by MSHA.
(2) Employees Hours for Oaktown Mining Complex includes all operational employee hours and additionally all preparation/mill site employee hours for each operation as listed by MSHA.
(3) Tons reported as Product (i.e., Clean Coal) Tons.
(4) TPEH is tons per emplyee-hour.

As a complex, Oaktown Mining Complex has produced a combined 75 million tons of clean coal between 2009 and 2024. Through the same period, the complex has recorded an average productivity level of 3.8 tons per employee-hour (TPEH). Figure 7.2, on the following page, illustrates the historic mining productivity for the

Oaktown Mining Complex and each mine individually since their start of commercial production.

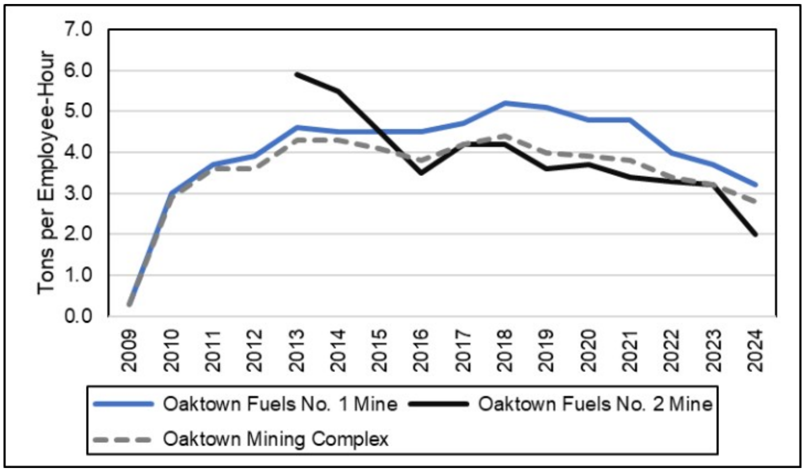


Figure 7.2: Historic Mining Productivity Levels

7.3.2 Forecasted Production

BOYD developed LOM plans for each of the Oaktown Mining Complex underground mines based on generally accepted engineering practices, and in alignment with historical and industry norms. It is BOYD's opinion that the forecasted production levels for the Oaktown Mining Complex operations are reasonable, logical, and consistent with typical CM mining practices within the ILB and historical practices utilized by the Oaktown Mining Complex.

The Oaktown Mining Complex LOM plans, as shown in Table 7.5, following this page, portray a consistent production output during 2025 through 2032 and then a decline in production as the number of CM units are reduced gradually as the mining reserves are depleted. In the aggregate, the Oaktown Mining Complex LOM plan projects the complex will produce approximately 57.1 million tons of ROM and approximately 34.4 million tons of clean coal over its operational horizon.

Table 7.5: Life-of-Mine Coal Production Summary

	Coal Tons (000)					
	Oaktown Fuels No. 1 Mine		Oaktown Fuels No. 2 Mine		Total - Oaktown Mining Complex	
Year	ROM	Clean	ROM	Clean	ROM	Clean
2025	5,970	3,663	-	-	5,970	3,663
2026	5,970	3,599	-	-	5,970	3,599
2027	5,970	3,608	-	-	5,970	3,608
2028	5,970	3,602	-	-	5,970	3,602
2029	5,970	3,601	-	-	5,970	3,601
2030	5,796	3,467	174	109	5,970	3,576
2031	4,477	2,630	1,492	940	5,969	3,570
2032	3,153	1,915	2,817	1,738	5,970	3,653
2033	1,657	1,020	2,788	1,687	4,445	2,707
2034	1,493	920	1,492	851	2,985	1,771
2035	503	310	1,362	777	1,865	1,087
Total	46,929	28,335	10,125	6,102	57,054	34,437

Average clean yield and quality on an annual basis over the life of the Oaktown Mining Complex is provided in Table 7.6, below.

Table 7.6: Life-of-Mine Plan Coal Quality Summary

				Average Clean Coal Quality (As-Received Basis)			
	Coal Production (Tons 000)						
Year	ROM	Clean	Plant Yield (%)	Ash (%)	Sulfur (%)	Heating Value (Btu/lb)	SO_2 (lbs per MMBtu)
2025	5,970	3,663	61.4	7.4	3.6	11,527	6.3
2026	5,970	3,599	60.3	7.4	3.4	11,533	5.9
2027	5,970	3,608	60.4	7.4	3.4	11,522	5.9
2028	5,970	3,602	60.3	7.5	3.4	11,518	5.9
2029	5,970	3,601	60.3	7.3	3.5	11,529	6.1
2030	5,970	3,576	59.9	7.6	3.5	11,499	6.0
2031	5,969	3,570	59.8	8.4	3.4	11,406	6.0
2032	5,970	3,653	61.2	7.3	3.1	11,580	5.4
2033	4,445	2,707	60.9	7.3	3.0	11,574	5.2
2034	2,985	1,771	59.3	7.5	3.1	11,513	5.3
2035	1,865	1,087	58.9	7.6	3.0	11,506	5.2
Total/Average	57,054	34,437	60.4	7.5	3.4	11,542	5.8
Minimum			58.9	7.3	3.0	11,406	5.2
Maximum			61.4	8.4	3.6	11,580	6.3

In general, Oaktown Mining Complex's annual clean coal yield and quality is relatively consistent over the 11-year period; this consistency is indicative of the local Indiana V Seam coal geology.

During the 11-year life of mine, the Oaktown Mining Complex is forecasted to produce approximately 34.4 million tons of clean coal. While it is expected that the mines will encounter local areas of high ash and/or sulfur from either individual mine, the aggregate product from Oaktown Mining Complex should see minimal impact. This reflects the fact that Oaktown Mining Complex's infrastructure allows for the blending of each the individual mines' segregated ROM product, thus mitigating the influence/impact that an individual mine or production unit (producing in a localized area of lesser coal quality) could have on the complex's overall product quality.

7.3.3 Mining Recovery and Dilution Factors

The Oaktown Mining Complex's underground R&P mines operate within the same geological setting and coal seam with little distinguishable differences. As such, the design of each mine is largely the same (e.g., mains width, panel width and length, and CM support pillars). As a result, mining recoveries within the individual mine plans are largely similar. The estimated mining recoveries for Oaktown Mining Complex generally range from 40% to 50%. Based on our review of Oaktown Mining Complex's reserves by individual mining areas, it is BOYD's opinion that the mining area recoveries utilized are reasonable and align with general engineering principles.

The proximity of the operations within the same geologic setting and coal seam also results in similar dilution factors for both Oaktown Mining Complex's mines. The mining horizon targeted by each of the mines includes the main bench of the Indiana V Seam and any in-seam partings. Both mines traditionally operate within the seam as much as possible with little OSD.

The CM mains sections are more subject to sporadic OSD due to maintaining proper ventilation airways, airway intersection locations with planned undercasts, provide adequate clearances for belt transfers, etc., regardless of the targeted mining horizon thickness. These variances are more likely a result of mine infrastructure and design rather than fluctuations in geology.

7.3.4 Expected Mine Life

The LOM plan for each of the Oaktown Mining Complex mines' operation was developed with input from both Sunrise and BOYD. The LOM plan was developed with consideration taken for mineral control and timing based upon forecasted production levels for each mine. The depicted general layout and mineral control for Oaktown Fuels No. 1 and No. 2 mines are shown in Figure 3.1.

The final year of the Oaktown LOM plan is 2035. While Oaktown Mining Complex is forecasted to operate through 2035, each mine has a different expected mining life. Table 7.7 provides the expected mine life for each of the individual underground R&P mines:

Table 7.7: Mine Life Projection

Mine	Remaining Life (years)	Last Year of Mining
Oaktown Fuels No. 1	11	2035
Oaktown Fuels No. 2	6	2035

Production units will start to decrease following 2031 as the coal reserves are gradually depleted at Oaktown Fuels No. 1 Mine. The Oaktown Fuels No. 2 Mine is scheduled to resume mining in 2030 with two production units until its second to last year of operation in 2034. Coal reserves at both mining operations of the Oaktown Mining Complex are expected to be exhausted in 2035.

7.4 Other Mining Considerations

7.4.1 Mine Design

Mines in the ILB region utilize a wide range of techniques for the extraction of coal including both surface and underground mining methods. However, the majority of coal mining production from the ILB region focuses largely on the Indiana V (Springfield) and Indiana VI (Herrin) seams extracted through underground mining methods.

Given the large extent of reported coal reserves, overall good mining conditions, general coal seam consistency, consistent depth of cover, and relatively low population density on the overlying surface, the Oaktown Mining Complex is well suited for underground R&P mining. Mining plans for R&P mines without secondary extraction are relatively simple yet highly flexible. Unlike LW operations (having a rigid system), the Oaktown Fuels No. 1 and No. 2 mines' mining method allows for the opportunity to alter the mining plan to avoid specific areas with adverse mining conditions (such as thin coal, poor roof, etc.) or poor coal quality (such as high sulfur, etc.). Mains and sub-mains are typically established in areas where confidence is highest regarding good mining conditions, roof conditions, coal thicknesses, etc. Panels are then developed out to a desired length (whether that be operationally, or engineering based) or until adverse mining conditions or poor coal quality warrant the cessation of development. When the mine panels reach the end of their advance stage of mining, the mine operator removes the production equipment and reinstalls it to another location within the mine to commence production.

The Oaktown Mining Complex is approved for "first only" mining and partial pillar extraction (fender cuts) on a case-by-case basis. Sunrise has no intentions of employing full pillar extraction mining methods at either of the operations. The use of "first only" mining and "fender cuts" is common for the ILB region R&P underground mines. There remains substantial public and environmental group opposition to mining in general, however this is more particularly targeted towards LW mining and full pillar extraction and the effects of subsidence on surface structures and, more recently, perennial streams. The Oaktown Mining Complex is shielded from a portion of this opposition given the implementation of "first only" and partial pillar extraction mining methods. While there are likely to be some instances of heightened environmental and communal concern regarding mining within the Oaktown Mining Complex plans, Sunrise has historically demonstrated the ability to apply for and obtain the necessary permits for continued mining within their controlled coal reserves, even while being met with some environmental pushback.

7.4.2 Mining Risk

Underground R&P mines face two primary types of operational risks. The first category of risk includes those daily variations in physical mining conditions, mechanical failures, and operational activities that can temporarily disrupt production activities. Several examples are as follows:

- Roof control problems and roof falls.
- Water accumulations/soft floor conditions.
- Ventilation disruption and concentrations of methane gas.
- Variations in seam consistency, thickness, and structure.
- Failures or breakdowns of operating equipment and supporting infrastructure.
- Weather disruptions (power outages, inability to load barges due to flooding of rivers, etc.).

The above conditions/circumstances can adversely affect production on any given day, but are not regarded as "risk issues" relative to the long-term operation of a mining operation. Instead, these are considered "nuisance items" that, while undesirable, are encountered on a periodic basis at virtually all mining operations. Engineered mining plans and projections for the Oaktown Mining Complex appear to incorporate generally-accepted industry and Sunrise historical performance levels as a basis, and thereby mitigate the likelihood that the mines will experience such disruptions to production operations to the extent that they have previously occurred. BOYD does not regard the issues listed above as being material to the Oaktown Mining Complex mining operations or otherwise compromising the forecasted performance.

The second type of risk is categorized as "event risk." Items in this category are rare, but significant occurrences that are confined to an individual mine, and ultimately have a pronounced impact on production activities and corresponding financial outcomes. Examples of event risks are major fires or explosions, floods, or unforeseen geological anomalies that disrupt extensive areas of underground mine workings and require alterations of mining plans. Such an event can result in the cessation of production activities for an undefined but extended period (measured in months, and perhaps years) and/or result in the sterilization of coal reserves.

The U.S. mining industry has made tremendous strides in enhancing employee safety and reducing the likelihood of fires, explosions, and other dramatic events over the past several decades. Underground R&P mining is largely a predictable and safe industry. BOYD does not regard the Oaktown Fuels No. 1 and No. 2 mining operations and mine plans as being particularly risky, inadequately managed, or otherwise susceptible to major events. There is no basis to predict or otherwise anticipate major operational shortfalls and/or extraction of coal reserves at the subject mining operation.

8.0 PROCESSING OPERATIONS

8.1 Overview

The centrally located Oaktown Complex CPP is designed to process the combined ROM output produced by Oaktown Mining Complex's two underground R&P mines. Comprised of ROM coal stockpile areas, a coal processing plant, clean coal storage, a rail loadout facility, and truck scales/loading, the approximate 150-acre processing complex is located within proximity of the active operations.

The Oaktown Complex CPP first began operation as the coal washing facility for the Oaktown Fuels No. 1 Mine in 2009. In 2013, major renovations were made to the Oaktown Complex CPP to accommodate additional tonnage supplied from the newly developed Oaktown Fuels No. 2 Mine. Major process upgrades focused on adding a second 800 TPH circuit, increasing total CPP throughput capacity to 1,600 TPH.

While the capacity of the facility has grown, the coal preparation process at Oaktown Complex CPP, like other preparation plants in the ILB mining region, has largely remained unchanged since commissioning. Processing circuits within the Oaktown Complex CPP consist of heavy media bath, heavy media cyclones, hydro-spirals, and froth flotation. Straightforward when compared to many other mineral processing techniques, the coal process is largely based on separating rock material from coal material contained in the raw coal feed by mechanically reducing the size of the feed and utilizing the materials' different densities to gravitationally separate one from the other. Largely, the process requires water, magnetite, and frothing agents.

ROM coal arrives directly to the complex from the Oaktown Fuels No. 1 and No. 2 mines via two independent slope conveyor belts. There are two ROM coal storage areas that provide approximately 1.2 million tons of above-ground storage capacity for the Oaktown Mining Complex underground mines. The ROM coal storage areas enable each mine to provide their plant feed separately to the preparation facility, or to be combined for a blended product. The clean coal product is dried with screen-bowl centrifuges. Processed product is then transported via overland conveyor belt just over 1 mile to the north and stored at the open-air clean coal storage area. The main clean coal storage area has a capacity of approximately 980,000 tons, with an auxiliary clean coal storage located adjacently (capacity of approximately 290,000 tons) that can be utilized as necessary.

Clean coal is sampled and loaded into 120-car unit trains through a flood load system. The Oaktown Complex CPP is served by both CSX and INRD via a short rail spur that connects the complex's double loop rail system with the mainline rail just north of Oaktown, Indiana. Two rail sidings are employed to facilitate railroad transportation logistics and allowing the accommodation of two-unit trains at any time.

Following this page are Figure 8.1, which provides an aerial overview of the preparation facility area, and Figure 8.2, which provides a generic flow sheet of the CPP and related facilities.

8.2 Historical Operation

Due to the evolution and enlargement of Sunrise's Oaktown Mining Complex operations, the Oaktown Complex CPP underwent modification and expansion to accommodate the complex's increased coal production and washing requirements. The plant's expanded capacity is evidenced by its current average annual plant feed, which has grown from approximately 6.2 million tons processed in 2012 and 2013, to an average plant feed of 8.6 million ROM tons between 2017 to 2021.

The Oaktown Complex CPP has historically produced a very consistent clean coal product that possesses medium ash and high sulfur characteristics and between 11,000 to 12,000 Btu per lb on an as received basis. The plant's ability to blend raw coal production from the two underground mines into a singular plant feed allows for both more consistent plant operation and coal product qualities.

8.3 Future Operations

Sunrise intends to utilize the Oaktown Complex CPP throughout the LOM. Table 7.6 (page 7-9) summarizes the planned production from the Oaktown Complex CPP over the expected life of the operations.

Annual plant feed (i.e., ROM coal) and clean coal production tonnages over the balance of the LOM are within the capacities of the Oaktown Complex CPP.

Figure 8.1

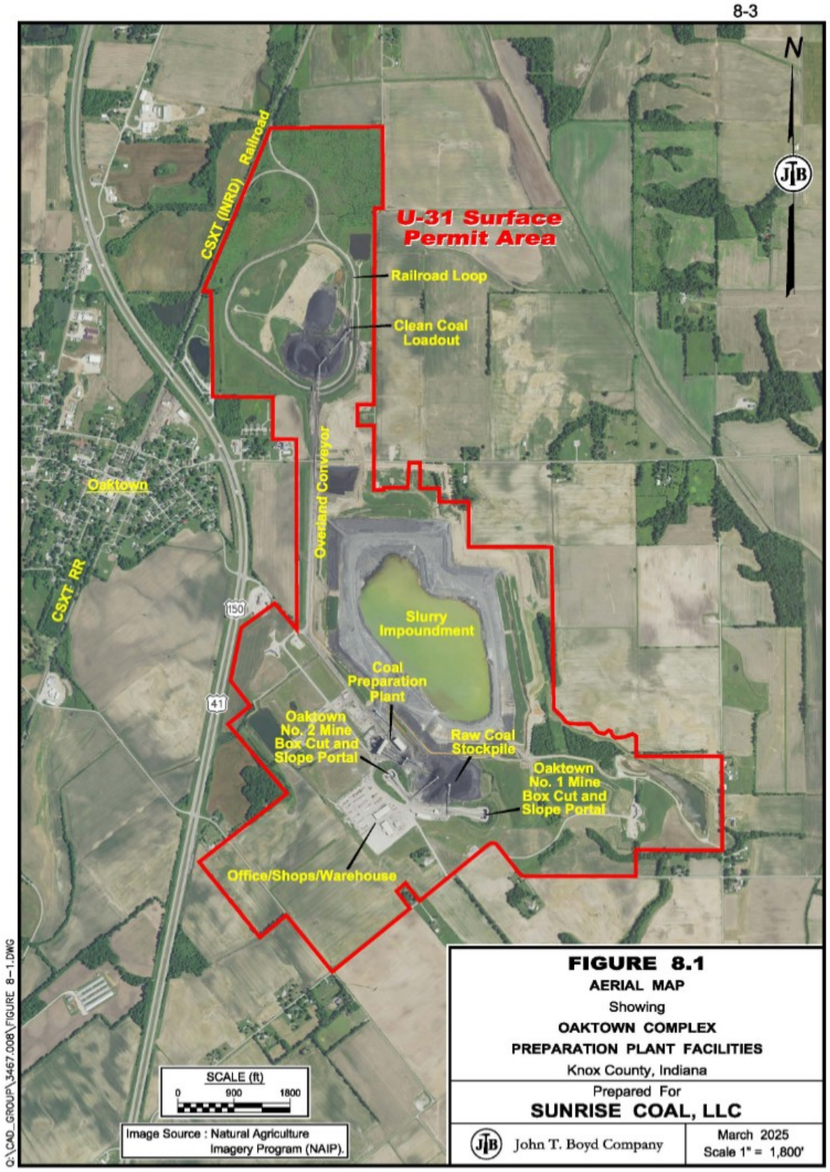
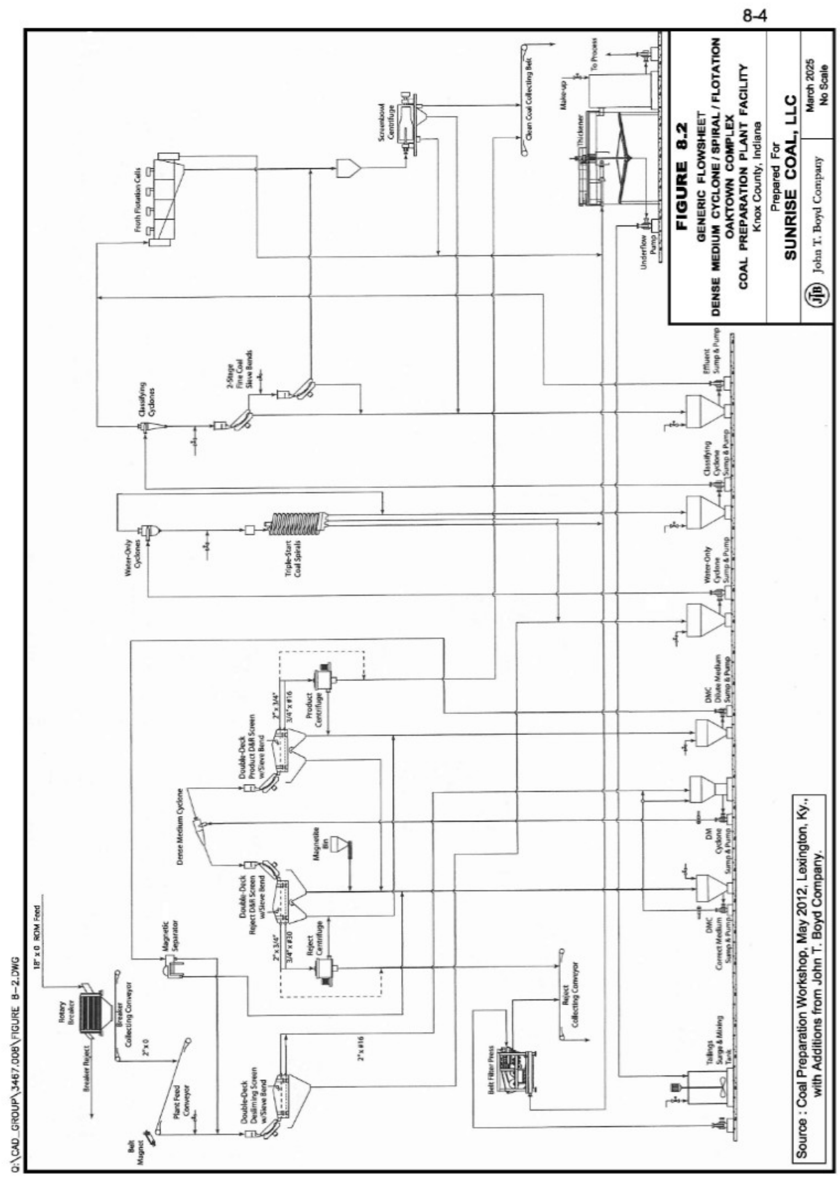

8-3
N
U-31 Surface Permit Area
CSXT (INRD) Railroad
Railroad Loop
Clean Coal Loadout
Overland Conveyor
Oaktown
CSXT RR
150
41
Slurry Impoundment
Coal Preparation Plant
Oaktown No. 2 Mine Box Cut and Slope Portal
Raw Coal Stockpile
Oaktown No. 1 Mine Box Cut and Slope Portal
Office/Shops/Warehouse
SCALE (ft)
0 900 1800
Image Source : Natural Agriculture Imagery Program (NAIP).
FIGURE 8.1
AERIAL MAP
Showing
OAKTOWN COMPLEX
PREPARATION PLANT FACILITIES
Knox County, Indiana
Prepared For
SUNRISE COAL, LLC
John T. Boyd Company
March 2025
Scale 1" = 1,800'

Figure 8.2


8-4
FIGURE 8.2
GENERIC FLOWSHEET
DENSE MEDIUM CYCLONE / SPIRAL / FLOTATION
OAKTOWN COMPLEX
COAL PREPARATION PLANT FACILITY
Knox County, Indiana
Prepared For
SUNRISE COAL, LLC
John T. Boyd Company
March 2025
No Scale
Source : Coal Preparation Workshop, May 2012, Lexington, Ky.,
with Additions from John T. Boyd Company.

8.4 Conclusion

Based on our review of historical processing data and forecasts of future production, it is BOYD's opinion that the present processing methods found at Oaktown Complex CPP will be sufficient for future processing of coals at Oaktown Mining Complex.

9.0 MINE INFRASTRUCTURE

9.1 Mine Surface Facilities

Operations at each of the two Oaktown Mining Complex underground mines are supported by multiple surface facilities located within the areal proximity of the mines' reserve boundary. Major surface infrastructure elements include: engineering and business offices, personnel bathhouses, parking areas, supply yards, warehouse buildings, ventilation fan structures, ventilation air shafts, high voltage power distribution stations, and primary underground access points, including slope tunnels (for transporting supplies underground/conveying ROM coal to the surface) and mine portals (shafts for transporting employees/supplies underground). Figure 3.1 provides a general location map highlighting the layout of the two Oaktown Mining Complex underground mines and the surface location of their primary deep mine access points. Each of the Oaktown Mining Complex underground R&P mines maintains their own separate surface facilities. In terms of industry standards, the Oaktown Mining Complex operations' surface infrastructure is comparable to facilities typically found within the ILB mining region.

The current surface facilities located at each of the mines are well constructed and have the necessary capacity/capabilities to support the Oaktown Mining Complex's near-term mining plans. Longer term, as the individual mines progress beyond their near-term mine plans and the location of future mining activities is centered outside the physical and/or operationally efficient limitations of the existing infrastructure, additional surface facilities of comparable design may be required to support continued mining (refer to Chapter 11 for a discussion regarding Sunrise's expectations for future capital expenditures).

Given Sunrise's demonstrated ability to steadily construct its expanding surface facility infrastructure in a timely fashion (relative to underground mine production), the need for continued surface facilities at the mines of Oaktown Mining Complex is not seen as a hindrance for the execution of the LOM plans.

All ROM output from the Oaktown Mining Complex mines is processed in the Oaktown Complex CPP, which is discussed in Chapter 8.

9.2 Oaktown Complex Refuse Facility

The Oaktown Complex refuse facility serves as the disposal location for all waste rock (coarse coal refuse) and a portion of fine coal slurry (fine coal refuse) produced during the processing of ROM coal from the two Oaktown Mining Complex underground R&P mines. The majority of the fine coal slurry is transported overland via a network of pumps and pipelines for underground disposal within mined-out void areas. The current Oaktown Complex refuse facility encompasses more than 320 permitted acres located adjacent to the Oaktown Complex CPP and across the Oaktown Mining Complex surface (i.e., to facilitate slurry injection).

The Oaktown Complex surface refuse facility includes one main disposal area for coarse coal refuse and fine coal refuse. In addition to the one main disposal area, multiple underground slurry injection locations are located across the Oaktown Mining Complex to utilize void space within mined out areas of the Oaktown Fuels No. 1 and No. 2 mines.

According to forecasted LOM coal refuse disposal requirements, currently permitted refuse areas can accommodate coarse disposal through approximately 2031 and fine coal refuse disposal through late-2027 or early-2028.

Sunrise representatives indicated that the fine refuse disposal plan post-2027 and coarse refuse disposal plan post-2031 will be based on proven practices and approaches. Sunrise has historically demonstrated the ability to operate the refuse facility and injection sites in a prudent manner, obtain associated permits, and to execute construction of disposal areas (injection sites) in a timely fashion. It is BOYD's opinion that Sunrise's staged injection disposal through 2028 will meet the practices demonstrated by other industry peers. At this time, lack of a properly staged and detailed fine coal refuse disposal plan post-2027 and coarse refuse disposal plan post-2031 is not seen as a major hindrance to Oaktown Mining Complex meeting the LOM plans.

10.0 MARKET ANALYSIS

10.1 Indiana Coal Industry Background

The following section provides a brief description of the Indiana coal mining industry.

10.1.1 Coal Reserves

The coalfield of Indiana covers an area of 6,500 square miles in the southwestern portion of the state forming the east-central portion of the ILB. The configuration of the coal-bearing area in Indiana is roughly triangular in shape, with a maximum east-west width of approximately 80 miles along the Ohio River and extending approximately 200 miles to the north to Benton County. The state's coal-bearing strata dip in a southwesterly direction at about 30 ft per mile toward the center of the ILB in southeastern Illinois.

According to the Indiana Geological Survey, Indiana's total coal geological resources are approximately 57 billion tons, of which 17 billion tons is recoverable using current technology. A distribution by mining method suggests 88% of the state's mineable resources (15 billion tons) are recoverable by underground mining techniques with the balance recoverable by surface mining. Based on current production rates, Indiana's 17 billion tons of available mineable coal resources could last more than 500 years. Twenty counties within, or partly within, the Indiana coalfield have significant coal resources. As seen in Table 10.1, below, coal production within the state has been primarily centered within Gibson, Sullivan, and Knox counties over the past five years.

Table 10.1: Historical Indiana Coal Production by County and Year (000 Tons)

County	2020	2021	2022	2023	2024
Clay	253	135	103	37	-
Daviess	2,101	63	474	434	409
Dubois	111	8	-	-	-
Gibson	4,207	4,788	7,569	7,628	7,414
Knox	5,243	5,636	6,401	6,475	3,982
Pike	118	13	215	585	627
Spencer	10	-	181	320	107
Sullivan	5,322	6,040	6,722	5,536	4,957
Warrick	2,212	2,789	2,385	2,768	2,652
Total	19,577	19,472	24,050	23,783	20,148

Currently, the Indiana V (Springfield) and VII (Danville) are the Indiana coal seams most extensively mined, although limited mining is also conducted in the Colchester and Survant seams. The Indiana VI (Herrin), which is one of the predominant economically mineable seams of the ILB, has limited presence within Indiana.

10.1.2 Coal Quality

Coal produced in Indiana is typically a medium to high volatile (25% to 30+%) bituminous rank coal with medium to high thermal content (i.e., ranges from approximately 11,000 to 11,500 Btu/lb) and relatively high sulfur content. The primary market for Indiana coal is the in-state coal-fired utility market. Table 10.2, below, summaries the Indiana coal quality shipped to domestic coal-fired generating plants in 2024, as reported by the U.S. Energy Information Administration (EIA).

Table 10.2: Quality Specifications for Indiana Coal Shipped to Domestic Utilities in 2024

	%		Heating Value
	Ash	Sulfur	(Btu/lb)
Average	9.1	2.90	11,273
Minimum	5.7	1.35	10,750
Maximum	13.1	3.96	12,119

Relative to chlorine content, Indiana coals are generally advantaged by relatively low levels of chlorine across the mining region. A summary of Indiana coal quality, including available chlorine content data derived from studies completed by the U.S. Geological Survey and other sources, is provided in Table 10.3, below.

Table 10.3: Indiana Coal Quality by County of Origin

	%			Heating Value
County	Ash	Sulfur	Chlorine	(Btu/lb)
Clay	9.0	0.75	0.025	10,855
Daviess	7.1	2.82	0.020	11,712
Dubois	10.3	3.05	0.036	11,101
Gibson	8.0	2.64	0.031	11,395
Knox	8.2	3.12	0.037	11,525
Pike	8.6	2.88	0.020	11,203
Spencer	9.2	1.65	n/a	10,544
Sullivan	9.2	2.80	0.032	11,134
Warrick	9.0	3.49	0.023	11,274

By comparison, the chlorine content of the Illinois No. 5 (Springfield) and No. 6 (Herrin) coal seams, which are the two seams mined extensively throughout Illinois, typically ranges from 0.1% to 0.6%. Coals having chlorine content above 0.3% is found to cause damaging boiler corrosion, a fact that negatively impacts the marketability of high-chlorine coal produced in Illinois.

10.1.3 Transportation

ILB coal producers are supported by a multi-modal transportation infrastructure system capable of moving coal to end users by truck, rail, and barge (operating alone and/or in combination). Class I railroads operating in the region include the Union Pacific, CSX, NS, and the Canadian National. The ILB is also supported by several regional short-line railways. In many instances, due to geographic location of the mine in relation to the end-user or river loading facility, rail delivery must be conducted via multi-line movements. Any coal movement could involve multiple rail-line hauls, third-party controlled river loading facilities, short rail haul distances or long truck haul distances.

Multiple transportation carriers and multiple transportation modes can have a significant influence on overall delivered costs. Situations can arise where two mines can be in fairly close proximity with one another, but one has a decided transportation advantage based on its access to a particular rail service provider.

Several coal producers in the basin have direct or indirect access to the inland waterway system providing river borne transportation options on the Green, Ohio, and/or Mississippi rivers. Mines located in western Kentucky are generally better suited to direct river loading than those in Indiana and Illinois.

The Indiana coal fields are crossed by numerous roads and railroads. Feeder lines from Class 1 railroads support numerous loadout facilities found in the State's coal-producing counties. In addition, a well-developed network of federal and state highways crosses the coal-producing region (as well as a supporting system of secondary all weather roads) and provide adequate truck hauling capacity.

10.1.4 Production Evolution

Table 10.4, below, illustrates the progression of Indiana's coal producers and their associated mines operating from 2020 to 2024.

Table 10.4: Historical Indiana Coal Production and Mine Count

Company	2020	2021	2022	2023	2024
Coal Production (000 Tons)					
Alcoa Corporation	-	-	-	685	485
Alliance Resource Partners LP	2,191	3,290	5,256	5,317	5,699
Sunrise Coal, LLC	5,636	5,771	6,542	6,650	4,004
Peabody Energy Corporation	9,300	9,878	10,790	9,479	8,488
Responsible Energy Ventures LLC	2,329	83	652	589	474
Others	121	450	810	1,063	998
Total	19,577	19,472	24,050	23,783	20,148
Number of Mines					
Alcoa Corporation	-	-	-	1	1
Alliance Resource Partners LP	1	1	1	1	1
Sunrise Coal, LLC	4	3	5	5	4
Peabody Energy Corporation	4	4	4	4	3
Responsible Energy Ventures LLC	4	4	2	2	2
Others	3	1	3	4	4
Total	16	13	15	17	15

In 2016, Indiana's coal industry produced approximately 29 million tons from 27 mines. By 2020, the number of operating mines decreased by 26% (to 20) while coal production from the State declined by 31% (to 20 million tons). The modest production rationalization that ensued during that period was primarily driven by the closure of less productive, marginal operations. As shown in the table above, coal production in the State has been relatively consistent, both in tons produced and number of active mines.

10.1.5 Mining Methods

Indiana coal operators utilize traditional surface and underground mining technology to produce over 20 million tons annually. Surface mines primarily employ truck/shovel operations and draglines (at select mines); underground mines typically utilize continuous miners in R&P and/or super-section applications. There are no LW operations in Indiana. Historical state coal production by mining method is shown in Figure 10.1, on the following page.

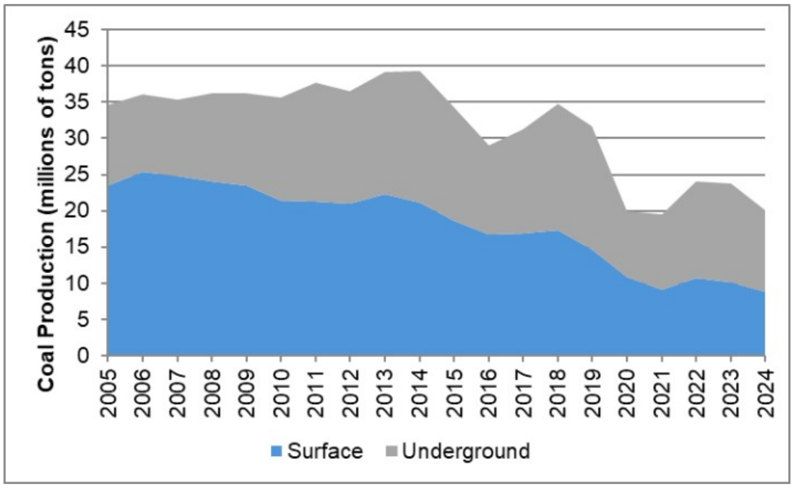


Figure 10.1: Indiana Coal Production by Mining Method

In 2005, Indiana coal output totaled nearly 35 million tons. In that year, approximately 68% (23.5 million tons) was produced from surface operations. Due to the depletion of mineable reserves with economic stripping ratios, as well as the encroachment of urban and farm development over time, coal mining in Indiana has gradually shifted towards underground operations. In 2024, of the 20.1 million tons of coal produced, approximately 56% (11.3 million tons) was attributed to surface mines.

10.1.6 Coal Demand by Market

Historically, coal produced from mines in Indiana has been used primarily for electric power generation, with the balance directed into the industrial coal market (including process heat, steam, and space heating). A major portion of the Indiana coal industry is located on or near major Class 1 railroads, enabling coal suppliers to service the regional markets and/or some out of state customers. In 2023, Indiana coal mines supplied approximately 19.3 million tons into the general coal market. Of the total Indiana coal sales, approximately 19 million tons (or 98%) went to electric generators, with the remaining balance shipped to industrial customers (e.g., cement and sugar plants). The annual distribution of Indiana coal shipments by market sector for 2019 through 2023 is shown in Table 10.5, below.

Table 10.5 : Distribution of Indiana Coal Shipments by Market Sector

	2019		2020		2021		2022		2023	
Market Segment	Tons (000)	%	Tons (000)	%	Tons (000)	%	Tons (000)	%	Tons (000)	%
Domestic Coke Plants	-	-	-	-	-	-	-	-	-	-
Electric Power Sector	26,024	90.1	19,133	95.1	17,870	91.0	20,535	92.3	18,971	98.4
Industrial Plants*	668	2.3	670	3.3	671	3.4	540	2.4	292	1.5
Commercial	52	0.2	35	0.2	50	0.3	56	0.3	23	0.1
Export Market	2,147	7.4	285	1.4	1,042	5.3	1,115	5.0	-	-
Total	28,891	100.0	20,123	100.0	19,633	100.0	22,246	100.0	19,286	100.0

* Excluding coke.

In the past five years, Indiana coal has had a limited presence in the international export markets. The majority of Indiana produced thermal coal is shipped to electricity generating plants in Indiana. Table 10.6, below, summarizes Indiana thermal coal shipments for the past five years to generating stations by state.

Table 10.6 : Historical Indiana Coal Deliveries to Utility Market by Destination State

	2020		2021		2022		2023		2024 (Jan–Nov)	
Plant State	Tons (000)	No. of Plants	Tons (000)	No. of Plants	Tons (000)	No. of Plants	Tons (000)	No. of Plants	Tons (000)	No. of Plants
Indiana	15,619	9	14,562	9	17,300	10	15,452	10	11,794	8
Kentucky	965	3	1,028	2	1,048	5	663	4	559	1
Florida	984	3	1,367	3	1,108	2	1,276	2	848	2
Ohio	-	-	-	-	67	3	6	1	-	-
Alabama	-	-	-	-	58	1	99	1	-	-
Tennesse	389	2	267	2	258	2	33	2	-	-
Georgia	509	1	252	1	455	1	1,059	1	178	1
Illinois	1	1	192	1	207	1	14	1	-	-
Michigan	106	1	53	1	66	1	39	1	-	-
N Carolina	560	1	341	1	176	1	330	1	356	1
Others	-	-	-	-	-	-	-	-	65	1
Total	19,133	21	18,062	20	20,742	27	18,971	24	13,800	14

Percentage of Utility Deliveries by State

	2020	2021	2022	2023	2024 (Jan–Nov)
Indiana	81.6	80.6	83.4	81.4	85.5
Kentucky	5.0	5.7	5.1	3.5	4.0
Florida	5.1	7.6	5.3	6.7	6.1
Ohio	-	-	0.3	0.0	-
Others	8.2	6.1	5.9	8.3	4.3
Total	100.0	100.0	100.0	100.0	100.0

In 2023, Indiana thermal coal directed into the domestic U.S. utility market totaled almost 19 million tons. Of this amount, generating plants operating in Indiana consumed 15.5 million tons or approximately 81% of Indiana's total thermal coal deliveries.

10.2 Sunrise Coal

10.2.1 Product Specifications

Sunrise's primary product from their main mining operations is a thermal coal that is directed into the U.S. generation market. Indicative quality specifications for coal shipped by Sunrise from the Oaktown Mining Complex to U.S. generating stations in 2024 is provided in Table 10.7, below.

Table 10.7: Quality Specifications for Sunrise Coal Shipped to Domestic Utilities in 2024

	%		Heating Value
	Ash	Sulfur	(Btu/lb)
Average	8.5	3.18	11,463
Minimum	3.4	1.09	10,750
Maximum	13.5	5.79	12,020

10.2.2 Primary Markets

Sales into the domestic thermal coal market is Sunrise's primary focus, accounting for over 97% of the company's annual coal production tonnage over the past five years. A summary of Sunrise's 2020 to 2024 (January to November only) deliveries to U.S. generating stations by state is provided in Table 10.8, below.

Table 10.8: Historical Sunrise Coal Deliveries to Utility Market by Destination State

	2020		2021		2022		2023		2024 (Jan–Nov)	
Plant State	Tons (000)	No. of Plants	Tons (000)	No. of Plants	Tons (000)	No. of Plants	Tons (000)	No. of Plants	Tons (000)	No. of Plants
Indiana	4,184	6	4,520	7	4,844	7	4,038	6	2,458	4
Florida	741	2	1,356	3	924	2	1,276	2	796	1
Georgia	-	-	-	-	165	1	846	1	178	1
N Carolina	103	1	102	1	47	1	221	1	178	1
Alabama	-	-	-	-	23	1	99	1	-	-
Tennesse	47	1	-	-	-	-	-	-	-	-
Total	5,075	10	5,977	11	6,004	12	6,480	11	3,609	7

Percentage of Utility Deliveries by State

	2020	2021	2022	2023	2024 (Jan–Nov)
Indiana	82.5	75.6	80.7	62.3	68.1
Florida	14.6	22.7	15.4	19.7	22.0
Georgia	-	-	2.8	13.1	4.9
N Carolina	2.0	1.7	0.8	3.4	4.9
Alabama	-	-	0.4	1.5	-
Tennesse	0.9	-	-	-	-
Total	100.0	100.0	100.0	100.0	100.0

During this period, the primary markets for Sunrise have been Indiana and Florida.

As an existing producer with a lengthy commercial history and established customer base, it is BOYD's opinion that market entry strategies are not required for continued sale of the Oaktown Mining Complex's thermal coal products.

10.2.3 Market Outlook

Coal use among domestic power generators has fallen out of favor in the United States and is systematically being replaced by natural gas and renewable forms of generation. In response to this development, domestic thermal coal markets are expected to weaken over the next few years, in line with coal plant retirements and the associated drop in coal demand. However, recent cold weather has increased domestic coal consumption, particularly in the midcontinent and mid-Atlantic regions that rely on coal for a significant portion of their electric power generation. In the near term, increased power demand and higher than average natural gas prices are expected to drive coal demand and pricing.

10.2.4 Future Sales

Sunrise is expected to align its future sales with the U.S. market trends, although the regional Indiana market is expected to remain relatively firm over the near term.

As shown in Figure 10.2, below, a significant portion of Sunrise's near-term coal production is "committed" (i.e., allocated) to existing supply contracts/agreements. It is reasonable to expect Sunrise to commit future production on an ongoing basis according to its business strategies.

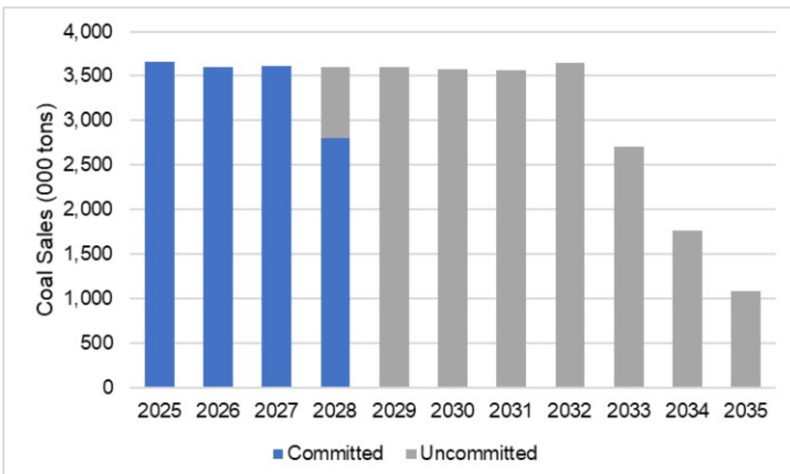


Figure 10.2: Future Coal Sales by Order Type

Historically, the top-five customers by sales revenue account for approximately 75% to 85% of total coal sales from the Oaktown Mining Complex annually.

10.2.5 Price Forecast

Market prices for Sunrise's thermal coal products are influenced by many factors, and the coal market environment can be volatile. The primary factors influencing future prices include: (1) demand, primarily at scrubbed base-load stations, (2) competition in the form of other regional coal suppliers, natural gas-fired generation, and renewables, (3) exhaustion of competing regional mines (thereby reducing local fuel supply), (4) transportation differentials, and (5) cost structures associated with sustained coal production levels.

Coal prices can change quickly. This has been demonstrated in the current market environment, as the price of Illinois Basin coal has rebounded by somewhere between $10/ton and $20/ton in various marketplaces in the span of a few months; coal prices have moved from the $30s in early 2021 to somewhere in the $40s or $50s by the end of 2021. Prices continued to rise into the low $60 range by 2023 but fell off slightly into the low-$50s in 2024. This is the result of increased demand coupled with declining stockpiles and a relatively constrained production response from mine operators.

The prices of competing fuel sources for power generation are meaningful, with the price of natural gas being the most significant. Coal and natural gas are at relative parity at a natural gas price of $2.50 per MMBtu, and when natural gas prices are more than $3 per MMBtu, coal becomes the fuel of choice. The relative scarcity of natural gas in the marketplace has resulted in prices that have recently surpassed $4 per MMBtu, which has further enhanced the competitiveness of coal, even at robust coal prices. While it is reasonable that there will eventually be some pullback in this marketplace, the current market for Illinois Basin coal is likely to remain strong for the next two years. Likewise, the lack of recent investment throughout the Illinois Basin will preclude meaningful coal production responses across that Basin that could contribute to oversupply.

BOYD anticipates the recent slow rise in coal pricing to be indicative of the market conditions over the next four years (2025 through 2028). Thereafter, we expect a pricing that is in the mid-to-high $40s/ton (FOB CPP) range when expressed in constant dollars.

BOYD's price forecast for the Oaktown Mining Complex's future coal sales is a weighted average of Sunrise's committed sales prices and our forecasted prices for uncommitted (or spot) sales. Our coal price forecast for the Oaktown Mining Complex is provided in Table 10.9, below.

Table 10.9: Coal Price Forecast

Year	Coal Sales (000 tons)	Average Sales Price* ($/ton)
2025	3,663	49.33
2026	3,599	51.16
2027	3,608	51.47
2028	3,602	51.05
2029	3,601	47.25
2030	3,576	47.25
2031	3,570	47.25
2032	3,653	47.25
2033	2,707	47.25
2034	1,771	47.25
2035	1,087	47.25
Total/Average	34,437	48.72

* FOB Oaktown Complex CPP

As shown, BOYD expects selling prices (FOB CPP) for the Oaktown Mining Complex's thermal coal products to range from $47.25 to $51.47 and average $48.72 per clean ton over the life of the reserves.

11.0 CAPITAL AND OPERATING COSTS

11.1 Historical Financial Performance

Oaktown Mining Complex's performance relative to productivity, cost control, and production has made it one of the leading underground coal operators within the ILB region. Comprised of two state-of-the-art underground R&P mines, the operation's ability to consistently achieve high annual output at generally low operating costs is attributed to its well-capitalized operations and financial controls.

Table 11.1 summarizes the past five years of financial data for the Oaktown Mining Complex.

Table 11.1: Historical Financials

	2020	2021	2022	2023	2024
Clean Coal Production (000 tons)	5,243	5,633	6,360	6,390	3,897
Average Selling Price ($/clean ton)	40.66	39.50	44.94	60.78	52.17
Cash Operating Costs ($/clean ton):					
Direct Labor	13.02	13.92	13.18	14.82	19.22
Direct Operating	11.57	10.81	13.03	16.68	20.55
Indirect Operating	4.02	4.13	4.33	5.78	5.87
Selling and General Administrative	1.68	1.58	1.36	1.60	1.69
Total - Cash Operating Costs	30.29	30.44	31.90	38.88	47.33
Capital Expenditures ($/clean ton)	3.91	4.97	6.69	13.40	4.95

Over the five-year period:

- Oaktown Mining Complex's average realization (i.e., coal selling price) was range-bound between $39.50 and $60.78 per ton.
- Cash operating costs for the complex were approximately $8.45 per ton higher in 2024 than 2023, primarily due to significant increases in direct labor and direct operating costs due to one-time reduction in workforce expenses.
- In response to weakening market conditions, Sunrise reduced production from Oaktown Mining Complex in early 2024 by idling the Oaktown Fuels No. 2 Mine. The drop in overall output in 2024, combined with one-time expenses related to the reduction in workforce, resulted in an increase to the complex's average unit cost (and declining cash margins) for 2024.

Cost performance for the individual mines is portrayed graphically in Figure 11.1, below.

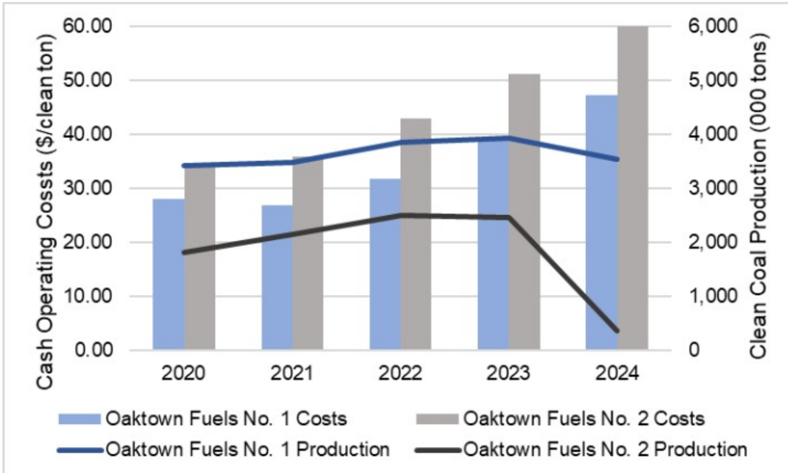


Figure 11.1: Historical Operating Costs by Mine

Historically, the Oaktown Fuels No. 1 and No. 2 mines have had operating costs that compare favorably with other industry producers.

Of the two Oaktown Mining Complex underground R&P mines, Oaktown Fuels No. 1 Mine has consistently demonstrated the lowest operating cost over the past five years. This is predominantly attributable to more favorable geologic conditions experienced and increased economies of scale[2].

Relative to industry peers, the Oaktown Mining Complex (including its supporting centralized preparation facilities) is well capitalized. This reflects Sunrise's ongoing attention to prudent capital upgrade/replacement programs, routine investment in mine infrastructure expansions, and maintenance of production equipment. The amount of capital spent (per individual mine or for the Oaktown Complex CPP) has varied on an annual basis as a percent of Oaktown Mining Complex's total expenditures, illustrating differing capital requirements and/or operational timelines for each operation. Notwithstanding the significant capital expenditures of 2022 and

[2] Economies of scale are of fundamental importance; a mine that has a productive year versus its budgeted plan can expect to have low unit costs while surpassing projected margins. Alternatively, a R&P mine that achieves poor production levels would see a proportional reduction in revenue, but this would not be accompanied by a corresponding reduction in total costs. Such a mine would instead see high unit costs, and most of the revenue loss would flow through to the bottom line.

2023 for major equipment rebuilds, Oaktown Mining Complex's aggregate capital expenditure level was relatively consistent and generally within the range of $4.00 to $5.00 per clean ton.

11.2 Estimated Costs

BOYD developed mine plans for the Oaktown Mining Complex based on engineered mine layouts[3] which were designed for optimum reserve recovery, using efficient mining methods and practices. Sunrise's historical and generally accepted industry operating performance parameters and mining rates were applied to the mine plan to develop coal production and mining schedules. Financial budgets were then prepared (based on mine plan outputs and labor requirements), resulting in operating cost projections (based on constant 2021 dollars). The individual mining plans recognize the impact of variations in physical mining conditions, mechanical failures, and operational activities that can temporarily disrupt production activities. The mine plans for Oaktown Mining Complex are reasonable and achievable, provided no major abnormalities are encountered.

Forecasting performance based on the continuation of consistent mining conditions, excluding impacts from unforeseen events, increases the risk of underperformance versus the mine plan. BOYD's approach does not directly account for situations that can occur in underground coal mining, such as fire, water inundations, geological anomalies, etc. However, risk mitigation has been reflected in the production schedules through the use of multiple CM sections operating in various locations throughout the mine reserve. The geographical distribution of mining sections throughout the area of the mine plan mitigates the likelihood that all CM sections will experience adverse mining conditions at a given time. Each CM section also utilizes production contingency factors, which are incorporated into the mining forecast.

BOYD reviewed historical Sunrise mining plans (including development strategy, production and productivity, capital expenditures, and total cash costs) and concluded: (1) the Sunrise pro-forma plans are reasonable and achievable and align with BOYD's independent LOM plans, and (2) Oaktown Mining Complex is well-positioned to achieve the conceptual LOM plan as projected by BOYD provided no major abnormalities are encountered: within the coal market, or at the mine level.

[3] The mining plans for R&P operations are relatively simple and highly flexible when compared to LW mines. The entire foundation of the mining plan is based upon locating mains and sub-mains in areas of the deposit where coal quality and mining conditions are most suitable. Panels are then developed out to a desired length or until adverse mining conditions (or poor coal quality) warrant the cessation of development. This results in the opportunity to alter the mining plan so as to avoid specific areas with adverse mining conditions (such as thin coal, poor roof, etc.) or poor coal quality (such as high sulfur, etc.).

The Sunrise forecasted financial performance aligns with what BOYD would anticipate for an established underground R&P coal facility operating in the ILB region. BOYD developed an independent LOM projection for operating and capital costs which aligns with general industry standards and the Sunrise forecasted figures. BOYD believes the extended LOM projection of operating and capital costs to align with those of other similarly capitalized mining complexes operating in the ILB region and to be accurate to within ±25%. We did not assign a contingency budget to the extended life-of-mine projection estimates.

In general, the projected operating costs and capital expenditures over the life of the coal reserves are informed by general engineering principles and are consistent with industry norms. BOYD considered the estimated costs reasonable and appropriate.

11.2.1 Forecasted Production

BOYD's LOM plans reflect: (1) the near-term continued idling of the Oaktown Fuels No. 2 Mine, and (2) status quo production levels from the Oaktown Fuels No. 1 Mine. The Oaktown Mining Complex forecast of saleable tons produced is summarized in Figure 11.2, below.

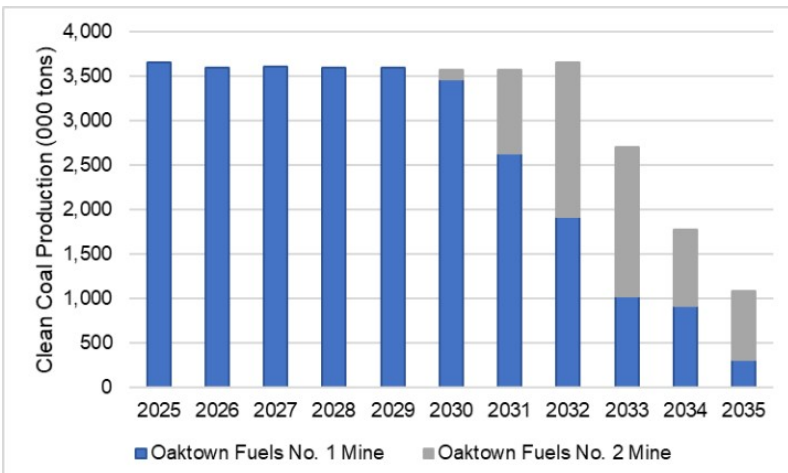


Figure 11.2
Oaktown Mining Complex
Projected Saleable Production

Oaktown Mining Complex's future production over the life of the reserves are expected to remain well within the complex's previously achieved output levels and in line with current infrastructure capacities and capabilities. This results in a less capital-intensive forward forecast, as capital expenditures are associated with sustaining production rather than new mine development and/or production capacity expansion.

11.2.2 Projected Operating Costs

Operating cost estimates were developed based on recent actual costs and considering specific operational activity levels and cost drivers. The estimates consider current and expected labor headcount and salaries, major consumables and unit prices, power costs, and equipment and maintenance costs. The total operating cost estimate includes all site costs related to mining, processing, and general and administrative activities.

Operating costs for Oaktown Mining Complex are projected to be more favorable versus those of 2024. This is primarily a result of reduced direct operating costs associated with the recent restructuring of mining operations, including the near-term idling of the Oaktown Fuels No. 2 Mine. BOYD anticipates relatively stable operating costs over the remaining life of the operations as the result of consistent performance and annual output. BOYD's estimate of operating costs over the life of the Oaktown Mining Complex as presented in Table 11.2, on the following page.

11.2.3 Projected Capital Expenditures

The Oaktown Mining Complex and related facilities are fully developed and should not require any near-term major capital investment to maintain full commercial production. Historically, the timing and amount of capital expenditures have been largely discretionary and within Sunrise's control.

Oaktown Mining Complex is expected to maintain a consistent level of spending on capital over the remaining life of the operations, focused on mine infrastructure expansion, maintenance of production equipment (new equipment purchases and/or rebuilds), and refuse placement (injection) expansions. BOYD projected sustaining capital expenditures using nominal unit cost rates which includes maintenance of production equipment as well as other items for the operation. These unit cost rates are based on our experience with other ILB underground R&P operations. Over the final four years of the Oaktown Mining Complex's operation, capital expenditures are projected to decline as production volumes decrease. BOYD's estimates of capital expenditure requirements over the life of the Oaktown Mining Complex are presented in Table 11.2, on the following page.

By
John T. Boyd Company
Mining and Geological Consultants
February 2025

Period	1	2	3	4	5	6	7	8	9	10	11	
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Production (000 tons):												
ROM Coal	5,970	5,970	5,970	5,970	5,970	5,970	5,969	5,970	4,445	2,985	1,865	57,054
Clean Coal	3,663	3,599	3,608	3,602	3,601	3,576	3,570	3,653	2,707	1,771	1,087	34,437
Direct Labor ($ 000)												
Labor (incl. Payroll Taxes and Works Comp.)	44,652	43,872	43,982	43,908	43,896	43,591	43,518	44,530	32,998	21,588	13,251	419,786
Retirement Benefits/401k	14,872	14,612	14,648	14,624	14,620	14,519	14,494	14,831	10,990	7,190	4,413	139,813
Subtotal - Direct Labor	59,524	58,484	58,630	58,532	58,516	58,110	58,012	59,361	43,988	28,778	17,664	559,599
Direct Operating ($ 000)												
Operating Supplies	26,688	26,541	26,565	26,547	26,546	26,502	26,485	26,627	20,060	13,594	8,528	254,683
Maintenance	23,493	22,815	22,962	22,842	22,846	22,769	22,704	22,856	20,603	16,588	11,274	231,752
Utilities	10,190	9,896	9,960	9,908	9,909	9,876	9,848	9,914	8,937	7,195	4,890	100,523
Other Operating Costs	4,579	4,499	4,510	4,503	4,501	4,470	4,463	4,566	3,384	2,214	1,359	43,048
Subtotal - Direct Operating	64,950	63,751	63,997	63,800	63,802	63,617	63,500	63,963	52,984	39,591	26,051	630,006
Indirect Operating* ($ 000)												
Insurance, Real Estate Tax, Penalties	183	180	180	180	180	179	179	183	135	89	54	1,722
Royalties	9,938	10,127	10,214	10,114	9,358	9,293	9,278	9,493	7,035	4,602	2,825	92,277
Preparation, Surface, and Coal Handling	8,132	7,990	8,010	7,996	7,994	7,939	7,925	8,110	6,010	3,932	2,413	76,451
Reclamation/Mine Closure	-	-	-	-	-	-	-	-	-	-	3,000	3,000
Other Costs	1,502	1,476	1,479	1,477	1,476	1,466	1,464	1,498	1,110	726	446	14,120
Subtotal - Indirect Operating	19,755	19,773	19,883	19,767	19,008	18,877	18,846	19,284	14,290	9,349	8,738	187,570
Selling and General Administrative ($ 000)	6,117	6,010	6,025	6,015	6,014	5,972	5,962	6,101	4,521	2,958	1,815	57,510
Total Cash Operating Costs ($ 000)	150,346	148,018	148,535	148,114	147,340	146,576	146,320	148,709	115,783	80,676	54,268	1,434,685

12.0 ECONOMIC ANALYSIS

12.1 Approach

The economic analysis presented in this chapter was prepared by BOYD for the purpose of confirming the commercial viability of the Oaktown Mining Complex's reported coal reserves and not for the purpose of valuing the Oaktown Mining Complex, or its assets. The economic analysis contains forward-looking information related to the projected operating and financial performance of the Oaktown Mining Complex. This projection involves inherent known and unknown risks and uncertainties, some of which may be outside of Sunrise's control. Sunrise, as with all mining companies, actively evaluates, changes, and modifies business and operating plans in response to various factors that may affect operational and/or financial results. Actual results, production levels, operating expenses, sales realizations, and all other modifying factors could vary significantly from the assumptions and estimates provided in this analysis. Risk is subjective, as such, BOYD recommends that each reader should evaluate the project based on their own investment criteria.

The financial model used for the purposes of the economic analysis forecasts future free cash flow from coal production and sales over the life cycle of the Oaktown Mining Complex using the annual forecasts of production, sales revenues, and operating and capital costs discussed earlier in this report. A DCF analysis, in which future free cash flows are discounted to present value, is used to derive an NPV for the coal reserves. The use of DCF-NPV analysis is a standard method within the mining industry to assess the economic value of a project after allowing for the cost of capital invested.

The financial evaluation of the Oaktown Mining Complex has been undertaken on a simplified after-tax basis and does not reflect Sunrise's corporate tax structure. NPV is calculated using an after-tax discount rate of 12% (NPV_{12}). Cash flows were assumed to occur in the middle of each year and are discounted to January 1, 2025. Cost estimates and other inputs to the cash flow model for the project have been prepared using constant 2024 money terms, i.e., without provision for inflation. The internal rate of return and project payback were not calculated, as there was no initial investment (sunk costs) considered in the financial model provided herein.

A suite of sensitivities was calculated to evaluate the effect of the main drivers of economic performance (including variations in sales prices, operating costs, and capital costs).

It is BOYD's opinion that the financial model provides a reasonable and accurate reflection of the Oaktown Mining Complex's expected economic performance based on the assumptions and information available at the time of our review.

12.2 Assumptions and Limitations

Cash flow projections for the Oaktown Mining Complex have been generated from the annual forecasts of production, sales prices, and operating and capital costs discussed earlier in this report. A summary of the key assumptions and limitations is provided below:

- Production quantities are based on BOYD's independently developed LOM plans for the Oaktown Mining Complex. Please refer to Chapters 7 and 8 for further information.
- Forecasted revenues are based on BOYD's FOB sales price forecast for washed thermal coal from the Oaktown Mining Complex's CPP (i.e., FOB CPP). Additional transportation and delivery costs are assumed to be incurred by the customer or added as a pass-through to the FOB CPP price. Market specifications and forecasted sales prices for the Oaktown Mining Complex's washed thermal coal are provided in Chapter 10.
- Capital and operating costs are discussed in Chapter 11. Capital expenditures and unit operating costs are expected to remain relatively constant over the life of the operation.
- No allowance for changes in or the recapture of working capital has been made in the financial analysis as the Oaktown Mining Complex has been in operation for many years. Exclusion of working capital from the financial analysis does not have a material impact on the NPV calculation.
- Depreciation and amortization expenses for existing assets are derived from Sunrise's depreciation schedules. Sustaining capital is depreciated over 8 years on a straight-line basis.
- A combined federal and state corporate tax rate of 25% has been applied on all taxable income. All other taxes and fees are included in the estimates of operating costs.

- Asset recovery/salvage values were not included in the financial analysis.
- Post-mining reclamation costs are included as a lump sum operating cost in the final year of the financial analysis.

It is BOYD's opinion that the production and financial projections provided herein are reasonable and are accurate to within ±25%.

12.3 Financial Model Results

Estimated LOM pre-tax and after-tax cash flows for coal production from the Oaktown Mining Complex are presented in Table 12.1 (on the following page) and summarized in Table 12.2 (below).

Table 12.2: Financial Results

Financial Metric	Remaining Life of Mine Total
Expected Remaining Life (years)	11
Production (000 tons):	
ROM Coal	57,054
Clean Coal	34,437
Total Revenues ($ millions)	1,677.8
Average Sales Price ($/clean ton)	48.72
Total Cash Operating Costs ($ millions)	1,434.7
Average Cash Operating Costs ($/clean ton)	41.66
Capital Expenditures ($ millions)	128.4
Average Capital Expenditures ($/clean ton)	3.73
Cash Flows ($ millions):	
Total Pre-Tax Cash Flow	114.7
Discounted Pre-Tax Cash Flow at 12%	82.1
Total After-Tax Cash Flow	98.8
Discounted After-Tax Cash Flow at 12%	70.7

DCF-NPV on a pre-tax and after-tax basis, using discount rates of 10%, 12% (the base case), 15%, and 18% were calculated utilizing the projected cash flows. Table 12.3, below, summarizes the results of the pre-tax and after-tax DCF-NPV analyses.

Table 12.3: DCF-NPV Analysis

	NPV ($ millions)			
	10%	12%	15%	18%
Pre-Tax	86.4	82.1	76.4	71.4
After-Tax	74.4	70.7	65.8	61.4

Period	1	2	3	4	5	6	7	8	9	10	11	2025		Total/
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	to 2034	2035	Average
Production (000 tons):														
ROM Coal	5,970	5,970	5,970	5,970	5,970	5,970	5,969	5,970	4,445	2,985	1,865	55,189	1,865	57,054
Clean Coal	3,663	3,599	3,608	3,602	3,601	3,576	3,570	3,653	2,707	1,771	1,087	33,350	1,087	34,437
Revenues:														
Coal Sales (000 tons)	3,663	3,599	3,608	3,602	3,601	3,576	3,570	3,653	2,707	1,771	1,087	33,350	1,087	34,437
Average Sales Price ($/ton FOB CPP)	49.33	51.16	51.47	51.05	47.25	47.25	47.25	47.25	47.25	47.25	47.25	48.77	47.25	48.72
Total Revenues ($ 000)	180,696	184,125	185,704	183,882	170,147	168,966	168,683	172,604	127,906	83,680	51,361	1,626,393	51,361	1,677,754
Cash Operating Costs ($ 000)	150,347	148,017	148,536	148,115	147,341	146,575	146,319	148,708	115,783	80,676	54,267	1,380,417	54,267	1,434,684
Gross Pre-Tax Cash Flow ($ 000)	30,349	36,108	37,168	35,767	22,806	22,391	22,364	23,896	12,123	3,004	(2,906)	245,976	(2,906)	243,070
Depreciation & Amortization ($ 000)	20,491	21,967	23,242	24,415	24,706	21,896	17,911	14,777	14,024	12,895	11,411	196,323	11,411	207,734
Operating Income ($ 000)	9,858	14,141	13,926	11,353	(1,900)	496	4,453	9,119	(1,901)	(9,891)	(14,317)	49,653	(14,317)	35,336
Income Taxes ($ 000)	2,465	3,535	3,482	2,838	-	124	1,113	2,280	-	-	-	15,836	-	15,836
Net Income ($ 000)	7,394	10,606	10,445	8,514	(1,900)	372	3,340	6,840	(1,901)	(9,891)	(14,317)	33,817	(14,317)	19,500

The economic analysis confirms that the Oaktown Mining Complex generates positive pre- and after-tax financial results and a real NPV_{12} of $70.7 million. As such, it is BOYD's opinion that the coal reserves of the Oaktown Mining Complex have demonstrated economic viability.

12.4 Sensitivity Analysis

Table 12.4, below, shows the sensitivity of the project after-tax for a cash flow discounted at 12% (NPV_{12}) to a variation over a range of 20% above and below the base case in: (1) average selling prices and (2) operating costs.

Table 12.4: After-Tax NPV_{12} Sensitivity Analysis ($ millions)

		Revenues								
		-20%	-15%	-10%	-5%	**0%**	5%	10%	15%	20%
Cash Operating Costs	-20%	44.9	86.0	125.1	164.1	203.0	241.8	280.5	319.1	357.7
	-15%	6.3	51.4	92.1	131.2	170.2	209.0	247.9	286.6	325.2
	-10%		13.9	57.8	98.2	137.3	176.3	215.1	253.9	292.7
	-5%			21.3	64.3	104.3	143.4	182.4	221.2	260.0
	0%				28.1	**70.7**	110.4	149.5	188.5	227.3
	5%					34.7	77.0	116.5	155.6	194.6
	10%						41.3	83.3	122.6	161.7
	15%						3.1	48.0	89.5	128.7
	20%							10.5	54.5	95.6

Note: Gray cells are marginal or uneconomic scenarios.

As expected, the project is most sensitive to changes in product pricing and operating costs. The project is less sensitive to changes in capital costs. There are only very minor impacts to the NPV_{12} when varying the capital costs from 80% to 120% of the base case.

This analysis demonstrates the project value to be very sensitive to fluctuations in coal sales prices and/or operating costs. However, BOYD recognizes that Sunrise is likely to modify operation plans and/or production levels to minimize the impact (or conversely, maximize the opportunity) of short-term coal price fluctuations. BOYD opines that such minor adjustments are likely to be immaterial to the economic viability of the Oaktown Mining Complex's coal reserves.

13.0 PERMITTING AND COMPLIANCE

13.1 Permitting Requirements and Status

Mining and related activities on the Oaktown Mining Complex properties is regulated by both federal and state laws. The relevant federal laws include:

- Clean Air Act of 1970/1977.
- Clean Air Act Amendments of 1990.
- Clean Water Act of 1977.
- Surface Mining Control and Reclamation Act of 1977 (SMCRA).
- Resource Conservation and Recovery Act of 1976.

In Indiana and Illinois, responsibility for enforcing these acts primarily lies with the IL-EPA and IN-DNR and their various subdivisions.

Numerous permits are required by federal and state law for underground mining, coal preparation and related facilities, and other incidental activities. BOYD reviewed the permits for the Oaktown Mining Complex that are necessary for continued operations. Such required permits appear to be valid and in good standing. The approved permits and certifications are adequate for the continued operation of the facility. A listing of the current permits for the Oaktown Mining Complex is provided in Table 13.1, on the following page.

Permits generally require that the permittee 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 regulations requirements of the permit are fully satisfied. Sunrise reports holding surety bonds to cover its current obligations relating to mining and reclamation, road repair, etc. Those obligations currently equate $6.7 million.

Table 13.1: Summary of Current Permits

Permit / Registration / Authorization	Permit / ID No.	Agency*	Expiration Date
MSHA ID			
Oaktown Fuels Mine No. 1	1202394	MSHA	*No Expiration*
Oaktown Fuels Mine No. 2	1202418	MSHA	*No Expiration*
Oaktown Fuels Preparation Plant	1202462	MSHA	*No Expiration*
Mine Operating (SMCRA)	U-031	IN-DNR	12/12/2027
	452	IL-DNR	3/16/2028
Minor Source Operating Permit (MSOP)	M-083-42294-00051	IDEM	3/10/2030
National Pollutant Discharge Elimination System (NPDES)			
Individual Permit	IN0064629	IDEM	8/31/2028
Coal Mine General Permit	ING040222	IDEM	*Renewal Pending*
Individual Permit	IL0080226	IL-EPA	1/31/2026
Wetlands Dredge and Fill	LRL-2008-623-RJB	USACOE	12/31/2029
Mining Under Navigable Waterway	LRL-2018-786-SEW	USACOE	12/31/2033
Section 401 Water Quality Certification	2008-569-42-JWR-A	IDEM	*No Expiration*
Underground Mine Backfill / Coal Slurry Injection	IN-083-5X13-0001 to IN-083-5X13-0010	USEPA	*No Expiration*

* Regulatory Agencies

MSHA: Mine Safety and Health Administration
IN-DNR: Indiana Department of Natural Resources
IL-DNR: Illinois Department of Natural Resources
IDEM: Indiana Department of Environmental Management
USACOE: United States Army Corps of Engineers
USEPA: Unted States Environmental Protection Agency

New permits and/or permit revisions/amendments may be necessary from time to time to facilitate future operations. Given sufficient time and planning, Sunrise should be able to secure new permits, as required, to maintain its planned operations within the context of the current regulations. Continuously increasing efforts are required to obtain permits for R&P mining and related activities in Indiana and Illinois. The primary contributing factors are the effects on protected surface areas and the ability to permit refuse sites.

13.2 Environmental Studies

It is BOYD's understanding that no standalone environmental studies have been conducted for the Oaktown Mining Complex. As part of the state and federal permitting process, various environmental assessments have been conducted and reviewed by the relevant local, state, and federal agencies. As the necessary permits for mining and processing operations have been issued, it is BOYD's understanding that all environmental assessments have been accepted by the relevant regulatory bodies and no material issues were found.

13.3 Waste Disposal and Water Management

The coarse refuse generated from the coal preparation process is used in the construction of the existing permitted, on-site slurry impoundment. The fine refuse generated from the coal preparation process is disposed of by pumping it into the slurry impoundment or by injecting it into former underground mining areas. Waste disposal facilities are in place for current mining operations, with plans to expand the disposal facilities to meet life of reserve storage requirements. Please refer to Section 9.2 for a detailed description of these facilities.

The underground mines are below drainage with shaft/slope access. Such mines are designed and permitted to avoid water break out and acid mine discharge. The potential for discharge of acid mine drainage at underground mines is limited to minor run off from disposal and other surface sites.

Water control structures are in place and function as required by regulatory agencies. All runoff from the slurry impoundment(s) is managed by sediment control structures including diversions, sumps, and sediment basins. Prior to discharge from the permitted areas, water must meet compliance standards as defined in the NPDES permits. Water samples at discharge locations are collected in accordance with the approved permit and analyzed by an independent laboratory.

13.4 Compliance

Based on our review of information provided by Sunrise and other public information sources, it is BOYD's opinion that Sunrise has a generally typical coal industry record of compliance with applicable mining, water quality, and environmental regulations. BOYD is not aware of any regulatory violation or compliance issue that would materially impact the coal reserve estimate.

13.5 Plans, Negotiations, or Agreements

New permits and certain permit amendments/revisions require public notification. The public is made aware of pending permits by advertisement in local newspapers. Additionally, a copy of the application is retained at the local county's public library for review. A comment period follows the last advertisement date to allow the public to submit comments to the regulatory authority.

BOYD is not aware of any community or stakeholder concerns, impacts, negotiations, or agreements that would materially impact the coal reserve estimate.

13.6 Mine Closure

A detailed plan for reclamation activities upon completion of mining required at the Oaktown Mining Complex has been prepared. Given the application of underground mining methods at the operation, the disturbed acreage on the surface is relatively limited. The primary reclamation liabilities are associated with the refuse disposal sites.

Mine site reclamation costs are funded from Sunrise's operating account. Funding for reclamation liabilities is included in the Oaktown Mining Complex's operating costs discussed in Chapter 11 and included in the economic analysis presented in Chapter 12. Reclamation liability estimates are reviewed annually and are currently estimated at approximately $6.7 million for the Oaktown Mining Complex. In BOYD's opinion, the estimated mine closure and reclamation costs for the property are reasonable and appropriate.

13.7 Local Procurement and Hiring

BOYD is not aware of any commitments for local procurement or hiring. However, Sunrise reports making efforts to source supplies and materials from regional vendors. The workforce is likewise located in the regional area.

14.0 INTERPRETATION AND CONCLUSIONS

14.1 Findings

BOYD's independent technical assessment conducted in accordance with S-K 1300 concludes:

- Sufficient data have been obtained through various exploration and sampling programs and mining operations to support the geological interpretations of seam structure, thickness, and quality for the portions of the Indiana V Seam situated within the bounds of the Oaktown Mining Complex area. The data are of sufficient quantity and reliability to reasonably support the coal resource and coal reserve estimates in this technical report summary.
- Estimates of coal reserves reported herein are reasonably and appropriately supported by technical studies, which consider mining plans, revenue, and operating and capital cost estimates.
- The 34.4 million tons of underground coal reserves identified on the property are economically mineable under reasonable expectations of market prices for thermal coal products, estimated operation costs, and capital expenditures.
- There is no other relevant data or information material to the Oaktown Mining Complex that is necessary to make this technical report summary not misleading.

14.2 Significant Risks and Uncertainties

As a mining operation with a lengthy operating history, the purpose of Sunrise's periodic mine planning exercises is to collect and analyze sufficient data to reduce or eliminate risk in the technical components of the project and to refine economic projections based on current data. There is a high degree of certainty for this project under the current and foreseeable operating environment. A general assessment of risk is presented in the relevant sections of this report.

GLOSSARY OF ABBREVIATIONS AND DEFINITIONS

$	:	U.S. dollar(s)
%	:	Percent or percentage
AC	:	Alternating current
As-Received Basis	:	Data or results are calculated to the moisture condition of the coal sample when it arrived at the testing facility.
ASTM	:	ASTM International (formerly American Society for Testing and Materials)
BOYD	:	John T. Boyd Company
Btu	:	British thermal unit. A unit of heat; it is defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
CM	:	Continuous Miner
CPP	:	Coal Preparation Plant
Coal	:	Combustible sedimentary rock in which organic matter, including residual moisture comprises more than 50% by weight and more than 70% by volume of carbonaceous material formed from altered plant remains.
Coal Reserve	:	An estimate of tonnage and grade or quality of indicated and measured coal resources that, in the opinion of the qualified person, can be the basis of an economically viable project. More specifically, it is the economically mineable part of a measured or indicated coal resource, which includes diluting materials and allowances for losses that may occur when the material is mined or extracted.
Coal Resource	:	A concentration or occurrence of coal of economic interest in or on the Earth's crust in such form, quality, and quantity that there are reasonable prospects for economic extraction. A coal resource is a reasonable estimate of mineralization, considering relevant factors such as cut-off grade, likely mining dimensions, location, or continuity, that, with the assumed and justifiable technical and economic conditions, is likely to, in whole or in part, become economically extractable. It is not merely an inventory of all mineralization drilled or sampled.
CRDA	:	Coal Refuse Disposal Area

CSX	:	CSX Corporation. A rail-based freight transportation company
CY	:	Cubic yards
DCF	:	Discounted Cash Flow
DOR	:	Indiana Department of Natural Resources' Division of Reclamation
Dry Basis	:	Data or results are calculated to a theoretical base as if there were no moisture in the coal sample.
EIA	:	U.S. Energy Information Administration
FOB	:	Free-on-Board
Hallador	:	Hallador Energy Company and its subsidiaries
ILB	:	Illinois Basin. Coal producing region consisting of Illinois, Indiana, and Western Kentucky.
IL-EPA	:	Illinois's Environmental Protection Agency
IN-DNR	:	Indiana's Department of Natural Resources
Indicated Coal Resource	:	That part of a coal resource for which quantity and quality are estimated based on adequate geological evidence and sampling. The level of geological certainty associated with an indicated coal resource is sufficient to allow a qualified person to apply modifying factors in sufficient detail to support mine planning and evaluation of the economic viability of the deposit. Because an indicated coal resource has a lower level of confidence than the level of confidence of a measured coal resource, an indicated coal resource may only be converted to a probable coal reserve.
INRD	:	Indiana Railroad Company. A rail-based freight transportation company
Inferred Coal Resource	:	That part of a coal resource for which quantity and quality are estimated based on limited geological evidence and sampling. The level of geological uncertainty associated with an inferred coal resource is too high to apply relevant technical and economic factors likely to influence the prospects of economic extraction in a manner useful for evaluation of economic viability. Because an inferred coal resource has the lowest level of geological confidence of all coal resources, which prevents the application of the modifying factors in a manner useful for evaluation of economic viability, an inferred coal resource may not be considered when assessing the economic viability of a mining

		project, and may not be converted to a coal reserve.
IRR	:	Internal rate-of-return
ISO	:	International Organization for Standardization
lb	:	Pound
LOM	:	Life-of-Mine
LW	:	Longwall
Measured Coal Resource	:	That part of a coal resource for which quantity and quality are estimated based on conclusive geological evidence and sampling. The level of geological certainty associated with a measured coal resource is sufficient to allow a qualified person to apply modifying factors, as defined herein, in sufficient detail to support detailed mine planning and final evaluation of the economic viability of the deposit. Because a measured coal resource has a higher level of confidence than the level of confidence of either an indicated coal resource or an inferred coal resource, a measured coal resource may be converted to a proven coal reserve or to a probable coal reserve
Mineral Reserve	:	*See "Coal Reserve"*
Mineral Resource	:	*See "Coal Resource"*
Modifying Factors	:	The factors that a qualified person must apply to indicated and measured coal resources and then evaluate to establish the economic viability of coal reserves. A qualified person must apply and evaluate modifying factors to convert measured and indicated coal resources to proven and probable coal reserves. These factors include, but are not restricted to: mining; processing; infrastructure; economic; marketing; legal; environmental compliance; plans, negotiations, or agreements with local individuals or groups; and governmental factors. The number, type and specific characteristics of the modifying factors applied will necessarily be a function of and depend upon the mineral, mine, property, or project.
MSHA	:	Mine Safety and Health Administration. A division of the U.S. Department of Labor
NPDES	:	National Pollutant Discharge Elimination System
NS	:	Norfolk Southern Corporation. A rail-based freight transportation company.

NPV	:	Net Present Value

Oaktown Mining Complex	:	Oaktown Mining Complex. Includes the Oaktown Fuels No. 1 Mine, Oaktown Fuels No. 2 Mine, and Oaktown Complex Coal Preparation Plant
OSD	:	Out-of-Seam Dilution. Rock, impurities recovered from above and below the coal seam with the coal seam during the normal mining process
OSMRE	:	Office of Surface Mining, Reclamation and Enforcement
Probable Coal Reserve	:	The economically mineable part of an indicated and, in some cases, a measured coal resource.
Production Stage Property	:	A property with material extraction of coal reserves.
Proven Coal Reserve	:	The economically mineable part of a measured coal resource which can only result from conversion of a measured coal resource.
QP	:	Qualified Person
Qualified Person	:	An individual who is:

1. A mineral industry professional with at least five years of relevant experience in the type of mineralization and type of deposit under consideration and in the specific type of activity that person is undertaking on behalf of the registrant; and
2. An eligible member or licensee in good standing of a recognized professional organization at the time the technical report is prepared. For an organization to be a recognized professional organization, it must:
   a. Be either:
      i. An organization recognized within the mining industry as a reputable professional association; or
      ii. A board authorized by U.S. federal, state, or foreign statute to regulate professionals in the mining, geoscience, or related field;
   b. Admit eligible members primarily based on their academic qualifications and experience;
   c. Establish and require compliance with professional standards of competence and ethics;
   d. Require or encourage continuing professional development;
   e. Have and apply disciplinary powers, including the power to suspend or expel a member regardless of where the member practices or resides; and

f. Provide a public list of members in good standing.

R&P	:	Room-and-pillar
RC	:	Ram cars
ROM	:	Run-of-Mine. The as-mined material including coal, in-seam rock partings mired with the coal, and out-of-seam dilution.
SC	:	Shuttle cars
SGF	:	Specific gravity float
SEC	:	U.S. Securities and Exchange Commission
S-K 1300	:	Subpart 1300 and Item 601(b)(96) of the U.S. Securities and Exchange Commission's Regulation S-K
SMCRA	:	Surface Mining Control and Reclamation Act of 1977
Sunrise	:	Sunrise Coal, LLC and its subsidiaries
Ton	:	Short Ton. A unit of weight equal to 2,000 pounds
TPH	:	Tons per Hour
TPEH	:	Tons per Employee-Hour