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, 2025** 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 (State of incorporation) 1183 East Canvasback Drive, Terre Haute, Indiana (Address of principal executive offices)	84-1014610 (IRS Employer Identification No.) 47802 (Zip Code)

Issuer's telephone number: 812.299.2800

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the common stock held by non-affiliates (public float) on June 30, 2025, was $520,726,758, based on the closing price reported that date by the NASDAQ of $15.83 per share.

As of March 10, 2026, we had 47,023,495 shares outstanding. Our Annual Meeting of Shareholders will be held on May 27, 2026, in Denver, Colorado.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the following document are incorporated by reference into this Report: Registrant's definitive proxy statement for the 2026 Annual Meeting of Shareholders, which is to be filed pursuant to Regulation 14A within 120 days after the end of our fiscal year ended December 31, 2025 (Part III).

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, natural gas and electricity commodity costs, inflation and economic conditions impact demand of our customers and our operating results;
- the outcome or escalation of current international hostilities;
- changes in competition in electricity or coal markets and our ability to respond to such changes;
- changes in electricity or coal prices, demand, and availability which could affect our operating results and cash flows;
- risks associated with the expansion of our operations and properties;
- risks relating to Midcontinent Independent System Operator's ("MISO") Expedited Resource Addition Study ("ERAS") program review and approval process;
- risks relating to our ability to secure agreements in support of the development and construction of planned projects, including the expansion of the Merom Generating Station;
- 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 ("GHG"), 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;
- 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, including uncertainty regarding tariffs on imports into the United States, which could impact the Company's procurement and sourcing strategies;
- risks relating to inflation and increasing interest rates;
- liquidity constraints, including due to restrictions contained in our debt agreements or other arrangements 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 or electricity 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, including challenges in operating an aging coal-fired power plant;
- 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-power plant and 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 the effects of the One Big Beautiful Bill Act ("OBBBA") or 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.

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PART I

ITEM 1. BUSINESS.

Hallador Energy Company ("Hallador" or the "Company") is a vertically integrated, independent power producer ("IPP") and fuel company with operations primarily in Indiana. The Company operates across multiple stages of the energy value chain, from accredited capacity and energy to coal. The Company's electric operations are located within the Midcontinent Independent System Operator's ("MISO") footprint. Our operations comprise Hallador Power Company, LLC ("Hallador Power") that provides accredited capacity and energy to utilities and other energy market participants through its MISO interconnection, and Sunrise Coal, LLC ("Sunrise") that mines bituminous coal in Indiana to serve various power plants in the Midwest and Southeast United States.

Our business is organized based on the services and products we provide in two segments: (i) Electric Operations and (ii) Coal Operations. The Company also holds 50% interests in Sunrise Energy, LLC and Oaktown Gas, LLC, which are accounted for using the equity method. Through its operating subsidiaries, the Company delivers three main products to its customers, as described below.

Accredited Capacity. Hallador Power, the Company's wholly-owned electric subsidiary, owns and operates the Merom Power Plant ("Merom"), a 1,080 MW coal-fired power generating station, consisting of two steam turbine generators. Unit 1 entered commercial operations in 1982 and Unit 2 in 1983. The units are dispatched through its MISO interconnection. In order to purchase energy through the MISO interconnection, an end user must supply or purchase accredited capacity for an equivalent load. As accredited capacity is primarily available in meaningful quantities from dispatchable sources of energy, such as natural gas and coal-fired power plants, Hallador Power sells accredited capacity to utilities and other energy market participants within the MISO system mainly through power purchase agreements ("PPAs") and other bilateral transactions.

Energy. In addition to accredited capacity, Hallador Power sells wholesale energy to utilities, generation and transmission cooperatives, and other energy market participants within the MISO system through PPAs and other bilateral transactions and sells on a spot basis in the day-ahead and real-time MISO markets.

Fuel. Sunrise, the Company's wholly-owned mining subsidiary, mines coal from reserves found in the Illinois Basin ("ILB"). Coal mined by Sunrise is used as a primary fuel source for generating electricity at various power plants in the Midwest and Southeast United States. In addition, Sunrise has a developed infrastructure for the transport of coal, which is typically sold free on board from the shipping point, including rail networks and truck loading systems, facilitating the efficient movement of the resource from the mine to its customers. Sunrise's Oaktown Mining Complex is about twenty miles from Merom, which is located in Sullivan County, Indiana, enabling Merom and Sunrise to take advantage of low-cost fuel on a delivered basis.

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

Regulation and Laws

Our electric power generation and coal mining businesses are subject to regulation by federal and state agencies and local authorities on matters such as:

- employee health and safety;
- mine permits and other licensing requirements;
- air quality standards, including greenhouse gas emissions;
- water quality standards;
- hazardous substances;
- solid waste management;
- plant and wildlife protection and historic and archeological site and cultural resource protection;

- 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.

Federal agencies that exercise regulatory authority over our businesses, include but are not limited to the Federal Energy Regulatory Commission ("FERC"), the Occupational Safety and Health Administration's ("OSHA"), and the Mine Safety and Health Administration ("MSHA"). The following discussion provides an overview of certain key federal regulatory matters applicable to our business.

FERC. Hallador Power is defined as a public utility under the Federal Power Act and is subject to the FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. The FERC has the authority to grant or deny market-based rate authority for wholesale sales of energy, capacity, and ancillary services to ensure that such sales are just and reasonable and not unduly discriminatory and to suspend market-based rate authority and set cost-based rates if it finds that its previous grant of market-based rate authority is no longer just and reasonable. Other matters subject to the FERC's jurisdiction include, but are not limited to: review of certain public utility dispositions of jurisdictional facilities, mergers, acquisitions of other public utility securities, or acquisitions of existing generation facilities; review of certain holding company acquisitions of securities of, or mergers with, a public utility or other holding company; third-party financings; affiliate transactions; intercompany financings and cash management arrangements; and certain internal corporate reorganizations.

RTOs and ISOs. Regional transmission organizations ("RTOs") and independent system operators ("ISOs") are the FERC-regulated entities that exist in several regions to provide transmission services across multiple transmission systems. FERC has approved PJM, MISO, ISO-NE, and SPP as RTOs and CAISO and NYISO as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through the Intercontinental Exchange and the New York Mercantile Exchange, and managing transmission charges across multiple systems and states. Merom participates in the wholesale electricity market administered by MISO.

OSHA/MSHA. We are also subject to the requirements of the federal Occupational Safety and Health Act and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations and similar state statutes and regulations require us to maintain information about hazardous materials used or produced in our operations, and this information is required to be provided to employees, state and local government authorities, and citizens. The Federal Mine Safety and Health Act of 1977 ("FMSHA") and regulations adopted thereunder, impose extensive and detailed safety and health standards on numerous aspects of our coal 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 and implements new regulations from time to time. The states where we operate also have state programs for mine safety and health regulation and enforcement. 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, a significant effect on our operating costs and an adverse impact on our results of operations and financial position. In addition, because MSHA regulations permit citations to be issued without regard to fault, it is not reasonable to expect any coal mining company to be free of citations, and we are issued citations from MSHA inspectors from time to time.

Other Regulation. In addition to federal regulation, our operations are subject to various state and local laws and regulations. These include oversight of siting, permitting, and environmental compliance for our facilities. Our operations are also subject to compliance with reliability standards developed and enforced by the North American Electric Reliability Corporation ("NERC") and its regional entities. Compliance with these standards is critical to maintaining the reliability of the bulk electric system and avoiding penalties for violations. See "—Environmental Regulation" below for additional information on environmental regulation of our business.

Environmental Regulation. Our business is subject to extensive federal, state, and local environmental laws, regulations, and requirements, including but not limited to those related to air emissions, water discharges, hazardous substances, and solid waste management. These requirements have become more stringent over time and impose, among other things: (i) permitting requirements for regulated activities; (ii) costs to limit or prevent pollution or other contamination; and (iii) substantial liabilities and remedial obligations for pollution or contamination. Accordingly, in the ordinary course of our business, we may: (1) incur significant costs to comply with environmental requirements; (2) be required to modify, curtail, replace, or cease certain operations for environmental reasons; (3) be required to perform environmental remediation work; or (4) become involved in other environmental matters, including government enforcement actions and citizen's suit litigation. In addition, environmental requirements are rapidly evolving, and we may become subject to new or revised environmental laws, regulations, or requirements. Executive orders directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions, including existing regulations, that are unduly burdensome on the identification, development, or use of domestic energy resources add to the uncertainty. In addition, on February 12, 2026, the U.S. Environmental Protection Agency ("EPA") rescinded the agency's prior finding in 2009 that GHG from motor vehicles threaten public health and welfare (the "Endangerment Finding"). While the EPA's repeal of the Endangerment Finding invalidates GHG emission standards for motor vehicles, it could impact GHG regulations applied to electric generation facilities that were supported by the Endangerment Finding. Legal challenges to environmental regulations, rules, and requirements, including leading to the rescission of the Endangerment Finding, add to the uncertainty of estimating future compliance and remedial costs. Future implementation and enforcement of these rules remain uncertain at this time.

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 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. 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. For more information, please see *"Air Emissions", "GHG Emissions"* and *"Water Discharge"* in this section, below, and the risk factors described in *"Item 1A. Risk Factors"* below.

We are committed to conducting our electric power generating and mining operations in compliance with applicable federal, state, and local laws and regulations. When we identify a failure to comply, we attempt to remediate any such failure 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 and have substantially increased the cost of electric power generation and the cost of coal mining for domestic coal producers.

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 required for electric power generation operations, including coal-fired power plants such as Merom. 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 GHG 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.

Under some circumstances, substantial fines and penalties, including revocation of electric power generating permits, may be imposed under applicable laws and regulations. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws and regulations. Like other power generating companies, we have been cited for violations in the ordinary course of our business, but 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.

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. Like other coal companies, we have been cited for violations in the ordinary course of our business, but we have never had a permit suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

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. SMCRA 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. Currently, 100% of our production involves underground room and pillar mining. We do not engage in either mountain top removal or long-wall mining. 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 current reclamation fee 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.

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. We are also required to post bonds to secure performance under our coal combustion residuals landfill permit. 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.

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. 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 coal 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 October 1, 2022, the trust fund was funded by an excise tax on production of 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.

The BLBA relaxed the stringent award criteria established under previous regulations and thus potentially allows new federal claims to be awarded and previously denied claimants to re-file under the revised criteria. The BLBA 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.

In addition, 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. We also provide for black lung 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.

Air Emissions

The Clean Air Act ("CAA") and similar state and local laws and regulations regulate emissions into the air and affect both our 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.

Under the CAA, as well as comparable state and local laws and regulation, Merom is subject to extensive emission control, emission allowance, emission monitoring, and air reporting obligations. Compliance with these requirements impacts the operation of Merom as well as our operating costs. There have been a series of federal rulemakings focused on emissions from coal-fired electric generating facilities. The imposition of requirements to install 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. In addition, regulation of the electric power industry regarding the environmental impact of power generation activities has adversely affected demand for coal, which could have a significant impact on the use of coal by the customers that purchase our coal and could have a material adverse effect on our coal mining operations and our business, financial condition, and results of operations. New or modified obligations could significantly impact how we produce electricity and could impede strategic planning. Key air matters currently affecting our business include, but are not limited to, nitrogen oxides requirements, as well as the revised 2024 Greenhouse Gas Rule, which could significantly impact certain facilities, including Merom. These rules are being legally challenged and are being reconsidered by the EPA, resulting in uncertainty in estimating compliance and remediation costs that we may incur.

In addition to the GHG issues discussed below, the air emissions compliance 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 ("FGD") systems, or "scrubbers," or by reducing electric generating levels.
- The Cross-State Air Pollution Rule ("CSAPR") addresses the "good neighbor" provision in the CAA, 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. 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.
- The Mercury and Air Toxic Standards ("MATS") issued by the EPA regulates the emission of mercury and other metals, fine particulates, and acid gases such as hydrogen chloride from coal and oil-fired power plants. The MATS rule has forced electric power generators to make capital investments to retrofit power plants. 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 MATS and the effects it 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 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 state implementation plans ("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. New or revised 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 PM 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 some cases, the EPA has negated the SIPs and imposed more 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.
- The EPA's new source review ("NSR") program under the CAA may require existing coal-fired power plants, when modifications to those plants significantly increase emissions, to install more stringent air emissions control equipment. During 2025, the EPA announced policies related to the withdrawal of the 2024 project emissions accounting rule, reinstatement of the "no-second-guessing" policy, retirement of the NSR Reactivation policy and planned rulemaking to revise "begin actual construction". The EPA plans to propose and finalize revisions to NSR regulations in 2026.

GHG Emissions

Combustion of fossil fuels, such as the coal we produce and the coal that is used at Merom, 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.

In May 2024, the EPA published a final rule that, among other things, established emissions guidelines for GHG emissions for existing coal-fired and new or substantially modified natural 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; and 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"). The rule has been challenged in court and it is not clear at present how the EPA's recission of the Endangerment Finding will impact the rule. Depending on the final outcome of legal challenges, implementation of modifications to Merom necessary to meet the emissions reductions requirements of 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. 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, and some regional cap and trade programs have been established in the Northeast and the Western U.S. There have also 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. Various state regulatory authorities have rejected the construction of new coal-fired 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, 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 electricity from renewable resources by a certain date. 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 and negatively impact demand for electricity from our coal-fired power plant at Merom, each of which could have an adverse effect on our operations.

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, tort claims or actions that may be brought against us could have an adverse impact on our business, financial condition, or results of operations.

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. Fossil fuel companies are also facing challenges by activists using 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

Various statutes and regulations at the federal, state, regional, and local levels govern water use, discharge, protection, and influence and add challenge and uncertainty to our business. The Federal Water Pollution Control Act, known as the Clean Water Act ("CWA"), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants into federal and state waters. The discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by the EPA or a state equivalent agency. Compliance with existing and future requirements may increase costs, affect operations, and impede strategic planning.

Section 402 of the CWA governs discharges of pollutants into waters of the United States, primarily through National Pollutant Discharge Elimination System ("NPDES") permits. Merom is subject to an NPDES permit for its wastewater and stormwater discharges. The definition of "waters of the United States," which governs federal jurisdiction under the CWA, 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 CWA. 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.

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 applicable, 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 relevant 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.

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. 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." The EPA has exercised its veto power over Section 404 permits for surface mining operations. 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.

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.

One of the most impactful CWA programs currently affecting our business is the Effluent Limitations Guidelines and Standards ("ELG") rule. Under the ELG rule, which became effective on January 4, 2016, the EPA established 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 EPA issued a supplemental rule in May 2024 (the "2024 EPA ELG Rule"), which established more stringent requirements for 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. In the future, new permit conditions could be established to meet the requirements in the 2024 EPA ELG Rule, which will be defined following negotiations with state permitting authorities. Legal challenges to the 2024 EPA ELG Rule have been filed and the EPA has extended the compliance deadlines for the 2024 EPA ELG Rule by five years. This extension has been legally challenged by environmental groups. Until litigation is complete and permit conditions are established, the full impact of the ELG rules on the market for our coal products and our electric power generation operations remain uncertain.

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 the rule and the outcome of any such challenges.

Merom 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 currently holds a 316(a) variance and is subject to alternative thermal effluent limits. If Merom'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 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. 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.

Many mining wastes as well as coal combustion residuals ("CCRs") 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 nonetheless impacts the coal industry and electric power generation industry in particular because it regulates the management and disposal of certain CCR. CCR is regulated as "non-hazardous" waste which avoids the stricter, more costly, regulations under RCRA's hazardous waste rules, but 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. In April 2015, the EPA finalized rules on 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 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. The EPA has mandated closure of unlined impoundments, with deadlines to initiate closure between 2021 and 2028, depending on site specific circumstances. Continuing legal challenges to EPA rulemaking regarding CCRs are creating uncertainty in estimating compliance and remediation costs that we may incur, and future rulemakings could lead to accelerated, abrupt, or unplanned suspension of coal-fired boilers. Further, in May 2024, the EPA finalized changes 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.

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.

We are not currently materially impacted by these requirements. 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. 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. While we perform ongoing assessments of physical risk, including physical climate risk, to our business, we are unable to predict these events.

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 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.

We continue to monitor the implementation of any final and proposed climate change-related legislation and regulations, but we cannot predict their impact on our business at this time. We are also reviewing such legislation and regulations for potential opportunities that may align with our strategy going forward.

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. 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.

Electric Operations

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, and 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. We maintain

oversight of CAMS through regular audits and performance reviews, confirming all procedures align with our Company policies and best practices.

We contract 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 RTOs or 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 also assists in risk management by executing short-term trades on our behalf to mitigate price volatility and lock in predictable revenues, as well as ensuring 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 management committee that evaluates all marketing activities and exposures. Volatility in wholesale power prices can impact revenue. Equipment failures or unexpected downtime at coal plants can lead to missed market opportunities or contractual liabilities. Our teams, in conjunction with CAMS and ACES, monitor emerging industry policies to proactively plan operational or strategic adjustments.

Significant third-party customers in 2025 include Hoosier Energy Rural Electric Cooperative, Inc., Citadel Energy Marketing, LLC and MISO.

U.S. Coal Industry

The major coal production basins in the U.S. include Central Appalachia ("CAPP"), Northern Appalachia ("NAPP"), the ILB, Powder River Basin ("PRB"), and the Western Bituminous region ("WB"). CAPP includes eastern Kentucky, Tennessee, Virginia, and southern West Virginia. NAPP includes Maryland, Ohio, Pennsylvania, and northern West Virginia. The PRB is located in northeastern Wyoming and southeastern Montana. The WB includes western Colorado, eastern Utah, and southern Wyoming. The ILB consists of coal mining operations covering more than 50,000 square miles in Illinois, Indiana, and western Kentucky.

Through our wholly-owned subsidiary, Sunrise, we mine coal exclusively in the ILB. The ILB is centrally located between four of the largest NERC 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.

Coal type varies by basin. Heat value and sulfur content are important quality characteristics and determine the end-use for each coal type. ILB coal is typically high sulfur coal and coal-fired plants that burn high sulfur coals are typically required to install scrubbers to comply with regulations limiting the release of sulfur dioxide in power plant emissions.

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.

Significant third-party customers in 2025 include Vectren Corporation, a wholly-owned subsidiary of CenterPoint Energy (NYSE: CNP), Orlando Utility Commission (OUC), and Duke Energy Corporation (NYSE: DUK).

Of our 2025 sales, on a segment basis 56%, excluding Merom, were derived to locations in the State of Indiana.

As of December 31, 2025, we are committed to supplying third-party customers a base amount of 5.7 million tons of coal through 2028. We are committed to supplying coal to Merom a base amount of 7.8 million tons of coal through 2028.

Based on the contracted tons described above, we anticipate our mines will need to produce at a 3.7 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 December of 2027, 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.

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, 2025, Hallador and its subsidiaries employed 633 full-time employees and temporary miners, 599 of those employees and temporary miners are directly involved in the coal mining or coal washing process. Our coal workforce is union-free. At our power plant, our operator, 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 all of our operations. With a robust safety department and safety standards that exceed mandated guidelines, we make safety the foundation of everything we do. At our Sunrise mine operations, while every precaution is taken to prevent mine emergencies, Sunrise maintains its own private mine rescue team. This team is trained and ready to manage emergency situations at a Sunrise 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 2025 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 95.1 to this Annual Report on Form 10-K.

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

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

Other

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

Corporate and Other Available Information

The Company is a Colorado corporation. Our principal executive office, as well as Sunrise's and Hallador Power's principal executive 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.

We file our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports with the SEC. You may obtain copies of these documents, free of charge, on the SEC's website at www.sec.gov. In addition, as soon as reasonably practicable after such materials are filed or furnished with the SEC, we make copies available free of charge on our website at www.halladorenergy.com under the "Investor Relations" section. We also post important information, including press releases, investor presentations, and notices of upcoming events on our website, and utilize it as a channel for distributions to public investors and for disclosing material non-public information in compliance with Regulation FD. Investors may be notified of postings to our website by signing up for alerts on the "Investor Relations" section of our website.

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 our planned addition of natural gas-fired generation to Merom and 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 accredited capacity, electric power or coal.

In 2025, a significant portion of our electric power, accredited 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 accredited capacity, electric power 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 our control.

Market prices for electric power, accredited 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 in residences and commercial businesses 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, 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 electric 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 electric 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, accredited 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, 2025. 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 limited number of 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, price of our products and profitability.

The following table shows consolidated operating revenue concentration greater than 10% in our Electric Operations segment in dollars and percentages for the periods presented:

	Segment	Year Ended December 31,		Year Ended December 31,	
		2025	2024	2025	2024
		(in thousands)			
Customer A	Electric Operations	$ 110,006	$ 123,504	23.4 %	30.6 %
Customer B	Electric Operations	$ 47,248	$ —	10.1 %	— %
Customer C	Electric Operations	$ —	$ 51,639	— %	12.8 %

The loss of one or more of these material customers without finding a replacement customer could have a material adverse effect on our business, financial condition and results of operations.

The following table shows consolidated operating revenue concentration greater than 10% in our Coal Operations segment in dollars and percentages for the periods presented:

	Segment	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2025	Year Ended December 31, 2024
		(in thousands)			
Customer A	Coal Operations	$ 48,983	$ 54,593	10.4 %	13.5 %
Customer B	Coal Operations	$ 64,799	$ 43,394	13.8 %	10.7 %

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 accredited capacity and energy to large load end user(s) through a utility or cooperative. Failure to enter into one or more long-term contracts may have a material adverse effect on our business, financial condition and results of operations.

Participation in MISO's ERAS program may not achieve the benefits targeted by the Company and, if not successful, could have a material adverse effect on the Company's business, financial condition and/or results of operations.

On November 3, 2025, Hallador Power submitted an application to MISO's ERAS program (the "ERAS program") to obtain an interconnection that would allow the Company to add up to an additional 515 MW of natural gas generation adjacent to Hallador Power's Merom Generating Station. On December 22, 2025, the Company received notice from MISO that its ERAS program application had been accepted by MISO, which is expected to move the Company into a 6- to 9-month MISO review and approval process to gain access to the power grid versus the traditional 4.5-year process.

MISO's acceptance of the ERAS application for review does not guarantee that the Company's application will ultimately be approved by MISO or, if approved, that the Company will be able to add additional 515 MW of natural gas generation, or any additional generation, to take advantage of the approved interconnection. Participation in the ERAS program and construction and development of additional generation is capital intensive and includes construction, operational, financial, regulatory and legal risks that could impact the project's viability and/or timeline, and the Company's failure to achieve all or any of the targeted benefits of the ERAS program could have a material adverse effect on the Company's business, financial condition and/or results of operations.

Expected demand growth from the technology sector, manufacturing and other users of electricity, which has driven recent improvements in the outlook for the competitive wholesale power generation market, may not actually occur or be sustained.

Recently, the market outlook for competitive wholesale power generation has improved largely based on expected future demand from several sources, including data centers and other technology sector requirements, re-shoring of manufacturing in the U.S., the electrification of industry, and other demand drivers. Various factors including but not limited to unfavorable macroeconomic conditions, increases in energy efficiency or supply, or advances in technology, could result in lower-than-expected electricity demand and unfavorable market conditions for our power generating business and lower demand for coal from our coal mining operations. A general economic slowdown or recession, a downturn in technology, manufacturing, or other sectors, an oversupply of natural gas, or various other economic

conditions could reduce electricity and coal demand and prices. Improvements in energy efficiency, conservation efforts, and demand-side power management technologies, as well as other shifts in energy consumption, may reduce demand or slow demand growth, both from our power generating business and from our coal operations. Furthermore, the penetration of renewable generation resources has, and may continue to have, negative effects on wholesale power prices and the economics of dispatchable generation units. Advances in technology may also provide alternative methods to produce, dispatch, and store power, which could also lead to increased overall electricity supply. Any of these factors could impact the dispatch, capacity factors, and value of our generation facility and adversely impact demand for our coal.

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, accredited 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, 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.

The Company acquired Merom in October 2022. 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 and prudent utility 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. Facility outages could also subject us to market or contractual penalties. Such increased costs, unplanned outages and market or contractual penalties 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. 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 risk profile 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 commodity pricing (including capacity, electric and coal), unplanned outages, technical and geological operating difficulties, an inability to economically extract our coal reserves and unanticipated increases in operating costs. In 2024, 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 Financial 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, commodity pricing, 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.

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. See "*Note 4 – Bank Debt"* to the Consolidated Financial Statements in this Form 10-K for further discussion of our credit facilities.

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

As of December 31, 2025, our funded bank debt was $30.0 million and we held letters of credit totaling $16.2 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 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 Industries

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, 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 continuing 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.

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. Natural gas fired 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 power plants.

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. 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, PM, 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 Coal 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. Increasing government attention is being paid to global climate issues and to emissions of GHGs, including emissions due to fossil fuels.

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 and increase costs of our power generation operations, 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 our coal mining and power generation businesses 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 capacity and electricity from Merom or 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 our businesses, revenues and results of operations.

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 electric and coal supply contracts relating to, among other things, electric and coal pricing, coal 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 Electric and Coal Operations could decline due to unanticipated operating conditions and other events that are not within our control and that may not be fully covered under our insurance policies.

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

- 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 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 electric and mining 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 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.

Changes in the U.S. political environment, including those resulting from the new 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, 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 or power generation operations. Limitations on our ability to conduct our operations due to the inability to obtain or renew necessary permits or similar approvals could reduce our production, cash flow, and profitability.

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 decades. This recent inflation has resulted in rising prices, including increases in labor costs, freight rates, prices for energy and other costs, and has adversely impacted us and may further impact us negatively in the future. 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 2025, 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 2026 or beyond. We have exposure to past increases in interest rates and may be affected further in the future. Based on our variable debt level of $30.0 million as of December 31, 2025, 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 $0.3 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, including integration risk, 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.
- 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.

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.

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 increasing hostilities in the Middle East, including the recent conflict between Iran and Israel and the United States' military actions against Iran, 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.

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 delays in mine production or delivery to customers, malfunctioning or shutdown of our generating facility. 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 cannot assure you that our power generation and mine facilities 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.

Electric Operations

Hallador Power, the Company's wholly-owned electric subsidiary, owns and operates the Merom Power Plant ("Merom"), a 1,080 MW coal-fired power generating station, consisting of two steam turbine generators. Unit 1 entered commercial operations in 1982 and Unit 2 in 1983. The units are dispatched through its MISO interconnection. In order to purchase energy through the MISO Interconnection, an end user must supply or purchase accredited capacity for an equivalent load. As accredited capacity is primarily available in large quantities from dispatchable sources of energy, such as natural gas and coal-fired power plants, Hallador Power sells accredited capacity and energy to utilities, generation and transmission cooperatives, and other energy market participants within the MISO system through power purchase agreements ("PPA") 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,	
	2025	2024
Power Capacity and Utilization		
Nameplate capacity (MW)[i]	1,080	1,080
Accredited capacity for the period (MW)[ii]	775	823
Net capacity factor[iii]	56 %	44 %

i. Nameplate capacity for Merom 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, market conditions and other factors.

ii. Accredited capacity is based on MISO's average seasonal accreditations for the year. Average seasonal accreditations were 775 MW and 808 MW per day for 2025 and 2024, respectively. Accreditations are weighted and adjusted annually based on 3-year rolling performance metrics.

iii. Net capacity factor is the net amount of electricity that a generating unit produces over a period of time divided by the net amount of electricity it could have produced if it had run at full power over that time period. The net amount of electricity produced is the total amount of electricity generated minus the amount of electricity used during generation by the station.

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

The preparation of coal reserve and resource estimates is conducted by independent entities 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

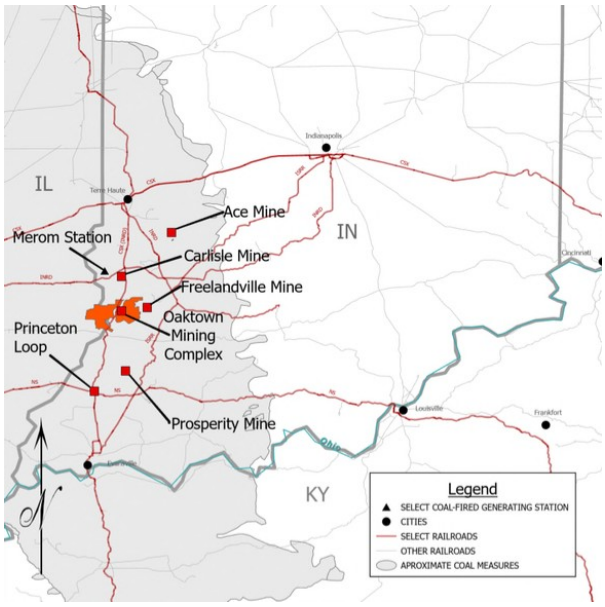
The Company has seven total mining properties. These properties are the Oaktown Mining Complex ("Oaktown"), which is comprised of Oaktown Fuels No. 1 Mine and Oaktown Fuels No. 2 Mine, the Ace in the Hole Mine, the Ace in the Hole Mine #2 Reserves, Prosperity, Freelandville and Carlisle. Oaktown Fuels 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 ILB 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 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 1,800 tons of raw coal per hour. Freelandville is a surface mine in the ILB 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 at the site of a former underground mine in the ILB 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 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 to the March 2025 Technical Report Summary ("TRS") prepared by the John T. Boyd Company in compliance with the Item 60(b)(96) and subpart 1300 of Regulation S-K ("S-K 1300") incorporated by reference as exhibit 96.1 to the 2024 Form 10-K filed on March 17, 2025.

Attached as Exhibit 96.2 to this Form 10-K is the letter from John T. Boyd Company providing an update of the Company's mineral reserves at Oaktown as of December 31, 2025, including a year-over-year comparison of those reserves.

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 S-K 1300 which 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 S-K 1300. Under S-K 1300, 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 QP's estimated our mineral reserves and mineral resources based on geologic data, coal ownership/control information, as well as current and 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 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 Oaktown Mining Complex is the Company's only individually material mining 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 includes the mineral price, cut-off grade, and metallurgical recovery factors utilized in John T. Boyd Company's preparation of the mineral reserve estimates.

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 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 room and pillar mining employing Continuous Miners ("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 75.1 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 3.7 million tons. The Oaktown Preparation Plant serves as the coal washing and shipment facility for Oaktown's two room and pillar mines. The plant was commissioned in 2009 to wash coal by the Oaktown Fuels No. 1 Mine. The Oaktown Preparation Plant's processing capacity is 1,800 raw tons-per-hour ("TPH"). 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: (i) provide assurance that any disturbance or liability created during mining operation is properly mitigated, and (ii) 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, 2025 and 2024

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	12/31/2025	12/31/2024	Change
Oaktown Mining Complex									
Oaktown Fuels No. 1 Mine	11,493	6.0	—	100.0	22.3	2.3	24.6	28.4	(13.4)%
Oaktown Fuels No. 2 Mine	11,576	5.0	—	100.0	5.9	0.2	6.1	6.1	0.0%
Total					28.2	2.5	30.7	34.5	(11.0)%

Proven and probable coal reserves decreased 11.0% during the year ended December 31, 2025. This decrease is primarily attributable to depletion through ordinary mining operations and coal sales.

Oaktown Fuels No. 1 Mine

As of December 31, 2025, the assigned and accessible reserve base for the Oaktown Fuels No. 1 Mine contains 24.6 million tons of recoverable Indiana V seam coal, of which 24.6 million tons are currently permitted compared to 28.4 million tons as of December 31, 2024. This represents a 13.4% decrease year-over-year. This decrease is the result of depletion through ordinary mining operations and coal sales. 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, 2025, 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 consistent with December 31, 2024. 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. 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.

Oaktown Fuel No. 1 and 2 Mines

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, with the coal sales price estimated over the life of the reserves, averaging approximately $49 (ranging from $47.25 to $51.47 per ton), as presented in the TRS. Coal sale 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.

Historical production for Oaktown during the years ended December 31, 2025, 2024, and 2023 are provided in the following table:

	Annual Saleable Production Tons (Million Tons)		
Mine/Reserve	**2025**	**2024**	**2023**
Oaktown Mining Complex			
Oaktown Fuels No. 1 Mine	4.0	3.5	3.9
Oaktown Fuels No. 2 Mine	-	0.4	2.5
Total Oaktown Mining Complex Production	4.0	3.9	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

The 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 five phases of reclamation that extend through 2029, of which, Phase 1 was complete as of December 31, 2025.

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 has an option through May 31, 2026 to assume the permit that contains approximately 1.7 million tons of salable coal with an additional 0.6 million available. Mining started in the fall of 2022 and was idled in February 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.

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.

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.

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 95.1 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 17.3% is held by our officers, directors, and their affiliates.

On March 10, 2026, we had 206 shareholders of record of our common stock. These amounts do not include the number of shareholders whose shares are nominally held by banks, brokerages or other institutions, but include each such institution as one shareholder of record.

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.

The following discussion and analysis, which should be read in conjunction with our consolidated financial statements, is intended to assist in providing an understanding of our results of operations and financial condition and is organized as follows:

- Overview. This section provides a general description of our business and recent events.
- Results of Operations. This section provides an analysis of our results of operations for the years ended December 31, 2025 and 2024.
- Liquidity and Capital Resources. This section provides an analysis of our liquidity and consolidated statements of cash flows.
- Critical Accounting Policies, Judgments and Estimates. This section discusses those material accounting policies that involve uncertainties and require significant judgment in their application.
- Quantitative and Qualitative Disclosures about Market Risk. This section provides discussion and analysis of the commodity, interest rate and other market risks that our company faces.

Included below is an analysis of our results of operations and cash flows for 2025, as compared to 2024. An analysis of our results of operations and cash flows for 2024, as compared to 2023, can be found under "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations"* included in Part II of our Annual Report on Form 10-K for the year ended December 31, 2024, which is available through the SEC's website at www.sec.gov.

The capitalized terms used below have been defined in the notes to our consolidated financial statements. In the following text, the terms "we," "our," "our company" and "us" may refer, as the context requires, to Hallador or collectively to Hallador and its subsidiaries.

OVERVIEW

General

Hallador is a vertically integrated, independent power producer IPP and fuel company with operations primarily in Indiana. The Company operates across multiple stages of the energy supply chain, from accredited capacity and energy to coal. The Company's electric operations are located within the MISO footprint. Our operations comprise Hallador Power that provides accredited capacity and energy to utilities and other energy market participants through the MISO interconnection, and Sunrise that mines bituminous coal in Indiana to serve various power plants in the Midwest and Southeast United States.

Operations

Our business is organized based on the services and products we provide in two segments: (i) Electric Operations and (ii) Coal Operations. The Company also holds 50% interests in Sunrise Energy, LLC and Oaktown Gas, LLC, which are accounted for using the equity method. Through its operating subsidiaries, the Company delivers three main products to its customers.

Accredited Capacity. Hallador Power, the Company's wholly-owned electric subsidiary, owns and operates the Merom Power Plant ("Merom"), a 1,080 MW coal-fired power generating station, consisting of two steam turbine generators. Unit 1 entered commercial operations in 1982 and Unit 2 in 1983. The units are dispatched through its MISO interconnection. In order to purchase energy through the MISO Interconnection, an end user must supply or purchase accredited capacity for an equivalent load. As accredited capacity is primarily available in large quantities from dispatchable sources of energy, such as natural gas and coal-fired power plants, Hallador Power sells accredited capacity to utilities and other energy market participants within the MISO system through PPAs and other bilateral transactions.

Energy. In addition to accredited capacity, Hallador Power sells wholesale energy to utilities, generation and transmission cooperatives, and other energy market participants within the MISO system through PPAs and other bilateral transactions, and sells on a spot basis in the day-ahead and real-time MISO markets.

Coal. Sunrise, the Company's wholly-owned mining subsidiary, mines coal from reserves found in the ILB. Coal mined by Sunrise is used as a primary fuel source for generating electricity at various power plants in the Midwest and Southeast United States. In addition, Sunrise has a developed infrastructure for the transport of coal, which is typically sold free on board from the shipping point, including rail networks and truck loading systems, facilitating the efficient movement of the resource from the mine to its customers. Sunrise's Oaktown Mining Complex is about twenty miles from Merom, which is located in Sullivan County, Indiana, enabling Merom and Sunrise to take advantage of low-cost fuel on a delivered basis.

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, that resulted in a significant reduction in headcount and the temporary idling of our mining operations at the Oaktown Mine No. 2. During the fourth quarter of 2024, we completed our review of the coal mining facilities and future mining plans. The 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.

Strategy and Management Focus

We view our business as two integrated operations, "Electric Operations" (our gigawatt Merom power generating station), and "Coal Operations" (our coal mining and coal sales group).

We strive to achieve margin expansion through organic revenue growth and profitability in our operations by negotiating and fulfilling contracts for accredited capacity, wholesale energy, and thermal coal to utilities and other energy market participants. We continue to monitor opportunities to expand the volume of our electric generation capabilities through expansion of existing facilities utilizing MISO's ERAS program, or via acquisition. 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 well-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. In addition, we focus our organic capital investments on strategic maintenance projects to maintain our safe operational performance and improve the reliability of Merom.

As discussed further under *"Liquidity and Capital Resources — Capitalization"* below, we also seek to maintain our debt at levels that provide for attractive equity returns without assuming undue risk.

Competition and Other External Factors

We are experiencing competition in both our Electric and Coal Operations. This competition drives lower market prices for our products and services. Competitors for our Electric Operations include other power generators who bid into the MISO interconnection, while competitors for our Coal Operations include other mining entities that are able to service our existing and potential customers via truck or rail within the Midwest and Southeast United States.

RESULTS OF OPERATIONS

Our contracted forward sales for electricity, accredited capacity and coal are detailed below with estimated revenue from forward sales of $1.3 billion as of December 31, 2025.

Forward Sales Position

	2026	2027	2028	2029	Total
Power					
Energy					
Contracted MWh (in millions)	4.06	3.06	1.09	0.27	8.48
Average contracted price per MWh	$ 43.32	$ 46.50	$ 52.94	$ 51.33	
Contracted revenue (in millions)	$ 175.88	$ 142.29	$ 57.70	$ 13.86	$ 389.73
Accredited Capacity					
Average daily contracted accredited capacity MW	733	623	454	100	
Average contracted accredited capacity price per MWd	$ 230	$ 226	$ 225	$ 230	
Contracted accredited capacity revenue (in millions)	$ 61.54	$ 51.40	$ 37.33	$ 3.47	$ 153.74
Total Energy & Accredited Capacity Revenue					
Contracted Power revenue (in millions)	$ 237.42	$ 193.69	$ 95.03	$ 17.33	$ 543.47
Coal					
Priced tons - 3rd party (in millions)	2.73	2.50	0.50	—	5.73
Avg price per ton - 3rd party	$ 55.72	$ 56.74	$ 59.00	$ —	
Contracted coal revenue - 3rd party (in millions)	$ 152.12	$ 141.85	$ 29.50	$ —	$ 323.47
TOTAL CONTRACTED REVENUE (IN MILLIONS) - CONSOLIDATED	$ 389.54	$ 335.54	$ 124.53	$ 17.33	$ 866.94
Priced tons - Intercompany (in millions)	2.30	2.30	3.17	—	7.77
Avg price per ton - Intercompany	$ 51.00	$ 51.00	$ 51.00	$ —	
Contracted coal revenue - Intercompany (in millions)	$ 117.30	$ 117.30	$ 161.67	$ —	$ 396.27
TOTAL CONTRACTED REVENUE (IN MILLIONS) - SEGMENT	$ 506.84	$ 452.84	$ 286.20	$ 17.33	$ 1,263.21

* Actual revenue related to 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.

Discussion and Analysis of our Reportable Segments

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 our 50% interests in Sunrise Energy, LLC, a private gas exploration company with operations in Indiana and Oaktown Gas, LLC, which we account for using the equity method.

Electric Operations

	Year Ended December 31,	
	2025	2024
	(in thousands)	
Delivered energy	$ 252,644	$ 203,434
Accredited capacity revenue	58,093	58,093
Electric sales	$ 310,737	$ 261,527
Fuel	$ (132,573)	$ (111,768)
Other operating costs (1)	(5)	(19)
Other operating and maintenance costs (2)	(29,358)	(28,622)
Cost of purchased power	(20,892)	(10,888)
Utilities	(4,612)	(2,070)
Labor	(32,672)	(30,842)
General and administrative	(5,195)	(5,311)
Segment EBITDA	85,430	72,007
Other operating revenue	3,534	946
Depreciation, depletion and amortization	(22,681)	(19,290)
ARO accretion	(497)	(457)
Interest income	52	36
Interest expense	(9,097)	(1,875)
Income before Income Taxes	$ 56,741	$ 51,367

1) Other operating costs primarily include costs for lime dust.
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,	
	2025	2024
	(per MWh)	
MWh generated (in thousands)	4,696	3,830
MWh purchased (in thousands)	479	354
MWh sold (in thousands)	5,175	4,184
Delivered energy	$ 48.82	$ 48.62
Accredited capacity revenue	11.23	13.88
Electric sales	$ 60.05	$ 62.50
Fuel	$ (25.62)	$ (26.71)
Other operating costs (1)	—	—
Other operating and maintenance costs (2)	(5.67)	(6.84)
Cost of purchased power	(4.04)	(2.60)
Utilities	(0.89)	(0.49)
Labor	(6.31)	(7.37)
General and administrative	(1.00)	(1.27)
Segment EBITDA	16.52	17.22
Other operating revenue	0.68	0.23
Depreciation, depletion and amortization	(4.38)	(4.61)
ARO accretion	(0.10)	(0.11)
Interest income	0.01	0.01
Interest expense	(1.76)	(0.45)
Income (Loss) before Income Taxes	$ 10.97	$ 12.29

1) Other operating costs primarily include costs for lime dust.
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).

Segment operating revenues from electric operations increased $49.2 million, or 18.8%, compared to 2024 attributable to an increase in sales of delivered energy while accredited capacity revenue was stable. Our electric operations generated an additional 0.9 million MWh and purchased an additional 0.1 million MWh for resale resulting in incremental energy sales of 1.0 million MWh, an increase of 23.7% compared to 2024. Seasonal weather in the first and third quarters of 2025 leading to incremental generation was offset by lower plant availability due to equipment issues at Merom in the fourth quarter impacting total MWh generated. The price per MWh was relatively flat year-over-year at $48.82 for 2025 compared to $48.62 for 2024. Accredited capacity revenue totaled $58.1 million for each of the years ended December 31, 2025 and 2024.

Other operating revenue increased $2.6 million, or 273.6%, compared to 2024 attributable to the exclusivity payments received during the contractual negotiations for the future accredited capacity and energy generated at Merom.

Fuel costs on a segment basis increased $20.8 million, or 18.6%, from 2024. Fuel costs on a consolidated basis increased $15.3 million or 33.0%, from 2024. This increase is due to electricity generation increasing by 0.9 million MWh, or 22.6%. We used an incremental 0.3 million tons in production on both a segment and consolidated basis compared to the prior year. We utilized approximately 0.1 million more tons produced at the Oaktown mining complex in 2025 compared to 2024. The increase in demand for electric power was related to seasonal weather in the first and third quarters of 2025, which resulted in 0.6 million and 0.5 million incremental MWh respectively, compared to the same periods in 2024. The weather contributed to higher demand for natural gas in Indiana causing an increase in the average spot prices of $0.84 per thousand cubic feet, or 24.1% compared to 2024. Total fuel costs benefited from a slight decrease in the cost of coal consumed from $54.30 per ton in 2024 to $53.98 per ton in 2025. We also made an adjustment to coal inventory during the third quarter of 2025 as part of the Company's routine inventory reconciliation process resulting in an increase in fuel costs of $2.6 million.

Cost of purchased power increased $10.0 million, or 91.9%, from 2024. When there is an outage at one of the generating units at Merom or energy hours at the Merom Hub are priced below our production cost, we have the option to make net hourly purchases of power in the MISO market to satisfy our obligations, which we record as cost of purchased power. Approximately 47.0% of the 2025 net hourly purchases occurred in the fourth quarter as a result of the equipment issues.

Utilities increased $2.5 million, or 122.8%, in 2025 compared to 2024. The change was attributable to increased production at Merom, as well as incremental billing for auxiliary power.

Labor increased $1.8 million, or 5.9%, in 2025 versus 2024. The increase in labor costs is attributable to year-over-year wage increases and the use of outsourced labor.

Interest expense increased $7.2 million, or 385.2%. The increase in our interest expense relates to accretion on our prepaid delivered energy contracts that were entered into in October 2024, and various points in 2025.

Income before income taxes increased $5.4 million, or 10.5%, compared to 2024 and is attributable to the items described in the discussion above.

Coal Operations

	Year Ended December 31,	
	2025	2024
	(in thousands)	
Coal sales	$ 221,008	$ 202,525
Fuel	$ (2,088)	$ (2,851)
Other operating and maintenance costs	(99,883)	(89,283)
Utilities	(12,189)	(13,844)
Labor	(78,006)	(85,322)
General and administrative	(8,712)	(9,877)
Segment EBITDA	20,130	1,348
Other operating revenue	5,373	2,559
Depreciation, depletion and amortization	(18,465)	(46,245)
Asset impairment	—	(215,136)
ARO accretion	(1,267)	(1,171)
Exploration costs	(216)	(260)
Gain (loss) on disposal or abandonment of assets, net	2,489	(1,629)
Interest income	235	197
Interest expense	(7,799)	(11,033)
Settlement of litigation	—	(2,750)
Income (Loss) before Income Taxes	$ 480	$ (274,120)

	Year Ended December 31,	
	2025	2024
	(per ton)	
Tons sold	4,311	3,864
Coal sales	$ 51.27	$ 52.41
Fuel	$ (0.48)	$ (0.74)
Other operating and maintenance costs	(23.17)	(23.11)
Utilities	(2.83)	(3.58)
Labor	(18.09)	(22.08)
General and administrative	(2.02)	(2.56)
Segment EBITDA	4.68	0.34
Other operating revenue	1.25	0.66
Depreciation, depletion and amortization	(4.28)	(11.97)
Asset impairment	—	(55.68)
ARO accretion	(0.29)	(0.30)
Exploration costs	(0.05)	(0.07)
Gain (loss) on disposal or abandonment of assets, net	0.58	(0.42)
Interest income	0.05	0.05
Interest expense	(1.81)	(2.86)
Settlement of litigation	—	(0.71)
Income (Loss) before Income Taxes	$ 0.13	$ (70.96)

During 2024, we undertook an Organizational Restructuring of our Coal Operations. See "*Note 17 – Organizational Restructuring*" in the Consolidated Financial Statements for further information. The Organizational Restructuring provided better operating leverage for our Coal Operations as decreased labor costs were a significant driver of our improved performance.

Segment operating revenue from coal operations increased $18.5 million, or 9.1%, versus 2024, despite only actively mining Oaktown Mine No. 1 during 2025. The increase was due to increases in volume offset by a reduction in the average sales price for our coal. We sold 4.3 million tons of coal in 2025, an increase of 0.4 million tons, or 11.6%, versus 2024. Our average sales price, on a segment basis, decreased $1.14 per ton from $52.41 per ton to $51.27 per ton. The incremental sales were made possible through increased demand for coal fired electricity due to seasonal weather specifically in the third quarter of 2025. On a consolidated basis, third-party sales increased $11.2 million, or 8.2%, versus 2024 attributable to 0.3 million incremental tons sold, offset by a 3.5% reduction in our average third-party price per ton.

Other operating and maintenance costs increased $10.6 million, or 11.9%, which is attributable to the 0.4 million ton, or 11.6%, increase in total tons sold versus 2024. Labor decreased $7.3 million, or 8.6%, from 2024, resulting in a reduction in labor cost per ton sold of $3.99 attributable to more efficient operations following the idling of Oaktown Mine No. 2 during 2024. The change was 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 in 2024 that were included in coal operations labor costs. These charges related to compensation, tax, professional, and insurance related expenses and are considered non-recurring charges paid during 2024. Through the organizational restructuring and regular attrition during the year, our coal employee headcount decreased by 305 employees.

We recorded an asset impairment of $215.1 million during 2024. During the fourth quarter of 2024, we completed 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. The core hole samples at our Oaktown Mine No. 2 mine were of a lower quality and density than that of Oaktown Mine No. 1. As such, we decided to temporarily seal Oaktown Mine No. 2, and to focus coal production at Oaktown Mine No. 1, 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 the 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 and recorded an impairment charge.

Depreciation, Depletion and Amortization decreased by $27.8 million, or 60.1%, in 2025 compared to 2024. Following the impairment of our coal operations discussed above, the cost basis of our coal operations assets upon which depreciation, depletion and amortization is calculated was much lower resulting in significantly lower expense.

Interest expense decreased $3.2 million, or 29.3%, from $11.0 million in 2024 to $7.8 million in 2025. The decrease is attributable to the net paydown of the Company's bank facility from $44.0 million at December 31, 2024 to $30.0 million at December 31, 2025 coupled with decreased interest rates of 1.5% on our revolving credit facility and 0.41% on the term loan from 2024 to 2025.

Income (loss) before income taxes increased $274.6 million, or 100.2%, from a loss of $274.1 million in 2024 to income of $0.5 million in 2025. The main drivers of this change in income from operations are described in the discussion above.

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

All Mines	1st 2025	2nd 2025	3rd 2025	4th 2025	T4Qs
Tons produced	1,020	1,059	1,034	905	4,018
Tons sold	1,071	890	1,355	995	4,311
Wash plant recovery in %	64 %	66 %	64 %	57 %	
Capex (Coal Operations)	$ 6,244	$ 5,793	$ 6,873	$ 6,449	$ 25,359
Capex per ton sold (Coal Operations)	$ 5.83	$ 6.51	$ 5.07	$ 6.48	$ 5.88
Average cost per ton sold[(i)]	$ 43.65	$ 46.03	$ 42.74	$ 46.75	$ 44.57

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
Capex per ton sold (Coal Operations)	$ 7.11	$ 8.90	$ 7.35	$ 12.66	$ 8.82
Average cost per ton sold[(i)]	$ 51.65	$ 49.94	$ 52.22	$ 43.25	$ 49.51

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, divided by tons sold for the respective period in this table. Coal Operations costs are presented in the "Discussion and Analysis of our Reportable Segments" above. During the fourth quarter of 2024, the Company made certain reclassification adjustments to other operating and maintenance costs and depreciation, depletion and amortization.

Presentation of Consolidated Information

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, 2025, 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 2025	Jun-30 2025	Sep-30 2025	Dec-31 2025	Total 2025
	(in thousands, except per share information)				
SALES AND OPERATING REVENUES:					
Electric sales	$ 85,943	$ 59,976	$ 93,235	$ 71,583	$ 310,737
Coal sales	30,185	38,147	51,256	29,067	148,655
Other revenues	1,596	4,702	2,066	1,710	10,074
Total revenue	117,724	102,825	146,557	102,360	469,466
EXPENSES:					
Fuel	15,210	15,063	27,119	6,462	63,854
Other operating and maintenance costs	28,389	28,955	44,415	27,487	129,246
Cost of purchased power	6,840	2,172	2,074	9,806	20,892
Utilities	4,152	4,507	4,543	3,599	16,801
Labor	27,029	26,799	27,574	29,276	110,678
Depreciation, depletion and amortization	14,977	5,542	9,142	11,561	41,222
ARO accretion	427	437	446	454	1,764
Exploration costs	21	98	38	59	216
General and administrative	6,825	7,501	4,770	7,130	26,226
Gain on disposal or abandonment of assets, net	(21)	(55)	(2,334)	(79)	(2,489)
Total operating expenses	103,849	91,019	117,787	95,755	408,410
INCOME (LOSS) FROM OPERATIONS	13,875	11,806	28,770	6,605	61,056
Interest income	63	64	289	186	602
Interest expense	(3,723)	(3,819)	(4,927)	(4,427)	(16,896)
Loss on extinguishment of debt	—	—	—	(608)	(608)
Equity method investment income (loss)	(236)	197	(248)	(163)	(450)
INCOME (LOSS) BEFORE INCOME TAXES	9,979	8,248	23,884	1,593	43,704
INCOME TAX EXPENSE (BENEFIT):					
Current	—	—	—	—	—
Deferred	—	—	—	1,833	1,833
Total income tax expense (benefit)	—	—	—	1,833	1,833
NET INCOME (LOSS)	$ 9,979	$ 8,248	$ 23,884	$ (240)	$ 41,871
NET INCOME (LOSS) PER SHARE:					
Basic	$ 0.23	$ 0.19	$ 0.56	$ (0.01)	$ 0.98
Diluted	$ 0.23	$ 0.19	$ 0.55	$ (0.01)	$ 0.96
WEIGHTED AVERAGE SHARES OUTSTANDING:					
Basic	42,619	42,619	43,007	43,119	42,932
Diluted	43,462	43,048	43,434	43,119	43,432

	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	1,175	992	1,334	1,683	5,184
Total revenue	111,486	93,258	104,711	94,704	404,159
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
ARO 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
(Gain) loss on disposal or abandonment of assets, net	(24)	(222)	(290)	486	(50)
Asset impairment	—	—	—	215,136	215,136
Settlement of litigation	—	—	—	2,750	2,750
Total operating expenses	108,841	100,597	100,042	313,070	622,550
INCOME (LOSS) FROM OPERATIONS	2,645	(7,339)	4,669	(218,366)	(218,391)
Interest income	88	53	43	51	235
Interest expense	(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

Income Taxes

Our effective tax rate ("ETR") is approximately 4% for the years ended December 31, 2025 and 2024. For the year ended December 31, 2025, our ETR differs from the statutory rate due primarily to statutory depletion in excess of tax basis and changes in the valuation allowance. The deduction for statutory percentage depletion does not necessarily change proportionately to changes in income (loss) before income taxes.

Restricted Stock Grants

See *"Item 8. Financial Statements - Note 8 - Stock Compensation Plans"* in the Consolidated Financial Statements for a discussion of RSUs.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

We are a holding company that is dependent on the capital resources of our subsidiaries to satisfy our liquidity requirements at the corporate level. Each of our significant operating subsidiaries typically generate cash from operating activities, but our ability to access the liquidity of these and other subsidiaries may be limited by tax and legal considerations, and other factors.

Cash and cash equivalents

Hallador had $15.4 million of cash and restricted cash as of December 31, 2025 versus $12.2 million at December 31, 2024.

Liquidity of Hallador

Our short-term sources of corporate liquidity include (i) cash and cash equivalents held by Hallador, (ii) cash provided by operations, (iii) interest income received on our cash and cash equivalents and, (iv) borrowing availability under our bank facility. For the details of the borrowing availability under our bank facility, see *"Item 8. Financial Statements - Note 4 – Bank Debt"* to our Consolidated Financial Statements.

The liquidity of Hallador generally is used to fund (i) capital expenditures, (ii) debt service requirements and (iii) general and administrative expenses, as well as to settle certain obligations that are not included on our December 31, 2025 consolidated balance sheet. In this regard, we have commitments related to (a) leases of railcars that qualify for the short-term lease exception and (b) certain operating costs associated with our Electric Operations and our Coal Operations.

From time to time, we may also require liquidity in connection with (i) acquisitions and other investment opportunities, (ii) the satisfaction of contingent liabilities, (iii) capital distributions to Hallador equity owners, (iv) the repayment of third-party debt, or (v) income tax payments. No assurance can be given that any external funding would be available to us on favorable terms, or at all.

Consolidated Statement of Cash Flows Summary.

The 2025 and 2024 consolidated statements of cash flows are summarized as follows:

	Year ended December 31,		
	12/31/2025	**12/31/2024**	Change
	(in millions)		
Net cash provided by operating activities	81,134	65,934	15,200
Net cash used in investing activities	(66,547)	(46,470)	(20,077)
Net cash used in financing activities	(11,368)	(14,434)	3,066
Increase in cash, cash equivalents, and restricted cash	3,219	5,030	(1,811)

Operating Activities. The increase in net cash provided by our operating activities is primarily attributable to the combination of (i) an increase in cash provided by our Adjusted EBITDA and related working capital items, (ii) new prepaid forward sales contracts in 2025, and (iii) lower cash payments of interest. Consolidated Adjusted EBITDA is a non-GAAP measure, which investors should view as a supplement to, and not a substitute for, GAAP measures of performance included in our consolidated statements of operations.

Investing Activities. The change in net cash used by our investing activities is primarily attributable to the net effect of (i) an increase in our capital expenditures of $15.8 million (ii) a $1.1 million decrease in the proceeds from sales of equipment, and (iii) a $3.2 million decrease in proceeds from held-for-sale investments.

For the year ended December 31, 2025, our Capex was $69.2 million allocated as follows (in millions):

Oaktown	25.4
Merom	25.5
Merom – ELG	4.7
ERAS Project	13.6
Capex per the Condensed Consolidated Statements of Cash Flows	$ 69.2

We expect our 2026 capital expenditures to modestly increase as compared to our 2025 capital expenditures, excluding any impacts of the ERAS project. The actual amount of our 2026 capital expenditures may vary from our expectations for a variety of reasons, including (i) changes in (a) the competitive or regulatory environment, (b) business plans, or (c) our expected future operating results and (ii) the availability of sufficient capital. Accordingly, no assurance can be given that our actual capital expenditures will not vary materially from our expectations.

Financing Activities. The decrease in net cash used in our financing activities is primarily attributable to the net effect of (i) a decrease in cash used of $33.5 million due to lower net repayments of debt, (ii) a reduction in cash provided from the issuance of equity securities of $21.0 million, and (iii) a decrease in cash provided of $5.1 million in proceeds from sales and leaseback arrangements.

Capitalization

We seek to maintain our debt at levels that provide for equity returns without assuming undue risk. Our ability to service or refinance our debt and to maintain compliance with the leverage covenants in our credit agreement is dependent primarily on our ability to maintain or increase the Adjusted EBITDA of our consolidated businesses, maintain adequate liquidity and coverage of fixed charges, and to achieve adequate returns on our capital expenditures and acquisitions. Consolidated Adjusted EBITDA is a non-GAAP measure, which investors should view as a supplement to, and not a substitute for, GAAP measures of performance included in our consolidated statements of operations. In addition, our ability to obtain additional debt financing is limited by the incurrence-based leverage covenants contained in our debt instruments. For example, if the Adjusted EBITDA of our business was to decline, our ability to obtain additional debt could be limited.

As of December 31, 2025, our bank debt was $30.0 million, which was repaid subsequent to year-end as further described below. 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 Bank, National Association (in its capacity as administrative agent, "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 provided for additional flexibility for the Company to enter into prepaid forward power sale contracts, provided that the Company repaid 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, would take the place of the $6.5 million quarterly Term Loan payments.

On June 27, 2025, the Company executed the Third Amendment (“Third Amendment”) to our Credit Agreement, which was accounted for as a debt modification. The primary purpose of the Third Amendment was to provide additional

operating flexibility for the remainder of 2025 by redefining covenants, deferring certain covenants until the third quarter of 2025 and moving our October 2025 payment to January 2026. The Third Amendment provided for additional flexibility for the Company to enter into prepaid forward power sale contracts, provided that the Company maintained one hundred percent of the outstanding aggregate principal balance of the Term Loan as a compensating balance. As part of the Third Amendment, the required October 2025 principal payment of $6.0 million and the January 2026 principal payment of $6.5 million, pursuant to the Term Loan, were both due in January 2026. The balance of the Term Loan was paid off in November 2025.

On March 5, 2026, Hallador entered into a credit agreement with Texas Capital Bank and Old National Bank, among others, that replaces the Credit Agreement with PNC Bank and includes a $75.0 million revolving credit facility (the "New Revolving Credit Facility") and a $45.0 million delayed draw term loan (the "Delayed Draw Term Loan", and together with the New Revolving Credit Facility, the "New Credit Facility"). The New Credit Facility bears interest with margins ranging from 2.25% to 3.75% above SOFR or the applicable base rate, subject to a SOFR floor of 1.00%. The applicable margin is determined based upon the Company's leverage ratio and the type of loan drawn. The New Credit Facility includes a commitment fee of 0.50% on any unused portions of the New Revolving Credit Facility. If the Delayed Draw Term Loan occurs, which is subject to meeting certain conditions, the principal balance of the Delayed Draw Term Loan shall be due and payable in equal quarterly installments of 2.5% of the original principal amount of such Delayed Draw Term Loan with a final payment of the remaining balance upon maturity. The New Credit Facility matures on March 5, 2029, and is collateralized by substantially all our assets. When drawn, the proceeds from the New Credit Facility may be used for ongoing working capital and general corporate purposes. Liquidity at December 31, 2025 excludes the availability under the New Credit Facility.

See "*Item 8. Financial Statements - Note 4 – Bank Debt*" 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 $17.8 million, including $6.2 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 $30.9 million to cover ARO.

CRITICAL ACCOUNTING ESTIMATES

In connection with the preparation of our consolidated financial statements, we make estimates and assumptions that affect the reported amounts of assets and liabilities, revenue and expenses and related disclosure of contingent assets and liabilities. Critical accounting policies are defined as those policies that are reflective of significant judgments, estimates and uncertainties, which would potentially result in materially different results under different assumptions and conditions. We believe the following accounting policies are critical in the preparation of our consolidated financial statements because of the judgment necessary to account for these matters and the significant estimates involved, which are susceptible to change:

- estimates of coal reserves;
- asset retirement obligations;
- income tax accounting; and
- impairment of long-lived assets.

Estimates of Coal Reserves

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.

Asset Retirement Obligations

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, reclamation of refuse areas, slurry ponds and our landfill.

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.

Income Tax Accounting

We are required to estimate the amount of income taxes for the current year and the deferred tax assets and liabilities for the future tax consequences of differences between the financial statement carrying amounts and income tax basis of assets and liabilities and the expected benefits of utilizing net operating losses and tax credit carryforwards, using enacted tax rates for the year in which those temporary differences are expected to be recovered or settled. This process requires our management to make assessments regarding the timing and probability of the ultimate tax impact of such items.

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.

Impairment of Long-lived Assets

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 analysis 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 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to several market risks in the Company's normal business activities. Market risk is the potential loss that may result from market changes associated with the Company's power generation and mining activities, or with existing or forecasted financial or commodity transactions. The types of market risks that Hallador is exposed to are commodity price risk, interest rate risk, inflation risk, and counterparty credit risk.

Commodity Price Risk

Commodity price risks result from exposures to changes in spot prices, forward prices, volatilities, and correlations between various commodities, such as natural gas, electricity, coal, oil, and emissions credits. We manage the commodity price risk of the Company's generation and mining operations by entering into various instruments to manage the variability in future cash flows from forecasted sales and purchases of power and fuel. These instruments include prepaid forward contracts, PPAs, and other bilateral agreements. Hallador uses these agreements to manage and fix the prices of certain purchases and sales to alleviate market risk and improve visibility into future results. See the *"Forward Sales Position"* table within the *"Results of Operations"* section of *"Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations"*.

We are exposed to market price fluctuations for emission credits related to our investments in Sunrise Energy and Oaktown Gas, which had an aggregate value of $2.6 million at December 31, 2025. For additional information regarding our investments in Sunrise Energy and Oaktown Gas, see *"Item 8. Financial Statements - Note 14. – Equity Method Investments"* to our Consolidated Financial Statements.

Interest Rate Risk

We are exposed to changes in interest rates primarily as a result of our borrowing activities, which include instruments with variable rates. Our primary exposure to variable rates is through our SOFR-indexed credit facilities.

In general, we monitor the interest rate market and determine whether to enter into instruments to protect against increases in the interest rates on our variable-rate debt. From time to time, we may use interest rate swaps, interest rate cap, floor or collar agreements that lock in a maximum interest rate if variable rates rise, but also may allow our company to benefit, to a limited extent in the case of collars, from declines in market rates. We use judgment to determine the appropriate composition of interest rate derivative instruments, taking into account the relative costs and benefits in light of current and expected future market conditions, liquidity issues and other factors. As of December 31, 2025 and 2024, we did not hold any interest rate derivative instruments.

Weighted Average Variable Interest Rate. At December 31, 2025 and 2024, the outstanding principal amount of our variable-rate indebtedness aggregated $30.0 million and $44.0 million, respectively, and the weighted average interest rate (including margin) on such variable-rate indebtedness was approximately 8.17% and 9.48%, respectively, excluding the effects of interest rate derivative contracts, deferred financing costs, original issue premiums or discounts and commitment fees, all of which affect our overall cost of borrowing. Assuming no change in the amount outstanding at December 31, 2025, and without giving effect to any interest rate derivative contracts, deferred financing costs, original issue premiums or discounts and commitment fees, a hypothetical 50 basis point (0.50%) increase (decrease) in our weighted average variable interest rate would increase (decrease) our annual consolidated interest expense and cash outflows by $0.2 million.

Inflation Risk

We are subject to inflationary pressures with respect to labor, procurement of electrical and mining equipment, and other costs. While we attempt to increase our revenue to offset increases in costs, there is no assurance that we will be able to do so. Therefore, costs could rise faster than associated revenue, thereby resulting in a negative impact on our operating results, cash flows and liquidity. The economic environment in which we operate is a function of government, economic,

fiscal and monetary policies and various other factors beyond our control that could lead to inflation. We are unable to predict the extent that price levels might be impacted in future periods in the markets in which we operate.

Counterparty Credit Risk

We are exposed to the risk that the counterparties to our undrawn debt facilities and cash investments will default on their obligations to us. We manage these credit risks through the evaluation and monitoring of the creditworthiness of, and concentration of risk with, the respective counterparties. In this regard, credit risk associated with our undrawn debt facilities is spread across multiple counterparties, however notwithstanding, the default of certain counterparties could have a significant impact on our consolidated statements of operations. Most of our cash currently is invested in either (i) money market funds, including funds that invest in high-quality short-term instruments that preserve principal and offer daily liquidity, or (ii) overnight deposits with banks that transfer balances nightly into repurchase agreements collateralized by high-quality securities, including US government instruments. To date, neither the access to nor the value of our cash and cash equivalent balances have been adversely impacted by liquidity problems of financial institutions.

We invest our cash with financial institutions that meet high credit quality standards. We are exposed to the credit risk of these financial institutions and to interest rate risk in relation to the interest earning potential of our cash and cash equivalent balances. In order to mitigate these risks, we actively manage the deposits of our cash balances in light of our and our subsidiaries' forecasted liquidity requirements.

At December 31, 2025 and 2024, our exposure to counterparty credit risk included (i) cash and cash equivalents and restricted cash of $15.4 million and $12.2 million, respectively, and (ii) aggregate availability of undrawn debt facilities of $28.8 million and $30.6 million, respectively.

While we currently have no specific concerns about the creditworthiness of any counterparty for which we have material credit risk exposures, we cannot rule out the possibility that one or more of our counterparties could fail or otherwise be unable to meet its obligations to us. Any such instance could have an adverse effect on our cash flows, results of operations, financial condition and/or liquidity.

Although we actively monitor the creditworthiness of our key vendors, the financial failure of a key vendor could disrupt our operations and have an adverse impact on our revenue and cash flows.

ITEM 8. FINANCIAL STATEMENTS

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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, 2025 and 2024, the related consolidated statements of operations, cash flows and stockholders' equity for each of the two years in the period ended December 31, 2025, 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, 2025 and 2024, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2025, 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, 2025, 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 12, 2026 expressed an unqualified opinion.

Basis for opinion

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

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

Critical audit matter

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

Asset retirement obligations

As of December 31, 2025, the Company's asset retirement obligations totaled $17.8 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.

/s/ GRANT THORNTON LLP

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

Tulsa, Oklahoma
March 12, 2026

PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

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

	2025	2024
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,070	$ 7,232
Restricted cash	5,302	4,921
Accounts receivable	13,989	15,438
Inventory	42,534	36,685
Parts and supplies	45,854	39,104
Prepaid expenses	5,638	1,478
Total current assets	123,387	104,858
Property, plant and equipment:		
Land and mineral rights	69,952	70,307
Buildings and equipment	421,037	402,649
Mine development	102,302	92,458
Construction work in process	39,671	27,208
Finance lease right-of-use assets	12,591	13,034
Total property, plant and equipment	645,553	605,656
Less - accumulated depreciation, depletion and amortization	(367,775)	(347,952)
Total property, plant and equipment, net	277,778	257,704
Equity method investments	2,647	2,607
Other assets	4,241	3,951
Total assets	$ 408,053	$ 369,120
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of bank debt, net	$ —	$ 4,095
Accounts payable and accrued liabilities	41,848	44,298
Current portion of lease financing	7,411	6,912
Contract liabilities - current	103,343	97,598
Total current liabilities	152,602	152,903
Long-term liabilities:		
Bank debt, net	29,678	37,394
Long-term lease financing	1,338	8,749
Deferred income taxes	1,833	—
Asset retirement obligations	15,241	14,957
Contract liabilities - long-term	45,714	49,121
Other	1,814	1,711
Total long-term liabilities	95,618	111,932
Total liabilities	248,220	264,835
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; 43,817 and 42,621 issued and outstanding, as of December 31, 2025 and December 31, 2024, respectively	438	426
Additional paid-in capital	202,963	189,298
Retained deficit	(43,568)	(85,439)
Total stockholders' equity	159,833	104,285
Total liabilities and stockholders' equity	$ 408,053	$ 369,120

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)

	2025	2024
SALES AND OPERATING REVENUES:		
Electric sales	$ 310,737	$ 261,527
Coal sales	148,655	137,448
Other revenues	10,074	5,184
Total sales and operating revenues	469,466	404,159
EXPENSES:		
Fuel	63,854	49,343
Other operating and maintenance costs	129,246	118,364
Cost of purchased power	20,892	10,888
Utilities	16,801	15,914
Labor	110,678	116,164
Depreciation, depletion and amortization	41,222	65,626
Asset retirement obligations accretion	1,764	1,628
Exploration costs	216	260
General and administrative	26,226	26,527
Gain on disposal or abandonment of assets, net	(2,489)	(50)
Asset impairment	—	215,136
Settlement of litigation	—	2,750
Total operating expenses	408,410	622,550
INCOME (LOSS) FROM OPERATIONS	61,056	(218,391)
Interest income	602	235
Interest expense (1)	(16,896)	(13,850)
Loss on extinguishment of debt	(608)	(2,790)
Equity method investment (loss)	(450)	(746)
NET INCOME (LOSS) BEFORE INCOME TAXES	43,704	(235,542)
INCOME TAX EXPENSE (BENEFIT):		
Current	—	(169)
Deferred	1,833	(9,235)
Total income tax expense (benefit)	1,833	(9,404)
NET INCOME (LOSS)	$ 41,871	$ (226,138)
NET INCOME (LOSS) PER SHARE:		
Basic	$ 0.98	$ (5.72)
Diluted	$ 0.96	$ (5.72)
WEIGHTED AVERAGE SHARES OUTSTANDING		
Basic	42,932	39,504
Diluted	43,432	39,504
(1) Interest Expense:		
Interest on bank debt	$ 5,806	$ 9,286
Other interest	9,097	2,817
Amortization of debt issuance costs	1,993	1,747
Total interest expense	$ 16,896	$ 13,850

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)

	2025	2024
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 41,871	$ (226,138)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Deferred income tax (benefit)	1,833	(9,235)
Equity method investment loss	450	746
Depreciation, depletion and amortization	41,222	65,626
Asset impairment	—	215,136
Loss on extinguishment of debt	608	2,790
(Gain) loss on disposal or abandonment of assets, net	(2,489)	(50)
Amortization of debt issuance costs	1,993	1,747
Asset retirement obligations accretion	1,764	1,628
Cash paid on asset retirement obligation reclamation	(727)	(1,407)
Stock-based compensation	3,529	4,454
Accretion on contract liabilities	8,408	1,170
Amortization of contract liabilities	(99,683)	(70,203)
Director fees paid in stock	192	150
Change in current assets and liabilities:		
Accounts receivable	1,449	4,499
Inventory	(5,849)	(13,610)
Parts and supplies	(6,750)	(227)
Prepaid expenses	1,910	784
Accounts payable and accrued liabilities	(2,154)	(14,580)
Contract liabilities	93,613	102,011
Other	(56)	643
Net cash provided by operating activities	$ 81,134	$ 65,934
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	$ (69,215)	$ (53,367)
Proceeds from sale of equipment	3,158	4,239
Proceeds from held-for-sale assets	—	3,200
Investment in equity method investments	(490)	(542)
Net cash used in investing activities	$ (66,547)	$ (46,470)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payments on bank debt	$ (106,000)	$ (147,000)
Borrowings of bank debt	92,000	99,500
Payments on lease financing	(6,994)	(5,633)
Proceeds from sale and leaseback arrangement	—	5,134
Issuance of related party notes payable	—	5,000
Payments on related party notes payable	—	(5,000)
Debt issuance costs	(330)	(673)
ATM offering	13,510	34,515
Taxes paid on vesting of RSUs	(3,554)	(277)
Net cash used in financing activities	$ (11,368)	$ (14,434)
Increase in cash, cash equivalents, and restricted cash	3,219	5,030
Cash, cash equivalents, and restricted cash, beginning of year	12,153	7,123
Cash, cash equivalents, and restricted cash, end of year	$ 15,372	$ 12,153
CASH, CASH EQUIVALENTS, AND RESTRICTED CASH:		
Cash and cash equivalents	$ 10,070	$ 7,232
Restricted cash	5,302	4,921
	$ 15,372	$ 12,153
SUPPLEMENTAL CASH FLOW DISCLOSURES:		
Cash paid for interest	$ 6,705	$ 10,511
Non-cash change in capital expenditures related to accounts payable and prepaid expenses	$ 7,232	$ 356
Stock issued on redemption of convertible notes and interest	$ —	$ 22,993

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

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

	Common Stock Issued		Additional Paid-in	Retained Earnings	Total Stockholders'
	Shares	Amount	Capital	(Deficit)	Equity
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
Stock-based compensation	—	—	3,529	—	3,529
Stock issued on vesting of RSUs	733	7	(7)	—	—
Taxes paid on vesting of RSUs	(244)	(2)	(3,552)	—	(3,554)
Stock issued in ATM offering	697	7	13,503		13,510
Stock issued for director fees	10		192		192
Net income	—	—	—	41,871	41,871
BALANCE, DECEMBER 31, 2025	43,817	$ 438	$ 202,963	$ (43,568)	$ 159,833

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2025 AND 2024

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Consolidation

Hallador Energy Company ("Hallador" or the "Company") is a vertically integrated, independent power producer ("IPP") and fuel company with operations primarily in Indiana. The Company operates across multiple stages of the energy supply chain, from accredited capacity and electricity to coal. The Company's consolidated financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). The consolidated financial statements include the accounts of Hallador and our wholly owned subsidiaries Hallador Power Company, LLC ("Hallador Power"), Sunrise Coal, LLC ("Sunrise") as well as their respective subsidiaries and Hourglass Sands, LLC. All significant intercompany accounts and transactions have been eliminated. Our operations comprise Hallador Power that provides accredited capacity and energy to utilities and other energy market participants through the MISO interconnection, and Sunrise that mines bituminous coal in Indiana to serve various power plants in the Midwest and Southeast United States.

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 our 50% interests 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.

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 most of which were idled during the year ended December 31, 2024.

Reclassifications

Amounts in the prior year's 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.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP 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 and assumptions included in the preparation of the financial statements relate to: (i) deferred income tax accounts, (ii) coal reserves, (iii) depreciation, depletion, and amortization, (iv) estimates used in our impairment analysis, and (v) estimates used in the calculation of asset retirement obligations ("ARO") under the Federal Surface Mining Control and Reclamation Act of 1977 ("SMCRA") and other state statues.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and on deposit at financial institutions, including highly liquid investments with original maturities 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 historically experienced any losses in such accounts.

Restricted Cash

Restricted cash represents cash held by third parties primarily for future workers' compensation claims and Midcontinent Independent System Operator's ("MISO") escrow payments. The amount restricted for workers' compensation is based on estimated claim liabilities. The amount restricted for MISO escrow payments is based on power purchased or sold through the MISO interconnection 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 at periodic intervals in accordance with contractual terms for delivered energy and accredited capacity. Coal customers are invoiced upon shipment. 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, 2025 or 2024.

Inventory and Parts and Supplies

Coal inventory is valued at the lower of cost or net realizable value ("NRV") determined using the first-in first-out method. Coal 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. Parts and supplies inventory is stated at cost basis determined using the first-in first-out method, less a reserve for surplus and obsolescence.

Prepaid Expenses

Prepaid expenses include prepaid insurance and other prepaid balances with vendors for various services paid 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.

Property, Plant and Equipment

The values of our Hallador Power's 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 estimated useful life of the assets ranging from six to nine years.

Construction work in process ("CWIP") on the consolidated balance sheets represent costs incurred for the construction, development, and installation of property, plant, and equipment that are not yet ready for their intended use. CWIP includes direct construction costs, labor, fees, and other directly attributable costs incurred during the construction period.

Costs are capitalized in CWIP as incurred and are not depreciated until the related asset is substantially complete and ready for its intended use. Upon completion, the accumulated costs are reclassified from CWIP to the appropriate property and equipment category and depreciation is commenced based on the asset's estimated useful life and applicable depreciation method.

In connection with MISO's Expedited Resource Addition Study ("ERAS") project, the Company has deposits totaling approximately $13.6 million as of December 31, 2025, related to project development activities. These amounts are included in CWIP to the extent that they represent costs directly attributable to the project. The deposit balance of approximately $12.9 million paid to MISO in 2025 is refundable in the event the project is terminated and therefore does not represent costs of assets that are ready for their intended use. Accordingly, such amounts are not depreciated and remain classified as CWIP until the project advances to a stage at which the related assets are placed in service. If the project is terminated, any refundable amounts will be reclassified as appropriate upon receipt.

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. Mining properties are depreciated using the units-of-production method over the estimated recoverable reserves. Mining equipment and other plant and equipment assets are depreciated using the straight-line method over their estimated useful life. Most surface and underground mining equipment is depreciated using estimated useful lives ranging from one 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 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, 2025.

Mine Development

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

ARO – Reclamation

Our operations are governed by various state and federal statues which establish reclamation and mine closure standards. 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 increase to the respective assets. Obligations are typically incurred when the Company commences development of underground and surface mines or acquires or expands power plant facilities. Obligations include reclamation of support facilities, refuse areas, slurry ponds and our landfill.

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 straight line method over the useful life of the related asset. 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 our properties be reclaimed in accordance with specific standards and approved reclamation plans, as outlined in applicable permits. Activities include reclamation of pit and support acreage at surface mines, sealing portals at underground mines, reclamation of refuse areas, slurry ponds and our landfill.

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. In the event the Company is not able to perform reclamation, it has surety bonds at December 31, 2025 totaling $30.9 million to cover ARO. The undiscounted asset retirement obligation was $25.3 million and $26.1 million at December 31, 2025 and 2024, respectively.

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

	Year Ended December 31,	
	2025	2024
Balance, beginning of year	$ 16,810	$ 16,589
Accretion	1,764	1,628
Change in estimate	—	—
Payments	(727)	(1,407)
Balance, end of year	17,847	16,810
Less current portion	(2,606)	(1,853)
Long-term balance, end of year	$ 15,241	$ 14,957

Contract Liabilities

The Company records contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. Contract liabilities are amortized to electric sales revenue pro-rata over the term of the agreements as the contracts are fulfilled. Contract liabilities primarily relate to accredited capacity or physically delivered energy.

Business Interruption Insurance

The Company carries an insurance policy to cover insurance risks including business interruption. There were no business interruption insurance settlements during the years ended December 31, 2025 and 2024. Business interruption insurance is recorded to cost of operations in the consolidated statements of operations and cash provided by operating activities in the consolidated statement of cash flows.

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.

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 in consolidation.

Income Taxes

Income taxes are provided based on the asset and 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.

Earnings 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. We apply the treasury stock method to account for the dilutive impact of its restricted stock units. 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 may be the same as the basic net loss per share for the periods presented.

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 respective vesting period of the stock award using the straight-line method.

Recent Accounting Pronouncements - Adopted

The Company has adopted Accounting Standards Update ("ASU") 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures ("ASU 2023-09"), which is effective for fiscal years beginning after December 15, 2024. 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. Please see "*Note 7 – Income Taxes*" for additional information.

Recent Accounting Pronouncements Not Yet Adopted

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 ("ASU 2024-03"). The update is intended to improve 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 NRV. As of December 31, 2025 and 2024, coal inventory includes NRV adjustments of $0.1 million and $0.3 million, respectively. During 2025, as part of the Company's routine inventory reconciliation process, a downward adjustment of $2.6 million was recorded to coal inventory.

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

	December 31,	
	2025	2024
Advanced coal royalties	$ 4,234	$ 3,906
Other	7	45
Total other assets	$ 4,241	$ 3,951

(4) BANK DEBT

The Company is a party to a credit agreement with PNC Bank, National Association ("PNC"), in its capacity as administrative agent, which consists of a revolving credit facility of up to $75.0 million and a term loan.

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 Bank, 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. 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 defined certain administrative changes which include, among other things, added requirements related to reporting, third party financial advisors, and appraisals on coal and power assets.

On June 27, 2025, the Company executed the Third Amendment ("Third Amendment") to our Credit Agreement, which was accounted for as a debt modification. The primary purpose of the Third Amendment was to provide additional operating flexibility for the remainder of 2025 by redefining covenants and deferring certain covenants until the third quarter of 2025. During the second quarter of 2025, the Company entered into a $35.0 million prepaid forward power sales contract of which $19.0 million of the proceeds were deposited into a money market account with the administrative agent as a compensating balance. The compensating balance was utilized to fully repay the outstanding term loan during the fourth quarter of 2025. As of March 5, 2026, the Company fully repaid its revolving credit facility.

Bank debt was reduced by $14.0 million and $47.5 million during the years ended December 31, 2025 and 2024, respectively.

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

Liquidity

As of December 31, 2025, we had additional borrowing capacity of $28.8 million under the revolving credit facility and total liquidity of $38.8 million. Our additional borrowing capacity is net of $16.2 million in outstanding letters of credit as of December 31, 2025 that were required to maintain surety bonds or related to PPAs. Liquidity consists of additional borrowing capacity and cash and cash equivalents.

PNC's commitment to make additional advances, and their obligation to issue letters of credit, may be terminated or reduced upon the occurrence of certain events, including, but not limited to (a) an event of default as defined in the Credit Agreement, including, among other things: (i) non-payment of principle, interest or other obligations; (ii) breaches of covenants, including financial covenants; (iii) breaches of representations and warranties; (iv) cross-defaults to other indebtedness; (v) change of control events; and (vi) bankruptcy or insolvency events; or (b) the failure to satisfy certain conditions at the time of a draw request. Upon the occurrence of an event of default, PNC, at its option, may terminate its commitments and obligation to issue letters of credit, declare all outstanding borrowings immediately due and payable, require cash collateralization of outstanding letters of credit and exercise other rights and remedies available under the Credit Agreement.

Fees

Unamortized bank fees and other costs incurred in connection with our initial facility totaled $4.3 million. Additional costs incurred with our Credit Agreement amendments totaled $0.9 million, of which $0.3 million related to our Third Amendment. These unamortized bank fees were deferred and are being amortized over the term of the Credit Agreement.

During 2025, we recognized a loss on extinguishment of debt of $0.6 million for the write-off of unamortized loan fees related to the Term Loan which was paid off in the fourth quarter of 2025. The remaining costs deferred are being amortized over the term of the revolving credit facility. Unamortized bank fees as of December 31, 2025 and 2024, were $0.3 million and $2.5 million, respectively. Commitment fees on the unused portion of the facility are 0.50% per annum.

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

	December 31,	
	2025	2024
Current bank debt	$ —	$ 6,000
Less unamortized debt issuance cost	—	(1,905)
Net current portion	$ —	$ 4,095
Long-term bank debt	$ 30,000	$ 38,000
Less unamortized debt issuance cost	(322)	(606)
Net long-term portion	$ 29,678	$ 37,394
Total bank debt	$ 30,000	$ 44,000
Less total unamortized debt issuance cost	(322)	(2,511)
Net bank debt	$ 29,678	$ 41,489

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.

The Third Amendment, among other things, deferred the Maximum Leverage Ratio and Minimum Debt Service Coverage Ratios until September 2025. The Maximum Leverage Ratio requirement was changed to 3.00 to 1.00 for our fiscal quarter ending September 30, 2025, and is 2.25 to 1.00 thereafter. The Debt Service Coverage Ratio requirement was changed to 3.25 to 1.00 as long as the Company maintains the required compensating balance, if not, the ratio remains at 1.25 to 1.00. The Third Amendment removed the First Lien Leverage Ratio (as defined in the First Amendment to the Credit Agreement) while maintaining the minimum liquidity requirement of $10.0 million.

We were in compliance with all covenants defined in the Credit Agreement throughout the year and as of December 31, 2025.

Interest Rate

The interest rate on the PNC facility ranges from secured overnight financing rate ("SOFR") plus 4.00% to SOFR plus 5.00%, depending on our Leverage Ratio. As of December 31, 2025, we were paying SOFR plus 4.25% on the outstanding bank debt which equates to an all-in rate of 8.17%.

The Company's total outstanding balance of $30.0 million on the revolving credit facility is scheduled to mature in 2026, with no amounts due in periods thereafter.

On March 5, 2026, Hallador entered into a credit agreement with Texas Capital Bank and Old National Bank, among others, that replaces the Credit Agreement with PNC Bank and includes a $75.0 million revolving credit facility (the "New Revolving Credit Facility") and a $45.0 million delayed draw term loan (the "Delayed Draw Term Loan", and together with the New Revolving Credit Facility, the "New Credit Facility"). The New Credit Facility bears interest with margins ranging from 2.25% to 3.75% above SOFR or the applicable base rate, subject to a SOFR floor of 1.00%. The applicable margin is determined based upon the Company's leverage ratio and the type of loan drawn. The New Credit Facility includes a commitment fee of 0.50% on any unused portions of the New Revolving Credit Facility. If the Delayed Draw Term Loan occurs, which is subject to meeting certain conditions, the principal balance of the Delayed Draw Term Loan shall be due and payable in equal quarterly installments of 2.5% of the original principal amount of such Delayed Draw Term Loan with a final payment of the remaining balance upon maturity. The New Credit Facility matures on March 5, 2029, and is collateralized by substantially all our assets. When drawn, the proceeds from the New Credit Facility may be used for ongoing working capital and general corporate purposes. Liquidity at December 31, 2025, excludes the availability under the New Credit Facility.

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

	December 31,	
	2025	2024
Accounts payable	$ 12,594	$ 12,822
Accrued liabilities	10,829	11,469
Workers' compensation reserve	5,223	4,321
Accrued property taxes	3,900	4,185
Accrued payroll	3,037	3,258
Asset retirement obligation - current portion	2,606	1,853
Group health insurance	1,420	1,700
Other	2,239	4,690
Total accounts payable and accrued liabilities	$ 41,848	$ 44,298

(6) REVENUE

Revenue from Contracts with Customers

We account for contracts with customers when the parties have executed 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 the 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.

Under PPAs we recognize revenue daily, based on an output method of capacity made available as part of any stand-ready obligations for contracted accredited capacity performance obligations and daily, based on an output method of megawatt hour ("MWh") of electricity delivered.

For PPAs, we recognize revenue daily for the actual delivered electricity. For the prepaid PPAs, we recognize revenue daily for the funds received for the actual delivered electricity plus any accretion attributable to the time value of money.

When there is an outage at one of the generating units at Merom or energy hours at the Merom Hub are priced below our production cost, we have the option to make net hourly purchases of power in the MISO market to satisfy our obligations, which we record as cost of purchased power in our consolidated statements of operations.

The following table shows consolidated operating revenue concentration greater than 10% from customers of our Electric Operations segment in dollars and percentages for the periods presented:

		Year Ended December 31,		Year Ended December 31,	
	Segment	2025	2024	2025	2024
		(in thousands)			
Customer A	Electric Operations	$ 110,006	$ 123,504	23.4 %	30.6 %
Customer B	Electric Operations	$ 47,248	$ —	10.1 %	— %
Customer C	Electric Operations	$ —	$ 51,639	— %	12.8 %

The following table shows consolidated accounts receivable concentration greater than 10% from customers of our Electric Operations segment in dollars and percentages for the periods presented:

		December 31,		December 31,	
	Segment	2025	2024	2025	2024
		(in thousands)			
Customer A	Electric Operations	$ 3,275	$ 3,460	23.4 %	22.4 %
Customer B	Electric Operations	$ 3,184	$ 5,952	22.8 %	38.6 %
Customer C	Electric Operations	$ 3,188	$ —	22.8 %	— %

Coal operations

Our coal revenue is derived from sales to customers of coal produced at our mining facilities. Our customers typically purchase coal free on board from our mine sites where title, risk of loss, and control pass to the customer. 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. When applicable, we have constrained the expected value of variable consideration in our estimation of transaction price and only included this consideration to the extent that it is probable that a significant revenue reversal will not occur.

The following table shows consolidated operating revenue concentration greater than 10% from customers of our Coal Operations segment in dollars and percentages for the periods presented:

	Segment	Year Ended December 31, 2025	Year Ended December 31, 2024	Year Ended December 31, 2025	Year Ended December 31, 2024
		(in thousands)			
Customer A	Coal Operations	$ 48,983	$ 54,593	10.4 %	13.5 %
Customer B	Coal Operations	$ 64,799	$ 43,394	13.8 %	10.7 %

The following table shows consolidated accounts receivable concentration greater than 10% from customers of our Coal Operations segment in dollars and percentages for the periods presented:

	Segment	December 31, 2025	December 31, 2024	December 31, 2025	December 31, 2024
		(in thousands)			
Customer A	Coal Operations	$ 1,871	$ 1,887	13.4 %	12.2 %

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, 2025	December 31, 2024
	(in thousands)	
Delivered energy (including contract liability amortization)	$ 252,644	$ 203,434
Accredited capacity	58,093	58,093
Total Electric Operations sales	$ 310,737	$ 261,527

Coal Operations

	December 31, 2025	December 31, 2024
	(in thousands)	
Third party Indiana customers	$ 83,353	$ 59,045
Customers in Florida, North Carolina and Georgia	65,302	78,403
Total Coal Operations sales	$ 148,655	$ 137,448

Performance Obligations

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.

Electric Operations

We concluded that each 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 accredited capacity provides an economic benefit to the holder and could be sold by the customer.

Coal Operations

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 using the base price per the contract, increased or decreased for quality adjustments.

The following table illustrates the balance of all current Electric and Coal Operations contracts allocated to performance obligations that are unsatisfied or partially unsatisfied as of December 31, 2025 and disaggregated by segment and contract duration (in thousands).

	2026	2027	2028	2029	Total
Delivered energy revenue	$ 175,880	$ 142,290	$ 57,700	$ 13,860	$ 389,730
Accredited capacity revenue	61,540	51,400	37,330	3,470	153,740
Coal Operations revenue (1)	152,120	141,850	29,500	—	323,470
Total revenue	$ 389,540	$ 335,540	$ 124,530	$ 17,330	$ 866,940

(1) Coal Operations revenue consists of consolidated revenue excluding our intercompany revenues from Merom.

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 the contracted price for electricity or accredited capacity. For coal contracts, the customer pays us a base price for the coal, increased or decreased for any quality adjustments. Amounts billed and due are recorded as trade accounts receivable and included in accounts receivable in our consolidated balance sheets. Payments received prior to fulfilling our performance obligations are included in contract liabilities in our consolidated balance sheets. When the Company receives customer payments more than one year in advance of the related performance obligations, in accordance with ASC 606, the Company adjusts the transaction price for the significant financing component associated with these contracts at risk adjusted market rates. The resulting interest accretion is recognized as interest expense over the period between the customer payment date and the expected satisfaction of the performance obligation.

The following table shows our beginning and ending accounts receivable balances from contracts with customers for the periods presented (in thousands):

	December 31,	
	2025	2024
Accounts receivable from contracts with customers - beginning balance	$ 15,438	$ 19,937
Accounts receivable from contracts with customers - ending balance	$ 13,989	$ 15,438

As the Company fulfills its contractual obligations, we recognized those amounts in revenue. The following table reconciles our beginning and ending contract liabilities for the periods presented (in thousands):

	December 31,	
	2025	2024
Total contract liabilities - beginning balance	$ 146,719	$ 113,741
Cash payments received on future contract obligations	136,880	159,965
Accretion on contract liabilities	8,408	1,170
Revenue recognized, cash payments received in prior period	(99,683)	(70,203)
Revenue recognized, cash payments received in current period	(43,267)	(57,954)
Total contract liabilities - ending balance	$ 149,057	$ 146,719

(7) INCOME TAXES

Effective January 1, 2025, the Company adopted an accounting standards update that provides guidance for reporting on income taxes and requires additional disclosures related to cash paid (received) for income taxes – net and the effective income tax rate. The Company adopted the updated standard for income taxes using the full retrospective approach, which changed the presentation of certain information below.

Net income (loss) before income taxes consisted of the following (in thousands):

	2025	2024
United States	$ 43,704	$ (235,542)
Foreign	—	—
Net Income (Loss) before income taxes	$ 43,704	$ (235,542)

The federal and state income tax provision (benefit) is summarized as follows (in thousands):

	2025	2024
Current tax expense:		
Federal	$ —	$ —
State and local	—	(169)
Total current tax expense	—	(169)
Deferred tax expense (benefit):		
Federal	1,833	(9,247)
State and local	—	12
Total deferred tax expense (benefit)	1,833	(9,235)
Total income tax expense (benefit):		
Federal	1,833	(9,247)
State and local	—	(157)
Total income tax expense (benefit)	$ 1,833	$ (9,404)

Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes, and (b) operating losses and tax credit carryforwards.

The tax effects of significant items comprising the Company's deferred taxes as of the years presented are as follows (in thousands):

	2025	2024
Deferred tax assets:		
Net operating loss	$ 28,320	$ 32,725
Power contracts	13,243	10,828
Compensation	1,407	1,955
Accrued liabilities	463	423
ARO liabilities	2,436	2,293
Lease liabilities	2,196	3,938
Coal properties	20,909	26,191
Other	1,875	5,215
Total deferred tax assets	70,849	83,568
Valuation allowance	(41,438)	(49,695)
Deferred tax assets, net of valuation allowance	29,411	33,873
Deferred tax liabilities:		
Coal properties	—	—
Power properties	(27,601)	(27,960)
Investment partnerships	(512)	(531)
ROU assets	(3,131)	(5,382)
Total deferred tax liabilities	(31,244)	(33,873)
Net deferred tax liability	$ (1,833)	$ —

ASC 740 requires that the tax benefit of net operating losses, temporary differences and credit carryforwards be recorded as an asset to the extent that management assesses that realization is more likely than not. Realization of the future tax benefits is dependent on the Company's ability to generate sufficient taxable income within the carryforward period. Because of the Company's recent history of operating losses, management believes that recognition of the deferred tax assets is currently not likely to be realized and, accordingly, has provided a valuation allowance. The valuation allowance decreased by $8.3 million during 2025 and increased $49.7 million during 2024.

Net operating losses and tax credit carryforwards as of the financial statement date are as follows (in thousands):

	Amount	Expiration Years
Net operating losses, federal (Post December 31, 2017)	$ 102,067	Do not Expire
Net operating losses, federal (Pre January 1, 2018)	4,928	2037
Net operating losses, state	151,604	2036 - 2044
Tax credits, federal	32	2026 - 2038
Tax credits, state	—	
Net operating losses, foreign	—	
Tax credits, foreign	$ —	

The effective tax rate of the Company's provision (benefit) for income taxes differs from the federal statutory rate as follows (amounts in thousands):

	2025		2024	
	Amount	Percent	Amount	Percent
U.S. federal statutory tax rate	$ 9,178	21.00 %	$ (49,464)	21.00 %
State and local income taxes, net of federal income tax effect	—	—	(124)	0.05
Enactment of new tax laws	—	—	—	—
Effect of cross-borders tax laws	—	—	—	—
Tax credits:	—	—	—	—
Mine rescue credits	10	0.02	20	(0.01)
Indiana EDGE credit	—	—	(169)	0.07
Change in valuation allowance	(6,605)	(15.11)	40,327	(17.12)
Nondeductible items	(1,112)	(2.54)	296	(0.13)
Worldwide changes in unrecognized tax benefits	—	—	—	—
Other	—	—	—	—
Prior period true-ups and other	362	0.82	(290)	0.12
Foreign tax effects	—	—	—	—
Total income tax expense (benefit)	$ 1,833	4.19 %	$ (9,404)	3.99 %

In each year, the state and local income taxes which comprise the majority of the state and local income taxes, net of federal effect category are Indiana.

The cash paid for income taxes (net of refunds) during the year was as follows (in dollars) (in thousands):

	2025	2024
Federal	$ —	$ —
State and local - Indiana	—	—
Foreign	—	—
Total income taxes paid	$ —	$ —

On July 4, 2025, the United States Congress passed budget reconciliation bill H.R.1, referred to as the One Big Beautiful Bill Act ("OBBBA"). The OBBBA contains several changes to corporate taxation, such as (i) the permanent extension of certain expiring provisions of the Tax Cuts and Jobs Act of 2017, including 100% expensing of qualified depreciable assets, (ii) interest deductibility, (iii) the repeal or acceleration of the sunset of certain tax credits under the 2022 Inflation Reduction Act and (iv) the elimination of certain penalties for violations of certain regulatory credit programs. The OBBBA has multiple effective dates with certain provisions effective in 2025 and others implemented through 2027. The Company continues to analyze the impact of this legislation on its business and does not anticipate a material impact as a result.

(8) STOCK COMPENSATION PLANS

Restricted Stock Units (RSUs)

A portion of the total compensation offered by the Company to its employees and directors includes stock-based compensation in the form of RSUs. The RSUs generally vest over a period of three years. The table below shows the number of RSUs available for issuance at December 31, 2025:

Total authorized RSUs in Plan approved by shareholders	6,850,000
Stock issued out of the Plan from vested grants	(4,260,472)
Unvested grants	(586,101)
RSUs available for future issuance	2,003,427

Unvested grants at December 31, 2023	858,363
Awarded - weighted average share price on grant date was $5.69	599,013
Vested	(380,390)
Forfeited	(42,500)
Unvested grants as of December 31, 2024	1,034,486
Awarded - weighted average share price on grant date was $16.96	365,237
Vested	(743,080)
Forfeited	(70,542)
Unvested grants as of December 31, 2025	586,101

RSU Vesting Schedule

Vesting Year	RSUs Vesting
2026	197,693
2027	377,192
2028	11,216
	586,101

Shares that vested in 2025 had a value of $10.6 million based on the average share price of $14.32 on their vesting dates. Under our RSU plan, participants are allowed to relinquish shares to pay for their required statutory income taxes.

Stock-based compensation expense is included in labor and in general and administrative in the consolidated statements of operations. For the years ended December 31, 2025 and 2024, stock-based compensation expense was $3.5 million and $4.5 million, respectively.

As noted in our Form 8-K filed with the SEC on June 2, 2025, on May 29, 2025, shareholders approved the Second Amended and Restated 2008 Restricted Stock Unit Plan (the "RSU Plan") which, (i) increased the number of shares available for issuance by 2,000,000 shares, and (ii) extended the term of the RSU Plan until May 29, 2035.

As of December 31, 2025, unrecognized stock compensation expense to be recognized over the respective vesting period was $4.1 million. RSUs are not allocated earnings and losses as they are considered non-participating securities. Forfeitures are recognized as they occur.

(9) EMPLOYEE BENEFITS

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

	2025	2024
Health benefits, including premiums	$ 11,326	$ 13,796
401(k) matching	1,957	1,851
Deferred bonus plan	770	553
Total	$ 14,053	$ 16,200

Of the amounts in the above table, $13.2 million and $15.2 million are recorded in labor in the consolidated statements of operations for the years ended December 31, 2025 and 2024, respectively, with the remainder in general and administrative.

(10) LEASES

The Company determines 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 seven years. As most of the leases do not provide an implicit rate, we calculate the ROU assets and lease liabilities using our secured incremental borrowing rate at the lease commencement date. At December 31, 2025 and 2024, we had approximately $0.6 million and $0.7 million, respectively, 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 previously entered into finance lease arrangements that are accounted for as failed sale-leaseback transactions. Finance lease assets are included in finance lease right-of-use assets on the consolidated balance sheets and the associated finance lease liabilities are reflected within current portion of lease financing and long-term lease financing on the consolidated balance sheets as applicable. Depreciation on our finance lease assets was $2.0 million and $5.2 million for the years ended December 31, 2025 and 2024, respectively. Interest expense on our finance lease liability was $0.1 million during the year ended December 31, 2025. Imputed interest expense on our future remaining finance lease liability was $0.5 million for the year ended December 31, 2025. We had deferred financing fees of $0.1 million and $0.2 million at December 31, 2025 and 2024, respectively, in connection with entry into the finance leases.

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

	December 31,	
	2025	2024
Operating lease information:		
Operating cash outflows from operating leases	$ 207	$ 169
Weighted average remaining lease term in years	6.6	8.0
Weighted average discount rate	8.2 %	9.5 %
Finance lease information:		
Financing cash outflows from finance leases	$ 6,994	$ 5,633
Proceeds from sale and leaseback arrangement	—	5,134
Weighted average remaining lease term in years	1.22	2.18
Weighted average discount rate	9.0 %	9.0 %

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

		For the Year Ended December 31, 2025	For the Year Ended December 31, 2024
		(In thousands)	
Operating lease assets	Buildings and equipment	$ 646	$ 664
Operating lease liabilities:			
Current operating lease liabilities	Accounts payable and accrued liabilities	$ 112	$ 99
Non-current operating lease liabilities	Other long-term liabilities	534	565
Total operating lease liability		$ 646	$ 664
Finance lease assets	Finance lease right-of-use assets	$ 12,591	$ 13,034
Finance lease liabilities:			
Current finance lease liabilities	Current portion of lease financing	$ 7,411	$ 6,912
Non-current finance lease liabilities	Long-term lease financing	1,338	8,749
Total finance lease liabilities		$ 8,749	$ 15,661

Future minimum lease payments under non-cancellable leases as of December 31, 2025, were as follows:

	Operating Leases	Finance Leases
	(In thousands)	
2026	$ 121	$ 7,972
2027	125	1,391
2028	129	—
2029	133	—
2030	137	—
Thereafter	224	—
Total minimum lease payments	$ 869	$ 9,363
Less imputed interest and deferred finance fees	(223)	(614)
Total lease liability	$ 646	$ 8,749

(11) SELF INSURANCE

The Company is self-insured for certain risks, including physical damage and operational liability, related to our non-leased underground mining equipment. The Company records a liability for self-insured risks when a loss is both probable and reasonably estimable. The Company had no accrual for self-insurance liabilities as of December 31, 2025 or December 31, 2024.

The Company also self-insures for workers' compensation claims under a guaranteed cost program. Under this program, the Company is responsible for the first $1.0 million per claim up to an aggregate of $4.0 million annually. The Company has restricted cash of $5.3 million and $4.9 million as of December 31, 2025 and 2024, respectively, which represents cash held and controlled by third parties and is restricted primarily for future workers' compensation claim payments. The Company had $5.2 million and $4.3 million of workers' compensation reserve as of December 31, 2025 and 2024, 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,	
	2025	2024
Basic earnings per common share:		
Net income (loss) - basic	$ 41,871	$ (226,138)
Weighted average shares outstanding - basic	42,932	39,504
Basic earnings (loss) per common share	$ 0.98	$ (5.72)

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

	Year Ended December 31,	
	2025	2024
Diluted earnings per common share:		
Net income (loss) - diluted	$ 41,871	$ (226,138)
Weighted average shares outstanding - basic	42,932	39,504
Add: Dilutive effects of Restricted Stock Units	500	—
Weighted average shares outstanding - diluted	43,432	39,504
Diluted net income (loss) per share	$ 0.96	$ (5.72)

(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.

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*". See asset impairment discussion below in the Nonrecurring Fair Value Measurements section below.

The carrying amounts for cash equivalents, accounts receivable, accounts payable, accrued and other liabilities, approximate fair value due to the short maturity of those instruments.

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 our 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.

Credit Risk

The Company's financial instruments exposed to concentrations of credit risk consist primarily of cash and cash equivalents, and restricted cash.

The Company's cash and cash equivalent and restricted cash balances on deposit with financial institutions total $15.4 million and $12.2 million as of December 31, 2025 and 2024, respectively, which exceeded FDIC insured limits. The Company regularly monitors these institutions' financial condition. The Company utilizes large and reputable banking institutions which it believes mitigates these risks. The Company has not experienced any losses in such accounts.

(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, 2025 and 2024, was $1.9 million and $2.1 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, 2025 and 2024, was $0.7 million and $0.5 million, respectively.

(15) CONVERTIBLE NOTES

During 2024, the Company issued 3.7 million shares in relation to the conversion of various previously issued convertible note instruments into shares of common stock. In connection with these conversions, we recognized $2.8 million in inducement expenses that were reported in loss on extinguishment of debt in the consolidated statements of operations. As of December 31, 2025 and 2024, there were no convertible debt instruments outstanding.

(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.

(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 was designed to strengthen our financial and operational efficiency and create significant operational savings and higher margins in our Coal Operations Segment. This step helped to advance our transition from a company primarily focused on coal production to a more resilient and diversified, vertically-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 included compensation, tax, professional, and insurance related expenses and were considered non-recurring charges paid during 2024. 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. On December 16, 2025, the Company increased the aggregate gross sales proceeds under the ATM Program from $50.0 million to $100.0 million by amending the Sales Agreement.

During the year ended December 31, 2025, we issued 697,227 shares of Common Stock under the ATM Program for net proceeds of $13.5 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. In January 2026, the Company delivered written notice to the Agent to terminate the Sales Agreement effective January 18, 2026. As a result of the termination of the Sales Agreement, the Company will not offer or sell any further shares under the ATM Program.

(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. There were no impairments recorded during the year ended December 31, 2025 in connection with the annual review. In 2024, the Company evaluated core hole samples at several of its mines, reviewing the quality of the mine seam and density of the coal. The core hole samples at the Oaktown 2 mine were of a lower quality and density than those of the Oaktown 1 mine. As such, at the conclusion of the Company's annual business plan review in 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 in 2024. 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 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, 2025.

(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. Revenue from our Electric Operations segment consist primarily of delivered energy and accredited capacity revenue. Fuel costs included in our Electric Operations segment include the cost of coal purchased from our Coal Operations segment, which is based on multi-year contracts that approximated market prices at the time the contracts were agreed.

Our Coal Operations segment includes the Oaktown 1 underground mining complex, as well as other currently idled mining facilities, which produce high-quality bituminous coal from the Illinois Basin. Revenue from our Coal Operations segment consists of sales of coal to various third parties and to Merom. Coal sales to our Electric Operations are based on multi-year contracts that approximated market prices at the time the contracts were agreed. 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 Segment EBITDA for each business segment. Segment EBITDA is calculated for each segment as follows:

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

Segment EBITDA 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, Segment EBITDA 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 segment's operations.

Presented below are the Electric and Coal Operations key metrics reviewed by the CODM at December 31, 2025 (in thousands):

	Electric Operations		Coal Operations
Delivered energy	$ 252,644	Coal sales	$ 221,008
Accredited capacity revenue	58,093		
Electric sales	$ 310,737		
Fuel	$ (132,573)		
Other operating costs (1)	(5)		
Total variable costs	$ (132,578)		
Other operating and maintenance costs (2)	$ (29,358)	Fuel	$ (2,088)
Cost of purchased power	(20,892)	Other operating and maintenance costs	(99,883)
Utilities	(4,612)	Utilities	(12,189)
Labor	(32,672)	Labor	(78,006)
Power margin without general and administrative	90,625	Coal margin without general and administrative	28,842
General and administrative	(5,195)	General and administrative	(8,712)
Electric Operations — Segment EBITDA	$ 85,430	Coal Operations — Segment EBITDA	$ 20,130

(1) Other operating costs include costs for lime dust.
(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, 2024 (in thousands):

	Electric Operations		Coal Operations
Delivered energy	$ 203,434	Coal sales	$ 202,525
Accredited 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 — Segment EBITDA	$ 72,007	Coal Operations — Segment EBITDA	$ 1,348

(1) Other operating costs include costs for lime dust.
(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, 2025 (in thousands):

Reconciliation of Revenue:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Delivered energy	$ 252,644	$ —	$ —	$ 252,644
Accredited capacity revenue	58,093	—	—	58,093
Other operating revenue	3,534	5,373	1,167	10,074
Coal sales (third party)	—	148,655	—	148,655
Coal sales (intercompany)	—	72,353	(72,353)	—
Operating Revenues	$ 314,271	$ 226,381	$ (71,186)	$ 469,466

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
Accredited capacity revenue	58,093	—	—	58,093
Other operating revenue	946	2,559	1,679	5,184
Coal sales (third party)	—	137,448	—	137,448
Coal sales (intercompany)	—	65,077	(65,077)	—
Operating Revenues	$ 262,473	$ 205,084	$ (63,398)	$ 404,159

Presented below is our reconciliation of Segment EBITDA to the most comparable GAAP account, income (loss) before income taxes at December 31, 2025 (in thousands):

Reconciliation of Income (Loss) before Income Taxes:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Income (Loss) before Income Taxes	$ 56,741	$ 480	$ (13,517)	$ 43,704
Other operating revenue	(3,534)	(5,373)	(1,167)	(10,074)
Depreciation, depletion and amortization	22,681	18,465	76	41,222
ARO accretion	497	1,267	—	1,764
Exploration costs	—	216	—	216
(Gain) loss on disposal or abandonment of assets, net	—	(2,489)	—	(2,489)
Interest income	(52)	(235)	(315)	(602)
Interest expense	9,097	7,799	—	16,896
Loss on extinguishment of debt	—	—	608	608
Equity method investment (loss)	—	—	450	450
Corporate — general and administrative	—	—	12,319	12,319
Segment EBITDA	$ 85,430	$ 20,130	$ (1,546)	$ 104,014

Presented below is our reconciliation of Segment EBITDA 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
Income (Loss) before Income Taxes	$ 51,367	$ (274,120)	$ (12,789)	$ (235,542)
Other operating revenue	(946)	(2,559)	(1,679)	(5,184)
Depreciation, depletion and amortization	19,290	46,245	91	65,626
Asset impairment	—	215,136	—	215,136
ARO 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 income	(36)	(197)	(2)	(235)
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
Segment EBITDA	$ 72,007	$ 1,348	$ 199	$ 73,554

Presented below are our Electric and Coal Operations assets and capital expenditures at December 31, 2025 (in thousands):

Other Reconciliations:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Assets	$ 256,529	$ 148,957	$ 2,567	$ 408,053
Capital expenditures	$ 43,853	$ 25,362	$ —	$ 69,215

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

(21) ASSETS HELD FOR SALE

During the third quarter of 2024, the Company considered strategic alternatives with respect to its wholly-owned subsidiary Summit Terminal LLC ("Summit"), which primarily held property, plant and equipment. On July 29, 2024, the Company entered into a ninety-day right of first refusal agreement with a potential buyer and subsequently sold Summit on December 23, 2024 for $3.2 million. As of July 29, 2024, Summit met the held-for-sale criteria but did not qualify for treatment as a discontinued operation, and its assets were included in assets held-for-sale in the current assets section of the consolidated balance sheets. In connection with the sale, the Company recorded a $2.3 million loss in (Gain) loss on disposal or abandonment of assets, net in its 2024 consolidated statements of operations.

(22) CONTINGENCIES

During 2024, our Coal Operations subsidiary was party to litigation in which the plaintiff's alleged 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 was recorded in operating expenses on our consolidated statements of

operations for the year ended December 31, 2024. During the third quarter of 2025, we transferred $2.7 million into an escrow account and in late 2025 the settlement terms were approved by the court. At December 31, 2025, there were no further amounts accrued on our consolidated balance sheet related to this litigation.

(23) SUBSEQUENT EVENTS

In January 2026, the Company conducted a confidentially marketed public offering (the "CMPO") pursuant to a base prospectus and a final prospectus supplement that were filed with the SEC. The Company sold a total of 3,194,444 shares of common stock, at a price to the public of $18.00 per share for aggregate gross proceeds of approximately $57.5 million, including the exercise of the underwriter's option prior to deducting underwriting discounts, commissions, and other offering expenses of $3.3 million.

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, 2025. Based on that evaluation, our management concluded that our ICFR was effective at December 31, 2025.

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, 2025, 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, 2025, 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, 2025, 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, 2025, 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, 2025, and our report dated March 12, 2026 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. 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 12, 2026

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, 2025.

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:

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 (4)
10.2	First Amendment to Fourth Amended and Restated Loan Agreement dated as of September 27, 2024 (5)
10.3	Second Amendment to Fourth Amended and Restated Loan Agreement dated as of October 23, 2024 (6)
10.4	Third Amendment to Fourth Amended and Restated Loan Agreement dated as of June 27, 2025 (12)
10.5	Hallador Energy Company Second Amended and Restated 2008 Restricted Stock Unit Agreement (11)
10.6	2022 Executive Officer Compensation Plan++(7)
10.7	2024 Executive Officer Compensation Plan * ++ (10)
10.8	Offer Letter, dated June 1, 2025, by and between Todd Telesz and Hallador Energy Company (12)
10.9	Asset and Purchase Agreement dated February 14, 2022 (8)
14.1	Code of Ethics for Senior Executive Officers (10)
19.1	Insider Trading Policy (10)
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*
31.3	SOX 302 Certifications - CAO*
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(10)
96.2	Letter from Boyd and Company, dated February 24, 2026*
97.1	Hallador Energy Company Policy for the Recovery of Erroneously Awarded Compensation (9)
101.INS	Inline XBRL Instance Document*
101.SCH	Inline XBRL Schema Document*
101.CAL	Inline XBRL Calculation Linkbase Document*
101.LAB	Inline XBRL Labels Linkbase Document*
101.PRE	Inline XBRL Presentation Linkbase Document*
101.DEF	Inline XBRL Definition Linkbase Document*
104*	Cover Page Interactive Data File (embedded within the Inline XBRL and contained in Exhibit 101)

(1) IBR to Form 8-K dated December 31, 2009
(2) IBR to Form 10-K/A amendment 1, filed June 12, 2020
(3) IBR to Form 10-K filed March 9, 2020
(4) IBR to Form 10-Q filed on August 7, 2023
(5) IBR to Form 8-K filed on October 3, 2024
(6) IBR to Form 10-Q filed on November 11, 2024
(7) IRB to Form 10-Q filed November 14, 2022
(8) IBR to Form 8-K/A filed March 11, 2022
(9) IBR to Form 10-K filed March 14, 2024
(10) IBR to Form 10-K filed March 17, 2025
(11) IBR to Appendix A to the Proxy Statement filed April 17, 2025
(12) IBR to Form 10-Q file August 11, 2025

* 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 12, 2026 /s/TODD E. TELESZ
Todd E. Telesz, CFO

Date: March 12, 2026 /s/ERIC VAN DEMAN
Eric Van Deman, CAO

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

/s/BRENT BILSLAND Brent Bilsland	Board Chairman, President and CEO	March 12, 2026
/s/DAVID J. LUBAR David J. Lubar	Director	March 12, 2026
/s/BRYAN LAWRENCE Bryan Lawrence	Director	March 12, 2026
/s/CHARLES WESLEY, IV Charles Wesley, IV	Director	March 12, 2026
/s/ZARRELL GRAY Zarrell Gray	Director	March 12, 2026
/s/BARBARA SUGG Barbara Sugg	Director	March 12, 2026
/s/DANIEL HUDSON Daniel Hudson	Director	March 12, 2026