UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(Mark One)

 ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2024

or

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

Commission File No. 1-9172

NACCO INDUSTRIES, INC.

(Exact name of registrant as specified in its charter)

Delaware	**34-1505819**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

22901 Millcreek Blvd, Suite 600
Cleveland, Ohio **44122**
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(440) 229-5151**

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Class A Common Stock, $1 par value per share	NC	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: Class B Common Stock, $1 par value per share. Class B Common Stock is not publicly listed for trade on any exchange or market system; however, Class B Common Stock is convertible into Class A Common Stock on a share-for-share basis.

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 Section 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 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, a smaller reporting company or an emerging growth company. See 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**

Aggregate market value of Class A Common Stock and Class B Common Stock held by non-affiliates as of June 30, 2024 (the last business day of the registrant's most recently completed second fiscal quarter): $117,744,151

Number of shares of Class A Common Stock outstanding at February 28, 2025: 5,866,937
Number of shares of Class B Common Stock outstanding at February 28, 2025: 1,565,359

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's Proxy Statement for its 2025 annual meeting of stockholders are incorporated herein by reference in Part III of this Form 10-K.

NACCO INDUSTRIES, INC.
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PART I

Item 1. BUSINESS

General

NACCO Industries, Inc.® (NACCO) and its wholly owned subsidiary, NACCO Natural Resources Corporation® (NACCO Natural Resources and with NACCO collectively, the Company, we, our or us), bring natural resources to life by delivering aggregates, minerals, reliable fuels and environmental solutions through our robust portfolio of businesses. We operate under three business segments: Coal Mining, North American Mining® (NAMining) and Minerals Management. The Coal Mining segment operates surface coal mines for power generation companies. The NAMining segment is a trusted mining partner for producers of aggregates, activated carbon, lithium and other industrial minerals. The Minerals Management segment, which includes the Catapult Mineral Partners (Catapult) business, acquires and promotes the development of mineral interests. Mitigation Resources of North America® (Mitigation Resources) provides stream and wetland mitigation solutions as well as comprehensive reclamation and restoration construction services. In addition, ReGen Resources is pursuing opportunities to develop new power generation resources.

We have items not directly attributable to a reportable segment that are not included in the reported financial results of the operating segment. These items primarily include administrative costs related to public company reporting requirements, including management and board compensation, and the financial results of Bellaire Corporation (Bellaire), Mitigation Resources, ReGen Resources and other developing businesses. Bellaire manages our long-term liabilities related to former Eastern U.S. underground mining activities.

NACCO was incorporated as a Delaware corporation in 1986 in connection with the formation of a holding company structure for a predecessor corporation organized in 1913.

Business Strategy

NACCO’s portfolio of businesses operate under the umbrella of NACCO Natural Resources. Management continues to view our long-term business outlook positively. Our businesses provide critical inputs for electricity generation, construction and development, and the production of industrial minerals and chemicals. Increasing demand for electricity, on-shoring and current federal policies are creating favorable macroeconomic trends within these industries. Management is confident in our trajectory and business prospects as well as longer-term growth opportunities.

While we realize the coal mining industry continues to face challenges, we believe the current political environment may change the sentiment surrounding fossil fuel industry-related regulations. These developments are expected to further support coal as an essential part of the energy mix in the United States for the foreseeable future.

NAMining is our primary platform for growth around mining activities. With a focus on operational excellence, scalability and driving profitable growth, NAMining expects to improve operating margins as well as achieve additional growth through its ongoing business development activities. New contracts and contract extensions are central to the business' organic growth strategy. The goal is to continue NAMining's ongoing expansion as a leading provider of contract mining services for customers who produce a wide variety of minerals and materials, and we expect NAMining to be a substantial contributor to operating profit over time.

The Minerals Management segment, through our Catapult business, has constructed a high-quality, diversified portfolio of oil and gas mineral and royalty interests in the United States that is expected to deliver near-term cash flow yields and long-term growth. As an owner of mineral and royalty interests, we are entitled to a portion of the revenues received from the production of oil, natural gas and associated natural gas liquids, typically net of post-production expenses and taxes. We are not obligated to fund drilling and completion costs, lease operating expenses or plugging and abandonment costs at the end of a well’s productive life. The current portfolio provides a strong foundation of well-positioned assets that are expected to continue to deliver solid financial results. This business model can deliver higher average operating margins over the life of a reserve than traditional oil and gas companies that bear the full cost of exploration, production and/or development. We intend to continue these activities, while at the same time evaluating investments in non-operated working interests that we believe can reliably increase cash flow and enhance overall returns. As a non-operator, we seek to diversify our investment and operational risk through participation in oil and gas wells with multiple operators across multiple basins. While the timing of returns could vary, we maintain a long-term perspective and believes the Minerals Management segment will provide unlevered after-tax returns on invested capital in the mid-teens as the business matures.

Mitigation Resources, which provides stream and wetland mitigation solutions as well as comprehensive reclamation and restoration construction services, continues to build on the substantial foundation it has established over the past several years. Our Mitigation Resources business offers an opportunity for growth and diversification in an industry where we have a strong reputation as well as substantial knowledge and expertise. In addition, Mitigation Resources is providing ecological restoration services for abandoned surface mines and was named a designated provider of abandoned mine land restoration by the State of Texas. Mitigation Resources is working to develop a protected habitat for toads in Texas, as well as pursuing additional environmental restoration projects. We believe that Mitigation Resources can provide solid rates of return on capital employed as this business matures. As of December 31, 2024, we have 11 mitigation banks and other mitigation projects located in Alabama, Florida, Georgia, Mississippi, Pennsylvania, Tennessee and Texas.

We believe our businesses have competitive advantages that provide value to customers and continuing to invest in our businesses can create long-term value for stockholders. We have strategically leveraged our core mining and natural resources management skills to build a robust portfolio of affiliated businesses and opportunities for additional growth remain strong. Acquisitions of additional mineral interests and improvements in the outlook for Coal Mining segment customers, as well as new contracts at Mitigation Resources and NAMining and development of other business opportunities should be accretive to our longer-term outlook.

NACCO also continues to pursue activities which can strengthen the resiliency of our existing coal mining operations. We remain focused on managing coal production costs and maximizing efficiencies and operating capacity at mine locations to help customers with management fee contracts be more competitive. These activities benefit both customers and our Coal Mining segment, as fuel cost is a significant driver for power plant dispatch. Increased power plant dispatch results in increased demand for coal by the Coal Mining segment's customers. Fluctuating natural gas prices, weather and availability of renewable energy sources, such as wind and solar, could affect the amount of electricity dispatched from coal-fired power plants.

We continue to look for ways to create additional value by utilizing our core mining competencies, which include reclamation and permitting. NACCO established ReGen Resources to utilize these skills to address the rapidly increasing demand for additional power generation sources in the United States through development of energy-related projects that utilize multiple generation technologies, such as solar combined with gas-fired generation, primarily on reclaimed mining properties. These projects could be developed by ReGen Resources directly or through joint ventures that include partners with expertise in energy development projects and their financing. Current opportunities in development include solar arrays, solar-gas hybrid projects and carbon capture on reclaimed mine land in Mississippi and Texas, as well as early-stage review of projects in other states.

NACCO is committed to maintaining a conservative capital structure as it continues to grow and diversify, while avoiding unnecessary risk. We believe strategic diversification will generate cash that can be re-invested to strengthen and expand our businesses. We also continue to maintain the highest levels of customer service and operational excellence with an unwavering focus on safety and environmental stewardship.

Business Developments

Coal Mining Segment
During 2023, Mississippi Lignite Mining Company (MLMC) received notice from its customer related to a boiler issue at the Red Hills Power Plant that began on December 15, 2023. We assessed MLMC's long-lived assets for impairment and recorded a $65.9 million impairment charge in 2023. See Note 9 to the Consolidated Financial Statements in this Form 10-K for further information on the long-lived asset impairment charge. While this issue has been resolved, it resulted in a reduction in customer demand which had a significant impact on our 2024 results of operations. We recognized income of $13.6 million in 2024 related to business interruption insurance recoveries that partially offset losses as a result of the boiler outage.

The Sabine Mining Company (Sabine) operates the Sabine Mine in Texas. All production from Sabine was delivered to Southwestern Electric Power Company's (SWEPCO) Henry W. Pirkey Plant (the Pirkey Plant). SWEPCO is an American Electric Power (AEP) company. As a result of the early retirement of the Pirkey Plant, Sabine ceased deliveries and commenced final reclamation on April 1, 2023. Funding for mine reclamation is the responsibility of SWEPCO, and Sabine receives compensation for providing mine reclamation services. Sabine will provide mine reclamation services through September 30, 2026. As of October 1, 2026, SWEPCO has an obligation to acquire all of the capital stock of Sabine and complete the remaining mine reclamation.

NAMining Segment
Sawtooth Mining, LLC (Sawtooth) will be the exclusive provider of comprehensive mining services for the Thacker Pass lithium project in Humboldt County, Nevada. Thacker Pass is owned by a joint venture between Lithium Americas Corp. (TSX: LAC) (NYSE: LAC) and General Motors Holdings LLC. Thacker Pass commenced construction in 2023 and is targeting initial production in 2027. Sawtooth will be reimbursed for costs of mining, capital expenditures and mine closure and will recognize a contractually agreed upon production fee once the mine is operating. In addition to providing comprehensive mining services,

Sawtooth is currently assisting with certain construction services and will transport clay tailings once lithium production commences.

During 2024 and 2023, NAMining amended and extended existing limestone contracts with two customers and expanded the scope of work with several other customers. New contracts signed in 2024 are expected to be accretive to earnings starting in 2026.

Minerals Management Segment
During 2024 and 2023, Minerals Management invested a total of $19.1 million, including $15.7 million in the fourth quarter of 2024, in Eiger, LLC (Eiger), which holds non-operated working interests in oil and natural gas assets in the Kansas and the Oklahoma portion of the Hugoton basin.

During 2023, Minerals Management acquired $36.7 million of mineral and royalty interests in the Texas portion of the Permian Basin.

Other Items
In December 2023, we entered into a power purchase agreement with the Tennessee Valley Authority (TVA) for the energy generated from a proposed 67.5 MW solar photovoltaic electric generation facility to be developed on reclaimed land at our Red Hills Mine. The development of this project is subject to the favorable completion of an Environmental Assessment under the National Environmental Policy Act (NEPA) and approval of an interconnection agreement with TVA. In addition, we entered into an engineering, procurement and construction agreement related to the interconnection of the project during 2025. The estimated commercial operation date for this generation facility is late 2027.

Operations

Coal Mining Segment
The Coal Mining segment operates surface coal mines under long-term contracts with power generation companies pursuant to a service-based business model. Coal is surface mined in North Dakota and Mississippi. Each mine is fully integrated with our customer's operations.

As of December 31, 2024, the Coal Mining segment's operating coal mines were: The Coteau Properties Company (Coteau), Coyote Creek Mining Company, LLC (Coyote Creek), The Falkirk Mining Company (Falkirk) and MLMC. Each of these mines supply lignite coal for power generation and delivers our coal production to an adjacent power plant or synfuels plant under a long-term supply contract. While MLMC's coal supply contract contains a take or pay provision, the contract contains a force majeure provision that allows for the temporary suspension of the take or pay provision during the duration of certain specified events beyond the control of either party; all other coal supply contracts are requirements contracts. Certain coal supply contracts can be terminated early, which would result in a reduction to future earnings.

The MLMC contract is the only coal supply contract in which we are responsible for all operating costs, capital requirements and final mine reclamation; therefore, MLMC is consolidated within our financial statements. MLMC sells coal to its customer at a contractually agreed-upon price which adjusts monthly, primarily based on changes in the level of established indices which reflect general U.S. inflation rates. Profitability at MLMC is affected by customer demand for coal and changes in the indices that determine sales price and actual costs incurred. As diesel fuel is heavily weighted among the indices used to determine the coal sales price, fluctuations in diesel fuel prices can result in significant fluctuations in earnings at MLMC. MLMC's customer operates the Red Hills Power Plant, which supplies electricity to TVA under a long-term power purchase agreement. MLMC's contract with its customer runs through April 1, 2032. TVA's power portfolio includes coal, nuclear, hydroelectric, natural gas and renewables. The decision regarding which power plants to dispatch is determined by TVA. Reduction in dispatch of the Red Hills Power Plant will result in reduced earnings at MLMC.

At Coteau, Coyote Creek and Falkirk, we are paid a management fee per ton of coal or heating unit (MMBtu) delivered. Each contract specifies the indices and mechanics by which fees change over time, generally in line with broad measures of U.S. inflation. Our customers are responsible for funding all mine operating costs, including final mine reclamation, and directly or indirectly providing all of the capital required to build and operate the mine. This contract structure eliminates exposure to spot coal market price fluctuations while providing income and cash flow with minimal capital investment. Other than at Coyote Creek, debt financing provided by or supported by the customers is without recourse to us. See Note 16 to the Consolidated Financial Statements in this Form 10-K for further discussion of Coyote Creek's guarantees.

Coteau, Coyote Creek, Falkirk and Sabine each meet the definition of a variable interest entity (VIE). In each case, NACCO is not the primary beneficiary of the VIE as it does not exercise financial control; therefore, we do not consolidate the results of these operations within our financial statements. Instead, these contracts are accounted for as equity method investments. The income before income taxes associated with these VIEs is reported as Earnings of unconsolidated operations on the Consolidated Statements of Operations and our investment is reported on the line Investments in unconsolidated subsidiaries in the Consolidated Balance Sheets. The mines that meet the definition of a VIE are referred to collectively as the Unconsolidated Subsidiaries. For tax purposes, the Unconsolidated Subsidiaries are included within our consolidated U.S. tax return; therefore, the Income tax benefit line on the Consolidated Statements of Operations includes income taxes related to these entities. See Note 16 to the Consolidated Financial Statements in this Form 10-K for further information on the Unconsolidated Subsidiaries.

We perform contemporaneous reclamation activities at each mine in the normal course of operations. Under all of the Unconsolidated Subsidiaries' contracts, our customer has the obligation to fund final mine reclamation activities. Under certain contracts, the Unconsolidated Subsidiary holds the mine permit and is therefore responsible for final mine reclamation activities. To the extent the Unconsolidated Subsidiary performs such final reclamation, it is compensated for providing those services in addition to receiving reimbursement from customers for costs incurred.

See Item 2. Properties on page 29 in this Form 10-K for discussion of our mineral resources and mineral reserves.

NAMining Segment
The NAMining segment provides value-added contract mining and other services for producers of industrial minerals. The segment is a platform for our growth and diversification of mining activities outside of the thermal coal industry. NAMining provides contract mining services for independently owned mines and quarries, creating value for our customers by performing the mining aspects of our customers' operations. This allows customers to focus on their areas of expertise: materials handling and processing, product sales and distribution. As of December 31, 2024, NAMining operates in Florida, Texas, Arkansas, Virginia and Nebraska.

In addition, Sawtooth will supply all of the lithium-bearing ore requirements for Thacker Pass, which is currently in the development stage with construction activities underway. Sawtooth will be reimbursed for costs of mining, capital expenditures and mine closure and will recognize a contractually agreed upon production fee once the mine is operating. In addition to providing comprehensive mining services, Sawtooth is currently assisting with certain construction services and will transport clay tailings once lithium production commences.

Minerals Management Segment
The Minerals Management segment derives income primarily by leasing our royalty and mineral interests to third-party exploration and production companies, and, to a lesser extent, other mining companies, granting them the rights to explore, develop, mine, produce, market and sell gas, oil, and coal in exchange for royalty payments based on the lessees' sales of those minerals.

The Minerals Management segment owns royalty interests, mineral interests, non-participating royalty interests and overriding royalty interests (collectively mineral and royalty interests).

- Royalty Interest. Royalty interests generally result when the owner of a mineral interest leases the underlying minerals to an exploration and production company pursuant to an oil and gas lease. Typically, the resulting royalty interest is a cost-free percentage of production revenues for minerals extracted from the acreage. A holder of royalty interests is generally not responsible for capital expenditures or lease operating expenses, but royalty interests may be calculated net of post-production expenses, and typically have no environmental liability. Royalty interests leased to producers expire upon the expiration of the oil and gas lease and revert to the mineral owner.
- Mineral Interest. Mineral interests are perpetual rights of the owner to explore, develop, exploit, mine and/or produce any or all of the minerals lying below the surface of the property. The holder of a mineral interest has the right to lease the minerals to an exploration and production company. Upon the execution of an oil and gas lease, the lessee (the exploration and production company) becomes the working interest owner and the lessor (the mineral interest owner) has a royalty interest.
- Non-Participating Royalty Interest (NPRIs). NPRI is an interest in oil and gas production which is created from the mineral estate. The NPRI is expense-free, bearing no operational costs of production. The term non-participating indicates that the interest owner does not share in the bonus, rentals from a lease, nor the right to participate in the execution of oil and gas leases. The NPRI owner does; however, typically receive royalty payments.
- Overriding Royalty Interest (ORRIs). ORRIs are created by carving out the right to receive royalties from a working interest. Like royalty interests, ORRIs do not confer an obligation to make capital expenditures or pay for lease

operating expenses and have limited environmental liability; however, ORRIs may be calculated net of post-production expenses, depending on how the ORRI is structured. ORRIs that are carved out of working interests are linked to the same underlying oil and gas lease that created the working interest, and therefore, such ORRIs are typically subject to expiration upon the expiration or termination of the oil and gas lease.

We may own more than one type of mineral and royalty interest in the same tract of land. For example, where we own an ORRI in a lease on the same tract of land in which we own a mineral interest, the ORRI in that tract will relate to the same gross acres as the mineral interest in that tract.

The Minerals Management segment does not currently have any material investments under which it would be required to bear the cost of exploration, production or development. The Minerals Management segment will benefit from the continued development of our mineral properties without the need for investment of additional capital once mineral and royalty interests have been acquired as the capital costs or lease operating expenses are born entirely by the operators or working interest owners.

During 2024 and 2023, Minerals Management invested a total of $19.1 million, including $15.7 million in the fourth quarter of 2024, in Eiger, which holds non-operated working interests in oil and natural gas assets in the Kansas and the Oklahoma portion of the Hugoton basin. This entity meets the definition of a VIE. NACCO is not the primary beneficiary of the VIE as it does not exercise financial control; therefore, we do not consolidate the results of these operations within our financial statements. Instead, this contract is accounted for as an equity method investment. During 2024, we recorded $0.6 million, which represented our share of earnings, as Earnings of unconsolidated operations on the Consolidated Statements of Operations. Our investment is reported on the line Equity method investment in Eiger, LLC in the Consolidated Balance Sheets. Due to a lag in Eiger's financial reporting, earnings or losses from this investment will be recorded on a one quarter lag.

Excluding the Eiger investment described above, total consideration for the acquisitions of mineral and royalty interests was $0.7 million and $36.7 million, in 2024 and 2023, respectively. The 2024 acquisitions include 13.7 thousand gross acres and 0.6 thousand net royalty acres. The 2023 acquisitions included 43.4 thousand gross acres and 2.5 thousand net royalty acres.

We also manage legacy royalty and mineral interests located in Ohio (Utica and Marcellus shale natural gas), Louisiana (Haynesville shale and Cotton Valley formation natural gas), Texas (Cotton Valley and Austin Chalk formation natural gas), Mississippi (coal), Pennsylvania (coal, coalbed methane and Marcellus shale natural gas), Alabama (coal, coalbed methane and natural gas) and North Dakota (coal, oil and natural gas). The majority of our legacy reserves were acquired as part of our historical coal mining operations.

Total oil and gas mineral and royalty interests include approximately 198.4 thousand gross acres and 63.9 thousand net royalty acres at December 31, 2024. Net royalty acres are calculated based on our ownership and royalty rate, normalized to a standard 1/8th royalty lease, and assumes a 1/4th royalty rate for unleased acres.

See Item 2. Properties on page 29 in this Form 10-K for discussion of our proved reserves.

Customers
The principal customers of the Coal Mining segment are electric utilities and an independent power provider.

The principal customers of the NAMining segment are limestone producers and to a lesser extent, sand and gravel producers. In addition, NAMining will serve as exclusive contract miner for the Thacker Pass lithium project in northern Nevada.

The Minerals Management segment generates income primarily from royalty-based lease payments from oil, gas and to a lesser extent, coal producers. The pricing of oil, gas and coal sales is primarily determined by supply and demand in the marketplace and can fluctuate considerably. As a mineral owner, we have limited access to timely information, involvement, and operational control over the volumes of oil, gas and coal produced and sold and the terms and conditions, including price, on which such volumes are marketed and sold.

In 2024 and 2023, three customers and two customers, respectively, accounted for more than 10% of consolidated revenue. The following represents the revenue attributable to each of these entities as a percentage of consolidated revenue for those years:

Segment	Percentage of Consolidated Revenues	
	2024	2023
Coal Mining customer	**29 %**	40 %
NAMining customer	**24 %**	22 %
NAMining customer	**11 %**	7 %

The loss of any of these customers could have a material adverse effect on the results of operations attributable to the applicable segment and on our consolidated results of operations.

Competition

Coteau, Coyote Creek, Falkirk and MLMC each have only one customer for which they extract and deliver coal. Our coal mines are directly adjacent to our customer’s property, with economical delivery methods that include conveyor belt delivery systems linked to the customer’s facilities or short-haul rail systems. All of the mines in the Coal Mining segment are the most economical suppliers to each of their respective customers as a result of transportation advantages over competitors. In addition, the customers' facilities were specifically designed to use the coal being mined.

The coal industry competes with other sources of energy, particularly oil, gas, hydro-electric power and nuclear power. In addition, it competes with subsidized sources of energy, primarily wind and solar. Among the factors that affect competition are the price and availability of oil and natural gas, environmental and related political considerations, the time and expenditures required to develop new energy sources, the cost of transportation, the cost of compliance with governmental regulations, the impact of federal and state energy policies, the impact of subsidies on pricing of renewable energy and our customers' dispatch decisions, which may also take into account carbon dioxide emissions. The ability of the Coal Mining segment to maintain comparable levels of coal production at existing facilities and develop our reserves will depend upon the interaction of these factors.

Coal-fired electricity generating units are chosen to run primarily based on operating costs, of which fuel costs account for the largest share. Natural gas-fired power plants have the most potential to displace coal-fired electric baseload power generation in the near term. Federal and state mandates for increased use of electricity derived from renewable energy sources could also negatively affect demand for coal. Such mandates, combined with other incentives to use renewable energy sources, such as tax credits, make alternative fuel sources more competitive with coal. Fluctuations in natural gas prices and the availability of renewable energy sources, particularly wind, can contribute to changes in power plant dispatch and customer demand for coal. Over the longer term, we continue to believe that customer demand will remain pressured by regulations mandating or incentivizing the purchase of power from subsidized renewable energy sources, particularly wind and solar. See Item 1. Business — Government Regulation on page 9 in this Form 10-K for further discussion. Environmental, social and governance considerations can also have an impact on power plant dispatch and demand for coal.

Based on industry information, we believe we were one of the ten largest coal producers in the U.S. in 2024 based on total coal tons produced.

NACCO believes that we were the largest dragline operator in the U.S. in 2024.

NAMining faces competition from producers of aggregates, lithium or other minerals that choose to self-perform mining operations and from other mining companies.

In the Minerals Management segment, the oil and gas industry is intensely competitive; we primarily compete with companies and investors for the acquisition of oil and gas properties, some of which have greater resources and may be able to pay more for productive oil and natural gas properties or to define, evaluate, bid for and purchase a greater number of properties than our financial resources permit. Additionally, many of the Minerals Management segment's competitors are, or are affiliated with, operators that engage in the exploration and production of their oil and gas properties, which allows them to acquire larger assets that include operated properties. Larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. The integrated competitors may also have a better understanding of when minerals they acquire will be developed, as they are often the developer. The Minerals Management segment’s ability to acquire additional properties in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Further, oil and natural gas compete with other forms of energy available to customers, primarily based on price. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations, and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Seasonality

We have experienced limited variability in our results due to the effect of seasonality; however, variations in coal demand can occur as a result of the timing and duration of planned or unplanned outages at our customers' facilities. Variations in coal demand can also occur as a result of changes in market prices of competing fuels such as natural gas, wind and solar power and demand for electricity, which can fluctuate based on changes in weather patterns. In addition, demand for coal-fired power generation can increase due to unusually hot or cold weather as consumers use more air conditioning or heating, respectively. Conversely, mild weather can result in weaker demand for coal-fired power generation.

The NAMining segment extracts a significant amount of the annual limestone produced in Florida. The Florida construction industry can be affected by the cyclicality of the economy, seasonal weather conditions, significant weather events, and pandemics, all of which can result in variations in demand for aggregates.

In the Minerals Management segment, oil and natural gas wells have high initial production rates and follow a natural decline before settling into relatively stable, long-term production. Decline rates can vary due to factors like well depth, well length, geology, formation pressure, and facility design. In addition to the natural production decline curve, royalty income can fluctuate favorably or unfavorably in response to a number of factors outside of our control, including the number of wells being operated by third parties, fluctuations in commodity prices (primarily oil and natural gas), fluctuations in production rates associated with operator decisions, regulatory risks, our lessees' willingness and ability to incur well-development and other operating costs, and changes in the availability and continuing development of infrastructure.

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices during the first and fourth quarters. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions can limit drilling and producing activities and other oil and natural gas operations. Due to these seasonal fluctuations, Minerals Management results of operations for individual quarterly periods may not be indicative of the results that may be realize on an annual basis.

Human Capital

As of December 31, 2024, we had approximately 1,700 employees, including approximately 1,100 employees at our unconsolidated mining operations, none of which are represented by a collective bargaining agreement. NACCO believes we have good relations with our employees.

Market-Based Compensation: We believe our employees are critical to our success and we invest in our employees by offering a market-based competitive total rewards package that includes a combination of salaries and wages and a benefits package that promotes employee well-being across all aspects of their lives. We offer a 100% 401(k) matching contribution up to 5% of compensation, which is immediately vested. Additionally, NACCO offers a generous profit-sharing contribution for all of our full-time and part-time employees. We provide employee wages that are competitive and consistent with employee positions, skill levels, experience, knowledge and geographic location. Benefits offered to employees include:

- Medical, dental and vision benefits for employees, spouses and dependents;
- Flexible spending accounts for both healthcare and dependent care;
- Health savings accounts and health reimbursement accounts, both of which receive company contributions;
- Paid vacation and holidays;
- Parental leave;
- Short-term and long-term disability benefits;
- Wellness incentives for employees;
- Life and AD&D insurance benefits;
- Identity protection benefits;
- Charitable donation matches; and
- Employee assistance program.

Employee Development: We recognize that our culture and success is strengthened when employees are respected, motivated and engaged. We work to match employees with assignments that capitalize on the skills, talents and potential of each employee, and provides opportunities for professional growth. NACCO believes training is a critical component of employee well-being and growth. Training ranges from equipment-specific task training and enhanced safety procedures to strategic leadership and management training, ethics training and role-specific training. Employees are encouraged to pursue continued professional development, skills training and other educational opportunities. Qualified employees are eligible to participate in a tuition reimbursement program to advance their formal education. We believe in hiring, engaging, developing and promoting people who are fully able to meet the demands of each position, regardless of race, color, religion, gender, sexual orientation, gender identity, national origin, age, veteran status or disability.

Safety: Employee safety in the workplace is one of our core values. We are committed to strict compliance with applicable laws and regulations regarding workplace safety and provides on-going safety training, education and communication. The National Mining Association ranks NACCO as an industry leader in safety, and our incident rate is consistently below the national average for comparable mines, based on Mine Safety and Health Administration data. We have earned more than 100 safety awards at the state and national levels since the 1980s. NACCO strives to have zero safety incidents or injuries. Our operations have onsite safety personnel who train employees in safe work practices, review safety-related incidents and recommend improvements when appropriate. Hazards in the workplace are actively identified and management tracks incidents so remedial actions can be taken to improve workplace safety. We believe communication related to near misses, safety incidents and protocols is essential to continuously developing and maintaining best-practices related to safety and enables identification and correction of operational practices that might impair employee safety or health. Every employee is responsible and accountable for safety performance.

Company Ethics: We have processes in place for compliance with our Code of Corporate Conduct, Insider Trading Policy and Anti-Corruption Policy. All of our Directors and employees annually complete certifications with respect to compliance with our Code of Corporate Conduct. In addition, all of our employees are required to complete annual Code of Corporate Conduct training. The Code of Corporate Conduct, Insider Trading Policy and Anti-Corruption Policy require employees to comply with applicable laws and regulations, maintain high ethical standards and report situations of actual or potential noncompliance. All NACCO personnel are required to report without delay any conduct which they believe to be illegal or a violation of our policies. The identity of any NACCO personnel making such a report is kept in strict confidence except as required by law, and we utilize a third-party hotline to ensure reports can be generated anonymously. Retaliation in any form against an individual who exercises their right to make a complaint in good faith is strictly prohibited.

Community Engagement: We value our local communities and provide support through volunteer activities, financial contributions and well-paying jobs. NACCO believes in making long-term investments in the areas where we operate by supporting numerous charitable efforts, including educational, arts and community organizations. Community engagement is encouraged and supported through our matching gift program. We will match employee contributions up to $5,000 per employee if program criteria are met.

Please visit nacco.com/stewardship/ for the full text of certain NACCO stewardship policies.

Available Information

We make 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 available through our website, www.nacco.com, as soon as reasonably practicable after such material is electronically filed with, or furnished to, the Securities and Exchange Commission (SEC). The content of our website is not incorporated by reference into this Form 10-K or in any other report or document filed with the SEC, and any reference to our website is intended to be an inactive textual reference only. The SEC maintains an internet site at http://www.sec.gov that contains reports, proxy and information statements, and other information regarding us and other issuers that file electronically with the SEC.

Under Rule 12b-2 of the Exchange Act, we qualify as a smaller reporting company because our public float as of the last business day of our most recently completed second quarter was less than $250 million. For as long as we remain a smaller reporting company, we may take advantage of certain exemptions from the SEC’s reporting requirements that are otherwise applicable to public companies that are not smaller reporting companies.

Government Regulation
Our operations are subject to various federal, state and local laws and regulations on matters such as employee health and safety, and certain environmental laws and regulations relating to, among other matters, the reclamation and restoration of coal mining properties, air pollution, water pollution, the disposal of wastes and effects on groundwater. In addition, the electric power generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities that could affect demand for coal from our Coal Mining segment.

Numerous federal, state and local governmental permits and approvals are required for coal mining operations. Our subsidiaries hold or will hold the necessary permits at all of our lignite coal mining operations. At the coal mining operations where our subsidiaries hold the permits, we are required to prepare and present to federal, state or local governmental authorities data pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment and public and employee health and safety.

Many aspects of the production, pricing and marketing of oil and natural gas are regulated by federal and state agencies. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, which frequently increases the regulatory burden on affected members of the industry and could affect the results of Minerals Management segment.

Mine Health and Safety Laws
The Federal Mine Safety and Health Act of 1977 imposes safety and health standards on all mining operations. Regulations are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters. The Federal Mine Safety and Health Administration enforces compliance with these federal laws and regulations.

Environmental Laws
Our coal mining operations are subject to various federal environmental laws, as amended, including:
- the Surface Mining Control and Reclamation Act of 1977 (SMCRA);
- the Clean Air Act, including amendments to that act in 1990 (CAA);
- the Clean Water Act of 1972 (CWA);
- the Resource Conservation and Recovery Act (RCRA);
- the National Environmental Policy Act of 1970 (NEPA); and
- the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA).

In addition to these federal environmental laws, various states have enacted environmental laws that provide for higher levels of environmental compliance than similar federal laws. These state environmental laws require reporting, permitting and/or approval of many aspects of coal mining operations. Both federal and state inspectors regularly visit mines to enforce compliance. We have ongoing training, compliance and permitting programs to ensure compliance with such environmental laws. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect the Coal Mining segment.

The election of Donald Trump, paired with Republican control of Congress, is likely to have a significant and favorable impact on the regulatory environment, particularly for fossil fuels. President Trump issued an Executive Order on January 20, 2025, "Unleashing American Energy," directing all federal executive agency heads to review all agency actions implicating energy reliability and affordability or potentially burdening the development of domestic energy resources. It is not yet clear how existing regulations affecting existing fossil fuel assets will be reconsidered or repealed.

Surface Mining Control and Reclamation Act
SMCRA establishes mining, environmental protection and reclamation standards for all aspects of surface coal mining operations. Where state regulatory agencies have adopted federal mining programs under SMCRA, the state becomes the primary regulatory authority.

Coal mine operators must obtain SMCRA permits and permit renewals for coal mining operations from the applicable regulatory agency. These SMCRA permit provisions include requirements for coal prospecting, mine plan development, topsoil removal, storage and replacement, selective handling of overburden materials, mine pit backfilling and grading, protection of the hydrologic balance, surface drainage control, mine drainage and mine discharge control and treatment, and revegetation. Although mining permits have stated expiration dates, SMCRA provides for a right of successive renewal. The cost of obtaining surface mining permits can vary widely depending on the quantity and type of information that must be provided to obtain the permits.

SMCRA establishes operational, reclamation and closure standards for surface coal mines. We accrue for the costs of final mine closure, including the cost of treating mine water discharges, at mines where our subsidiaries hold the mining permit. While these obligations are largely unfunded, they can require securitization through bonding, with the exception of the final mine closure costs for the Coyote Creek Mine, which are being funded throughout the production stage.

SMCRA stipulates compliance with many other major environmental programs, including the CAA and CWA. The U.S. Army Corps of Engineers regulates activities affecting navigable waters, and the U.S. Bureau of Alcohol, Tobacco and Firearms regulates the use of explosives for blasting. In addition, the U.S. Environmental Protection Agency (the EPA), the U.S. Army Corps of Engineers and the Office of Surface Mining Reclamation and Enforcement (OSMRE) have engaged in a series of rulemakings and other administrative actions under the CWA and other statutes that are directed at reducing the impact of coal mining operations on water bodies.

Greenhouse Gas (GHG) Emissions
The process of burning coal can cause many compounds and impurities in the coal to be released into the air, including sulfur dioxide, nitrogen oxides (NOx), mercury, particulates and other matter. Federal and state laws that extensively regulate the emissions of materials into the air affect coal mining operations both directly and indirectly. Direct impacts on coal mining operations occur through permitting requirements and/or emission control requirements relating to air contaminants, especially particulate matter. Indirect impacts on coal mining operations occur through regulation of the air emissions of sulfur dioxide, nitrogen oxides, mercury, particulate matter and other compounds emitted by coal-fired power plants.

In May 2024, the EPA published the final rules for GHG emissions and Mercury Air Toxics Standards (MATS) in the Federal Register. The final MATS and GHG rules will require compliance as early as 2027 and 2032, respectively.

Previous efforts by the EPA were met with extensive litigation and there has been a similar response to the new GHG and MATS rules. State coalitions have filed lawsuits challenging both of these rules. Several other entities, including electric generators and industry groups, have joined the lawsuits. In July 2024 and October 2024, stay motions for the GHG and MATS rules were denied by the U.S. Court of Appeals for the District of Columbia Circuit (the D.C. Circuit Court), respectively. Following the D.C. Circuit Court denial, emergency stay motions were filed for the GHG and MATS rules with the Supreme Court of the United States (SCOTUS). In October 2024, the SCOTUS denied the stay applications for the GHG and MATS rules. The GHG and MATS cases continue through the normal procedures in the D.C. Circuit Court without stays in place. On February 19, 2025, the D.C. Circuit granted an EPA motion to hold the GHG case in abeyance for 60 days while the new EPA evaluates its position on the GHG rule. Similarly, on February 20, 2025, the D.C. Circuit granted an EPA motion to hold the MATS case in abeyance and removing the case from the upcoming oral argument calendar while the new EPA evaluates its position on the MATS rule. We cannot predict the full impact of the MATS and GHG rules on the operations of the coal-fired generation facilities operated by our customers; however, if the rules go into effect, the additional compliance costs could have a material adverse effect on our Coal Mining segment.

The GHG standards are based on technologies such as carbon capture and sequestration/storage and natural gas co-firing. The compliance deadline for existing coal-fired, steam generating electric generating units (EGUs) planning to install carbon capture and sequestration/storage technology has been extended to January 1, 2032 for plants that intend to operate beyond 2039. If a coal-fired plant intends to close prior to 2032, no controls will be required and if a plant plans to close between 2032 and 2039, they must begin co-firing with natural gas by January 1, 2030.

The MATS rules finalize changes for the filterable particulate matter surrogate emission standard for non-mercury metal hazardous air pollutants for existing coal-fired EGUs, the filterable particulate matter emission standard compliance demonstration requirements, and the mercury emission standard for lignite-fired EGUs. Review of the MATS rules indicate that the EPA significantly reduced the fine particulate matter emission standard for all existing coal-fired EGUs and will require continuous monitoring equipment to demonstrate compliance. Furthermore, the EPA elected to remove the lignite subcategory for mercury limits and will require lignite-fired EGUs to meet the same standard as other types of coal.

The recent change in presidential administrations, recent executive actions, and the resulting changes at the EPA make it unclear whether the promulgated GHG or MATS Rules will be enforced, revised, or repealed. The various parties are working through the legal and administrative processes and the actual outcome remains unknown at this time.

The CAA requires the EPA to review national ambient air quality standards (NAAQS) every five years to determine whether revisions to current standards are appropriate. In addition, states are required to submit to the EPA revisions to their state implementation plans (SIPs) that demonstrate the manner in which the states will attain NAAQS every time a NAAQS is issued or revised by the EPA. The EPA has adopted NAAQS for several pollutants, which continue to be reviewed periodically for revisions. When the EPA adopts new, more stringent NAAQS for a pollutant, some states have to change their existing SIPs. If a state fails to revise its SIP and obtain EPA approval, the EPA may adopt regulations to affect the revision. Coal mining operations and coal-fired power plants that emit particulate matter or other specified material are, therefore, affected by changes in the SIPs. Through this process over the last few years, the EPA has reduced the NAAQS for particulate matter, ozone and nitrogen oxides. Our coal mining operations and power generation customers may be directly affected when the revisions to the SIPs are made and incorporate new NAAQS for sulfur dioxide, nitrogen oxides, ozone and particulate matter. In March 2019, the EPA published a final rule that retains the current primary (health-based) NAAQS for sulfur oxides (SOx) without revision. On May 6, 2024, the EPA lowered the level for particulate matter by 25%. States are required to update their state implementation plans by February 2027. The rule is currently being challenged at the D.C. Circuit by a coalition of states led by Kentucky and West Virginia. Oral argument was held at the D.C. Circuit on December 16, 2024.

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to address interstate transport of pollutants. While the CSAPR affects states in the eastern half of the U.S. and Texas, it does not affect EGUs in North Dakota. This rule imposes
additional emission restrictions on coal-fired power plants to attain ozone and fine particulate NAAQS. The EPA began
implementation of the rule in 2015, when Phase I emission reductions in sulfur dioxide and nitrogen dioxide became effective.
In 2019, certain states submitted SIPs to the EPA in response to the 2015 ozone standard reduction. On February 13, 2023, the EPA rejected the SIPs. The EPA's action to deny the SIPs was challenged in various courts, including the 5th Circuit Court of Appeals (the Fifth Circuit). The Fifth Circuit issued a stay of the SIP rejection in Texas, Louisiana, and Mississippi which prevents the federal implementation plan (FIP) from going into effect pending the outcome of the litigation challenges.

On June 5, 2023, the EPA published the FIP in the Federal Register. The FIP decreases, over time, the ozone-season NOx allowances allocated to generators in the states not affected by the judicial stay beginning in 2024 by assuming that participants in this cap-and-trade program had or would optimize existing NOx controls and later install additional NOx controls. On July 31, 2023, the EPA promulgated an interim rule (Interim FIP) that addresses the various judicial orders where the SIP rejection has been stayed. The Interim FIP requires these states to return to the previously approved NOx trading program and emission caps. The Interim FIP maintains the state emissions budgets, unit level allowance allocation provisions, and banked allowance holdings reflecting the status quo for the power plants in these states under the Group 2 trading program.

In June 2024, the SCOTUS decided to stay the rule pending further review on the merits because the EPA's justifications were flawed. The Ozone Transport Rule was premised on its applicability to 23 states, but litigation resulted in the removal of 12 of those states that accounted for over 70 percent of the emissions the EPA had planned to address. The EPA purported to select control measures that would maximize cost effectiveness in achieving downwind ozone air quality improvements, but it did so based on an assumption that all 23 states would apply the uniform levels of controls required by the FIP. The case was remanded to the D.C. Circuit where the parties fully briefed the case. Subsequent to briefing, the EPA asked to partially remand the rule to "take a supplemental final action addressing the record deficiency preliminarily identified by the Supreme Court." The EPA finalized the supplemental response in December 2024. On February 6, 2025, the EPA filed a motion requesting abeyance of litigation for 60 days to allow a transition to the new administration. On February 21, 2025, the D.C. Circuit denied the EPA's request to hold the litigation in abeyance and extending the briefing schedule through March 27, 2025.

Should the FIP be fully implemented in states where a stay has been issued, the rule could influence the closure of some coal-fired EGUs that have not installed selective catalytic reduction technologies, potentially including the EGU supplied by MLMC. We cannot predict the outcome of the legal challenges to the: (i) various state challenges; (ii) the FIP promulgated on June 5, 2023; (iii) the interim final rule promulgated on July 31, 2023; nor (iv) the supplemental response dated December 10, 2024 that seeks to address the judicial orders. If the original FIP withstands legal challenge, it would increase the cost of operating the customer facility serviced by MLMC.

The EPA promulgated a regional haze program designed to protect and to improve visibility at and around Class I Areas, which are generally National Parks, National Wilderness Areas and International Parks. State implementation of the EPA's Regional Haze Rule could require our North Dakota customers to incur significant new costs at their respective power plants, which could result in the premature closure of such power plants and their associated mines. The North Dakota Department of Environmental Quality (NDDEQ) finalized its state implementation plan and submitted it to the EPA for approval in August 2022. The NDDEQ determined that visibility progress was being made and did not require significant emissions controls at the North Dakota power plants. In July 2024, the EPA issued a proposed partial denial of the state implementation plan. We submitted comments to the EPA on the proposed partial denial during the third quarter of 2024 and have filed a petition for review with the Eight Circuit Court of Appeals. The State of North Dakota, several of our customers, and others have also filed petitions for review. On February 27, 2025, the EPA filed an unopposed motion to hold these consolidated cases in abeyance for 120 days while the new administration evaluates its position on the partial denial of the state implementation plan. Notwithstanding NDDEQ's determination, the EPA may require additional costly emission controls and it may not be economically feasible for our North Dakota customers to invest in such equipment, which could result in early retirement of our customers' power plants and our associated mines.

Substantially all of the Coal Mining segment's profits are derived from long-term mining contracts. These new rules may raise the cost of fossil fuel generated energy, making coal-fired power plants less competitive, and/or result in early closure of the coal-fired EGU's operated by our customers which could have an adverse impact on demand for coal and ultimately result in the early closure of the mines servicing these plants, including closure of our coal mines. We cannot predict the full impact of the various GHG and CAA rules on the operations of the coal-fired EGUs operated by our customers and any early closure of our mines could have a material adverse effect on our business, financial condition and results of operations.

The Trump administration is expected to direct the EPA to reconsider and revise or rescind the EPA's rules regulating emissions from power plants, among other regulatory actions affecting power generation, and has already issued executive orders aimed at this outcome. President Trump issued an Executive Order on January 20, 2025, "Unleashing American Energy," directing all federal executive agency heads to review all agency actions implicating energy reliability and affordability or potentially burdening the development of domestic energy resources. It is not yet clear how existing regulations affecting existing fossil fuel assets will be reconsidered or repealed. Although we anticipate the EPA's review of such regulations likely will result in less stringent requirements, we cannot predict the outcome of any final EPA actions or court challenges to such final actions.

Clean Water Act
CWA affects coal mining operations by establishing in-stream water quality standards and treatment standards for wastewater discharge, including from coal mines.

In many instances, mining operations require securing CWA authorization or a permit from the U.S. Army Corps of Engineers for operations in waters of the United States (WOTUS.) On May 25, 2023, the SCOTUS issued its Sackett vs. EPA ruling that defined WOTUS as "a relatively permanent body of water connected to traditional interstate navigable waters" with a "continuous surface connection with that water, making it difficult to determine where the 'water' ends and the 'wetland' begins." As a result of the Sackett decision, the EPA and the Army Corps of Engineers authored a revised definition of WOTUS and promulgated a final rule. The new rule does not go into effect in states where a stay had been issued for the previous rule, including North Dakota, Texas, Louisiana, and Mississippi. In these states, the legal challenges to this rule have resumed. In the meantime, securing CWA permits may be more challenging since the agencies in the states where a stay has been issued have less guidance to rely on to determine whether certain features are considered WOTUS. To the extent the implementation of the final rule, results of the litigation, or any further action expands the scope of jurisdiction, it may impose greater compliance costs or operational requirements on our coal mining operations.

Bellaire is treating mine water drainage from coal refuse piles associated with former underground coal mines in Ohio and Pennsylvania and is treating mine water from a former underground coal mine in Pennsylvania. Bellaire anticipates that it will need to continue these activities indefinitely. In 2004, Bellaire was notified by the Pennsylvania Department of Environmental Protection that it was required to establish a mine water treatment trust to serve as a long-term funding mechanism related to this obligation. See Note 7 and Note 9 to the Consolidated Financial Statements in this Form 10-K for further information on Bellaire.

These federal and state requirements could require more costly water treatment and could materially adversely affect our business, financial condition and results of operations.

Resource Conservation and Recovery Act
RCRA affects coal mining operations by establishing requirements for the treatment, storage and disposal of wastes, including hazardous wastes. Coal mine wastes, such as overburden and coal cleaning wastes, currently are exempted from hazardous waste management. In 2020, the EPA finalized changes to the coal combustion residual (CCR) rule that classified all clay-lined surface impoundments that receive CCR as unlined. The EPA also established alternative deadlines to cease receipt of waste to include new site-specific alternatives due to lack of disposal capacity with a deadline to initiate closure and a new site-specific alternative due to permanent cessation of coal-fired boilers with deadlines to complete closure.

In May 2023, the EPA published proposed regulations that would impose federal regulatory requirements for previously exempt inactive CCR surface impoundments at inactive facilities (legacy CCR surface impoundments). In May 2024, the EPA published a final rule amending CCR regulations which introduces new requirements for the management of coal ash at active coal-fired power plants and inactive coal-fired power plants with a legacy surface impoundment. The regulations impose new requirements including groundwater monitoring, closure standards, post-closure care obligations, and potential remediation activities.

These rules may raise the cost for CCR disposal at coal-fired power plants, making them less competitive, and/or result in early closure which could have an adverse impact on demand for coal and ultimately result in the early closure of the mines servicing these plants, including closure of our mines. Any such closure of our mines could have a material adverse effect on our business, financial condition and results of operations.

In compliance with these regulations, Falkirk's customer, the owner of the Coal Creek Station power plant, submitted a CCR Part B application to the EPA in 2020 asserting a unit complied with the CCR rules. In the first quarter of 2023, the EPA proposed to deny the owner's application. The owner and other parties have submitted additional information and comments supporting the owner's position. If the EPA ultimately denies the owner's application, a new liner may need to be installed or new waste management processes and/or units may need to be constructed. Accordingly, it is possible that a denial by the EPA could require a temporary unit shut down. Any temporary unit shut down could result in a temporary suspension of operations at Coal Creek Station. To minimize any impact to operations, Coal Creek Station continues to work with the EPA and is moving forward with plans to dry CCR materials produced by the plant, reducing the need to utilize the lined area in question. Falkirk is the sole supplier of lignite coal to Coal Creek Station. Any suspension of operations at Coal Creek Station would eliminate the need for lignite coal during the suspension period. Any such suspension of operations at Coal Creek Station or any of the power plants supplied by our mines could have a material adverse effect on our business, financial condition and results of operations.

National Environmental Policy Act

NEPA requires federal agencies to review the environmental impacts of their decisions and issue either an environmental assessment or an environmental impact statement. There are certain actions associated with surface coal mining that may trigger these types of assessments by federal agencies. When a NEPA action is required, we provide the required information to the appropriate federal agency to enable it to complete the required study. Historically, this process has been lengthy and may take several years to complete. In January 2023, the White House Council on Environmental Quality (CEQ) issued interim guidance that instructs federal agencies to quantify GHG emissions and use the social cost of greenhouse gases to calculate a monetary metric associated with the proposed actions' climate effects. The NEPA and interim guidance could adversely affect our ability to secure necessary permits.

On June 3, 2023, President Biden signed the Fiscal Responsibility Act of 2023 into law, which included certain provisions collectively known as the Builder Act. The Builder Act includes amendments to NEPA which codify past regulatory reforms, including narrowing what qualifies as a major federal action, limiting the scope of NEPA review to "reasonably foreseeable environmental effects," narrowing consideration of cumulative effects, directing agencies to only consider technically and economically feasible reasonable alternatives and providing page limits and timelines for environmental impact statements and environmental assessments. In April 2024, the CEQ finalized the revised NEPA rules.

On February 16, 2025, CEQ issued a notice that it intends to rescind all CEQ NEPA implementing regulations. These actions have raised significant questions regarding how CEQ's NEPA regulations and agency-specific NEPA procedures will be interpreted and enforced going forward. We are unable to predict what impact the new CEQ guidance will have on our ability to obtain governmental permits.

Federal Coal Leasing

We enter into leases of Federally owned coal for a small portion of the coal mined at certain of our North Dakota mines. In July 2024, the Department of Interior's Bureau of Land Management (BLM) published its North Dakota Proposed Resource Management Plan (RMP), which provided that no Federal coal which lies more than four miles away from a currently existing surface coal mining permit will be available for future leasing in North Dakota. In September 2024, the Company, along with other stakeholders, including the Governor of North Dakota, filed protests against the RMP. The BLM denied the protests and published the final RMP in January 2025. The State of North Dakota filed a challenge to the RMP in the United States District Court for the District of North Dakota on February 25, 2025. We are currently evaluating a similar challenge. If any such challenges are not successful, we may be required to alter our mine plans to avoid areas of Federal coal in the future.

Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases the cost of doing business, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar assets.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation of oil and natural gas and the sale or resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission (FERC). Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the Minerals Management segment. Sales of crude oil, condensate and natural gas liquids (NGLs) are not currently regulated and are made at market prices.

Environmental Matters

Oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. These laws and regulations have the potential to impact production on our mineral interests, which could materially adversely affect the Minerals Management segment. Numerous federal, state and local governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing earthen pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from operations. The strict, joint and several liability nature of such laws and regulations could impose liability upon the operators on our mineral interests, regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

In December 2023, EPA finalized a rule that will require oil and gas producers to reduce methane and other air pollutants from existing sources. Oil and gas companies will be required to phase out routine flaring of natural gas and install methane leak detection equipment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect the Minerals Management segment.

In May 2024, the EPA finalized a rule containing revisions and additions to the New Source Performance Standards (NSPS) program rules (the Final Methane Rule). The Final Methane Rule formally reinstates emission limitations on methane, a GHG emission, for existing and modified facilities in the oil and gas sector. Specifically, the Final Methane Rule requires states to implement plans that meet or exceed federally established emission reduction guidelines for oil and natural gas facilities. Several states and industry groups have filed suit before the D.C. Circuit challenging the Final Methane Rule. On October 4, 2024, the SCOTUS denied applications for an immediate stay of the Final Methane Rule pending review by the D.C. Circuit Court of Appeals. Though the final outcome is uncertain, the rule establishes standards of performance for sources that commence construction, modification or reconstruction after March 8, 2024, and establishes emissions guidelines that will inform state plans to establish standards for existing sources. The Final Methane Rule could have a significant impact on the upstream and midstream oil and gas sectors.

In November 2024, the EPA announced a final rule to reduce methane emissions from the oil and gas sector. The rule requires payment of a Waste Emissions Charge (WEC) on waste emissions of methane from certain oil and gas facilities. The Inflation Reduction Act-mandated fee would be triggered when companies report more than 25 metric tons of carbon dioxide equivalent per year to the EPA's Greenhouse Gas Reporting Program. The fee begins at $900 per metric ton of methane exceeding that threshold in 2024 and increases over time. A petition for review was filed in January 2025 by a coalition of Texas-led states and other industry groups. The fee could have a significant impact on the upstream and midstream oil and gas sectors.

Drilling and Production

The operations of the Minerals Management segment's third-party lessees and our equity method investee are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and generating reports concerning operations. The states, and some counties and municipalities, in which we have mineral interests also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas that the lessees of our mineral interests can produce from existing wells or limit the number of wells or the locations at which operators can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but the effect of any future regulations could have a material effect on the Minerals Management segment. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our mineral interests, negatively affect the economics of production from these wells or limit the number of locations operators can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where the operators of the acreage underlying our mineral and royalty interests operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the U.S. Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

On January 20, 2025, President Trump issued several executive orders that prioritized energy security, exploration and production on federal lands and processing of Liquefied Natural Gas export applications. Implementation of these executive orders could positively impact domestic drilling and production of oil and natural gas.

Regulation of Hydraulic Fracturing

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The CWA regulates the underground injection of substances through the Underground Injection Control (UIC) program. Hydraulic fracturing generally is exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions.

Several states, including Texas, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Legislature previously adopted legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission subsequently adopted rules and regulations implementing this legislation that apply to all wells for which the Railroad Commission issues an initial drilling permit. This law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the Occupational Safety and Health Act for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Further, in May 2013, the Texas Railroad Commission issued a well integrity rule, which updates the requirements for drilling, putting pipe down, and cementing wells. The rule also includes new testing and reporting requirements, such as: (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later; and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative or regulatory changes could cause operators of the operation on the acreage underlying our mineral interests, including those held by our equity method investee, to incur substantial compliance costs, and compliance or the consequences of any failure to comply by operators could have a material adverse effect on the Minerals Management segment.

In addition, hydraulic fracturing operations require the use of a significant amount of water, and the inability of the operators of the acreage underlying our mineral interests to locate sufficient amounts of water or dispose of or recycle water used in their drilling and production operations could adversely impact their operations. Moreover, new environmental initiatives and regulations could include restrictions on the ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the development or production of natural gas.

In some instances, the operation of underground injection wells has been alleged to cause earthquakes. Such issues have sometimes led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. Future orders or regulations addressing concerns about seismic activity from well injection could affect operations on the acreage underlying our mineral interests or our equity method investment.

Endangered Species Act
The Endangered Species Act (ESA) and analogous state laws restrict activities that may affect endangered or threatened species or their habitats. Pursuant to a settlement with environmental groups, the U.S. Fish and Wildlife Service (USFWS) was required to determine whether over 250 species required listing as threatened or endangered under the ESA. USFWS has not yet completed its review, but the potential remains for new species to be listed under the ESA. Some of our properties or mineral interests may be located in areas that are or may be designated as habitats for endangered or threatened species, and previously unprotected species may later be designated as threatened or endangered in areas where we hold interests. For example, recently, there have been renewed calls to review protections currently in place for the Dunes Sagebrush Lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. Likewise, there have been calls to review protections in place for the Greater Sage Grouse, which can be found across a large swath of the northwestern United States in oil and gas producing states. The listing of either of these species, or any others, in areas where we hold mineral interests could cause lessees to incur increased costs arising from species protection measures, delay the completion of exploration and production activities, and/or result in limitations on operating activities that could have an adverse impact the Minerals Management segment.

Natural Gas Sales and Transportation
Historically, federal legislation and regulatory controls have affected the price and marketing of natural gas. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in first sales. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which operators may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that operators produce, as well as the revenues operators receive for sales of natural gas and release of natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC’s initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on natural gas-related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in-state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. Although its policy is still in flux, FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase operators' costs of transporting gas to point-of-sale locations.

Oil Sales and Transportation
Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by portioning provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to our operators to the same extent as they are to our competitors.

State Regulation
States regulate the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowable from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot be certain that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from wells and to limit the number of drilled wells or locations of our third-party lessee operators or of our equity method investment.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on our results of operations or financial condition.

Comprehensive Environmental Response, Compensation and Liability Act
CERCLA and similar state laws create liabilities for the investigation and remediation of releases of hazardous substances into the environment and for damages to natural resources. We must also comply with reporting requirements under the Emergency Planning and Community Right-to-Know Act and the Toxic Substances Control Act.

From time to time, we have been the subject of administrative proceedings, litigation and investigations relating to environmental matters. The extent of the liability and the cost of complying with environmental laws cannot be predicted with certainty due to many factors, including the lack of specific information available with respect to many sites, the potential for new or changed laws and regulations, the development of new remediation technologies and the uncertainty regarding the timing of work with respect to particular sites. As a result, we may incur material liabilities or costs related to environmental matters in the future, and such environmental liabilities or costs could materially and adversely affect our results of operations and financial condition. In addition, there can be no assurance that changes in laws or regulations would not affect the manner in which we are required to conduct our operations.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The following tables set forth as of March 1, 2025 the name, age, current position and principal occupation and employment during the past five years of our executive officers. There exists no arrangement or understanding between any executive officer and any other person pursuant to which such executive officer was selected.

EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Current Position
J.C. Butler, Jr.	64	President and Chief Executive Officer of NACCO and President and Chief Executive Officer of NACCO Natural Resources Corporation (NNRC) (from prior to 2019)
Elizabeth I. Loveman	55	Senior Vice President and Controller and Principal Financial Officer (from prior to 2019)
John D. Neumann	49	Senior Vice President, General Counsel and Secretary of NACCO, Senior Vice President, General Counsel and Secretary of NNRC (from prior to 2019)
Thomas A. Maxwell	47	Senior Vice President - Financial Planning and Analysis and Treasurer (from prior to 2019)

PRINCIPAL OFFICERS OF THE COMPANY'S SUBSIDIARIES

Name	Age	Current Position
J.C. Butler, Jr.	64	President and Chief Executive Officer of NACCO and President and Chief Executive Officer of NNRC (from prior to 2019)
Carroll L. Dewing	68	Senior Vice President and Chief Operating Officer of NNRC (from prior to 2019)
John D. Neumann	49	Senior Vice President, General Counsel and Secretary of NACCO, Senior Vice President, General Counsel and Secretary of NNRC (from prior to 2019)
J. Patrick Sullivan, Jr.	66	Senior Vice President and Chief Financial Officer of NNRC (from prior to 2019)

Item 1A. RISK FACTORS

We operate in a rapidly changing environment that involves a number of risks. The following discussion highlights some of these risks and others are discussed elsewhere in this report. These and other risks could materially and adversely affect our business, financial condition, operating results or cash flows. The following risk factors are not an exhaustive list of the risks associated with our business. New factors may emerge or changes to these risks could occur that could materially affect our business.

Risks related to the Coal Mining segment

Termination of or default under long-term mining contracts could adversely affect our business, financial condition, results of operation and cash flows.
Substantially all of the Coal Mining segment's profits are derived from long-term mining contracts. Although we have long-term contracts, numerous regulatory authorities, along with well-funded political and environmental activist groups, are devoting substantial resources to anti-coal activities to minimize or eliminate the use of coal as a source of electricity generation. Any customer's premature facility closure or contract default could have a material adverse effect on our business, financial condition and results of operations.

The coal mining industry is subject to ongoing complex governmental regulations and legislation that could adversely impact our long-term mining contracts and our results of operations, liquidity, financial condition and cash flow.
The coal mining industry and the electric generation industry are subject to extensive regulation by federal, state and local authorities on matters concerning the health and safety of employees, land use, stream and wetland protection, permit and licensing requirements, air and water quality standards, plant and wildlife protection, reclamation and restoration of mining properties after mining, the discharge of GHGs and other materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Legislation mandating certain benefits for current and retired coal miners also affects the industry. Mining operations require numerous governmental and regulatory permits and approvals. We are required to prepare and present to federal, state or local authorities data pertaining to the impact the production and combustion of coal may have upon the environment. The public, including non-governmental organizations, opposition groups and individuals, have statutory rights to comment upon and submit objections to requested permits and

approvals and to legally challenge certain permits subsequent to their issuance. Compliance with these requirements is costly and time-consuming and may delay commencement or continuation of development or production. New legislation and/or regulations and orders may materially adversely affect our mining operations, cost structure or customers. All of these factors could significantly reduce our profitability.

Congress has considered climate change legislation aimed at reducing GHG emissions, particularly from coal combustion by power plants. Enactment of laws and passage of regulations regarding GHG emissions at the federal or state level, or other actions to limit carbon dioxide emissions, such as opposition by environmental groups of coal-fired power plants, could result in electric generators switching from coal to other fuel sources or premature facility closures.

Congress continues to consider a variety of proposals to reduce GHG emissions from the combustion of coal and other fuels. These proposals include emission taxes, emission reductions, including carbon tax and cap-and-trade programs, and mandates or incentives to generate electricity by using renewable energy sources, such as wind or solar power. Some states have established programs to reduce GHG emissions. Further, certain governmental agencies provide grants or other financial incentives to entities developing or selling alternative energy sources with lower levels of GHG emissions, which may lead to more competition from those entities.

The potential impact on us of future laws, regulations or other policies or circumstances will depend upon the degree to which any such laws, regulations or other policies or circumstances require electricity generators to diminish their reliance on coal as a fuel source. Complicating these matters further, over the last several decades, U.S. Administrations have increasingly relied on regulations and executive orders to implement environmental policies and objectives in the absence of Congressional agreement regarding new legislation. This condition, which creates instability and unpredictability of environmental regulations, seems likely to persist and could increase due to apparent polarization between the two main political parties. As a result, we and/or our customers, often must comply with and otherwise adapt to environmental regulations without assurance of their continued effect. We and/or our customers often do not have the ability to anticipate, or prepare in advance for, changes in regulatory approaches that may be implemented following a change in Administration. The SCOTUS’s recent decision in Loper Bright Enterprises v. Raimondo overturned the SCOTUS’s longstanding deferral to the applicable agency’s interpretation of ambiguous federal laws. We are unable to predict whether, or to what extent, this decision will alter the outcome of judicial reviews of current or future regulations. We do not know whether risks related to current and future regulations affecting us will be significantly mitigated by the decision in Loper Bright.

In view of the significant uncertainty surrounding each of these factors, it is not possible for us to predict reasonably the impact that any such laws, regulations or other policies may have on our business, financial condition and results of operations. However, such impacts could have a material adverse effect on our business, financial condition and results of operations.

See Item 1. Business — Government Regulation on page 9 in this Form 10-K for discussion of regulations that could materially adversely affect the Coal Mining segment.

The loss of, or significant reduction in, purchases by NACCO's coal customers could adversely affect our business, financial condition, results of operation and cash flows.
Earnings from the Coal Mining segment's customers may fluctuate from time to time based on numerous factors, including market conditions and the realignment of customers' power generation portfolios that reduce the electric power generated from coal, which may be outside of our control. If any of the Coal Mining segment's customers experience declining demand due to market, economic, regulatory or competitive conditions, it could have an adverse effect on our profitability, cash flows and financial position. In addition, if any customers were to significantly reduce or eliminate their purchases of coal from us or if we are unable to renew expiring long-term sales agreements with existing customers or enter into new supply agreements, our business, financial condition, results of operations and cash flows could be adversely affected. See Item 1. Business — Business Developments on page 2 in this Form 10-K for further discussion.

MLMC is subject to risks associated with our capital investment, operating and equipment costs, growing use of alternative generation that competes with coal-fired generation, changes in customer demand and inflationary adjustments.
The profitability of MLMC is subject to the risk of loss of investment in this operation, increases in the cost of mining, changes in customer demand, adverse mining conditions and growing competition from alternative power generation that competes with coal-fired generation. At MLMC, the costs of mining operations are not reimbursed by MLMC's customer. As such, increased costs or decreased revenues could materially reduce our profitability.

Profitability at MLMC is affected by customer demand for coal and changes in the indices that determine sales price and actual costs incurred. MLMC sells lignite at contractually agreed upon prices which are subject to changes in the level of established indices over time. All production costs at MLMC are capitalized into inventory and recognized in cost of sales as tons are delivered. In periods of limited or no deliveries, MLMC may be required to reduce inventory carrying value using the lower of cost and net realizable value approach, which could adversely affect MLMC’s results of operations.

Diesel fuel is heavily weighted among the indices used to determine the coal sales price. The diesel fuel-related component of the coal sales price is based on average price changes over time whereas the impact on actual costs from changes in diesel fuel prices is more immediate; therefore, fluctuations in diesel fuel prices can result in significant fluctuations in earnings at MLMC.

Any reduction in customer demand at MLMC, including, but not limited to, reduced availability of the customer’s power plant, dispatch of power generated by other energy sources, fluctuations in demand due to unanticipated weather conditions, planned and unplanned outages at the customer's Red Hills Power Plant, economic conditions, governmental regulations and inflationary adjustments could have a material adverse effect on MLMC's financial condition, results of operations and cash flows.

The Coal Mining segment's Unconsolidated Subsidiaries are subject to risks created by changes in customer demand and inflationary adjustments.
The contracts with the Unconsolidated Subsidiaries' customers are primarily based on a management fee approach, whereby compensation includes reimbursement of all operating costs, plus a fee based on the amount of coal delivered. The fees earned adjust over time in line with various indices which reflect general U.S. inflation rates. During the production stage, the Unconsolidated Subsidiaries' customers pay us our agreed upon fee only for the coal delivered to them for consumption or use. As a result, reduced coal usage by customers for any reason, including, but not limited to, reduced availability of the customer’s power plant, dispatch of power generated by other energy sources, fluctuations in demand due to unanticipated weather conditions, planned and unplanned outages at the Coal Mining segment's customers' facilities, economic conditions and governmental regulations could have a material adverse effect on our results of operations. Because of the contractual price formulas for the management fees at these Unconsolidated Subsidiaries, the profitability of these operations is also subject to fluctuations in inflationary adjustments (or lack thereof) that can impact the agreed upon management fees. These factors could materially reduce our profitability.

Changes in coal consumption patterns of U.S. electric power generators could adversely affect our profitability.
The amount of coal consumed by the electric power generation industry is affected by general economic conditions; overall demand for electricity; availability of transmission; competition from alternative fuel sources for power generation, such as natural gas, nuclear, hydroelectric, wind and solar power, and the location, availability, quality and price of those alternative fuel sources; environmental and other governmental regulations, including those impacting coal-fired power plants; and energy conservation efforts and related governmental policies.

Changes in the utility industry that affect NACCO's customers could also adversely affect us. The increased availability of renewable energy sources has contributed to a reduction in demand for coal-fired electric power generation. Competition from natural gas-fired plants that are relatively more efficient, less expensive to construct and less difficult to permit than coal-fired plants have the most potential to continue to displace a significant amount of coal-fired electric power generation. Federal and state mandates for increased use of electricity derived from renewable energy sources have also adversely affected demand for coal-fired electric power generation. Such mandates make alternative fuel sources more competitive with coal-fired electric power generation.

Any of these risks could result in a decrease in coal consumption by our customers and could have a material adverse effect on our business, financial condition and results of operations.

We are subject to burdensome federal and state mining regulations and the assumptions underlying our reclamation and mine closure obligations could be materially inaccurate.
Federal and state statutes require us to restore mine property in accordance with specified standards and an approved reclamation plan, and require that we obtain and periodically renew permits for mining operations. Regulations require us to incur the cost of reclaiming current mine disturbance at operations where we hold the mining permit. Estimates of our total reclamation and mine closing liabilities are based upon permit requirements and our engineering expertise related to these requirements. While management regularly reviews the estimated reclamation liabilities and believes that appropriate accruals have been recorded for all expected reclamation and other costs associated with closed mines, the estimate can change significantly if actual costs vary from assumptions or if governmental regulations change significantly. Such changes could have a material adverse effect on our business and could significantly reduce our profitability.

The Coal Mining segment's customers' operations require significant capital expenditures.
Maintaining and installing environmental controls on power plants requires significant capital expenditures. Any delay or reduction in making capital expenditures to maintain or upgrade coal-fired power plants by the Coal Mining segment's customers, principally electric utilities, could result in an increase in outage days and a corresponding decrease in coal consumption. A decrease in coal consumption could have a material adverse effect on the Coal Mining segment's financial condition, results of operations and cash flows.

We face numerous uncertainties in estimating economically recoverable reserves and resources, and inaccuracies in estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.
Information concerning our mining operations in Item 2 - Properties on page 29 has been prepared in accordance with the requirements of subpart 1300 of Regulation S-K. A mineral is economically recoverable when the price at which it can be sold exceeds the costs and expenses of mining, processing and selling the mineral. Forecasts of NACCO's future performance are based on, among other things, estimates of mineral reserves and resources. Mineral reserve and resource estimates of the remaining tons of coal at MLMC are based on many factors, including engineering, economic and geological data assembled and analyzed by internal staff, which includes various engineers and geologists, the area and volume covered by mining rights, assumptions regarding extraction rates and duration of mining operations, and the quality of in-place reserves and resources. The reserve and resource estimates as to both quantity and quality are updated from time to time to reflect, among other matters, production of minerals, new mining or other data received.

There are numerous uncertainties inherent in estimating quantities and qualities of minerals and costs to mine recoverable reserves and resources, including many factors beyond our control. While we believe that our mineral reserve and resource estimates are developed using well-established practices and with appropriate controls, mineral reserve and mineral resource estimation is an imprecise and subjective process. Estimates of mineral reserves and resources depend upon a number of variable factors and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions include:

- Geologic and mining conditions, including our ability to access certain mineral deposits as a result of the nature of the geologic formations of coal deposits or other factors, which may not be fully identified by available exploration data and may differ from past experience;
- Demand for our minerals;
- Contractual arrangements, operating costs and capital expenditures;
- Development and reclamation costs;
- Mining technology and processing improvements;
- The effects of regulation by governmental agencies, including volatility in the political, legal and regulatory environments due to the U.S. presidential administration;
- The ability to obtain, maintain and renew all required permits;
- Employee health and safety; and
- Our ability to convert all or any part of mineral resources to economically extractable mineral reserves.

As a result, actual tonnage recovered, estimated revenues, expenditures and cash flows with respect to reserves and resources may vary materially from estimates. Thus, these estimates may not accurately reflect our actual reserves and resources. Any material inaccuracy in estimates related to our reserves or resources could result in lower than expected revenues, higher than expected costs or decreased profitability and changes in future cash flow, which could materially and adversely affect our business, results of operations, financial position and cash flows. Additionally, reserve and resource estimates may be adversely affected in the future by interpretations of, or changes to, the SEC’s property disclosure requirements for mining companies.

A defect in title or the loss of a leasehold interest in certain property could limit our ability to mine coal reserves or result in significant unanticipated costs.
We conduct a significant part of our coal mining operations on leased properties. A title defect or the loss of a lease could adversely affect the ability to mine the associated coal reserves. We may not verify title to leased properties or associated coal reserves until we are committed to developing those properties or coal reserves. We may not commit to develop property or coal reserves until we have obtained necessary permits and completed exploration. As such, the title to property that we intend to lease or mine may contain defects prohibiting the ability to conduct mining operations. Similarly, leasehold interests may be subject to superior property rights of third parties. In order to conduct mining operations on properties where these defects exist, we may incur unanticipated costs. In addition, some leases require us to produce a minimum quantity of coal and/or pay minimum production royalties. Our inability to satisfy those requirements may cause the leasehold interest to terminate.

Risks related to the NAMining segment

We have experienced growth in our NAMining business in recent periods and we may not be able to sustain growth or manage future growth effectively.
We have expanded our overall NAMining business, operations and headcount in recent periods. NAMining’s operating expenses may continue to increase as we scale the NAMining business. We must effectively integrate, develop and motivate employees, while integrating new equipment and customers in an efficient and effective manner. We anticipate that it will continue to incur costs and capital expenditures associated with future growth prior to realizing the full measure of anticipated long-term benefits, and the return on these investments may be lower, may develop more slowly than expected or may never be realized. If we are unable to manage this growth and the associated expenses effectively, we may not be able to take advantage of market opportunities or remain competitive. We may also fail to execute on our business plan or respond to competitive pressures, any of which could adversely affect the NAMining business, operating results and financial condition.

NAMining faces competition from aggregates producers that choose to self-perform mining operations and from other mining companies.
NAMining faces competition from existing and prospective customers that are capable of performing, or engaging other companies to perform the services NAMining provides. NAMining cannot be certain that our existing customers will continue to outsource these services to NAMining in the future, which could adversely affect the NAMining business, operating results and financial condition.

We are subject to risks involved in the development of new mining projects.
From time to time, we seek to develop new mining projects, including the Thacker Pass project. The risks associated with such projects can be substantial. New mining projects can take up to several years to complete, are complex and require significant capital expenditures. These projects are subject to significant risks, including delays or reductions in making capital expenditures by NAMining's customers, timely regulatory approvals, extreme weather events, unexpected increases in the cost of required materials, and disputes with third party providers of materials, equipment or services, and a completed project may not yield the anticipated operational or financial benefit, any of which could have a material adverse effect on our business, financial condition and results of operations.

NAMining operations are currently geographically concentrated and therefore subject to regional economic risk, regulatory conditions, natural disasters, severe weather events or other circumstances affecting Florida.
As of December 31, 2024, over 75% of the quarries NAMining operates are located in Florida. A prolonged economic downturn or adverse change in regulatory conditions in the Florida mining or construction industry could result in a significant reduction in demand for NAMining’s services. The occurrence of one or more natural disasters, severe weather events, terrorist attacks, or disruptive political events in Florida could adversely affect the NAMining business.

Risks related to the Minerals Management segment

We have no control over the timing of the development and operation of our natural gas, oil and coal reserves extracted by third parties.
We own mineral and royalty interests in the continental United States. The Minerals Management segment does not currently have any material investments under which it would be required to bear the cost of exploration, production or development. We primarily derive income from royalty-based leases under which lessees make payments to us based on their sale of natural gas, oil and coal. Future royalty-based income is dependent on the number of oil and gas wells being developed and operated on our mineral acreage. The decision to pursue development and operation of oil and gas wells is made by third-party operators, not by us, and depends on a number of factors outside of our control, including fluctuations in commodity prices (primarily natural gas), regulatory risk, our lessees' willingness and ability to incur well-development and other operating costs, the rate of production of the reserves and changes in the availability and continuing development of infrastructure. Lower commodity prices may reduce the amount of oil and natural gas that third-party operators can produce economically. In the event that new federal or state restrictions related to the hydraulic fracturing process are adopted in areas where we own mineral and royalty interests, our lessees may incur additional costs or permitting requirements to comply with such requirements that may be significant and could result in added restrictions, delays or curtailments in the pursuit of exploration, development, or production activities. In addition, if a lessee were to experience financial difficulty, the lessee might not be able to pay our royalty payments or continue operations. A failure on the part of the lessee to make royalty payments may give us the right to terminate the lease, repossess the property and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement lessee. However, we may not be able to find a replacement lessee or might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, if we are able to enter into a new

lease with a new lessee, the replacement lessee may not achieve the same levels of production or sales prices as the lessee it replaced. Any of these risks could materially reduce our expected royalty income and profitability.

Minerals are a depleting asset. Unless we replace existing mineral and royalty interests with new mineral and royalty interests and third-party lessees develop those mineral and royalty interests, our reserves and royalty income will decline.

Producing oil and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless our third-party lessees conduct successful ongoing well development activities or we continually acquire mineral and royalty interests, production and income related to our mineral and royalty interests will decline as those reserves are depleted. The future cash flow and results of operations of the Minerals Management segment are highly dependent on third-party operators' success in developing our current and future mineral and royalty interests. These operators may not have access to the capital needed to develop our mineral interests. We may not be able to acquire or find sufficient additional mineral and royalty interests to replace third-party operators' current and future production. Further, the decline curve we use to project future royalty income is subject to numerous assumptions and limitations. Natural gas wells have high initial production rates and follow a natural decline before settling into relatively stable, long-term production. Decline rates can vary due to factors like well depth, well length, formation pressure, and facility design. Any of these risks could materially reduce our expected royalty income and profitability.

Substantially all of the Minerals Management segment's revenues are derived from royalty payments that are based on the price at which oil and natural gas produced from the acreage underlying our interests are sold. Prices of oil and natural gas are volatile due to factors beyond our control. A substantial or extended decline in commodity prices may adversely affect the Minerals Management segment's financial condition or results of operations.

The Minerals Management segment's revenues and operating results depend significantly upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in: supply and demand, including if energy supply exceeds demand; market uncertainty and a variety of additional factors that are beyond our control; market expectations about future prices of oil and natural gas; the level of global oil and natural gas exploration and production; the cost of exploring for, developing, producing and delivering oil and natural gas; the price and quantity of foreign imports and U.S. exports of oil and natural gas; the level of U.S. domestic production; political and economic conditions in oil producing regions; the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; trading in oil and natural gas derivative contracts; the level of consumer product demand; weather conditions and natural disasters; technological advances affecting energy consumption, energy storage and energy supply; domestic and foreign governmental regulations and taxes; the continued threat of terrorism and the impact of military and other action, including ongoing conflicts in foreign nations and associated oil and natural gas import bans as well as economic sanctions such as those imposed by the U.S. on oil and gas exports from Iran; the proximity, cost, availability and capacity of oil and natural gas pipelines and other transportation facilities; the price and availability of alternative fuels; volatility in the political, legal and regulatory environments due to the U.S. presidential election; and overall domestic and global economic conditions. A substantial or extended decline in commodity prices may adversely affect the Minerals Management segment's financial condition or results of operations.

The marketability of oil and natural gas production is dependent upon transportation, pipelines and refining facilities and continued operation of the U.S. power grid. Any limitation in the availability of these items could interfere with our third-party lessee's ability to market oil and natural gas production and may adversely affect the Minerals Management segment's financial condition or results of operations.

The marketability of our third-party lessee's production depends in part on the availability, proximity, and capacity of pipelines, tanker trucks, and other transportation methods, and processing and refining facilities owned by third parties as well as continued reliable operation of the U.S power grid. Any significant disruption in the U.S. power grid, gathering system or transportation, processing, or refining-facility capacity could reduce our third-party lessee's ability to market oil production and may adversely affect the Minerals Management segment's financial condition or results of operations.

Risks related to long-term growth strategy

Our investments in mitigation solutions, comprehensive reclamation and restoration construction services as well as solar and other energy-related development projects are subject to substantial risks and uncertainties.

There are risks associated with NACCO's ability to execute on our longer term growth strategy, including our investment in mitigation solutions, comprehensive reclamation and restoration construction services as well as clean energy projects through our Mitigation Resources of North America and ReGen Resources businesses, and our ability to develop and manage such projects profitably. These include political and regulatory developments that may make it more costly, or impossible, to pursue these business opportunities, logistical risks and potential delays related to construction, permitting and regulatory approvals; operational risk that the projects will not perform according to expectations; weather conditions or other factors beyond our control. All of the aforementioned risks could reduce the viability of project development. We have and will continue to incur costs in connection with these projects and the results of operations and/or return on investment could be negative or lower than anticipated and we may need to write-down the value of capitalized assets associated with these projects. Furthermore, our ability to forecast results may be hindered or inaccurate and the projects may not perform as predicted. Even if these projects are profitable in the long term, they may not be profitable in the short term, and results of operations are unlikely to be even quarter over quarter.

In addition, our investments in solar and other energy projects are dependent, in part, upon current state regulatory incentives and federal tax credits in order for the projects to be economically viable. These projects face the risk that the current state regulatory programs and tax laws may expire or be adversely modified and could have a material adverse effect on our operating results and financial condition.

Risks related to corporate structure

The amount and frequency of dividend payments made on NACCO's common stock could change.
The Board of Directors has the power to determine the amount and frequency of the payment of dividends. Decisions regarding whether or not to pay dividends and the amount of any dividends are based on earnings, capital and future expense requirements, financial conditions and other factors the Board of Directors may consider. Accordingly, holders of our common stock should not rely on past payments of dividends in a particular amount as an indication of the amount of dividends that will be paid in the future.

The price of NACCO's securities may be volatile.
The price of our common stock may fluctuate due to a variety of market and industry factors that may materially reduce the market price of NACCO's common stock regardless of operating performance, including, among others: (i) actual or anticipated fluctuations in our quarterly and annual results and those of other public companies in the industry; (ii) industry cycles and trends; (iii) changes in government regulation; (iv) potential or actual military conflicts or acts of terrorism; (v) announcements concerning NACCO, our customers or competitors; (vi) lack of trading liquidity as a result of low trading volumes could make it difficult for investors to sell shares; and (vii) the general state of the securities market. In addition, the stock market in general has experienced significant volatility that often has been unrelated to the operating performance of companies whose shares are traded. These market fluctuations could adversely affect the trading price of our common stock, regardless of NACCO's actual operating performance. As a result of all of these factors, investors in our common stock may not be able to resell their stock at or above the price they paid or at all. Further, we could be the subject of securities class action litigation due to any such stock price volatility, which could divert management's attention and have a material adverse effect on our operating results.

NACCO's certificate of incorporation and by-laws include provisions that may discourage a takeover attempt.
Provisions contained in our certificate of incorporation and by-laws and Delaware law could make it more difficult for a third-party to acquire us, even if doing so might be beneficial to NACCO's stockholders. Provisions in our by-laws and certificate of incorporation impose various procedural and other requirements that could make it more difficult for stockholders to affect certain corporate actions. These provisions could limit the price that certain investors might be willing to pay in the future for shares of our common stock and may have the effect of delaying or preventing a change in control.

Our stock repurchase program could affect the price of NACCO's common stock and increase volatility and may not enhance long-term shareholder value.
Our Board of Directors has authorized a stock repurchase program. The timing and amount of any repurchases under the stock repurchase program are determined at the discretion of our management based on a number of factors, including the availability of capital, other capital allocation alternatives, market conditions for our Class A common stock and other legal and contractual restrictions. The stock repurchase program does not require us to acquire any specific number of shares and may be modified, suspended, extended or terminated without prior notice and may be executed through open market purchases, privately negotiated transactions or otherwise.

Repurchases under the stock repurchase program could affect the price of our Class A common stock. The existence of a stock repurchase program could cause the price of our Class A common stock to be higher than it would be in the absence of such a program and could potentially reduce the market liquidity for our Class A common stock. There can be no assurance that any stock repurchases will enhance shareholder value because the market price of our Class A common stock may decline below the levels at which we repurchased the shares. Although the stock repurchase program is intended to enhance long-term shareholder value, there is no assurance that it will do so and short-term price fluctuations in the Class A common stock could reduce the program's effectiveness. Furthermore, the stock repurchase program does not obligate us to repurchase any dollar amount or number of shares of our Class A common stock, and it may be suspended or discontinued at any time and any suspension or discontinuation could cause the market price of our Class A common stock to decline.

NACCO is a smaller reporting company and cannot be certain if the reduced disclosure requirements applicable to smaller reporting companies will make our common stock less attractive to investors.
We are currently a smaller reporting company as defined in the Securities Exchange Act of 1934, and thus allowed to provide simplified executive compensation disclosures and other decreased disclosure in SEC filings. The reduced disclosures may make it more difficult to compare our performance with other public companies.

NACCO cannot predict whether investors will find our common stock less attractive because of these exemptions. If some investors find NACCO's common stock less attractive as a result, there may be a less active trading market for our common stock and the stock price may be more volatile.

Certain members of our extended founding family own a substantial amount of our Class A and Class B common stock and, if they were to act in concert, could control the outcome of director elections and other stockholder votes on significant corporate actions.
We have two classes of common stock: Class A common stock and Class B common stock. Holders of Class A common stock are entitled to cast one vote per share and, as of December 31, 2024, accounted for approximately 27 percent of our voting power. Holders of Class B common stock are entitled to cast ten votes per share and, as of December 31, 2024, accounted for our remaining voting power. As of December 31, 2024, certain members of our extended founding family held approximately 36 percent of our outstanding Class A common stock and approximately 99 percent of our outstanding Class B common stock. On the basis of this common stock ownership, certain members of our extended founding family could have exercised approximately 82 percent of our total voting power. Although there is no voting agreement among such extended family members, in writing or otherwise, if they were to act in concert, they could control the outcome of director elections and other stockholder votes on significant corporate actions, such as certain amendments to our certificate of incorporation and our sale or the sale of our assets. Because certain members of our extended founding family could prevent other stockholders from exercising significant influence over significant corporate actions, we may be a less attractive takeover target, which could adversely affect the market price of our common stock.

General Risk Factors

Our effective income tax rate could be volatile and materially change as a result of changes in tax laws, mix of earnings and other factors.
We are subject to income taxes in the United States and the effective income tax rate is impacted by certain U.S. federal income tax benefits currently available to coal mining and oil and gas exploration and development companies. Future results of operations could be affected by changes in our effective income tax rate as a result of an increase in the statutory tax rate or the reduction or elimination of percentage depletion as well as changes in the mix of earnings between entities that benefit from percentage depletion and those that do not.

Current and future capital and credit market conditions could adversely affect our ability to obtain bank financing on reasonable terms. Certain financial institutions have acted to limit available financing for companies in the fossil fuel industry, including coal mining, which could result in increases in costs of borrowing or in our ability to maintain financing at current levels.
We may be unable to obtain financing on reasonable terms. Historically, we have addressed our liquidity needs (including funds required to pay dividends and fund working capital and planned capital expenditures) with operating cash flow and borrowings under credit facilities. Our wholly-owned subsidiary has a revolving line of credit of up to $200.0 million that expires in September 2028. Our ability to access the capital markets and the costs and terms of available financing depends on many factors, including perceived credit risks of companies with coal and/or oil and gas exposure as a result of current market sentiment for fossil fuels. Certain financial institutions have taken actions to limit available financing to entities that produce or use fossil fuels. The volatility in the energy industry and additional perceived credit risks of companies with coal and/or oil and gas exposure has resulted in traditional bank lenders seeking to reduce or eliminate their lending exposure to these companies. An inability to obtain bank financing, or refinance with terms that are as favorable as the existing terms of such indebtedness, could have a material adverse effect on our operating results and financial condition.

Failure to obtain financial assurance to secure reclamation and other long-term obligations, including surety bonds and letters of credit on acceptable terms, could affect NACCO's ability to mine.
Federal and state laws require us to provide financial assurance or financial security to secure performance or payment of certain long-term obligations, such as mine closure or reclamation costs, federal and state workers' compensation and black lung benefit costs, leases, transmission interconnection construction costs, power purchase agreement delivery obligations and other obligations. Future federal and state laws and regulations, regional transmission organizations and power purchase agreement customers may require higher amounts of financial security, including as a result of changes to certain factors used

to calculate the bonding or security amounts. Bond issuers may demand higher fees or additional collateral, including cash or letters of credit or other terms less favorable upon renewals. As we are required by state and federal law to have bonds or other acceptable security in place before mining can commence or for certain projects to move forward, the failure to maintain surety bonds, letters of credit or other guarantees or security arrangements would materially and adversely affect NACCO's ability to mine. 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. In addition, as a result of increasing credit pressures on the coal industry, it is possible that surety bond providers could demand other forms of collateral as a condition to providing or maintaining surety bonds. Any such demands, could have a material adverse impact on our liquidity and financial position. If we are unable to meet collateral requirements and cannot otherwise obtain or retain required surety bonds, it may be unable to satisfy legal requirements necessary to conduct mining operations. Difficulty in acquiring surety bonds, or additional collateral requirements, would increase our costs and likely require greater use of alternative sources of funding for this purpose, which would reduce our liquidity.

Insurance coverage is increasingly expensive, contains more stringent terms and may be difficult to obtain in the future. A number of global insurance companies have taken steps to limit coverage for companies in the fossil fuel industry, including coal mining, which could result in significant increases in costs of insurance or in our ability to maintain insurance coverage at current levels.
We hold a number of insurance policies, including director and officers' liability and property and casualty insurance coverages. Because we are involved in coal mining, costs of insurance may increase substantially or insurance carriers may limit or decide not to insure us in the future. In addition, if we make significant insurance claims under our insurance policies, such claims may have a material adverse effect on our ability to obtain future insurance coverage at commercially reasonable rates. Limited, or an inability to obtain, insurance coverage, significant increases in the premiums or deductibles of insurance, or losses in excess of our liability insurance coverage limits, could have a material adverse effect on our operating results and financial condition.

Increasing emphasis and changing expectations with respect to environmental, social and governance matters may impose additional costs on us or expose us to new or additional risks.
Expectations relating to environmental, social and governance (ESG) matters have been rapidly evolving. Government organizations are enhancing or advancing legal, regulatory and disclosure requirements specific to ESG matters. The heightened focus on ESG issues requires the continuous monitoring of various and evolving laws, regulations, standards and expectations and the associated reporting requirements. Investor advocacy groups, certain institutional investors, investment funds and other influential investors are also increasingly focused on ESG practices. We could face pressures from investors, who are increasingly focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability. Investors may request that we implement ESG procedures or standards as a condition to maintain their investment or to make further investments. Lenders and insurers may also limit lending to and insuring of companies that do not meet certain ESG measures endorsed by them. Additionally, we may face reputational challenges in the event our ESG practices are inconsistent with the third-party views of acceptable ESG practices. Further, there is an increasing number of state-level anti-ESG initiatives in the United States that may conflict with other regulatory requirements or various stakeholders' expectations. Companies which do not adapt to or comply with regulatory, investor or stakeholder expectations and standards, which are evolving, or which are perceived to have not responded appropriately, may suffer from reputational damage and the business, financial condition, and/or stock price of such a company could be materially and adversely affected.

We may be subject to litigation seeking to hold energy companies accountable for the effects of climate change.
Increasing attention to climate change risk has also resulted in a recent trend of governmental investigations and private litigation by local and state governmental agencies as well as private plaintiffs in an effort to hold energy companies accountable for the effects of climate change. Other public nuisance lawsuits have been brought in the past against power, coal, oil and gas companies alleging that their operations are contributing to climate change. We could incur substantial legal costs associated with defending such lawsuits in the future. Government entities in certain states have brought similar claims seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of emissions attributable to those fuels or for other grounds related to climate change, such as improper disclosure of climate change risks. Those lawsuits allege damages as a result of climate change and the plaintiffs are seeking unspecified damages and abatement under various tort theories. We have not been made a party to these 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 business could suffer if NACCO's information technology systems are disrupted, cease to operate effectively or if we experience a security breach, a cyber incident or cyber attack.
Like many other companies, we are the target of malicious cyber attack attempts in the normal course of business. Cybersecurity incidents involving businesses and other institutions are on the rise. Cyber threats are rapidly evolving and those threats and the means for obtaining access to information in digital and other storage media are becoming increasingly sophisticated. Cyber threats and cyber attackers can be sponsored by nation states or sophisticated criminal organizations or be the work of independent hackers.

As cyber threats evolve and become more difficult to detect and successfully defend against, one or more cyber attacks might defeat our, or a third-party service provider's, security measures in the future. Employee error or other irregularities may also result in a failure of security measures and a breach of information systems. Moreover, hardware, software or applications we may use have inherent defects of design, manufacture or operations or could be inadvertently or intentionally implemented or used in a manner that could compromise information security.

A security breach and loss of information may not be discovered for a significant period of time after it occurs. Any compromise of data security could result in a violation of applicable privacy and other laws or standards, the loss of valuable business data, or a disruption of our business. A security breach involving the misappropriation, loss or other unauthorized disclosure of sensitive or confidential information could give rise to unwanted media attention, materially damage customer relationships and our reputation, and result in fines, fees, or liabilities, which may not be covered by insurance policies.

We rely on information technology systems to operate our business and to record and process transactions; respond to customer inquiries; purchase supplies; provide services; deliver inventory on a timely basis; and maintain cost-efficient operations. Despite our efforts, our information technology systems may be vulnerable, from time to time, to damage or interruption from user error, computer viruses, power outages, third-party intrusions and other technical malfunctions.

Through our business operations, we collect and store confidential information from our customers and vendors and personal information and other confidential information from our employees. Although we have taken steps designed to safeguard such information, there can be no assurance that such information will be protected against unauthorized access, use or disclosure. Unauthorized parties may penetrate our or our vendors' network security and, if successful, misappropriate such information. Additionally, methods to obtain unauthorized access to confidential information change frequently and may be difficult to detect, which can impact our ability to respond appropriately.

We could be subject to liability for failure to comply with privacy and information security laws, for failing to protect personal information or for failing to respond appropriately. Loss, unauthorized access to, or misuse of confidential or personal information could disrupt our operations, damage our reputation, and expose us to claims from customers, financial institutions, regulators, employees and other persons, any of which could have an adverse effect on our business, financial condition and results of operations.

Security breaches, cyber incidents or cyber attacks could include, among other things, computer viruses, malicious or destructive code, ransomware, social engineering attacks (including phishing and impersonation), hacking, denial of service attacks and other attacks. Cybersecurity threats to, and incidents involving, vendors and other third-parties who support our activities could impact the business. We are continuously installing new and upgrading existing information technology systems. We use employee awareness training around phishing, malware, and other cyber risks. We believe these incidents are likely to continue and are unable to predict the direct or indirect impact of future attacks or breaches to business operations.

Our operations could be disrupted by natural or human causes beyond our control.
Our operations are subject to disruption from natural or human causes beyond our control, including physical risks from hurricanes, severe storms, floods and other forms of severe weather, accidents, fires, earthquakes, terrorist acts and epidemic or pandemic diseases, any of which could result in suspension of operations or harm to people or the environment. While all of our operations are located in the United States, we participate in a global supply chain, and if governments regulate or restrict the flow of labor or products or impede the travel of our personnel, our ability to conduct normal business operations could be impacted which could adversely affect our results of operations and liquidity.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 1C. CYBERSECURITY

Cybersecurity continues to be a key governance priority for us. NACCO maintains a cybersecurity program that is aligned with our business and has established policies and processes for assessing, identifying, and managing material risk from cybersecurity threats, which have been integrated into our overall risk management processes and governance structure.

We have implemented and invested in, and will continue to implement and invest in, controls, technologies, and resources (both internal and external) that are designed to identify, protect against, detect, respond to and mitigate cybersecurity risks, in alignment with frameworks established by the National Institute of Standards and Technology. These include, but are not limited to, internal reporting mechanisms, monitoring and detection tools, threat intelligence, and general and role-based training. NACCO's commitment to cybersecurity emphasizes cultivating a security-minded culture through education and training that reflect best practices and improved cybersecurity awareness. We also maintain third party management processes to identify and manage the cybersecurity risks associated with third party service providers. We periodically evaluate our cybersecurity program internally and by engaging with consultants to conduct reviews and assessments of the program. Such reviews and assessments may include penetration testing, maturity assessments as well as table-top and other exercises with subsequent remediation of key findings. Additionally, we have a Cybersecurity Task Force in place that is comprised of individuals across various departments within our organization including information systems, legal, finance, human resources and internal audit which meets regularly to further advance our cybersecurity strategy.

Our Board of Directors (Board) oversees NACCO's risk management. Our full Board regularly reviews information provided by management to oversee risk identification, risk management and risk mitigation strategies. The Audit Review Committee assists the Board with cybersecurity risk oversight. The Audit Review Committee is responsible for regularly reviewing and discussing with management risk exposure relating to cybersecurity, which includes reviewing the state of our cybersecurity program and emerging cybersecurity developments and threats, as well as the steps management has taken to monitor and mitigate such exposure. In 2024, our Board and the Audit Review Committee received periodic updates throughout the year on cybersecurity matters and these updates are part of their standing agendas.

Our Chief Information Security Officer (CISO) leads NACCO's cybersecurity program and is responsible for the management of our cybersecurity risks. The CISO has extensive cybersecurity knowledge and skills gained from over 30 years of technical and business experience, including as General Manager & President of MLMC, Vice President of Mississippi Operations and Vice President of Innovation & Technology. The CISO holds a bachelor’s degree in engineering, an executive MBA, and certifications in cybersecurity from Harvard. Additionally, the CISO successfully completed an Executive course through Northwestern’s Kellogg School of Management focused on artificial intelligence during 2024. The CISO reports directly to the President and Chief Executive Officer. The CISO manages a team of internal and external resources that have expertise and experience in cybersecurity. The CISO is informed of cybersecurity incidents by the cybersecurity team, which is generally responsible for monitoring the prevention, detection, mitigation, and remediation of cybersecurity incidents. We have an established process governing our assessment, response and internal and external notifications upon the occurrence of a cybersecurity incident, including evaluation of the potential impacts of cybersecurity incidents to determine materiality. Depending on the nature and severity of an incident, this process provides for escalation procedures upon discovery of material cybersecurity risks, including notification to our executive management and/or Board.

As of the date of this filing, our business strategy, results of operations, and financial condition have not been materially impacted as a result of any previously identified cybersecurity incidents; however, NACCO cannot provide assurance that we will not be materially impacted in the future by such risks or any future material incidents. For additional information regarding our cybersecurity risks, please refer to Item 1A - Risk Factors on page 18.

Item 2. PROPERTIES

Coal Mining Segment - Operations

NACCO-owned Properties

1.0 INTRODUCTION

Information concerning our mining properties in this Form 10-K have been prepared in accordance with the requirements of subpart 1300 of Regulation S-K. As used in this Report on Form 10-K, the terms mineral resource, measured mineral resource, indicated mineral resource, inferred mineral resource, mineral reserve, proven mineral reserve and probable mineral reserve are defined and used in accordance with subpart 1300 of Regulation S-K. Under subpart 1300 of Regulation S-K, mineral resources may not be classified as mineral reserves unless the determination has been made by a qualified person that the mineral resources can be the basis of an economically viable project. Readers 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 subpart 1300 of Regulation S-K.

Readers are cautioned that, except for that portion of mineral resources classified as mineral reserves, mineral resources do not have demonstrated economic value. Inferred mineral resources are estimates based on limited geological evidence and sampling and have too high of a degree of uncertainty as to their existence to apply relevant technical and economic factors likely to influence the prospects of economic extraction in a manner useful for evaluation of economic viability. Estimates of inferred mineral resources may not be converted to a mineral reserve. It cannot be assumed that all or any part of an inferred mineral resource will ever be upgraded to a higher category. A significant amount of exploration must be completed in order to determine whether an inferred mineral resource may be upgraded to a higher category. Therefore, readers are cautioned not to assume that all or any part of an inferred mineral resource exists, that it can be the basis of an economically viable project, or that it will ever be upgraded to a higher category. Likewise, readers are cautioned not to assume that all or any part of measured or indicated mineral resources will ever be converted to mineral reserves. See Item 1A - Risk Factors on page 18.

The information that follows is derived, for the most part, from, and in some instances is an extract from, the technical report summary (TRS) prepared in compliance with the Item 601(b)(96) and subpart 1300 of Regulation S-K. The TRS was prepared by certain of our employees. Portions of the following information are based on assumptions, qualifications and procedures that are not fully described herein. Reference should be made to the full text of the TRS, incorporated herein by reference and made a part of this Report on Form 10-K. The information regarding MLMC was reviewed by our employees that are qualified persons as defined by subpart 1300 of Regulation S-K.

Coteau, Falkirk, Coyote Creek and MLMC, each wholly-owned subsidiaries of NACCO, operate surface coal mines under long-term contracts with power generation companies pursuant to a service-based business model.

Locations of the properties subject to SEC Section 1300 reporting are shown in Figure 1.1 Surface Coal Mines Operational During 2024 Subject to SEC Section 1300 Reporting.

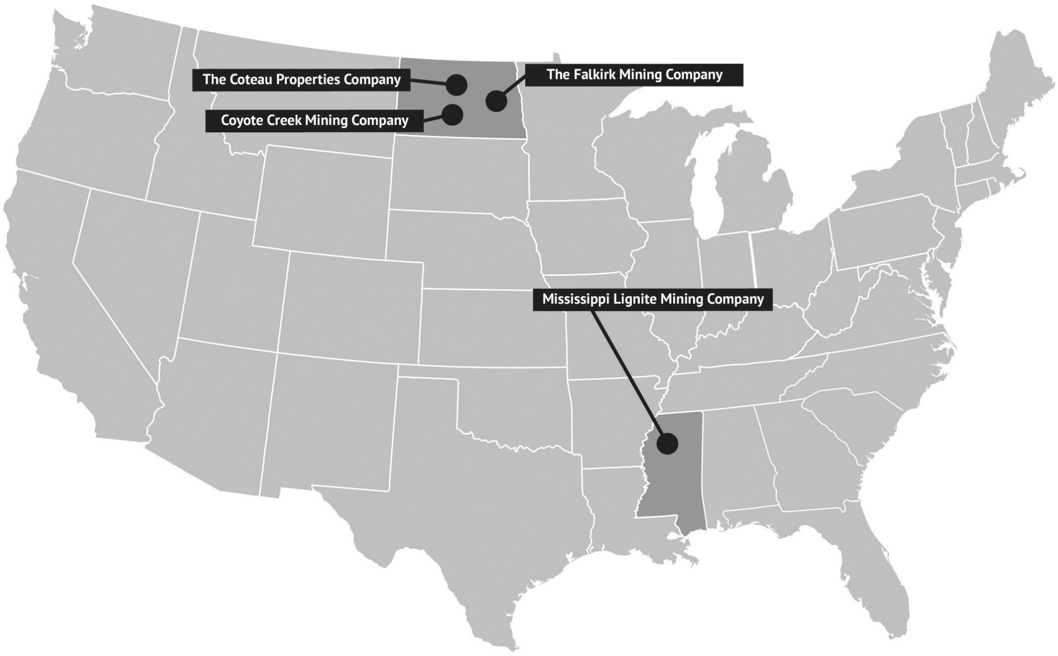


Figure 1.1 Surface Coal Mines Operational During 2024 Subject to SEC Section 1300 Reporting

A summary of coal production at the Mines subject to SEC Section 1300 Reporting for the past three years has been tabulated and is presented on Table 1.1 Production Summary.

	Tons (in millions)		
	2022	2023	**2024**
The Coteau Properties Company	13.4	11.4	**11.9**
The Falkirk Mining Company	7.6	6.6	**7.5**
Coyote Creek Mining Company	1.8	2.2	**1.9**
Mississippi Lignite Mining Company	3.2	2.7	**1.9**
Totals	26.0	22.9	**23.2**

Table 1.1 Production Summary

2.0 MINING PROPERTIES SUBJECT TO SUBPART 1300 OF REGULATION S-K REPORTING

2.1 Red Hills Mine — Mississippi Lignite Mining Company

MLMC is the owner and operator of the Red Hills Mine. The Red Hills Mine is a lignite surface mine in production. Prior to MLMC, there were no previous mining operations on the Red Hills Mine property.

The MLMC contract is the only operating coal contract in which we are responsible for all operating costs, capital requirements and final mine reclamation; therefore, MLMC is consolidated within our financial statements. MLMC sells coal to its customer at a contractually agreed-upon price which adjusts monthly, primarily based on changes in the level of established indices which reflect general U.S. inflation rates. Profitability at MLMC is affected by customer demand for coal and changes in the indices that determine sales price and actual costs incurred.

A summary of coal production at MLMC for the past three years has been tabulated and is presented on Table 2.1 Production Summary.

	Tons (in millions)		
	2022	2023	**2024**
Mississippi Lignite Mining Company	3.2	2.7	**1.9**

Table 2.1 Production Summary

The Red Hills Mine generally produces between 2 million and 3 million tons of lignite coal annually. The Red Hills Mine started operations in 2000 for plant commissioning, with initial commercial deliveries starting in 2001, and full production and commercial deliveries starting in 2002. All production from the mine is delivered to MLMC's customer's Red Hills Power Plant. During 2023, MLMC received notice from its customer related to a boiler issue at the Red Hills Power Plant that began on December 15, 2023. While this issue has been resolved, it resulted in a reduction in customer demand which had a significant impact on our 2024 results of operations.

The Red Hills Mine, operated by MLMC, is located approximately 120 miles northeast of Jackson, Mississippi (Figure 2.1). The entrance to the mine is by means of a paved road located approximately one mile west of Highway 9. MLMC owns in fee approximately 8,090 acres of surface interest and 5,150 acres of coal interests. MLMC holds leases granting the right to mine approximately 5,423 acres of coal interests and the right to utilize approximately 4,890 acres of surface interests. MLMC holds subleases under which it has the right to mine approximately 1,683 acres of coal interest. The majority of the leases held by MLMC were originally acquired during the mid-1970s to the early 1980s with terms extending 50 years, many of which can be further extended by the continuation of mining operations. The lignite deposits of the Gulf Coast are found primarily in a narrow band of strata that outcrops/subcrops along the margin of the Mississippi Embayment. The potentially exploitable tertiary lignites in Mississippi are found in the Wilcox Group. The outcropping Wilcox is composed predominately of non-marine sediments deposited on a broad flat plain.

The towns of Ackerman, Eupora, Starkville, Louisville, Kosciusko, and numerous smaller communities are within a 40-mile radius of the Red Hills Mine and provide a vast employment base. Furthermore, Mississippi State University (MSU) is located approximately 30 miles east of the mine in Starkville. MLMC has a history of partnership with MSU as well as the local community colleges for science, technology, engineering, and mathematics (STEM) research and skilled trades training.

The Red Hills Mine sources power for mine office facilities and operations from 4-County Electric Power Association, and water for the mine office facilities from the Reform Water Association. Fuel for equipment is supplied by a local vendor. The Red Hills Mine has, or is currently constructing, all supporting infrastructure for mining operations.

Local access to the Red Hills Mine is by way of Highway 9 between Ackerman, Mississippi and Eupora, Mississippi which connects to Pensacola Road that leads to the Red Hills Mine paved access road. Pensacola Road connects with Highway 9 approximately 5 miles north of Ackerman, MS. The mine road is approximately 1 mile west from Highway 9 along Pensacola Road.

Travel to the Red Hills Mine by air is possible using the Jackson-Medgar Wiley Evers International Airport in Jackson, Mississippi, approximately 104 miles south of the mine, and then using ground transportation, traveling via Highway 25, Highway 15, and Highway 9. Alternatively, the Golden Triangle Regional Airport is a smaller airport approximately 50 miles from the Red Hills Mine by means of Highway 82 west, Highway 15 south, and Highway 9 north.

The Red Hills Mine is in close proximity to river ports of the Tennessee-Tombigbee Waterway and the Mississippi River. The Lowndes County Port is approximately 60 miles east of the mine. The Port of Greenville is approximately 135 miles west of the mine, and the Port of Vicksburg, approximately 150 miles southwest of the mine. All ports are connected by major state and federal highways.

In addition to transportation via roadways, air and waterways, the Kansas City Southern (KCS) railroad has a depot located approximately 5 miles south of the mine in Ackerman, and is accessible by Highway 9 and Highway 15. MLMC currently has all permits in place for the Red Hills Mine to operate and adhere to a mine plan projected through April 1, 2032. No mineral processing occurs at the Red Hills Mine.

The geology encountered at the Red Hills Mine is stratigraphic in nature with depositional sequences of sands, silts, clays, and lignite. The vertical repetition of geologic strata facilitated a straightforward setting to establish and study the baseline geological, geochemical, geotechnical, and geohydrological conditions at the Red Hills Mine.

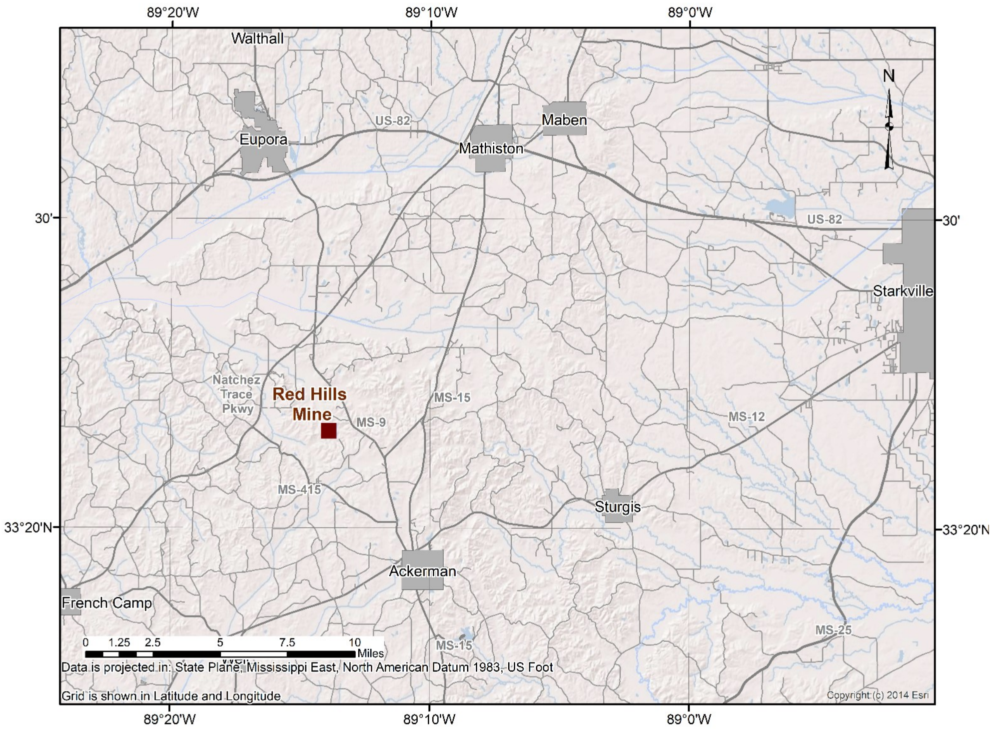
Development of the Red Hills Mine began in 1997, with full commercial deliveries commencing in 2002. The mining operation is comprised of four major equipment fleets. Primary removal of burden is achieved with one 82-cubic yard electric-powered dragline, four large track-type push dozers, and a truck and shovel fleet utilizing a 41-cubic yard electric rope shovel. Lignite is mined using a surface miner or a hydraulic backhoe to load a fleet of end dump haul trucks, and is directly shipped to the RHPP or the lignite stockpile. The overall average quality of the mined lignite seams meets the required power plant quality specifications. Therefore, no mineral processing is performed by MLMC.

The mine office facilities and original equipment fleets at the Red Hills Mine were constructed, acquired, or purchased new during the development stage of the mine. The facilities and equipment are maintained to allow for safe and efficient operation. The equipment is well maintained, in good physical condition and is either updated or replaced periodically with newer models or upgrades available to keep up with modern technology. As equipment wears out, MLMC evaluates what replacement option will be the most cost-efficient, including the evaluation of both new and used equipment.

The total cost of the property and equipment, net of applicable accumulated amortization, depreciation and impairment as of December 31, 2024 is $52.5 million.

The Red Hills Mine currently has no significant encumbrances to the property. No mining permit violations have been issued at the Red Hills Mine in the past ten years. One notice of violation (NOV) was issued in April 2020 for a water quality exceedance that was determined to not be the fault of Red Hills Mine and no further action was required. A second NOV was issued in June 2022 for a water sampling violation. Both NOVs were not related to the mining permit. Permitting requirements are discussed in Section 17.0 of the TRS.

Figure 2.1 – Red Hills Mine Location



Mineral Resources and Reserves have been summarized from the December 31, 2024 TRS for MLMC. The Mineral Resources and Mineral Reserves as of December 31, 2024 are included as Table 2.2 and Table 2.3. Coal qualities are reported on an as-received moisture basis. Based on the December 31, 2024 TRS, prices in Table 2.2 are based on economic cut-off grades of $34.02 per ton at MLMC and prices in Table 2.3 are based on economic cut-off grades of $34.40 per ton at MLMC.

Material assumptions and criteria used in the determination of Mineral Resource and Mineral Reserves reported herein are provided within the filed TRS for the MLMC – Red Hills Mine dated December 31, 2024.

Section 11.0 of the TRS describes the key assumptions, parameters, and methods used for the estimation of Mineral Resources. Assumptions include a maximum cumulative stripping ratio of 18:1 based on an assumed lignite sales price of $34.02 per ton. A further description of the verified drilling data used to model the lignite deposit for estimation of Mineral Resources is provided in Section 7.2 Drilling Exploration, 8.0 Sample Preparation, Analyses, and Security, and Section 9.0 Data Verification.

Section 12.0 of the TRS describes the key assumptions, parameters, and methods used for the estimation of Mineral Reserves, and include the following:
- Maximum stripping ratio: 14:1;
- Mining production rates on a cubic yard and per ton basis remain relatively consistent with historical performance;
- Mining costs on a unit basis remain relatively consistent with historical performance;
- Minimum minable lignite thickness: 1.0 feet;
- Minimum parting thickness before seams are composited: 6.0 inches;
- Maximum depth of mining: approximately 320 feet;
- Lignite density defined by seam from coal core drilling data and modified by dilution parameters and approximately 80 lb/ft^3; and
- Recovery rates by seam ranging from 67% to 100%.

Modifying factors including dilution parameters and technical information related to the mining process are described in detail under Section 13.0 Mining Methods. Economic factors to support the Mineral Reserve estimates are described in Section 18.0 Capital and Operating Costs and 19.0 Economic Analyses.

The Mineral Resources as of December 31, 2024 presented in Table 2.2 below have been estimated by applying a series of geologic and physical limits as well as high-level mining and economic constraints. The mining and economic constraints were limited to a level sufficient to support reasonable prospect for future economic extraction of the estimated Mineral Resources. The categorized Mineral Resources reported herein are exclusive of Mineral Reserves.

Lignite Coal	**Resource Classification**	**Tonnage (Kt)**	**Grades/Qualities**			
			Calorific Value (Btu/lb)	**Moisture (%wt)**	**Ash (%wt)**	**Sulfur (%wt)**
Mississippi Lignite Mining Company	Measured	4,400	5,200	44.6	13.0	0.6
Mississippi Lignite Mining Company	Indicated	400	5,180	44.1	13.6	0.6
Mississippi Lignite Mining Company	Measured + Indicated	4,700	5,200	44.5	13.0	0.6
Mississippi Lignite Mining Company	Inferred	100	5,200	45.5	12.0	0.5

Note:
- Mineral Resources estimates have been prepared by a qualified person employed by NACCO Natural Resources as of December 31, 2024.
- Mineral Resources that are not Mineral Reserves do not have demonstrated economic viability and there is no certainty that all or any part of such Mineral Resources will be converted into Mineral Reserves.
- Mineral Resources are in-situ and exclusive of 22.9 million tons (Mt) of Mineral Reserves.
- Mineral Resources are reported using an economic cutoff of $34.02 per ton.
- Resources are presented with a minimum 1 foot seam thickness, a maximum as received moisture basis ash content of 30%, and a minimum calorific value of 4000 BTU/lb on an as received moisture basis cutoff.
- Resources are estimated using Vulcan Software.
- Tonnages and qualities have been rounded to an accuracy level deemed appropriate by the QP. Summation errors due to rounding may exist.

Table 2.2 Mineral Resources Summary as of December 31, 2024

The Mineral Reserves as of December 31, 2024 presented in Table 2.3 below were determined to be the economically mineable portion of the measured and indicated Mineral Resources after the consideration of modifying factors related to the mining process. Inferred Mineral Resources were not considered for Mineral Reserves.

Lignite Coal	Reserve Classification	Tonnage (Kt)	Grades/Qualities			
			Calorific Value (Btu/lb)	Moisture (%wt)	Ash (%wt)	Sulfur (%wt)
Mississippi Lignite Mining Company	Proven	18,200	5,090	43.3	14.9	0.6
Mississippi Lignite Mining Company	Probable	4,700	5,080	43.1	15.1	0.6
Mississippi Lignite Mining Company	Total	22,900	5,090	43.3	14.9	0.6

Note:
- Mineral Reserves Estimates have been prepared by a qualified person employed by MLMC as of December 31, 2024.
- Mineral Reserves have been demonstrated to be economic based on a positive cash flow
- Mineral Reserves are stated on a Run of Mine basis
- An economic cutoff in the Life of Mine plan averaged $34.41 per ton and was used to demonstrate coal reserves
- Recovery varies by coal seam and ranges from 67% to 100%
- Mineral Reserves use an economic cut-off of a maximum cumulative stripping ratio of 14:1. There are some instances where the stripping ratio for a single year could exceed 14:1, but the average for the entire area evaluated is less than 14:1.
- Historical coal recovery rates at Red Hills Mine have been applied to generate the Mineral Reserve tonnages.
- Mineral Reserves are estimated using Vulcan Software.
- Tonnages and qualities have been rounded to an accuracy level deemed appropriate by the QP. Summation errors due to rounding may exist.

Table 2.3 Mineral Reserves Summary as of December 31, 2024

Table 2.4 describes the difference between the Mineral Reserves and Mineral Resources reported as of December 31, 2023 and December 31, 2024.

Resource Classification	December 31, 2023 Tonnage (Kt)	December 31, 2024 Tonnage (Kt)	Percent Change
Measured	4,300	4,400	2%
Indicated	500	400	(20)%
Measured + Indicated	4,800	4,700	(2)%
Inferred	1,600	100	(94)%

Reserve Classification	December 31, 2023 Tonnage (Kt)	December 31, 2024 Tonnage (Kt)	Percent Change
Proven	15,100	18,200	21%
Probable	7,400	4,700	(36)%
Proven + Probable	22,500	22,900	2%

Table 2.4. Net difference of reported Mineral Resources and Mineral Reserves from previous reporting period to current reporting period.

The Mineral Resources and Mineral Reserves as of December 31, 2024 reflect modifications from mining extraction of Mineral Reserves, acquisition of additional leased tracts which increased Mineral Reserves and an update to the resource model which allowed conversion of portions of Mineral Resources to Mineral Reserves. The update to the resource model added 31 quality core holes and 10 structural drill holes to the resource model. Mining extraction is occurring solely in Mine Area 3. Additionally, MLMC delivered 1.9 million tons during 2024.

2.2 Material Properties with no Mineral Resources or Mineral Reserves

The lignite coal tonnages at Coteau, Falkirk and Coyote Creek have not been classified as measured resources, indicated resources, or inferred resources as defined in Items 1300 through 1305 of Regulation S-K, and as a result, do not have any proven or probable reserves under such definition and are therefore classified as an Exploration Stage Property pursuant to Items 1300 through 1305 of Regulation S-K. Coteau, Falkirk and Coyote Creek will continue to be classified as exploration stage properties until such time as proven or probable mineral reserves have been established in accordance with subpart 1300 of Regulation S-K, even though they continue to deliver lignite to their respective customers.

At Coteau, Coyote Creek and Falkirk, we are paid a management fee per ton of coal or heating unit (MMBtu) delivered. Each contract specifies the indices and mechanics by which fees change over time, generally in line with broad measures of U.S. inflation. The customers are responsible for funding all mine operating cost, including final mine reclamation, and directly or indirectly providing all of the capital required to build and operate the mine. This contract structure eliminates our exposure to spot coal market price fluctuations.

Coteau, Coyote Creek and Falkirk each have only one customer for which they extract and deliver coal. These customers operate coal-fired electric generation power plants adjacent to each mine location (and in the case of Coteau, a synthetic natural gas and chemical/fertilizer production facility).

The sales price under the Coteau, Coyote Creek and Falkirk contracts are not market driven. Unlike traditional sales made based on market factors, under the provisions of the long-term mining agreements, the coal sales price at Coteau, Coyote Creek and Falkirk includes (i) all costs incurred to extract, process and deliver coal (i.e. the cost of production) and (ii) the agreed-upon profit per ton of coal or MMBtu unit delivered to the customer. Cost of production includes all the costs actually incurred in the operation of the mine including mining, processing and delivery of coal. Costs included within revenue include all production, transportation and maintenance costs including, without limitation, the following types of costs:

- Labor, which include wages and all related payroll taxes, benefits and fringes, including welfare plans; group insurance, vacations and other comparable benefits of employees
- Materials and supplies,
- Tools,
- Machinery and equipment not capitalized or leased,
- Costs of acquiring interests in coal reserves and surface lands,
- Rental of machinery and equipment,
- Power costs,
- Reasonable and necessary services by third parties
- Insurance including worker’s compensation
- Certain taxes, and
- Cost of reclamation

The contractually-determined coal sales price includes reimbursement of all costs incurred and the agreed-upon profit. The agreed-upon profit adjusts based on changes in the level of established indices (e.g., CPI-U and/or PPI indices). The cost-plus nature of the contracts provide assurance that all costs incurred, including contemporaneous and final reclamation, will be reimbursed by the respective customer and negates any risk of loss which allows the mines to remain cash flow positive through the end of the contract terms. The coal sales price as well as profitability at Coteau, Falkirk and Coyote Creek are not subject to any change based on market factors. Profitability at these mines is affected by two factors: demand for coal (because this impacts units of agreed profit that are charged) and changes in the indices that determine coal sales price (because this adjusts the agreed-upon per unit profit). Under any scenario, Coteau, Coyote Creek and Falkirk will be cash flow positive as a result of the terms of the mining agreements.

Extraction of Coteau, Coyote Creek and Falkirk’s lignite tonnages is only economically viable as a result of the long-term mining agreements in place with each mine’s respective customer. The development of the Coteau, Coyote Creek and Falkirk mines was conducted in tandem with the development of the respective mine mouth power plants each serve. The power plants were designed to operate exclusively on the coal provided by the adjacent mines. No other market exists for the lignite at Coteau, Coyote Creek and Falkirk as the cost of transportation makes sales to any entity other than the current mine-mouth operator unprofitable.

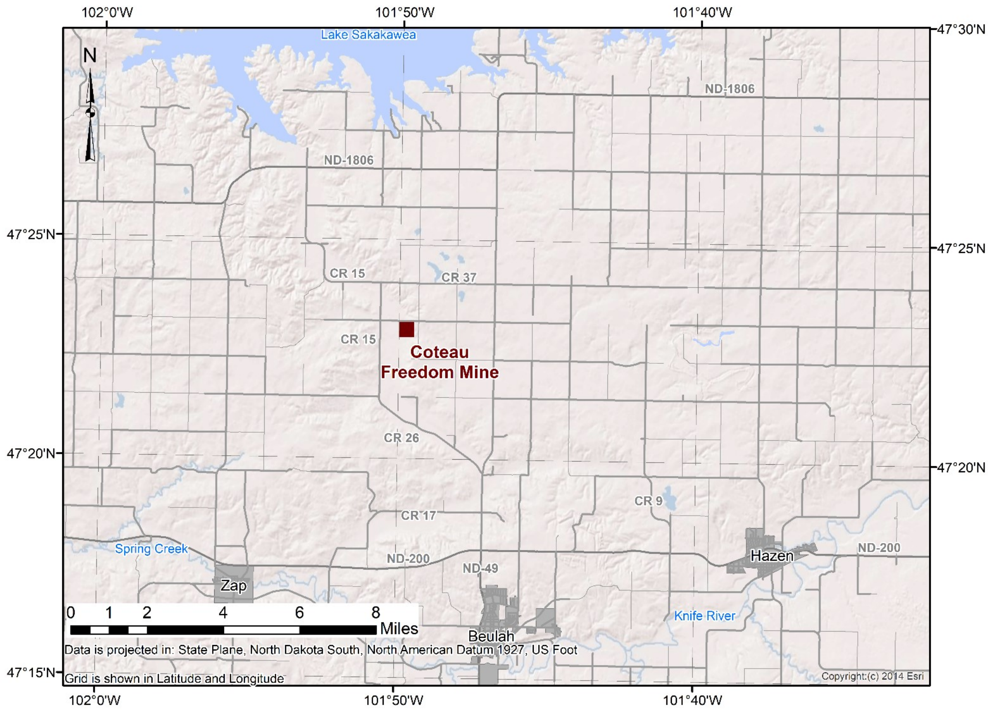
Coteau, Coyote Creek and Falkirk meet the definition of a VIE. In each case, NACCO is not the primary beneficiary of the VIE as it does not exercise financial control; therefore, NACCO does not consolidate the results of these operations within our financial statements. Instead, these contracts are accounted for as equity method investments. The income before income taxes associated with these VIEs is reported as Earnings of unconsolidated operations on the Consolidated Statements of Operations, and our investment is reported on the line Investments in unconsolidated subsidiaries in the Consolidated Balance Sheets.

Coteau

The Freedom Mine, operated by Coteau, generally produces between 11.5 million and 13.5 million tons of lignite coal annually. The mine started delivering coal in 1983. All production from the mine is delivered to Dakota Coal Company, a wholly owned subsidiary of Basin Electric. Dakota Coal Company then sells the coal to the Synfuels Plant, Antelope Valley Station and Leland Olds Station, all of which are operated by affiliates of Basin Electric. The Synfuels Plant is a coal gasification plant that manufactures synthetic natural gas and produces fertilizers, solvents, phenol, carbon dioxide, and other chemical products for sale. In March 2025, the term of the existing lignite sales agreement was extended until 2032. The term may be extended for an additional five year period, or until 2037, at the option of Coteau.

The Freedom Mine is located approximately 90 miles northwest of Bismarck, North Dakota (Figure 2.2). The main entrance to the Freedom Mine is accessed by means of a paved road and is located on County Road 15. Coteau holds 355 leases granting the right to extract approximately 32,748 acres of coal interests and the right to utilize approximately 22,771 acres of surface interests. In addition, Coteau owns in fee 33,888 acres of surface interests and 4,117 acres of coal interests. Substantially all of the leases held by Coteau were acquired in the early 1970s and have been replaced with new leases or have lease terms for a period sufficient to meet Coteau's contractual production requirements.

Figure 2.2 – Freedom Mine Location



The towns of Beulah, Hazen, and Stanton along with other smaller communities are within a 40-mile radius of the Freedom Mine and provide a vast supply of the employment base. Employees also come from the cities of Bismarck, Minot, and Dickinson, all of which are less than 100 miles away from the mine.

The Freedom Mine sources power for mine office facilities and operations from Roughrider Electric Cooperative, and water for the mine office facilities from the Southwest Water Authority. Fuel for equipment is supplied by multiple local vendors. The Freedom Mine has, or is currently constructing, all supporting infrastructure for mining operations.

The main entrance to the Freedom Mine is accessed by traveling north of Beulah on Highway 49 for one mile, then north on County Road 21 for two miles, then west on County Road 26 for three miles, and then north on County Road 15 for two miles as shown on Figure 2.2. Location of the Freedom Mine.

Travel to the Freedom Mine by air is possible by means of the Bismarck Municipal Airport, Bismarck, ND, which is approximately 90 miles southeast of the mine. From the airport, the mine is accessed by means of ground transportation by traveling west approximately 50 miles via Interstate 94, taking exit 110 and traveling north approximately 28 miles on ND Highway 49 to Beulah, ND, and so on as explained in the previous paragraph.

Travel to the Freedom Mine by rail is possible using the Amtrak Network, which runs through northern North Dakota mostly along the US Highway 2 corridor, and passes through the larger cities of Williston, Minot, Grand Forks, and Fargo, and smaller cities of Stanley, Rugby, and Devils Lake. From these locations, the mine can be accessed via ground transportation on Interstate 29 or Interstate 94 and various highways. The main highways are US Highway 2, US Highway 83, US Highway 85, US Highway 200, and US Highway 281.

North Dakota's freight rail service is largely provided by Burlington Northern Santa Fe Railway and Canadian Pacific Railway.

The coal tonnages are located in Mercer County, North Dakota, starting approximately two miles north of Beulah, North Dakota. The formations of sedimentary origin were deposited in the Williston Basin, the dominant structural feature of western North Dakota. The center of the basin is located near the city of Williston, North Dakota, approximately 100 miles northwest of the Freedom Mine. The economically mineable coal occurs in the Sentinel Butte Formation, and is overlain by the Coleharbor Formation. The Coleharbor Formation unconformably overlies the Sentinel Butte Formation. It includes all of the unconsolidated sediments resulting from deposition during glacial and interglacial periods. Lithologic types include gravel, sand, silt, clay and till. The modified glacial channels are in-filled with gravels, sands, silts and clays overlain by till. The coarser gravel and sand beds are generally limited to near the bottom of the channel fill. The general stratigraphic sequence in the upland portions of the reserve area consists of till, silty sands and clayey silts.

Fill-in drilling programs are routinely conducted by Coteau for the purpose of refining guidance related to ongoing operations. It is common practice at the Freedom Mine to tighten the drilling density within the three to four-year block ahead of active operations to an average drill hole spacing of 660-feet. However, additional exploration may also be scheduled in areas farther out to increase confidence in future mine plan projections.

Coteau utilizes standard surface mining techniques to extract coal from the proposed permit area. Mining operations will typically occur in a sequence of seven events: suitable plant growth material removal, overburden removal, coal removal, overburden replacement, final grading, suitable plant growth material replacement, and revegetation.

The mine office facilities and original equipment fleets at the Freedom Mine were constructed, acquired, or purchased new during the development stage of the mine. The facilities and equipment are maintained to allow for safe and efficient operation. The equipment is well maintained, in good physical condition and is either updated or replaced periodically with newer models or upgrades available to keep up with modern technology. As equipment wears out, Coteau evaluates what replacement option will be the most cost-efficient, including the evaluation of both new and used equipment.

The total cost of the property, plant and equipment, net of applicable accumulated amortization, depreciation and impairment as of December 31, 2024 is $162.2 million.

The Freedom Mine currently has no significant encumbrances to the property. No NOVs have been issued at the Freedom Mine in the past three years. Coteau currently has all permits in place for the Freedom Mine to operate through 2031. Permit expansions required to extend the life of the mine through 2045 will be acquired as needed. No mineral processing occurs at the Freedom Mine.

Falkirk Mine

The Falkirk Mine generally produces between 7 million and 8 million tons of lignite coal annually. The mine started delivering coal in 1978 primarily for the Coal Creek Station, an electric power generating station. Coal Creek Station was owned by GRE until May 1, 2022 when it was purchased by Rainbow Energy. The initial production period is expected to run through May 1, 2032, but the coal sales agreement may be extended or terminated early under certain circumstances. In 2014, Falkirk began delivering coal to Spiritwood Station, another electric power generating station owned by GRE.

The Falkirk Mine, operated by Falkirk, is located approximately 50 miles north of Bismarck, North Dakota on a paved access road off U.S. Highway 83 (Figure 2.3). Falkirk holds 334 leases granting the right to extract approximately 43,015 acres of coal interests and the right to utilize approximately 22,964 acres of surface interests. In addition, Falkirk owns in fee 41,034 acres of surface interests and 1,788 acres of coal interests. Substantially all of the leases held by Falkirk were acquired in the early 1970s with initial terms that have been further extended by the continuation of mining operations.

The towns of Underwood and Washburn are located within ten miles of the mine, with other small communities also nearby. Numerous employees also reside in Bismarck and Mandan, a distance of about 50 miles.

The Falkirk Mine receives both power and water from Coal Creek Station. However, Falkirk's East shift change building receives water from McLean-Sheridan Rural Water. Fuel for equipment is supplied by multiple local vendors including: Farstad Oil, Missouri Valley Petroleum, and Enerbase Cooperative Resources.

The main entrance to the Falkirk Mine is accessed by traveling north from Bismarck on State Highway 83 for approximately 50 miles, then going west on the access road, 1st Street SW located four miles south of Underwood. The mine office is located two miles to the west.

Travel to the Falkirk Mine by air is possible using the Bismarck Airport in Bismarck, ND, approximately 55 miles south of the mine, and then using ground transportation, traveling via US Highway 83.

The main railway systems near the Falkirk Mine are Canadian Pacific, BNSF, and Dakota Missouri Valley & Western (DMVW). DMVW crosses through the Falkirk Mine Reserve.

The coal tonnages are located in McLean County, North Dakota, from approximately nine miles northwest of the town of Washburn, North Dakota to four miles north of the town of Underwood, North Dakota. Structurally, the area is located on an intercratonic basin containing a thick sequence of sedimentary rocks. The economically mineable coal occurs in the Sentinel Butte Formation and the Bullion Creek Formation and are unconformably overlain by the Coleharbor Formation. The Sentinel Butte Formation conformably overlies the Bullion Creek Formation. The general stratigraphic sequence in the upland portions of the reserve area (Sentinel Butte Formation) consists of till, silty sands and clayey silts, main hagel lignite bed, silty clay, lower lignite of the hagel lignite interval and silty clays. Beneath the Tavis Creek, there is a repeating sequence of silty to sand clays with generally thin lignite beds.

Operationally, overburden and interburden removal are accomplished using scrapers, dozers, front end loaders, truck shovel fleets, and draglines. Lignite is mined with front end loaders or hydraulic backhoes, and loaded into haul trucks to transport to the stockpile or directly to the customer via truck dumps and conveyors.

Fill-in drilling programs are routinely conducted by Falkirk for the purpose of refining guidance related to ongoing operations. It is common practice at the Falkirk Mine to tighten the drilling density within the three to four-year block ahead of active operations to an average drill hole spacing of 1320-feet. However, additional exploration may also be scheduled in areas farther out to increase confidence in future mine plan projections.

The mine office facilities and original equipment fleets at the Falkirk Mine were constructed, acquired, or purchased new during the development stage of the mine. The facilities and equipment are maintained to allow for safe and efficient operation. The equipment is well maintained, in good physical condition and is either updated or replaced periodically with newer models or upgrades available to keep up with modern technology. As equipment wears out, Falkirk evaluates what replacement option will be the most cost-efficient, including the evaluation of both new and used equipment.

The total cost of the property, plant and equipment, net of applicable accumulated amortization, depreciation and impairment as of December 31, 2024 is $58.7 million.

The Falkirk Mine currently has no significant encumbrances to the property. No Notice of Violations (NOVs) have been issued at the Falkirk Mine in the past three years. There are no outstanding permits related to the LOM plan awaiting regulatory approval. The Falkirk Mining Company currently has all permits in place to operate and adhere to the current mine plan. No mineral processing occurs at the Falkirk Mine.

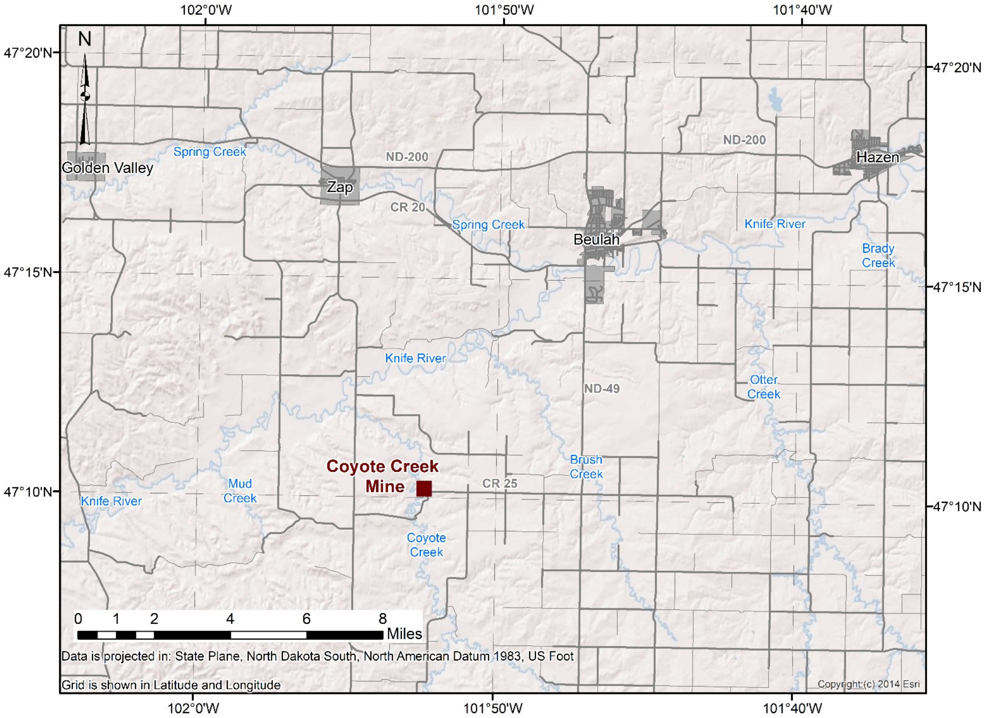
Figure 2.3 – Falkirk Mine Location

Coyote Creek

The Coyote Creek Mine generally produces between 1.5 million and 2.0 million tons of lignite annually. The mine began delivering coal in 2016 to the Coyote Station owned by Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Company and Northwestern Corporation. The term of the existing lignite sales agreement terminates in 2040.

The Coyote Creek Mine is located approximately 70 miles northwest of Bismarck, North Dakota (Figure 2.4). The main entrance to the Coyote Creek Mine is accessed by means of a four-mile paved road extending west off of State Highway 49. Coyote Creek holds a sublease to 86 leases granting the right to mine approximately 8,129 acres of coal interests and the right to utilize approximately 15,168 acres of surface interests. In addition, Coyote Creek Mine owns in fee 160 acres of surface interests and has four easements to conduct coal mining operations on approximately 352 acres.

Figure 2.4 – Coyote Creek Mine Location



The towns of Beulah, Hazen, and Stanton along with other smaller communities are within a 40-mile radius of the Coyote Creek Mine and provide a vast supply and employment base. A vast supply and employment base also come from some of the major cities of Bismarck, Minot, and Dickinson, all of which are less than 100 miles away from the mine.

The Coyote Creek Mine sources power for mine office facilities and operations from Roughrider Electric Cooperative and Montana-Dakota Utilities Co., and water for the mine office facilities from the Southwest Water Authority. Fuel for equipment is supplied by multiple local vendors. The Coyote Creek Mine has all supporting infrastructure for mining operations.

The main entrance to the mine will be accessed by traveling south of Beulah on Highway 49 for five miles, then west on County Road 25 for four miles. The general location of the Coyote Creek Mine is shown in Figure 1.0 Location of Coyote Creek Mine.

Travel to the Coyote Creek Mine by air is possible using the Bismarck Municipal Airport, Bismarck, ND, approximately 75 miles southeast of the mine. From the airport, the mine is accessed using ground transportation by traveling west approximately 50 miles via Interstate 94, taking exit 110 and traveling north approximately 21 miles on ND Highway 49 to County Road 25, then west for four miles on County Road 25.

Travel to the Coyote Creek Mine by rail is possible using the Amtrak Network, which runs through northern North Dakota mostly along the US Highway 2 corridor, and passes through the larger cities of Williston, Minot, Grand Forks, and Fargo, and smaller cities of Stanley, Rugby, and Devils Lake. From these locations, the mine can be accessed via ground transportation on Interstate 29 or Interstate 94 and various highways. The main highways are US Highway 2, US Highway 83, US Highway 85, US Highway 200, and US Highway 281.

North Dakota’s freight rail service is largely provided by Burlington Northern Santa Fe Railway and Canadian Pacific Railway.

The coal tonnages are located in Mercer County, North Dakota, starting approximately six miles southwest of Beulah, North Dakota. The formations of sedimentary origin were deposited in the Williston Basin, the dominant structural feature of western North Dakota. The center of the basin is located near the city of Williston, North Dakota, approximately 110 miles northwest of the Coyote Creek Mine. The economically mineable coal occurs in the Sentinel Butte Formation, and is overlain by the Coleharbor Formation. The Coleharbor Formation unconformably overlies the Sentinel Butte Formation. It includes all of the unconsolidated sediments resulting from deposition during glacial and interglacial periods. Lithologic types include gravel, sand silt, clay and till. The modified glacial channels are in-filled with gravels, sands, silts and clays overlain by till. The coarser gravel and sand beds are generally limited to near the bottom of the channel fill. The general stratigraphic sequence in the upland portions of the reserve area consists of till, silty sands and clayey silts.

Fill-in drilling programs are routinely conducted by Coyote Creek for the purpose of refining guidance related to ongoing operations. It is common practice at the Coyote Creek Mine to tighten the drilling density within the three to four-year block ahead of active operations to an average drill hole spacing of 660-feet. However, additional exploration may also be scheduled in areas farther out to increase confidence in future mine plan projections.

Operationally, overburden removal is accomplished using scrapers, dozers, front end loaders, excavators, truck fleets, and a dragline. Lignite is mined with front end loaders, and loaded into haul trucks to transport to the coal stockpile.

The mine office facilities and original equipment fleets at the Coyote Creek Mine were constructed, acquired, or purchased during the development stage of the mine. The facilities and equipment are maintained to allow for safe and efficient operation. The equipment is well maintained, in good physical condition and is either updated or replaced periodically with newer models or upgrades available to keep up with modern technology. As equipment wears out, Coyote Creek evaluates what replacement option will be the most cost-efficient, including the evaluation of both new and used equipment.

The total cost of the property, plant and equipment, net of applicable accumulated amortization, depreciation and impairment as of December 31, 2024 is $105.9 million.

The Coyote Creek Mine currently has no significant encumbrances to the property. No NOVs have been issued at the Coyote Creek Mine in the past three years. There are no outstanding permits related to the LOM plan awaiting regulatory approval. Coyote currently has all permits in place for the Coyote Creek Mine to operate and adhere to a mine plan projected through 2040. No mineral processing occurs at the Coyote Creek Mine.

3.0 Internal Control Disclosure Over Mineral Resources and Reserves

The modeling and analysis of our resources and reserves has been developed by our mine personnel and reviewed by several levels of internal management, including the QPs. The development of such resources and reserves estimates, including related assumptions, was a collaborative effort between the QPs and Company staff. This section summarizes the internal control considerations for our development of estimations, including assumptions, used in resource and reserve analysis and modeling.

When determining resources and reserves, as well as the differences between resources and reserves, management developed specific criteria, each of which must be met to qualify as a resource or reserve, respectively. These criteria, such as demonstration of economic viability, points of reference and grade, are specific and attainable. The QPs and our management team agree on the reasonableness of the criteria for the purposes of estimating resources and reserves. Calculations using these criteria are reviewed and validated by the QPs.

Estimations and assumptions were developed independently for each significant mineral location. All estimates require a combination of historical data and key assumptions and parameters. When possible, resources and data from generally accepted industry sources were used to develop these estimations. Review teams were created by utilizing subject matter experts from across all of NACCO to review the cost assumptions and estimations used as the basis of the classification of mineral resources and reserves.

Geological modeling and mine planning efforts serve as a base assumption for resource estimates at MLMC. These outputs have been prepared and reviewed by Company personnel. Mine planning decisions are determined and agreed upon by our management. Management adjusts forward-looking models by reference to historic mining results, including by reviewing actual versus predicted levels of production from the mineral deposit, and if necessary, re-evaluating mining methodologies if production outcomes were not realized as predicted. Ongoing mining of the mineral deposit, coupled with product quality validation pursuant to our and our customer expectations, provides further empirical evidence as to the homogeneity, continuity and characteristics of the deposit. Geologic modeling assumptions are evaluated to historic mining results and are adjusted if necessary to better reflect actual mining results. Ongoing quality validation of production also provides a means to monitor for any potential changes in quality. Also, ongoing monitoring of ground conditions within the mine, surveying for evidence of subsidence and other visible signs of deterioration that may signal the need to re-evaluate rock mechanics and structure of the mine ultimately inform extraction ratios and mine design, which underpin mineral reserve estimates.

Management also assesses risks inherent in mineral resource and reserve estimates, such as the accuracy of geophysical data that is used to support mine planning, changes in QPs, identifying hazards and informing operations of the presence of mineable deposits. Also, management is aware of risks associated with potential gaps in assessing the completeness of mineral extraction licenses, entitlements or rights, or changes in laws or regulations that could directly impact the ability to assess mineral resources and reserves or impact production levels. Risks inherent in overestimated reserves can impact financial performance when revealed, such as changes in amortizations that are based on life of mine estimates.

4.0 Customer-owned Properties

South Hallsville No. 1 Mine — The Sabine Mining Company

The Sabine Mining Company (Sabine) operated the Sabine Mine in Texas. All production from Sabine was delivered to Southwestern Electric Power Company's (SWEPCO) Henry W. Pirkey Plant (the Pirkey Plant). SWEPCO is an American Electric Power (AEP) company. As a result of the early retirement of the Pirkey Plant, Sabine ceased deliveries in the first quarter of 2023 and commenced final reclamation on April 1, 2023. Funding for mine reclamation is the responsibility of SWEPCO, and Sabine receives compensation for providing mine reclamation services. Sabine will provide mine reclamation services through September 30, 2026. As of October 1, 2026, SWEPCO has an obligation to acquire all of the capital stock of Sabine and complete the remaining mine reclamation.

5.0 Facilities and Equipment

The facilities and equipment for each of the coal mines are maintained to allow for safe and efficient operation. The equipment is well maintained, in good physical condition and is either updated or replaced periodically with newer models or upgrades available to keep up with modern technology. As equipment wears out, the mines evaluate what replacement option will be the most cost-efficient, including the evaluation of both new and used equipment, and proceed with that replacement. The mining method and total cost of the property, plant and equipment, net of applicable accumulated amortization, depreciation and impairment as of December 31, 2024 is set forth in the chart below:

Location	Mining Method	Total Historical Cost of Mine Property, Plant and Equipment, Net of Applicable Accumulated Amortization, Depreciation and Impairment	
Unconsolidated Mining Operations		*(in millions)*	
Freedom Mine — The Coteau Properties Company	Dragline operation with 3 draglines	$	162.2
Falkirk Mine — The Falkirk Mining Company	Dragline operation with 4 draglines	$	58.7
Coyote Creek Mine — Coyote Creek Mining Company, LLC	Dragline operation with 1 dragline	$	105.9
Consolidated Mining Operations			
Red Hills Mine — Mississippi Lignite Mining Company	Dragline operation with 1 dragline	$	52.5

NAMining Segment - Operations

NAMining provides contract mining services for independently owned mines and quarries, primarily operating and maintaining draglines at limestone quarries and utilizing other mining equipment at sand and gravel quarries. At December 31, 2024, NAMining operated 31 draglines and other equipment at 23 quarries. Of the 31 draglines, 7 are owned by us and 24 are owned by customers. At December 31, 2024, NAMining had $72.7 million in property, plant and equipment, net of applicable accumulated amortization, depreciation and impairment.

The mining process at the limestone mines involves excavating limestone from a water-filled quarry utilizing draglines. The excavated limestone is transported and processed by the customer. The following mines were operational during 2024:

Location Name	Aggregate	Location	State	Customer	Year NACCO Started Operations
White Rock — North	Limestone	Miami	FL	WRQ	1995
Krome	Limestone	Miami	FL	Cemex	2003
Alico	Limestone	Ft. Myers	FL	Cemex	2004
FEC	Limestone	Miami	FL	Cemex	2005
SCL	Limestone	Miami	FL	Cemex	2006
Central State Aggregates	Limestone	Zephyrhills	FL	McDonald Group	2016
Mid Coast Aggregates	Limestone	Sumter County	FL	McDonald Group	2016
West Florida Aggregates	Limestone	Hernando County	FL	McDonald Group	2016
St. Catherine	Limestone	Sumter County	FL	Cemex	2016
Center Hill	Limestone	Sumter County	FL	Cemex	2016
Inglis	Limestone	Crystal River	FL	Cemex	2016
Titan Corkscrew	Limestone	Ft. Myers	FL	Titan America	2017
Palm Beach Aggregates	Limestone	Loxahatchee	FL	Palm Beach Aggregates	2017
Perry	Limestone	Lamont	FL	Martin Marietta	2018
SDI Aggregates	Limestone	Florida City	FL	Martin Marietta	2018
Queenfield	Sand and gravel	King William County	VA	Holcim Group	2018
Newberry	Limestone	Alachua County	FL	Summit Materials/Quikrete	2019
Seven Diamonds	Limestone	Pasco County	FL	Summit Materials/Quikrete	2021
Little River	Sand and gravel	Ashdown	AR	Heidelberg Materials	2021
Rosser	Sand and gravel	Ennis	TX	Heidelberg Materials	2021
Brooksville Cement Plant	Limestone	Brooksville	FL	Cemex	2021
Ash Grove	Limestone	Louisville	NE	Ash Grove, A CRH Company	2022
MDL[(a)]	Phosphate	Polk County	FL	Mineral Development, LLC	2024

[(a)] The MDL quarry was idled during 2024. NAMining mined de minimis amounts at this location during 2024.

NAMining's customers control all of the limestone and sand reserves within their respective mines. NAMining has no title, claim, lease or option to acquire any of the reserves at any of the mines where it provides services.

Access to the White Rock mine is by means of a paved road from 122nd Avenue.

Access to the Krome mine is by means of a paved road from Krome Avenue.

Access to the Alico mine is by means of a paved road from Alico Road.

Access to the FEC mine is by means of a paved road from NW 118th Avenue.

Access to the SCL mine is by means of a paved road from NW 137th Avenue.

Access to the Central State Aggregates mine is by means of a paved road from Yonkers Boulevard.

Access to the Mid Coast Aggregates mine is by means of a paved road from State Road 50.

Access to the West Florida Aggregates mine is by means of a paved road from Cortez Boulevard.

Access to the St. Catherine mine is by means of a paved road from County Road 673.

Access to the Center Hill mine is by means of a paved road from West Kings Highway.

Access to the Inglis mine is by means of a paved road from Highway 19 South.

Access to the Titan Corkscrew mine is by means of a paved road from Corkscrew Road.

Access to the Palm Beach Aggregates mine is by means of a paved road from State Road 80.

Access to the Perry mine is by means of paved road from Nutall Rise Road.

Access to the SDI Aggregates mine is by means of paved road from SW 167th AVE.

Access to the Queenfield Mine is by means of paved road from Dabney's Mill Road (SR 604).

Access to the Newberry mine is by means of paved road from NW County Road 235 (CR 235).

Access to the Seven Diamonds mine is by means of a paved road from US-41 S/Broad St.

Access to the Little River mine is by means of an unpaved road from Little River 60.

Access to the Rosser mine is by means of a paved road from TX-34 S.

Access to Brooksville Cement plant is by means of a paved road from Cement Plant Road.

Access to Ash Grove Louisville Quarry is by means of a paved road from HWY 50.

Access to MDL Quarry is by means of Noralyn Mine Road.

Minerals Management - Operations

As an owner of royalty and mineral interests, our access to information concerning activity and operations of our royalty and mineral interests is limited. We do not have information that would be available to a company with oil and natural gas operations because detailed information is not generally available to owners of royalty and mineral interests. Consequently, the exact number of wells producing from or drilling on our mineral interests at a given point in time is not determinable. The following table sets forth our estimate of the number of gross and net productive wells:

	December 31, 2024		December 31, 2023	
	Gross	**Net**	Gross	Net
Oil	**1,295**	**4.3**	1,646	6.6
Natural Gas	**922**	**18.5**	246	13.5
Total	**2,217**	**22.8**	1,892	20.1

Gross wells are the total wells in which an interest is owned.

Net wells are calculated based on our net royalty interest, factoring in both ownership percentage of gross wells and royalty rate.

The majority of our producing mineral and royalty interest acreage now, or in the future, can be pooled with third-party acreage to form pooled units. Pooling proportionately reduces our royalty interest in wells drilled in a pooled unit, and it proportionately increases the number of wells in which we have such reduced royalty interest.

The following table includes our estimate of acreage for oil and gas mineral interests, NPRIs, and ORRIs:

	December 31, 2024		December 31, 2023	
	Gross Acres	**Net Royalty Acres**	Gross Acres	Net Royalty Acres
Appalachia	**34,661**	**36,199**	34,661	36,199
Gulf Coast	**27,932**	**20,105**	27,932	20,105
Permian	**121,437**	**4,568**	120,636	4,556
Rockies	**13,233**	**659**	326	72
Williston	**1,194**	**2,388**	1,194	2,388
Total	**198,457**	**63,919**	184,749	63,320

We may own more than one type of interest in the same tract of land, but the overlap is not significant. Net royalty acres are calculated based on our ownership and royalty rate, normalized to a standard 1/8th royalty lease, and assumes a 1/4th royalty rate for unleased acres.

The following table includes our estimate of developed and undeveloped acreage based on the gross acres in a basin or region and includes mineral interests, NPRIs, and ORRIs:

	December 31, 2024			December 31, 2023		
	Developed Acreage	**Undeveloped Acreage**	**Gross Acreage**	Developed Acreage	Undeveloped Acreage	Gross Acreage
Appalachia	**32,156**	**2,505**	**34,661**	32,156	2,505	34,661
Gulf Coast	**22,191**	**5,741**	**27,932**	22,191	5,741	27,932
Permian	**118,021**	**3,416**	**121,437**	117,220	3,416	120,636
Rockies	**7,696**	**5,537**	**13,233**	326	—	326
Williston	**—**	**1,194**	**1,194**	—	1,194	1,194
Total	**180,064**	**18,393**	**198,457**	171,893	12,856	184,749

Undeveloped acres are either unleased and open or are leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Production and Price History

The following table sets forth the estimated oil and natural gas production data related to our mineral and royalty interests as well as certain price and cost information for the years ended December 31:

	2024 [4]	2023 [4]
Production data:		
Oil (bbl) [1]	**149,529**	98,553
NGL (bbl) [1]	**65,053**	56,768
Residue gas (Mcf) [2]	**8,482,414**	7,601,521
Total BOE [3]	**1,628,318**	1,422,241
Average realized prices:		
Oil (bbl) [1]	**$ 78.45**	$ 72.19
NGL (bbl) [1]	**$ 22.94**	$ 23.33
Residue gas (Mcf) [2]	**$ 2.08**	$ 2.37
Average unit cost		
BOE [3]	**$ 2.79**	$ 3.32

[1] Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume.

[2] Mcf. One thousand cubic feet of natural gas at the contractual pressure and temperature bases.

[3] BOE. Barrel of Oil Equivalent, a conversion factor of 6 MCF of gas was used for 1 equivalent bbl of oil.

[4] As an owner of mineral and royalty interests, our access to information concerning activity and operations of our royalty and mineral interests is limited. As a result, we estimated the last two months of 2024 and 2023 production and pricing data using projections based on decline rates of wells and prior expense information.

Evaluation and Review of Reserves

The reserve estimates as of December 31, 2024 were prepared by Haas & Cobb Petroleum Consultants (Haas & Cobb). Haas & Cobb is an independent, third-party, petroleum engineering firm that meets industry-standards for qualifications, independence, objectivity and confidentiality. The primary technical person, Franklin Stagg, responsible for preparing the Reserve Report, Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at Haas & Cobb since 2016 and has over 9 years of industry experience. Haas & Cobb does not own an interest in NACCO or any of our properties, nor is it employed on a contingent basis. A copy of Haas & Cobb's estimated proved reserve report as of December 31, 2024 is incorporated by reference herein to Exhibit 99.1 to this Form 10-K.

The properties evaluated for proved reserves are located in Alabama, Louisiana, New Mexico, Ohio, Pennsylvania, Texas, Utah and Wyoming and represent all of our oil and gas reserves. A reserves audit is not the same as a financial audit. Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing, and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on several variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices, and future production rates and costs.

The reserves estimates have been prepared using standard engineering practices generally accepted by the petroleum industry. Decline curve analysis was used to estimate the remaining reserves of pressure depletion reservoirs with enough historical production data to establish decline trends. Reservoirs under non-pressure depletion drive mechanisms and non-producing reserves were estimated by volumetric analysis, research of analogous reservoirs, or a combination of both. Reserves have been estimated using deterministic and probabilistic methods. The appropriate methodology was used, as deemed necessary, to estimate reserves in conformance with SEC regulations. The maximum remaining reserves life assigned to wells included in this report is 50 years.

Total net proved reserves are defined as our natural gas and hydrocarbon liquid reserves after deducting all royalties, overriding royalties, and reversionary interests owned by outside parties that become effective upon payout of specified monetary balances. All reserves estimates have been prepared using standard engineering practices generally accepted by the petroleum industry and conform to guidelines developed and adopted by the SEC.

Technologies Used in Reserve Estimation

The SEC's reserves rules allow the use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. The term reasonable certainty implies a high degree of confidence that the quantities of oil, natural gas and/or NGLs actually recovered will equal or exceed the estimate. To achieve reasonable certainty, we employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The accuracy of the estimates of our reserves is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating costs, development costs and workovers, all of which may vary considerably from actual results;
- future prices of oil, natural gas and NGLs, which may vary considerably from those estimated; and
- the judgment of the persons preparing the estimates.

The following table presents our estimated net proved oil and natural gas reserves based on the reserve report prepared by Haas & Cobb, our independent petroleum engineering firm. All of our reserves are located in the United States.

	Net reserves as of December 31, 2024			Net reserves as of December 31, 2023		
	Oil (bbl) (1)	**NGL (bbl) (1)**	**Residue gas (Mcf) (2)**	Oil (bbl) (1)	NGL (bbl) (1)	Residue gas (Mcf) (2)
Proved developed	**620,790**	**443,650**	**27,491,840**	656,370	380,650	23,596,110
Proved undeveloped	**74,400**	**30,280**	**135,830**	9,020	3,720	26,420
Total	**695,190**	**473,930**	**27,627,670**	665,390	384,370	23,622,530

(1) Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume.

(2) Mcf. One thousand cubic feet of natural gas at the contractual pressure and temperature bases.

We do not currently have any material investments under which it would be required to bear the cost of exploration, production or development. We did not make capital expenditures to convert proved undeveloped reserves from undeveloped to developed.

Internal Control Disclosure

Our internal staff works closely with Haas & Cobb to ensure the integrity, accuracy and timeliness of the data used to calculate proved reserves relating to NACCO's assets. Internal technical team members met with independent reserve engineers periodically during the period covered by the reserves report to discuss the assumptions and methods used in the proved reserve estimation process.

The preparation of our proved reserve estimates is completed in accordance with internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- Review and verification of historical production data, which data is based on actual production as reported by third-party producers who lease our royalty and mineral interests;
- Preparation of reserve estimates by Haas & Cobb under the direct supervision of internal staff; and
- Verification of property ownership by our land department.

The Minerals Management Segment's Vice President of Engineering and Finance is the technical person primarily responsible for overseeing the preparation of the internal reserve estimates and for coordinating with Haas & Cobb in the preparation of the third-party reserve report. The Vice President of Engineering and Finance has over 15 years of industry experience with positions of increasing responsibility and reports directly to the President of Catapult Mineral Partners, our business unit focused on managing and expanding our portfolio of oil and gas mineral and royalty interests.

Estimated Proved Reserves

The following table summarizes changes in proved reserves during the year ended December 31, 2024:

	Estimated Proved Reserves		
	Oil (bbl) (1)	**NGL (bbl) (1)**	**Residue gas (Mcf) (2)**
December 31, 2023	665,390	384,370	23,622,530
Purchases	14,005	1,233	29,268
Extensions and discoveries	236,491	85,087	7,040,710
Revisions of previous estimates (3)	(105,479)	63,441	(498,627)
Production	(32,077)	(15,687)	(1,843,911)
Other	(83,140)	(44,514)	(722,300)
December 31, 2024	**695,190**	**473,930**	**27,627,670**

Estimated Proved Undeveloped Reserves (PUDs)

The following table summarizes changes in PUDs during the year ended December 31, 2024:

	Estimated Proved Undeveloped Reserves		
	Oil (bbl) (1)	**NGL (bbl) (1)**	**Residue gas (Mcf) (2)**
December 31, 2023	9,020	3,720	26,420
Purchases	2,208	38	5,237
Extensions and discoveries	69,716	27,902	126,724
Conversions	(3,322)	(1,914)	(10,017)
Revisions of previous estimates (3)	(3,222)	534	(12,534)
December 31, 2024	**74,400**	**30,280**	**135,830**

(1) Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume.

(2) Mcf. One thousand cubic feet of natural gas at the contractual pressure and temperature bases.

(3) Revisions of previous estimates include technical revisions due to changes in commodity prices, historical and projected performance and other factors.

As an owner of mineral and royalty interests, we generally do not have evidence or approval of operators' development plans. As a result, proved undeveloped reserve estimates are limited to those relatively few locations for which drilling permits have been publicly filed. As of December 31, 2024, PUD reserves consists of 89 wells in various stages of drilling or completions. As of December 31, 2024, less than 1% of our total proved reserves were classified as PUDs.

Headquarter locations

NACCO leases office space in Highland Hills, Ohio, a suburb of Cleveland, Ohio, which serves as our corporate headquarters.

Coal Mining and Minerals Management lease corporate headquarters office space in Plano, Texas.

NAMining leases office and warehouse space in Medley, Florida.

Item 3. LEGAL PROCEEDINGS

We are not a party to any material legal proceeding other than ordinary routine litigation incidental to our respective business.

Item 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of The Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95 filed with this Form 10-K.

PART II

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

NACCO's Class A common stock is traded on the New York Stock Exchange under the ticker symbol NC. Because of transfer restrictions, no trading market has developed, or is expected to develop, for our Class B common stock. The Class B common stock is convertible into Class A common stock on a one-for-one basis.

At December 31, 2024, there were 648 Class A common stockholders of record and 110 Class B common stockholders of record.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Issuer Purchases of Equity Securities (1)

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of the Publicly Announced Program	(d) Maximum Number of Shares (or Approximate Dollar Value) that May Yet Be Purchased Under the Program (1)
October 1 to 31, 2024	—	$ —	—	$ 8,909,786
November 1 to 30, 2024	—	$ —	—	$ 8,909,786
December 1 to 31, 2024	12,610	$ 29.20	12,610	$ 8,541,574
Total	12,610	$ 29.20	12,610	$ 8,541,574

(1) On November 7, 2023, our Board of Directors approved a stock purchase program providing for the purchase of up to $20.0 million of our outstanding Class A common stock through December 31, 2025. See Note 12 to the Consolidated Financial Statements in this Form 10-K for a discussion of our stock repurchase programs.

Item 6. [RESERVED]

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
NACCO INDUSTRIES, INC. AND SUBSIDIARIES
(Tabular Amounts in Thousands, Except Per Share and Percentage Data)

OVERVIEW

Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These statements are based upon management's current expectations and are subject to various uncertainties and changes in circumstances. Important factors that could cause actual results to differ materially from those described in these forward-looking statements are set forth below under the heading Forward-Looking Statements.

Management's Discussion and Analysis of Financial Condition and Results of Operations include NACCO Industries, Inc.® (NACCO) and its wholly owned subsidiary, NACCO Natural Resources Corporation® (NACCO Natural Resources and with NACCO collectively, the Company, we, our or us). NACCO Natural Resources brings natural resources to life by delivering aggregates, minerals, reliable fuels and environmental solutions through our robust portfolio of businesses. We operate under three business segments: Coal Mining, North American Mining® (NAMining) and Minerals Management. The Coal Mining segment operates surface coal mines for power generation companies. The NAMining segment is a trusted mining partner for producers of aggregates, activated carbon, lithium and other industrial minerals. The Minerals Management segment, which includes the Catapult Mineral Partners (Catapult) business, acquires and promotes the development of mineral interests. Mitigation Resources of North America® (Mitigation Resources) provides stream and wetland mitigation solutions as well as comprehensive reclamation and restoration construction services. In addition, ReGen Resources is pursuing opportunities to develop new power generation resources.

We have items not directly attributable to a reportable segment that are not included in the reported financial results of the operating segment. These items primarily include administrative costs related to public company reporting requirements, including management and board compensation, and the financial results of Bellaire Corporation (Bellaire), Mitigation Resources, ReGen Resources and other developing businesses. Bellaire manages our long-term liabilities related to former Eastern U.S. underground mining activities.

All financial statement line items below operating profit (loss) (other income, including interest expense and interest income, the provision (benefit) for income taxes and net income (loss)) are presented and discussed within this Form 10-K on a consolidated basis.

See Item 1. Business beginning on page 1 in this Form 10-K for further discussion of NACCO's subsidiaries. Additional information relating to financial and operating data on a segment basis (including unallocated items) is set forth in Note 15 to the Consolidated Financial Statements contained in this Form 10-K.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities (if any). On an ongoing basis, we evaluate our estimates based on historical experience, actuarial valuations and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from those estimates.

We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of the consolidated financial statements.

Revenue recognition: Revenues are recognized when control of the promised goods or services is transferred to our customers, in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. We account for revenue in accordance with Accounting Standards Codification (ASC) Topic 606, Revenue from Contracts with Customers. See Note 3 to the Consolidated Financial Statements in this Form 10-K for further discussion of our revenue recognition.

Long-lived assets: We periodically evaluate long-lived assets for impairment when changes in circumstances or the occurrence of certain events indicate the carrying amount of an asset or asset group may not be recoverable. Upon identification of indicators of impairment, we evaluate the carrying value of the asset by comparing the estimated future undiscounted cash flows generated from the use of the asset or asset group and its eventual disposition with the asset's net carrying value. If the carrying value of an asset is considered impaired, an impairment charge is recorded for the amount that the carrying value of the long-lived asset or asset group exceeds its fair value. Fair value is estimated as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Identifying and assessing whether impairment indicators exist, or if events or changes in circumstances have occurred, including assumptions about future power plant dispatch levels, changes in future sales price, operating costs and other factors that impact anticipated revenue and customer demand, requires significant judgment. We determined that indicators of impairment existed at MLMC during the fourth quarter of 2023 and, as a result, MLMC's long-lived assets were reviewed for impairment. We assessed the recoverability of the MLMC asset group and determined that the assets were not fully recoverable when compared to the remaining future undiscounted cash flows from these assets. As a result, we estimated the fair value of the asset group which resulted in a non-cash, long-lived asset impairment charge of $65.9 million in 2023.

See Note 9 to the Consolidated Financial Statements in this Form 10-K for further discussion of our impairment analysis.

Income taxes: We file income tax returns in the U.S. federal jurisdiction, and in various state and foreign jurisdictions. Tax law requires certain items to be included in the tax return at different times than the items are reflected in the financial statements. Some of these differences are permanent, such as the benefit associated with percentage depletion (tax deductions for depletion that may exceed the tax basis in the mineral reserve) and expenses that are not deductible for tax purposes, and some differences are temporary, reversing over time, such as depreciation expense. These temporary differences create deferred tax assets and liabilities using currently enacted tax rates. The objective of accounting for income taxes is to recognize the amount of taxes payable or refundable for the current year, and deferred tax liabilities and assets for the future tax consequences of events that have been recognized in the financial statements or tax returns. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the provision for income taxes in the period that includes the enactment date. Management is required to estimate the timing of the recognition of deferred tax assets and liabilities, make assumptions about the future deductibility of deferred tax assets and assess deferred tax liabilities based on enacted laws and tax rates for the appropriate tax jurisdictions to determine the amount of such deferred tax assets and liabilities. Changes in the calculated deferred tax assets and liabilities may occur in certain circumstances, including statutory income tax rate changes, statutory tax law changes, or changes in the structure or tax status.

Our tax assets, liabilities, and tax expense are supported by historical earnings and losses and our best estimates and assumptions of future earnings. We assess whether a valuation allowance should be established against our deferred tax assets based on consideration of all available evidence, both positive and negative, using a more likely than not standard. This assessment considers, among other matters, scheduled reversals of deferred tax liabilities, projected future taxable income, tax-planning strategies, and results of recent operations. The assumptions about future taxable income require significant judgment and are consistent with the plans and estimates we use to manage the underlying businesses. When we determine, based on all available evidence, that it is more likely than not that deferred tax assets will not be realized, a valuation allowance is established.

Since significant judgment is required to assess the future tax consequences of events that have been recognized in our financial statements or tax returns, the ultimate resolution of these events could result in adjustments to our financial statements and such adjustments could be material. We believe the current assumptions, judgments and other considerations used to estimate the current year accrued and deferred tax positions are appropriate. If the actual outcome of future tax consequences differs from these estimates and assumptions, due to changes or future events, the resulting change to the provision for income taxes could have a material impact on our results of operations and financial position. Since 2021, we have participated in a voluntary program with the IRS called Compliance Assurance Process (CAP). The objective of CAP is to contemporaneously work with the IRS to achieve federal tax compliance and resolve all or most issues prior to the filing of the tax return.

See Note 13 to the Consolidated Financial Statements in this Form 10-K for further discussion of our income taxes.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
NACCO INDUSTRIES, INC. AND SUBSIDIARIES
(Tabular Amounts in Thousands, Except Per Share and Percentage Data)

CONSOLIDATED FINANCIAL SUMMARY

Our results of operations were as follows for the years ended December 31:

	2024	2023
Revenues:		
Coal Mining	$ 68,611	$ 85,415
NAMining	119,600	90,532
Minerals Management	34,579	32,985
Unallocated Items	17,707	8,459
Eliminations	(2,789)	(2,597)
Total revenue	$ 237,708	$ 214,794
Operating profit (loss):		
Coal Mining	$ 24,311	$ (71,342)
NAMining	5,772	3,348
Minerals Management	28,927	19,418
Unallocated Items	(23,317)	(21,461)
Eliminations	12	(100)
Total operating profit (loss)	$ 35,705	$ (70,137)
Interest expense	5,566	2,460
Interest income	(4,428)	(6,081)
Closed mine obligations	2,381	3,585
Gain on equity securities	(1,805)	(1,958)
Other, net	345	(3,985)
Other expense (income), net	2,059	(5,979)
Income (loss) before income tax benefit	33,646	(64,158)
Income tax benefit	(95)	(24,571)
Net income (loss)	$ 33,741	$ (39,587)
Effective income tax rate	(0.3)%	38.3 %

The components of the change in revenues and operating profit are discussed below in Segment Results.

Other expense (income), net
Interest expense increased in 2024 compared with 2023 due to higher average borrowings as well as an increase in interest rates.

Interest income decreased in 2024 compared with 2023 due to lower earnings on reduced cash balances.

Gain on equity securities represents changes in the market price of invested assets reported at fair value. The change during 2024 compared with 2023 was due to fluctuations in the market prices of the exchange-traded equity securities. See Note 9 to the Consolidated Financial Statements in this Form 10-K forfurther discussion of our invested assets reported at fair value.

During 2023, our Board of Directors approved the termination of the Combined Defined Benefit Plan and participants were offered lump-sum distributions as part of the termination process. As a result of the lump-sum distributions, we recognized a non-cash, pension settlement charge of $1.8 million in 2023 on the line Other, net within the accompanying Consolidated Statements of Operations. See Note 14 to the Consolidated Financial Statements in this Form 10-K for further information on the Combined Defined Benefit Plan.

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On December 1, 2022, we transferred our ownership interest in Midwest AgEnergy Group, LLC (MAG) to HLCP Ethanol Holdco, LLC. We received cash payments totaling $3.6 million during 2023 in connection with MAG and recognized the gain on the line Other, net within the accompanying Consolidated Statements of Operations.

Income Taxes

We recorded an income tax benefit of $0.1 million for the year ended December 31, 2024 on income before income tax of $33.6 million, or 0.3%, compared to an income tax benefit of $24.6 million on loss before income tax of $64.2 million, or 38.3%, for the year ended December 31, 2023. The years ended December 31, 2024 and 2023 both included $4.0 million of discrete tax benefits, primarily from the reversal of uncertain tax provisions. Excluding the $4.0 million of discrete tax benefits in each year, the effective income tax rate in 2024 and 2023 was 11.5% and 32.0%, respectively.

The change in the effective income tax rate for 2024 compared to 2023, excluding the impact of the long-lived asset impairment charge and discrete items, is primarily due to an increase in earnings at entities that do not qualify for percentage depletion. The benefit from percentage depletion is not directly related to the amount of pre-tax income recorded in a period. Accordingly, in periods where income or loss before income tax is relatively small, the proportional effect of the benefit from percentage depletion on the effective tax rate may be significant. When income tax expense is recorded, the benefit from percentage depletion decreases the effective income tax rate, while the effect is to increase the effective income tax rate when a benefit for income taxes is recorded.

See Note 13 to the Consolidated Financial Statements in this Form 10-K for further discussion of our income taxes.

(Tabular Amounts in Thousands, Except Per Share and Percentage Data)

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

The following tables detail the change in cash flow for the years ended December 31:

	2024	2023	Change
Operating activities:			
Net income (loss)	**$ 33,741**	$ (39,587)	$ 73,328
Depreciation, depletion and amortization	**24,652**	29,387	(4,735)
Deferred income taxes	**1,517**	(21,114)	22,631
Stock-based compensation	**5,832**	5,157	675
(Gain) loss on sale of assets	**(5,146)**	221	(5,367)
Inventory impairment charges	**9,643**	7,514	2,129
Long-lived asset impairment charge	—	65,887	(65,887)
Other	**(3,352)**	1,473	(4,825)
Working capital changes	**(44,598)**	5,552	(50,150)
Net cash provided by operating activities	**22,289**	54,490	(32,201)
Investing activities:			
Expenditures for property, plant and equipment and acquisition of mineral interests	**(55,419)**	(82,122)	26,703
Proceeds from the sale of assets	**822**	561	261
Proceeds from the sale of private company equity units	—	3,574	(3,574)
Equity method investment	**(16,556)**	(3,464)	(13,092)
Other	**(139)**	(146)	7
Net cash used for investing activities	**(71,292)**	(81,597)	10,305
Cash flow before financing activities	**$ (49,003)**	$ (27,107)	$ (21,896)

The $32.2 million unfavorable change in net cash provided by operating activities during 2024 compared with 2023 was primarily due to an unfavorable change in cash provided by working capital, partially offset by an increase in cash provided by net income adjusted for non-cash items. The unfavorable change in working capital was mainly the result of:

- A significant reduction in the Federal income tax receivable during 2023 that did not reoccur in 2024.
- The changes in Inventory during the period as coal inventory increased during 2024 compared with a decrease in 2023. In addition, there was a larger increase in mining supplies inventory during 2024.
- An increase in Trade accounts receivable during 2024 compared with a decrease during 2023, primarily due to changes in the level and timing of collections as well as the payment terms provided to various customers.

Our non-cash items primarily include Long-lived asset impairment charge, Inventory impairment charges, Depreciation, depletion and amortization, Deferred income taxes, Stock-based compensation and (Gain) loss on sale of assets.

(Tabular Amounts in Thousands, Except Per Share and Percentage Data)

	2024	2023	Change
Financing activities:			
Net additions to long-term debt and revolving credit agreements	**$ 55,710**	$ 11,023	$ 44,687
Debt issuance costs	**(2,415)**	—	$ (2,415)
Cash dividends paid	**(6,624)**	(6,452)	(172)
Purchase of treasury shares	**(9,944)**	(3,103)	(6,841)
Net cash provided by financing activities	**$ 36,727**	$ 1,468	$ 35,259

The change in net cash provided by financing activities was primarily due to higher additions in debt borrowings during 2024 compared with 2023, partially offset by increased share repurchases and debt issuance costs during 2024. See Note 12 to the Consolidated Financial Statements in this Form 10-K for a discussion of our stock repurchase programs.

1031 exchange transactions

During 2024, we had cash proceeds from the sale of assets held by a qualified intermediary to facilitate tax-deferred exchange transactions under Section 1031 of the Internal Revenue Code. In May 2024, we sold land for $7.0 million and recognized a $4.5 million gain in the Minerals Management segment. We structured this transaction in a manner that qualified as a like-kind exchange pursuant to Section 1031 of the Internal Revenue Code and used all of the net proceeds from the sale during the year ended December 31, 2024.

Financing Activities

In September 2024, NACCO Natural Resources amended the secured revolving line of credit (Facility) to increase the revolving credit commitments to $200.0 million and extend the maturity to September 2028. Borrowings outstanding under the Facility were $70.0 million at December 31, 2024. At December 31, 2024, the excess availability under the Facility was $99.1 million, which reflects a reduction for outstanding letters of credit of $30.9 million.

NACCO has not guaranteed any borrowings of NACCO Natural Resources. The Facility allows for the payment to NACCO of dividends and advances under certain circumstances. Dividends (to the extent permitted by the Facility) and management fees are the primary sources of cash for NACCO and enable us to pay dividends to stockholders and repurchase shares.

The Facility has performance-based pricing, which sets interest rates based upon NACCO Natural Resources achieving various levels of debt to EBITDA ratios, as defined in the Facility. Borrowings bear interest at a floating rate plus a margin based on the level of debt to EBITDA ratio achieved. The applicable margins, effective December 31, 2024, for base rate and Term Secured Overnight Financing Rate loans were 1.50% and 2.50%, respectively. The Facility has a commitment fee which is based upon achieving various levels of debt to EBITDA ratios. The commitment fee was 0.40% on the unused commitment at December 31, 2024. During the years ended December 31, 2024 and December 31, 2023, the average borrowing under the Facility was $27.2 million and $6.2 million, respectively, and the weighted-average annual interest rate was 8.83% and 6.06%, respectively.

The Facility contains restrictive covenants, which require, among other things, NACCO Natural Resources to maintain a maximum net debt to EBITDA ratio of 2.75 to 1.00 and an interest coverage ratio of not less than 4.00 to 1.00. The Facility provides the ability to make loans, dividends and advances to NACCO, with some restrictions based on maintaining a maximum debt to EBITDA ratio of 1.50 to 1.00, or if greater than 1.50 to 1.00, a Fixed Charge Coverage Ratio of 1.10 to 1.00. At December 31, 2024, NACCO Natural Resources was in compliance with all financial covenants in the Facility.

The obligations under the Facility are guaranteed by certain of NACCO Natural Resources' direct and indirect, existing and future domestic subsidiaries, and is secured by certain assets of NACCO Natural Resources and the guarantors, subject to customary exceptions and limitations.

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We believe funds available from cash on hand, the Facility and operating cash flows will provide sufficient liquidity to meet our operating needs and commitments arising during the next twelve months and until the expiration of the Facility in September 2028.

See Note 8 and Note 10 to the Consolidated Financial Statements in this Form 10-K for further information on our other financing arrangements and leases, respectively.

Expenditures for property, plant and equipment and mineral interests

Following is a table which summarizes actual and planned expenditures (in millions):

	Planned 2025	Actual 2024	Actual 2023
NACCO	$ 58.0	**$ 55.4**	$ 82.1

Planned expenditures for 2025 are expected to be approximately $13 million in the Coal Mining segment, $17 million in the NAMining segment, $20 million in the Minerals Management segment and $8 million in growth businesses included in Unallocated Items.

Expenditures are expected to be funded from internally generated funds and/or bank borrowings.

Capital Structure

NACCO's consolidated capital structure is presented below:

	December 31		
	2024	2023	Change
Cash and cash equivalents	**$ 72,833**	$ 85,109	$ (12,276)
Other net tangible assets	**451,962**	349,934	102,028
Intangible assets, net	**5,475**	6,006	(531)
Net assets	**530,270**	441,049	89,221
Total debt	**(99,514)**	(35,956)	(63,558)
Closed mine obligations	**(25,809)**	(22,753)	(3,056)
Total equity	**$ 404,947**	$ 382,340	$ 22,607
Debt to total capitalization	**20 %**	9 %	11 %

The increase in other net tangible assets was mainly the result of increases in Property, plant and equipment, Other non-current assets and Inventory during 2024. The increase in Other non-current asset was primarily due to our investment of $15.7 million in Eiger, which holds non-operated working interests in oil and natural gas assets in the Kansas and the Oklahoma portion of the Hugoton basin. The increase in Inventory was mainly due to higher mining supplies and coal inventory.

Contractual Obligations, Contingent Liabilities and Commitments

Pension and postretirement funding can vary significantly each year due to plan amendments, changes in the market value of plan assets, legislation and our decisions to contribute above the minimum regulatory funding requirements. We do not expect to contribute to our pension plan in 2025 and any settlements will be paid out of pension plan assets. NACCO maintains one supplemental retirement plan that pays monthly benefits to participants directly out of corporate funds. NACCO also expects to make payments related to our other postretirement plans. See Note 14 to the Consolidated Financial Statements in this Form 10-K for further information on future benefit payments.

NACCO has asset retirement obligations. See Note 7 to the Consolidated Financial Statements in this Form 10-K for further discussion of our asset retirement obligations.

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NACCO has unrecognized tax benefits, including interest and penalties. See Note 13 to the Consolidated Financial Statements in this Form 10-K for further discussion of our income taxes.

We are a party to certain guarantees related to Coyote Creek. We believe that the likelihood of future performance under the guarantees is remote, and no amounts related to these guarantees have been recorded. See Note 16 to the Consolidated Financial Statements in this Form 10-K for further discussion of our guarantees.

We utilize letters of credit to support commitments made in the ordinary course of business. As of December 31, 2024 and 2023, outstanding letters of credit totaled $30.9 million and $34.9 million, respectively.

ENVIRONMENTAL MATTERS

We are affected by the regulations of numerous agencies, particularly the Federal Office of Surface Mining, the U.S. Environmental Protection Agency, the U.S. Army Corps of Engineers and associated state regulatory authorities. In addition, we closely monitor proposed legislation and regulation concerning SMCRA, CAA, ACE, CWA, RCRA, CERCLA and other regulatory actions.

Compliance with these increasingly stringent regulations could result in higher expenditures for both capital improvements and operating costs. The election of Donald Trump, paired with Republican control of Congress, is likely to have a significant and favorable impact on the regulatory environment, particularly for fossil fuels. President Trump issued an Executive Order on January 20, 2025, "Unleashing American Energy," directing all federal executive agency heads to review all agency actions implicating energy reliability and affordability or potentially burdening the development of domestic energy resources. It is not yet clear how existing regulations affecting existing fossil fuel assets will be reconsidered or repealed. Our policies stress environmental responsibility and compliance with these regulations. See Item 1 and Item 1A. in Part I of this Form 10-K for further discussion of these matters.

SEGMENT RESULTS

COAL MINING SEGMENT

FINANCIAL REVIEW

See Item 2. Properties on page 29 in this Form 10-K for discussion of our mineral resources and mineral reserves.

Tons of coal delivered by the Coal Mining segment were as follows for the years ended December 31:

	2024	2023
Unconsolidated mines	**21,308**	20,741
Consolidated mines	**1,922**	2,931
Total tons delivered	**23,230**	23,672

The results of operations for the Coal Mining segment were as follows for the years ended December 31:

	2024	2023
Revenues	**$ 68,611**	$ 85,415
Cost of sales	**79,375**	108,760
Gross loss	**(10,764)**	(23,345)
Earnings of unconsolidated operations[(a)]	**51,821**	44,633
Business interruption insurance recoveries	**13,612**	—
Selling, general and administrative expenses and long-lived asset impairment charge	**30,112**	89,971
Amortization of intangible assets	**531**	2,998
Gain on sale of assets	**(285)**	(339)
Operating profit (loss)	**$ 24,311**	$ (71,342)

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[a] See Note 16 to the Consolidated Financial Statements in this Form 10-K for a discussion of our unconsolidated subsidiaries, including summarized financial information.

2024 Compared with 2023

Revenues decreased 19.7% in 2024 compared with 2023 due to a reduction in customer requirements at MLMC as a result of a boiler issue at the customer's Red Hills Power Plant.

The following table identifies the components of change in Operating profit (loss) for 2024 compared with 2023:

	Operating Profit (Loss)
2023	$ (71,342)
Increase (decrease) from:	
Long-lived asset impairment charge in 2023	60,832
Business interruption insurance recoveries	13,612
Gross loss, excluding inventory impairment charges	14,710
Earnings of unconsolidated operations	7,188
Amortization of intangibles	2,467
Inventory impairment charges	(2,129)
Selling, general and administrative expenses	(973)
Net change on sale of assets	(54)
2024	**$ 24,311**

Operating profit (loss) changed favorably by $95.7 million in 2024 compared with 2023. The change in Operating profit (loss) was primarily due to:

- The absence of a long-lived asset impairment charge;
- Business interruption insurance recoveries for the boiler issue at the Red Hills Power Plant;
- A decrease in gross loss, excluding inventory impairment charges;
- An increase in the earnings of unconsolidated operations; and
- A decrease in the amortization of intangibles.

During 2023, MLMC received notice from its customer related to a boiler issue at the Red Hills Power Plant that began on December 15, 2023. We assessed for impairment and recorded a non-cash, long-lived asset impairment charge of $65.9 million in 2023. The $65.9 million relates exclusively to MLMC; however, $60.8 million and $5.1 million were recorded on the Coal Mining segment and the Minerals Management segment, respectively, as certain MLMC land assets were recorded within the Minerals Management segment. See Note 9 to the Consolidated Financial Statements in this Form 10-K for further information on the 2023 impairment. While this issue has been resolved, it resulted in a reduction in customer demand which had a significant impact on our 2024 results of operations. We recognized income of $13.6 million in 2024 related to business interruption insurance recoveries that partially offset losses as a result of the boiler outage.

The reduction in revenues at MLMC was offset by lower cost of goods sold, resulting in a decrease in the gross loss during 2024 compared with 2023. The reduction in cost of goods sold was primarily attributable to changes in the level of coal inventory and costs capitalized into inventory as the decrease in demand resulted in an increase in the coal stockpile during 2024. In addition, the gross loss in 2024 and 2023 included $9.6 million and $7.5 million of inventory impairment charges, respectively, to write down MLMC's coal inventory to its net realizable value.

The increase in earnings of unconsolidated operations was primarily due to improved results at Falkirk, primarily due to a higher per ton management fee beginning in June 2024 when temporary price concessions ended and an increase in customer demand. Improved results at Coteau also contributed to the increase in earnings of unconsolidated operations.

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NORTH AMERICAN MINING (NAMining) SEGMENT

FINANCIAL REVIEW

Aggregate tons delivered by the NAMining segment were as follows for the years ended December 31:

	2024	2023
Total tons delivered	**54,963**	56,655

The results of operations for the NAMining segment were as follows for the years ended December 31:

	2024	2023
Total revenues	**$ 119,600**	$ 90,532
Reimbursable costs	**74,636**	56,611
Revenues excluding reimbursable costs	**$ 44,964**	$ 33,921
Revenues	**$ 119,600**	$ 90,532
Cost of sales	**110,821**	83,719
Gross profit	**8,779**	6,813
Earnings of unconsolidated operations[a]	**5,010**	5,361
Selling, general and administrative expenses	**8,365**	8,308
(Gain) loss on sale of assets	**(348)**	518
Operating profit	**$ 5,772**	$ 3,348

[a] See Note 16 to the Consolidated Financial Statements in this Form 10-K for a discussion of our unconsolidated subsidiaries, including summarized financial information.

2024 Compared with 2023

Revenues excluding reimbursable costs increased 32.6% in 2024 compared with 2023, mainly due to favorable pricing and delivery mix at the consolidated limestone quarries and an increase in the scope of work at Sawtooth. Reimbursable costs, which have an offsetting amount in cost of sales and have no impact on gross profit, also increased during 2024.

The following table identifies the components of change in Operating profit for 2024 compared with 2023.

	Operating Profit
2023	$ 3,348
Increase (decrease) from:	
Gross profit	1,966
Net change on sale of assets	866
Earnings of unconsolidated operations	(351)
Selling, general and administrative expenses	(57)
2024	**$ 5,772**

Operating profit increased $2.4 million in 2024 compared with 2023 primarily due to an increase in gross profit and a favorable change on the sale of assets. The improvement in gross profit was mainly the result of favorable pricing and improved margins at the consolidated limestone quarries and an increase in the scope of work at Sawtooth.

Selling, general and administrative expenses include a $0.9 million charge to establish an allowance against a receivable from one of NAMining's customers during 2024, which was offset by a reduction in outside services.

(Tabular Amounts in Thousands, Except Per Share and Percentage Data)

MINERALS MANAGEMENT SEGMENT

FINANCIAL REVIEW

Oil and natural gas prices have been historically volatile and may continue to be volatile in the future. The table below shows the average price as reported by the United States Energy Information Administration for the twelve months ended December 31:

	2024	2023
West Texas Intermediate Average Crude Oil Price	**$ 76.55**	$ 77.64
Henry Hub Average Natural Gas Price	**$ 2.19**	$ 2.54

These indicated prices do not necessarily reflect the contract terms for our sales. As an owner of royalty and mineral interests, our access to information concerning activity and operations of our royalty and mineral interests is limited. We do not have information that would be available to a company with working interests in oil and natural gas operations because detailed information is not generally available to owners of royalty and mineral interests.

The results of operations for the Minerals Management segment were as follows for the years ended December 31:

	2024	2023
Oil and natural gas revenues	**$ 27,157**	$ 22,922
Other revenues	**7,422**	10,063
Total Revenues	**$ 34,579**	$ 32,985
Total Revenues	**$ 34,579**	$ 32,985
Cost of sales	**5,234**	3,969
Gross profit	**29,345**	29,016
Earnings of unconsolidated operations	**647**	—
Selling, general and administrative expenses and asset impairment charge	**5,577**	9,556
(Gain) loss on sale of assets	**(4,512)**	42
Operating profit	**$ 28,927**	$ 19,418

Revenues increased in 2024 compared with 2023 primarily due to an increase in oil and natural gas revenues as a result of increased oil production volumes related to an acquisition that closed during the fourth quarter of 2023. These improvements were partially offset by a reduction in other revenues, primarily coal royalty income. In addition, revenues during 2023 included $1.4 million of settlement income.

Operating profit increased $9.5 million in 2024 compared with 2023, primarily due to the absence of a $5.1 million long-lived asset impairment charge recognized during 2023 and a $4.5 million gain on the sale of land related to legacy operations recognized during 2024. The increase in revenue was offset by an increase in cost of sales, primarily related to higher depletion expense due to increased production volumes. See Note 9 to the Consolidated Financial Statements in this Form 10-K for further information on the 2023 impairment.

(Tabular Amounts in Thousands, Except Per Share and Percentage Data)

UNALLOCATED ITEMS AND ELIMINATIONS

FINANCIAL REVIEW

Unallocated Items and Eliminations were as follows for the years ended December 31:

	2024	2023
Operating loss	**$ (23,305)**	$ (21,561)

2024 Compared with 2023

The operating loss increased during 2024 compared with 2023 primarily due to higher employee-related costs, partially offset by lower expenses for growth initiatives as certain costs expensed in 2023 were capitalized in 2024.

NACCO Industries, Inc. Outlook

NACCO's businesses provide critical inputs for electricity generation, construction and development, and the production of industrial minerals and chemicals. Increasing demand for electricity, on-shoring and current federal policies are creating favorable macroeconomic trends within these industries. We are confident in our trajectory and business prospects as we enter 2025 and prepare for longer-term growth opportunities. Specifically in 2025, we expect to generate a modest year-over-year increase in consolidated operating profit.

In 2025, the Coal Mining segment anticipates solid customer demand, with deliveries expected to increase modestly from 2024. We anticipate that evolving policy frameworks may create a more favorable regulatory environment for the fossil fuel industry moving forward. These developments are expected to further support coal as an essential part of the energy mix in the United States for the foreseeable future.

The Coal Mining segment expects to benefit from the expiration of temporary price concessions at Falkirk. In addition, MLMC continues to recover from inefficiencies experienced while its customer's Red Hills Power Plant operated on one of two generation units for more than half of 2024. With the power plant now anticipated to operate at a level consistent with historical averages, coal deliveries are expected to return to more normal levels, resulting in moderate cost efficiencies. However, an anticipated reduction in the 2025 contractually determined per ton sales price compared with 2024 is expected to offset these improvements, resulting in lower results at MLMC. An expected increase in operating expenses will contribute to an overall anticipated modest year-over-year decrease in Coal Mining segment operating profit.

NAMining is expected to generate increasing levels of operating profit over time as the benefits of new and extended contracts add to the profitability of existing contracts. During 2024, NAMining executed three new or amended existing contracts, which are expected to deliver net present value after-tax cash flows of approximately $20 million over contract terms that range from 6 to 20 years. NAMining is expected to deliver further improved results in 2025, predominantly in the second half of the year based on expectations for comparable year-over-year customer demand. NAMining is continuously seeking to enter into new or amended contracts to solidify its position as the foundation for NACCO's mining-related growth initiatives.

NAMining's subsidiary, Sawtooth, is the exclusive provider of comprehensive mining services at Thacker Pass, which is owned by Lithium Americas Corp. (TSX: LAC) (NYSE: LAC). Sawtooth will supply all of the lithium-bearing ore requirements for Thacker Pass, which is currently under construction. We expect to continue to recognize moderate income at Sawtooth while it assists with certain construction services. Once the mine is operating, Sawtooth will be reimbursed for costs of mining, capital expenditures and mine closure and will recognize a contractually agreed upon production fee. In addition to providing comprehensive mining services, Sawtooth will receive a fee to transport clay tailings once lithium production commences. Phase 1 lithium production is estimated to begin in late 2027.

The Minerals Management segment, through its Catapult business, has constructed a high-quality, diversified portfolio of oil and gas mineral and royalty interests in the United States. In the fourth quarter of 2024, Minerals Management invested $15.7 million in a company that holds non-operated working interests in oil and natural gas assets in the Kansas and Oklahoma portions of the Hugoton basin. While this investment, accounted for under the equity method, is expected to be accretive to earnings, 2025 operating profit is expected to be comparable to 2024. Lower first-half earnings are expected to be offset by an improvement in the second half given expected trends in oil and natural gas prices and projected volumes.

Minerals Management continues to build its portfolio with a mix of producing wells, near-term development opportunities and undeveloped acreage. We believe our data-driven approach to acquisitions and our long-term perspective provides a competitive advantage as undeveloped assets provide additional upside potential over the life of the reserve. While we continue to budget up to $20 million annually to expand our portfolio and provide long-term stable cash flow generation, our business model allows flexibility regarding the cadence and type of investment based on available opportunities that we believe will create long-term value and generate increasing profitability.

Mitigation Resources provides stream and wetland mitigation solutions as well as comprehensive reclamation and restoration construction services. This business is an avenue for growth and diversification in an area where NACCO has built a strong reputation based on its substantial knowledge and expertise. Mitigation Resources continued to expand during 2024, and now has 11 mitigation banks and other mitigation projects located in Alabama, Florida, Georgia, Mississippi, Pennsylvania, Tennessee and Texas.

Mitigation Resources also provides ecological restoration services for abandoned surface mines and plans to pursue other environmental restoration projects. It was named a designated provider of abandoned mine land restoration by the State of Texas, and in January 2025 secured a restoration project in Kentucky that is expected to be accretive to earnings beginning in 2026.

Mitigation Resources is expected to achieve full-year profitability beginning in 2025 based on current expectations for the timing of permit approvals and mitigation credit releases, as well as income generated from service-related projects. Mitigation Resources is expected to increase profitability over time, and provide a return on capital employed in the mid-teens as the business matures.

We established ReGen Resources in 2023 to address the rapidly increasing demand for additional power generation sources in the United States through development of energy and energy-related projects that utilize multiple-generation technologies, such as solar combined with gas-fired generation, primarily on reclaimed mining properties. These projects could be developed by ReGen Resources directly or through joint ventures that include partners with expertise in energy development projects. Current projects include solar arrays, solar-gas hybrid projects and carbon capture projects on reclaimed mine land in Mississippi and Texas. Additional projects in other states are in early-stage review.

We are taking actions to terminate our defined benefit pension plan in 2025, which will eliminate future volatility from changes in the pension obligation. Once complete, obligations under the terminated plan will be transferred to a third-party insurance provider. Surplus assets are expected to be utilized to fund a qualified replacement plan, reducing future cash funding requirements. Although the plan is currently over funded, a significant non-cash settlement charge is anticipated upon termination, which is expected to lead to a substantial year-over-year decrease in net income and EBITDA compared with 2024.

Consolidated capital expenditures are expected to total approximately $58 million in 2025, which includes approximately $13 million for Coal Mining, $17 million for NAMining, $20 million for Minerals Management and $8 million predominantly for ReGen Resources and other growth businesses. We expect significant annual cash flow generation beginning in 2025, based on the current business plan.

We believe that each of our businesses have competitive advantages that provide value to customers and create long-term value for stockholders. We are pursuing growth and diversification by strategically leveraging our core natural resources management skills to build a robust portfolio of affiliated businesses. Opportunities for growth remain strong and are increasing amid recent successes and a significant positive change in the regulatory environment, particularly for fossil fuels. Acquisitions of additional mineral interests and improvements in the outlook for Coal Mining segment customers, as well as new contracts at Mitigation Resources and NAMining should be accretive to the longer-term outlook.

We are committed to maintaining a conservative capital structure as we continue to grow and diversify, while avoiding unnecessary risk. We believe strategic diversification will generate cash that can be re-invested to strengthen and expand the businesses or distributed to investors in the form of share repurchases or dividends. We continue to maintain the highest levels of customer service and operational excellence with an unwavering focus on safety and environmental stewardship.

RECENTLY ISSUED ACCOUNTING STANDARDS

See Note 2 to the Consolidated Financial Statements in this Form 10-K for a description of recently issued accounting standards including actual and expected dates of adoption and effects to our Consolidated Financial Statements.

FORWARD-LOOKING STATEMENTS

The statements contained in Management’s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere throughout this Annual Report on Form 10-K that are not historical facts are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements are made subject to certain risks and uncertainties, which could cause actual results to differ materially from those presented. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly revise these forward-looking statements to reflect events or circumstances that arise after the date hereof. Among the factors that could cause plans, actions and results to differ materially from current expectations are, without limitation: (1) changes to or termination of customer or other third-party contracts, or a customer or other third party default under a contract, (2) any customer's premature facility closure or extended project development delay, (3) regulatory actions, including the United States EPA's rules finalized in 2024 relating to mercury and greenhouse gas emissions for coal-fired power plants, changes in mining permit requirements or delays in obtaining mining permits that could affect deliveries to customers, (4) a significant reduction in purchases by the Company's customers, including as a result of changes in coal consumption patterns of U.S. electric power generators, or changes in the power industry that would affect demand for the Company's coal and other mineral reserves, (5) changes in the prices of hydrocarbons, particularly diesel fuel, natural gas, natural gas liquids and oil as a result of factors such as OPEC and/or government actions, geopolitical developments, economic conditions and regulatory changes, as well as supply and demand dynamics, (6) changes in development plans by third-party lessees of the Company's mineral interests, (7) failure or delays by the Company's lessees in achieving expected production of natural gas and other hydrocarbons; the availability and cost of transportation and processing services in the areas where the Company's oil and gas reserves are located; federal and state legislative and regulatory initiatives relating to hydraulic fracturing and U.S. export of natural gas; and the ability of lessees to obtain capital or financing needed for well-development operations and leasing and development of oil and gas reserves on federal lands, (8) failure to obtain adequate insurance coverages at reasonable rates, (9) supply chain disruptions, including price increases and shortages of parts and materials, (10) changes in tax laws or regulatory requirements, including the elimination of, or reduction in, the percentage depletion tax deduction, changes in mining or power plant emission regulations and health, safety or environmental legislation, (11) impairment charges, (12) changes in costs related to geological and geotechnical conditions, repairs and maintenance, new equipment and replacement parts, fuel or other similar items, (13) weather conditions, extended power plant outages, liquidity events or other events that would change the level of customers' coal or aggregates requirements, (14) weather or equipment problems that could affect deliveries to customers, (15) changes in the costs to reclaim mining areas, (16) costs to pursue and develop new mining, mitigation, oil and gas and solar development opportunities and other value-added service opportunities, (17) delays or reductions in coal or aggregates deliveries, (18) the ability to successfully evaluate investments and achieve intended financial results in new business and growth initiatives, (19) disruptions from natural or human causes, including severe weather, accidents, fires, earthquakes and terrorist acts, any of which could result in suspension of operations or harm to people or the environment, and (20) the ability to attract, retain, and replace workforce and administrative employees.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

As a smaller reporting company as defined by Rule 12b-2 of the Securities Exchange Act of 1934, we are not required to provide this information.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this Item 8 is set forth in the Financial Statements and Supplementary Data contained in Part IV of this Form 10-K and is hereby incorporated herein by reference to such information.

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

There were no disagreements with accountants on accounting and financial disclosure for the two-year period ended December 31, 2024 that require disclosure pursuant to this Item 9.

Item 9A. CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures: An evaluation was carried out under the supervision and with the participation of our management, including the principal executive officer and the principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, these officers have concluded that our disclosure controls and procedures are effective.

Management's report on internal control over financial reporting: Management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on this evaluation under the framework, management concluded that our internal control over financial reporting was effective as of December 31, 2024. Our effectiveness of internal control over financial reporting as of December 31, 2024 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 15 of this Form 10-K and incorporated herein by reference.

Changes in internal control: There have been no changes in our internal control over financial reporting, that occurred during the fourth quarter of 2024, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. OTHER INFORMATION

During the fourth quarter of 2024, none of our directors or executive officers adopted or terminated a Rule 10b5-1 Trading Plan, or a non-Rule 10b5-1 trading arrangement (as defined in Item 408(c) of Regulation S-K).

Item 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information with respect to our Directors will be set forth in the 2025 Proxy Statement under the subheadings Part III — Proposals To Be Voted On At The 2025 Annual Meeting — Proposal 1 — Election of Directors which information is incorporated herein by reference.

Information with respect to the audit review committee and the audit review committee financial expert will be set forth in the 2025 Proxy Statement under the subheading Part I — Corporate Governance Information — Directors' Meetings and Committees, which information is incorporated herein by reference.

Information with respect to compliance with Section 16(a) of the Securities Exchange Act of 1934 by our Directors, executive officers and holders of more than ten percent of our equity securities will be set forth in the 2025 Proxy Statement under the subheading Part IV — Other Important Information, which information is incorporated herein by reference.

We have adopted a code of business conduct and ethics applicable to all Company personnel, including the principal executive officer, principal financial officer, principal accounting officer or controller, or other persons performing similar functions. The code of business conduct and ethics, entitled the Code of Corporate Conduct, is posted on our website at www.nacco.com under Corporate Governance. If we make any amendments to or grant any waivers from the code of business conduct and ethics which are required to be disclosed pursuant to the Securities and Exchange Act of 1934, we will make such disclosure on the NACCO website.

We have adopted an insider trading policy that governs the purchase, sale and other disposition of our securities by our directors, officers and employees that is designated to promote compliance with insider trading laws, rules, regulations and applicable listing standards. A copy of our insider trading policy is filed as Exhibit 19 to this Annual Report on Form 10-K for the year ended December 31, 2024.

Item 11. EXECUTIVE COMPENSATION

Information with respect to executive compensation will be set forth in the 2025 Proxy Statement under the headings Part II — Executive Compensation Information and Part III — Proposals To Be Voted On At The 2025 Annual Meeting — Proposal 1 — Election of Directors, which information is incorporated herein by reference.

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

Information with respect to security ownership of certain beneficial owners and management will be set forth in the 2025 Proxy Statement under the subheading Part IV — Other Important Information — Beneficial Ownership of Class A Common and Class B Common, which information is incorporated herein by reference.

Information with respect to compensation plans (including individual compensation arrangements) under which equity securities are authorized for issuance will be set forth in the 2025 Proxy Statement under the subheading Part IV — Other Important Information — Equity Compensation Plan Information, which information is incorporated herein by reference.

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

Information with respect to certain relationships and related transactions will be set forth in the 2025 Proxy Statement under the subheadings Part I — Corporate Governance Information — Review and Approval of Related-Person Transactions, which information is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information with respect to principal accountant fees and services will be set forth in the 2025 Proxy Statement under the heading Part III — Proposals To Be Voted On At The 2025 Annual Meeting — Proposal 4 — Ratification of the Appointment of Company's Independent Registered Public Accounting Firm, which information is incorporated herein by reference.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) (1) and (2) The response to Item 15(a)(1) and (2) is set forth beginning at page F-1 of this Form 10-K.

(b) Financial Statement Schedules — The response to Item 15(c) is set forth beginning at page F-42 of this Form 10-K.

(c) Exhibits required by Item 601 of Regulation S-K

Exhibit Number	Exhibit Description
(3) Articles of Incorporation and By-laws.	
3.1(i)	Restated Certificate of Incorporation of the Company is incorporated herein by reference to Exhibit 3(i) to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1992, Commission File Number 1-9172.
3.1(ii)	Certificate of Amendment of the Restated Certificate of Incorporation of the Company, dated July 23, 2024, is incorporated herein by reference to Exhibit 3(ii) to the Company's Quarterly Report on Form 10-Q, filed by the Company on July 31, 2024, Commission File Number 1-9172.
3.1(iii)	Amended and Restated By-laws of the Company are incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, filed by the Company on December 18, 2014, Commission File Number 1-9172.
(4) Instruments defining the rights of security holders, including indentures.	
4.1	The Company by this filing agrees, upon request, to file with the Securities and Exchange Commission the instruments defining the rights of holders of long-term debt of the Company and its subsidiaries where the total amount of securities authorized thereunder does not exceed 10% of the total assets of the Company and its subsidiaries on a consolidated basis.
4.2	Amended and Restated Stockholders' Agreement, dated as of September 29, 2017, among NACCO Industries, Inc., the other signatories thereto and NACCO Industries, Inc., as depository, is incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, filed by the Company on October 5, 2017, Commission File Number 1-9172.
4.3	Amendment to Amended and Restated Stockholders' Agreement, dated as of February 14, 2019, among NACCO Industries, Inc., the other signatories thereto and NACCO Industries, Inc., as depository, is incorporated by reference to Exhibit 4.5 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2018, Commission File Number 1-9172.
4.4	Second Amendment to Amended and Restated Stockholders' Agreement, dated as of February 12, 2021, by and among the Depository, NACCO Industries, Inc., the new Participating Stockholders identified on the signature pages thereto and the Participating Stockholders under the Amended and Restated Stockholders' Agreement, dated as of September 29, 2017, as amended, is incorporated by reference to Exhibit 99.60 of the Company's General statement of acquisition of beneficial ownership on Form SC 13D, filed on February 12, 2021, Commission File Number 1-9172.
4.5	Third Amendment to Amended and Restated Stockholders' Agreement, dated as of February 11, 2022, by and among the Depository, NACCO Industries, Inc., the new Participating Stockholders identified on the signature pages thereto and the Participating Stockholders under the Amended and Restated Stockholders' Agreement, dated as of September 29, 2017, as amended, is incorporated by reference to Exhibit 99.62 of the Company's General statement of acquisition of beneficial ownership on Form SC 13D, filed on February 11, 2022, Commission File Number 1-9172.
4.6	Fourth Amendment to Amended and Restated Stockholders' Agreement, dated as of February 10, 2023, by and among the Depository, NACCO Industries, Inc., the new Participating Stockholders identified on the signature pages thereto and the Participating Stockholders under the Amended and Restated Stockholders' Agreement, dated as of September 29, 2017, as amended, is incorporated by reference to Exhibit 99.67 of the Company's General statement of acquisition of beneficial ownership on Form SC 13D, filed on February 10, 2023, Commission File Number 1-9172.
4.7	Fifth Amendment to Amended and Restated Stockholders' Agreement, dated as of February 9, 2024, by and among the Depository, NACCO Industries, Inc., the new Participating Stockholders identified on the signature pages thereto and the Participating Stockholders under the Amended and Restated Stockholders' Agreement, dated as of September 29, 2017, as amended, is incorporated by reference to Exhibit 99.69 of the Company's General statement of acquisition of beneficial ownership on Form SC 13D, filed on February 12, 2024, Commission File Number 1-9172.

Exhibit Number	Exhibit Description
4.8	Sixth Amendment to Amended and Restated Stockholders' Agreement, dated as of December 16, 2024, by and among the Depository, NACCO Industries, Inc., the new Participating Stockholders identified on the signature pages thereto and the Participating Stockholders under the Amended and Restated Stockholders' Agreement, dated as of September 29, 2017, as amended, is incorporated by reference to Exhibit 99.71 of the Company's General statement of acquisition of beneficial ownership on Form SC 13D, filed on December 17, 2024, Commission File Number 1-9172.
4.9	Description of Securities is incorporated herein by reference to Exhibit 4.6 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2019, Commission File Number 1-9172.
(10) Material contracts	
10.1*	NACCO Industries, Inc. Supplemental Executive Long-Term Incentive Bonus Plan (Amended and Restated March 1, 2012) is incorporated herein by reference to Appendix B to NACCO's Definitive Proxy Statement, filed by NACCO on March 16, 2012, Commission File Number 1-9172.
10.2*	NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan (Amended and Restated March 1, 2023) is incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed by the Company on May 16, 2023, Commission File Number 1-9172.
10.3*	Amendment No. 1 to NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan (Amended and Restated March 1, 2023), dated as of February 20, 2024, is incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, filed by the Company on February 22, 2024, Commission File Number 1-9172.
10.4*	NACCO Industries, Inc. Non-Employee Directors' Equity Compensation Plan (Amended and Restated May 19, 2021) is incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, filed by the Company on May 19, 2021, Commission File Number 1-9172.
10.5*	Amendment No. 1 to NACCO Industries, Inc. Non-Employee Directors' Equity Compensation Plan (Amended and Restated May 19, 2021), dated as of February 20, 2024, is incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed by the Company on February 22, 2024, Commission File Number 1-9172.
10.6*	Form of Award Agreement for the NACCO Industries, Inc. Supplemental Executive Long-Term Incentive Bonus Plan is incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K, filed by the Company on September 17, 2012, Commission File Number 1-9172.
10.7*	Form of Cashless Exercise Award Agreement for the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan is incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed by the Company on May 1, 2024, Commission File Number 1-9172.
10.8*	Form of Non-Cashless Exercise Award Agreement for the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan is incorporated herein by reference to Exhibit 10.10 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2019, Commission File Number 1-9172.
10.9	Consulting Agreement, dated as of September 29, 2017, between NACCO Industries, Inc. and Alfred M. Rankin, Jr., is incorporated by reference to Exhibit 10.5 of NACCO Industries, Inc.'s Current Report on Form 8-K, filed on October 5, 2017, Commission File Number 1-9172.
10.10	Amendment to Consulting Agreement, dated as of December 15, 2020, between NACCO Industries, Inc. and Alfred M. Rankin, Jr., is incorporated by reference to Exhibit 10.1 of NACCO Industries, Inc.'s Current Report on Form 8-K, filed on December 15, 2020, Commission File Number 1-9172.
10.11	Amendment to Consulting Agreement, dated as of December 21, 2021, between NACCO Industries, Inc. and Alfred M. Rankin, Jr., is incorporated by reference to Exhibit 10.1 of NACCO Industries, Inc.'s Current Report on Form 8-K, filed on December 22, 2021, Commission File Number 1-9172.
10.12	Amendment to Consulting Agreement, dated as of December 19, 2023, between NACCO Industries, Inc. and Alfred M. Rankin, Jr., is incorporated by reference to Exhibit 10.1 of NACCO Industries, Inc.'s Current Report on Form 8-K, filed on December 19, 2023, Commission File Number 1-9172.
10.13	Amendment to Consulting Agreement, dated as of December 19, 2024, between NACCO Industries, Inc. and Alfred M. Rankin, Jr., is incorporated by reference to Exhibit 10.1 of NACCO Industries, Inc.'s Current Report on Form 8-K, filed on December 23, 2024, Commission File Number 1-9172.
10.14*	NACCO Industries, Inc. Short-Term Incentive Compensation Plan (Effective as of March 1, 2019) is incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed by the Company on February 13, 2019, Commission File Number 1-9172.
10.15*	The North American Coal Corporation Supplemental Retirement Benefit Plan (Amended and Restated as of January 1, 2008) is incorporated herein by reference to Exhibit 10.12 to the Company's Current Report on Form 8-K, filed by the Company on December 19, 2007, Commission File Number 1-9172.

Exhibit Number	Exhibit Description
10.16*	Amendment No. 1 to The North America Coal Corporation Supplemental Retirement Benefit Plan (Amended and Restated as of January 1, 2008) is incorporated herein by reference to Exhibit 10.41 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2009, Commission File Number 1-9172.
10.17*	The North American Coal Corporation Annual Incentive Compensation Plan (Amended and Restated Effective March 1, 2015) is incorporated herein by reference to Exhibit 10.3 to the Company’s Current Report on Form 8-K, filed by the Company on May 18, 2015, Commission File Number 1-9172.
10.18*	Amendment No. 2 to The North American Coal Corporation Supplemental Retirement Benefit Plan (Amended and Restated as of January 1, 2008) is incorporated herein by reference to Exhibit 10.40 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2010, Commission File Number 1-9172.
10.19	Coteau Lignite Sales Agreement by and between The Coteau Properties Company and Dakota Coal Company, dated as of January 1, 1990, is incorporated herein by reference to Exhibit 10.11 to the Company’s Quarterly Report on Form 10-Q/A, filed by the Company on March 20, 2013, Commission File Number 1-9172.+
10.20	First Amendment to Coteau Lignite Sales Agreement by and between The Coteau Properties Company and Dakota Coal Company, dated as of June 1, 1994, is incorporated herein by reference to Exhibit 10.12 to the Company’s Quarterly Report on Form 10-Q/A, filed by the Company on March 20, 2013, Commission File Number 1-9172.+
10.21	Second Amendment to Coteau Lignite Sales Agreement by and between The Coteau Properties Company and Dakota Coal Company, dated as of January 1, 1997, is incorporated herein by reference to Exhibit 10.13 to the Company’s Quarterly Report on Form 10-Q/A, filed by the Company on March 20, 2013, Commission File Number 1-9172.+
10.22	Option and Put Agreement by and among The North American Coal Corporation, Dakota Coal Company and the State of North Dakota, dated as of January 1, 1990, is incorporated herein by reference to Exhibit 10.14 to the Company’s Quarterly Report on Form 10-Q/A, filed by the Company on March 20, 2013, Commission File Number 1-9172.
10.23	First Amendment to the Option and Put Agreement by and among The North American Coal Corporation, Dakota Coal Company and the State of North Dakota, dated as of June 1, 1994, is incorporated herein by reference to Exhibit 10.15 to the Company’s Quarterly Report on Form 10-Q/A, filed by the Company on March 20, 2013, Commission File Number 1-9172.
10.24	Lignite Sales Agreement by and between Mississippi Lignite Mining Company and Choctaw Generation Limited Partnership, dated as of April 1, 1998, is incorporated herein by reference to Exhibit 10.16 to the Company’s Quarterly Report on Form 10-Q/A, filed by the Company on March 20, 2013, Commission File Number 1-9172.+
10.25	First Amendment to Lignite Sales Agreement by and between Mississippi Lignite Mining Company and Choctaw Generation Limited Partnership, dated as of August 30, 2016, is incorporated herein by reference to Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q, filed by the Company on November 1, 2016, Commission File Number 1-9172.
10.26	Pay Scale Agreement by and between Mississippi Lignite Mining Company and Choctaw Generation Limited Partnership, dated as of September 29, 2005, is incorporated herein by reference to Exhibit 10.17 to the Company’s Quarterly Report on Form 10-Q/A, filed by the Company on March 20, 2013, Commission File Number 1-9172.
10.27	Consent and Agreement by and among Mississippi Lignite Mining Company, Choctaw Generation Limited Partnership, SE Choctaw L.L.C. and Citibank, N.A., dated as of December 20, 2002, is incorporated herein by reference to Exhibit 10.29 to the Company’s Quarterly Report on Form 10-Q/A, filed by the Company on March 20, 2013, Commission File Number 1-9172.
10.28	Amendment No. 1 to Lignite Sales Agreement, Settlement Agreement and Release by and between Mississippi Lignite Mining Company and Choctaw Generation Limited Partnership, LLLP, dated as of November 16, 2018, is incorporated herein by reference to Exhibit 10.33 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2018, Commission File Number 1-9172.
10.29	Amendment No. 2 to Lignite Sales Agreement, Settlement Agreement and Release by and between Mississippi Lignite Mining Company and Choctaw Generation Limited Partnership, LLLP, dated as of November 24, 2021, is incorporated herein by reference to Exhibit 10.29 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2021, Commission File Number 1-9172.
10.30	Termination Agreement and Release, by and among The Falkirk Mining Company, Great River Energy and NoDak Energy Investments Corporation, dated June 30, 2021, is incorporated herein by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q, filed by the Company on August 4, 2021, Commission File Number 1-9172.
10.31	Amendment No. 1 to Termination Agreement and Release, by and between The Falkirk Mining Company, NoDak Energy Investments Corporation and Great River Energy, dated as of December 28, 2021, is incorporated herein by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2021, Commission File Number 1-9172.

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Exhibit Number	Exhibit Description
10.32***	Coal Sales Agreement, by and between The Falkirk Mining Company and Rainbow Energy Center, LLC, dated June 30, 2021, is incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed by the Company on August 4, 2021, Commission File Number 1-9172.
10.33	First Amendment to Coal Sales Agreement, by and between The Falkirk Mining Company and Rainbow Energy Center, LLC, dated March 8, 2022, is incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed by the Company on May 4, 2022, Commission File Number 1-9172.
10.34	Second Amendment to Coal Sales Agreement, by and between the Falkirk Mining Company and Rainbow Energy Center, LLC, dated August 5, 2022, is incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed by the Company on November 2, 2022, Commission File Number 1-9172.
10.35***	Guaranty by REMC Assets, LP, dated June 17, 2021, is incorporated herein by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed by the Company on August 4, 2021, Commission File Number 1-9172.
10.36***	Mortgage, Assignment of Leases, Rents and As-Extracted Collateral, Security Agreement, Financing Statement and Fixture Filing, by and between The Falkirk Mining Company and Rainbow Energy Center, LLC, dated June 30, 2021, is incorporated herein by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, filed by the Company on August 4, 2021, Commission File Number 1-9172.
10.37	Security Agreement, by and between The Falkirk Mining Company and Rainbow Energy Center, LLC, dated June 30, 2021, is incorporated herein by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q, filed by the Company on August 4, 2021, Commission File Number 1-9172.
10.38	Option Agreement, by and between The Falkirk Mining Company, Rainbow Energy Center, LLC and the State of North Dakota, Doing Business as The Bank of North Dakota, dated June 30, 2021, is incorporated herein by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q, filed by the Company on August 4, 2021, Commission File Number 1-9172.
10.39	Lignite Sales Agreement between Coyote Creek Mining Company, L.L.C. and Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co. and Northwestern Corporation dated as of October 10, 2012 is incorporated herein by reference to Exhibit 10.58 to the Company's Annual Report on Form 10-K, filed by the Company on March 6, 2013, Commission File Number 1-9172.++
10.40	First Amendment to Lignite Sales Agreement, dated as of January 30, 2014, between Coyote Creek Mining Company, L.L.C. and Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. and NorthWestern Corporation is incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 8-K, filed by the Company on January 30, 2014, Commission File Number 1-9172.
10.41	Second Amendment to Lignite Sales Agreement, dated as of March 16, 2015, between Coyote Creek Mining Company, L.L.C. and Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and NorthWestern Corporation is incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed by the Company on May 5, 2015, Commission File Number 1-9172.
10.42*	Amendment No. 3 to The North American Coal Corporation Supplemental Retirement Benefit Plan (Amended and Restated as of January 1, 2008) is incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed by the Company on October 30, 2013, Commission File Number 1-9172.
10.43*	Amendment No. 4 to The North American Coal Corporation Supplemental Retirement Benefit Plan (Amended and Restated as of January 1, 2008) is incorporated herein by reference to Exhibit 10.54 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2014, Commission File Number 1-9172.
10.44*	Amendment No. 5 to The North American Coal Corporation Supplemental Retirement Benefit Plan (Amended and Restated as of January 1, 2008) is incorporated herein by reference to Exhibit 10.57 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2015, Commission File Number I-9172.
10.45*	Amendment No. 6 to The North American Coal Corporation Supplemental Retirement Benefit Plan (Amended and Restated as of January 1, 2008) is incorporated herein by reference to Exhibit 10.52 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2016, Commission File Number I-9172.
10.46	Agreement, dated as of March 16, 2015, among The North American Coal Corporation, Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. and Northwestern Corporation is incorporated herein by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed by the Company on May 5, 2015, Commission File Number 1-9172.
10.47*	The North American Coal Corporation Excess Retirement Plan (Amended and Restated Effective January 1, 2020) is incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed by the Company on December 18, 2019, Commission File Number 1-9172.

Exhibit Number	Exhibit Description
10.48*	The NACCO Natural Resources Excess Retirement Plan (Effective January 1, 2025) is incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed by the Company on December 17, 2024, Commission File Number 1-9172.
10.49	Amended and Restated Credit Agreement by and among The North American Coal Corporation and the Guarantors party thereto and the Lenders party thereto and KeyBank National Association as Syndication Agent, PNC Bank National Association as Administrative Agent and KeyBanc Capital Markets Inc. and PNC Capital Markets LLC as Joint Lead Arrangers and Joint Bookrunners, dated as of November 12, 2021 is incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed by the Company on November 15, 2021, Commission File Number 1-9172.
10.50	Revolving Credit Commitment Increase Agreement, dated as of December 10, 2021 is incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed by the Company on December 13, 2021. Commission File Number 1-9172.
10.51	ESG Amendment to Amended and Restated Credit Agreement, dated as of June 30, 2022, is incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed by the Company on July 7, 2022. Commission File Number 1-9172.
10.52	First Amendment to Amended and Restated Credit Agreement, dated as of September 17, 2024, among NACCO Natural Resources Corporation, the guarantors party thereto, the lenders party thereto and PNC Bank, National Association, as administrative agent, is incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed by the Company on September 19, 2024, Commission File Number 1-9172.

(19**)	NACCO Industries, Inc. Insider Trading Policy
(21**)	Subsidiaries. A list of the subsidiaries of the Company is attached hereto as Exhibit 21.

(23) Consents of experts and counsel.

23.1**	Consents of experts and counsel.
23.2**	Consent of Qualified Person.
23.3**	Consent of Qualified Person.
23.4**	Consent of experts and counsel.

(24) Powers of Attorney.

24.1**	A copy of a power of attorney for John S. Dalrymple is attached hereto as Exhibit 24.1.
24.2**	A copy of a power of attorney for John P. Jumper is attached hereto as Exhibit 24.2.
24.3**	A copy of a power of attorney for Dennis W. LaBarre is attached hereto as Exhibit 24.3.
24.4**	A copy of a power of attorney for W. Paul McDonald is attached hereto as Exhibit 24.4.
24.5**	A copy of a power of attorney for Michael S. Miller is attached hereto as Exhibit 24.5.
24.6**	A copy of a power of attorney for Alfred M. Rankin, Jr. is attached hereto as Exhibit 24.6.
24.7**	A copy of a power of attorney for Matthew M. Rankin is attached hereto as Exhibit 24.7.
24.8**	A copy of a power of attorney for Roger F. Rankin is attached hereto as Exhibit 24.8.
24.9**	A copy of a power of attorney for Lori J. Robinson is attached hereto as Exhibit 24.9.
24.10**	A copy of a power of attorney for Valerie Gentile Sachs is attached hereto as Exhibit 24.10.
24.11**	A copy of a power of attorney for Robert S. Shapard is attached hereto as Exhibit 24.11.
24.12**	A copy of a power of attorney for Britton T. Taplin is attached hereto as Exhibit 24.12.

Exhibit Number	Exhibit Description
(31) Rule 13a-14(a)/15d-14(a) Certifications.	
31(i)(1) **	Certification of J.C. Butler, Jr. pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act is attached hereto as Exhibit 31(i)(1).
31(i)(2) **	Certification of Elizabeth I. Loveman pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act is attached hereto as Exhibit 31(i)(2).
(32)****	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, signed and dated by J.C. Butler, Jr. and Elizabeth I. Loveman.
(95)**	Mine Safety Disclosure Exhibit.
96.1**	Technical Report Summary relating to the Mississippi Lignite Mining Company, effective date as of December 31, 2024.
(97.1)**	NACCO Industries, Inc. Dodd-Frank Clawback Policy
(99.1**)	Reserve Report of Catapult Mineral Partners.
101.INS	Inline XBRL Instance Document
101.SCH	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

*	Management contract or compensation plan or arrangement required to be filed as an exhibit pursuant to Item15(b) of this Annual Report on Form 10-K.
**	Filed herewith.
***	Certain confidential information contained in this agreement has been omitted because it (i) is not material and (ii) would be competitively harmful if publicly disclosed.
****	Furnished herewith.
+	Portions of Exhibit have been omitted and filed separately with the Securities and Exchange Commission in reliance on Rule 24b-2 and an Order from the Commission granting the Company's request for confidential treatment dated March 27, 2013. Portions for which confidential treatment has been granted have been marked with three asterisks [***] and a footnote indicating Confidential treatment requested.
++	Portions of Exhibit have been omitted and filed separately with the Securities and Exchange Commission in reliance on Rule 24b-2 and an Order from the Commission granting the Company's request for confidential treatment dated April 2, 2013. Portions for which confidential treatment has been granted have been marked with three asterisks [***] and a footnote indicating Confidential treatment requested.

Item 16. Form 10-K Summary

None.

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.

NACCO Industries, Inc.

By: /s/ Elizabeth I. Loveman
Elizabeth I. Loveman
Senior Vice President and Controller
(principal financial and accounting officer)

March 5, 2025

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/ J.C. Butler, Jr. J.C. Butler, Jr.	President and Chief Executive Officer (principal executive officer)	March 5, 2025
/s/ Elizabeth I. Loveman Elizabeth I. Loveman	Senior Vice President and Controller (principal financial and accounting officer)	March 5, 2025
*John S. Dalrymple John S. Dalrymple	Director	March 5, 2025
* John P. Jumper John P. Jumper	Director	March 5, 2025
* Dennis W. LaBarre Dennis W. LaBarre	Director	March 5, 2025
* W. Paul McDonald W. Paul McDonald	Director	March 5, 2025
* Michael S. Miller Michael S. Miller	Director	March 5, 2025
* Alfred M. Rankin, Jr. Alfred M. Rankin, Jr.	Director	March 5, 2025
* Matthew M. Rankin Matthew M. Rankin	Director	March 5, 2025
* Roger F. Rankin Roger F. Rankin	Director	March 5, 2025
*Lori J. Robinson Lori J. Robinson	Director	March 5, 2025
* Valerie Gentile Sachs Valerie Gentile Sachs	Director	March 5, 2025
*Robert S. Shapard Robert S. Shapard	Director	March 5, 2025
* Britton T. Taplin Britton T. Taplin	Director	March 5, 2025

* Elizabeth I. Loveman, by signing her name hereto, does hereby sign this Form 10-K on behalf of each of the above named and designated directors pursuant to a Power of Attorney executed by such persons and filed with the Securities and Exchange Commission.

/s/ Elizabeth I. Loveman Elizabeth I. Loveman, Attorney-in-Fact	March 5, 2025

ANNUAL REPORT ON FORM 10-K

ITEM 8, ITEM 15(a)(1) AND (2), AND ITEM 15(c)

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

FINANCIAL STATEMENTS

FINANCIAL STATEMENT SCHEDULES

YEAR ENDED DECEMBER 31, 2024

NACCO INDUSTRIES, INC.

CLEVELAND, OHIO

FORM 10-K

ITEM 15(a)(1) AND (2)

NACCO INDUSTRIES, INC. AND SUBSIDIARIES

LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

The following consolidated financial statements of NACCO Industries, Inc. and Subsidiaries and the reports of our independent registered public accounting firm (PCAOB ID:42) are incorporated by reference in Item 8:

The following consolidated financial statement schedules of NACCO Industries, Inc. and Subsidiaries are included in Item 15(c):

All other schedules for which provision is made in the applicable accounting regulation of the SEC are not required under the related instructions or are inapplicable, and therefore have been omitted.

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of NACCO Industries, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of NACCO Industries, Inc. and subsidiaries (the Company) as of December 31, 2024 and 2023, the related consolidated statements of operations, comprehensive (loss) income, equity and cash flows for each of the two years in the period ended December 31, 2024, and the related notes and financial statement schedule listed in the Index at Item 15(b) (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 at December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2024, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated March 5, 2025 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit review 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 the critical audit matter does not alter in any way our opinion on the consolidated 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.

Unconsolidated subsidiaries – accounting for variable interest entities

Description of the Matter	As discussed in Note 1 and 16 to the consolidated financial statements, certain of the operating coal mines and entities within the NAMining segment, collectively referred to as the "Unconsolidated Subsidiaries," are variable interest entities (VIEs) and are accounted for under the equity method. In each case, NACCO is not the primary beneficiary of the VIE as it does not exercise financial control. Although NACCO owns 100% of the equity and manages the daily operations of the Unconsolidated Subsidiaries, the Company has determined that the equity capital provided by NACCO is not sufficient to adequately finance the ongoing activities or absorb any expected losses without additional support from the customers. The customers have a controlling financial interest and have the power to direct activities that most significantly affect the economic performance of the entities. As a result, the Company is not the primary beneficiary and therefore does not consolidate these entities' financial position or results of operations. The Company regularly evaluates if there are reconsideration events which could change the Company's conclusion as to whether these entities meet the definition of a VIE and the determination of the primary beneficiary. The income before income taxes associated with these VIEs is reported as Earnings of unconsolidated operations on the Consolidated Statements of Operations, and the Company's investment is reported on the line Investments in unconsolidated subsidiaries in the Consolidated Balance Sheets. Evaluating the Company's judgments in determining whether an entity is a VIE and the primary beneficiary of the VIE at formation and reconsideration events requires a high degree of complex auditor judgment. The Company also monitors for reconsideration events relating to the Unconsolidated Subsidiaries, which necessitates on-going critical judgments over whether any such events have arisen that require a re-evaluation of prior accounting judgments.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated and tested the design and operating effectiveness of the controls surrounding the Company's application of the variable interest model and the processes to continually assess the implications of significant transactions and events that could trigger a VIE reconsideration event. For those entities where the Company has determined it is not the primary beneficiary, we evaluated the Company's accounting for and disclosure of the Unconsolidated Subsidiaries under the equity method in accordance with the generally accepted accounting principles. To test the identification of reconsideration events, we obtained and inspected amendments to the agreements with customers, if any, and evaluated evidence from other parts of the audit to determine if a reconsideration event arose that necessitated a re-evaluation of previous accounting judgments. These procedures included, among others, reading board minutes, inquiring of management about transactions or events that could require a reconsideration of previous consolidation conclusions and obtaining direct confirmation of the total annual support provided in accordance with the contractual arrangements from the customers.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2002.
Cleveland, Ohio
March 5, 2025

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of NACCO Industries, Inc.

Opinion on Internal Control Over Financial Reporting

We have audited NACCO Industries, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, NACCO Industries, Inc. and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the 2024 consolidated financial statements of the Company and our report dated March 5, 2025 expressed an unqualified opinion thereon.

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 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/ Ernst & Young LLP

Cleveland, Ohio
March 5, 2025

NACCO INDUSTRIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31	
	2024	2023
	(In thousands, except per share data)	
Revenues	**$ 237,708**	$ 214,794
Cost of sales	**207,952**	200,203
Gross profit	**29,756**	14,591
Earnings of unconsolidated operations	**57,476**	49,994
Business interruption insurance recoveries	**13,612**	—
Operating expenses		
Selling, general and administrative expenses	**69,754**	65,616
Amortization of intangible assets	**531**	2,998
(Gain) loss on sale of assets	**(5,146)**	221
Long-lived asset impairment charge	**—**	65,887
	65,139	134,722
Operating profit (loss)	**35,705**	(70,137)
Other expense (income)		
Interest expense	**5,566**	2,460
Interest income	**(4,428)**	(6,081)
Closed mine obligations	**2,381**	3,585
Gain on equity securities	**(1,805)**	(1,958)
Other, net	**345**	(3,985)
	2,059	(5,979)
Income (loss) before income tax benefit	**33,646**	(64,158)
Income tax benefit	**(95)**	(24,571)
Net income (loss)	**$ 33,741**	$ (39,587)
Earnings (loss) per share:		
Basic earnings (loss) per share	**$ 4.58**	$ (5.29)
Diluted earnings (loss) per share	**$ 4.55**	$ (5.29)
Basic weighted average shares outstanding	**7,363**	7,478
Diluted weighted average shares outstanding	**7,411**	7,478

See notes to the Consolidated Financial Statements.

NACCO INDUSTRIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

	Year Ended December 31	
	2024	2023
	(In thousands)	
Net income (loss)	**$ 33,741**	$ (39,587)
Other comprehensive (loss) income		
Current period pension and postretirement plan adjustment, net of $205 and $615 tax benefit in 2024 and 2023, respectively	**(706)**	(2,118)
Pension settlement, net of $417 tax benefit in 2023	—	1,398
Reclassification of pension and postretirement adjustments into earnings, net of $89 and $24 tax benefit in 2024 and 2023, respectively	**308**	79
Total other comprehensive loss	**(398)**	(641)
Comprehensive income (loss)	**$ 33,343**	$ (40,228)

See notes to the Consolidated Financial Statements.

NACCO INDUSTRIES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31	
	2024	2023
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	**$ 72,833**	$ 85,109
Trade accounts receivable	**49,706**	37,429
Accounts receivable from affiliates	**5,793**	7,860
Inventories	**94,608**	77,000
Assets held for sale	**14,159**	6,466
Other current assets	**27,639**	18,134
Total current assets	**264,738**	231,998
Property, plant and equipment, net	**259,457**	223,902
Intangibles, net	**5,475**	6,006
Deferred income taxes	**14,641**	15,081
Investments in unconsolidated subsidiaries	**14,137**	12,371
Operating lease right-of-use assets	**9,661**	8,667
Equity securities	**18,663**	17,208
Equity method investment in Eiger, LLC	**19,147**	2,800
Other non-current assets	**25,768**	21,675
Total assets	**$ 631,687**	$ 539,708
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	**$ 17,721**	$ 16,702
Accounts payable to affiliates	**1,826**	904
Revolving credit agreements	**—**	10,000
Current maturities of long-term debt	**4,179**	3,953
Asset retirement obligations	**9,747**	13,114
Accrued payroll	**22,663**	17,317
Other current liabilities	**8,752**	7,996
Total current liabilities	**64,888**	69,986
Long-term debt	**25,335**	22,003
Long-term revolving credit agreement	**70,000**	—
Operating lease liabilities	**9,042**	8,782
Asset retirement obligations	**39,780**	39,499
Pension and other postretirement obligations	**4,787**	5,183
Liability for uncertain tax positions	**794**	5,795
Other long-term liabilities	**12,114**	6,120
Total liabilities	**226,740**	157,368
Stockholders' equity		
Common stock:		
Class A, par value $1 per share, 5,730,470 shares outstanding (2023 - 5,882,845 shares outstanding)	**5,730**	5,883
Class B, par value $1 per share, convertible into Class A on a one-for-one basis, 1,565,359 shares outstanding (2023 - 1,565,819 shares outstanding)	**1,566**	1,566
Capital in excess of par value	**34,340**	28,672
Retained earnings	**373,363**	355,873
Accumulated other comprehensive loss	**(10,052)**	(9,654)
Total stockholders' equity	**404,947**	382,340
Total liabilities and equity	**$ 631,687**	$ 539,708

See notes to the Consolidated Financial Statements.

NACCO INDUSTRIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31	
	2024	2023
	(In thousands)	
Operating Activities		
Net income (loss)	**$ 33,741**	$ (39,587)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	**24,652**	29,387
Amortization of deferred financing fees	**619**	505
Deferred income taxes	**1,517**	(21,114)
Stock-based compensation	**5,832**	5,157
(Gain) loss on sale of assets	**(5,146)**	221
Inventory impairment charges	**9,643**	7,514
Long-lived asset impairment charge	**—**	65,887
Other	**(3,971)**	968
Working capital changes:		
Accounts receivable	**(11,725)**	2,519
Inventories	**(27,250)**	(12,971)
Other current assets	**(8,677)**	(1,904)
Accounts payable	**1,955**	3,148
Income taxes receivable/payable	**(148)**	14,996
Other current liabilities	**1,247**	(236)
Net cash provided by operating activities	**22,289**	54,490
Investing Activities		
Expenditures for property, plant and equipment	**(54,706)**	(45,408)
Acquisition of mineral interests	**(713)**	(36,714)
Proceeds from the sale of assets	**822**	561
Equity method investment	**(16,556)**	(3,464)
Proceeds from the sale of private company equity units	**—**	3,574
Other	**(139)**	(146)
Net cash used for investing activities	**(71,292)**	(81,597)
Financing Activities		
Net additions to revolving credit agreement	**60,000**	10,000
Additions to long-term debt	**624**	5,232
Reductions to long-term debt	**(4,914)**	(4,209)
Debt issuance costs	**(2,415)**	—
Cash dividends paid	**(6,624)**	(6,452)
Purchase of treasury shares	**(9,944)**	(3,103)
Net cash provided by financing activities	**36,727**	1,468
Cash and Cash Equivalents		
Total decrease for the year	**(12,276)**	(25,639)
Balance at the beginning of the year	**85,109**	110,748
Balance at the end of the year	**$ 72,833**	$ 85,109

See notes to the Consolidated Financial Statements.

NACCO INDUSTRIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY

	Class A Common Stock	Class B Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Total Stockholders' Equity
	(In thousands, except per share data)					
Balance, January 1, 2023	$ 5,783	$ 1,566	$ 23,706	$ 404,924	$ (9,013)	$ 426,966
Stock-based compensation	191	—	4,966	—	—	5,157
Purchase of treasury shares	(91)	—	—	(3,012)	—	(3,103)
Net loss	—	—	—	(39,587)	—	(39,587)
Cash dividends on Class A and Class B common stock: $0.8600 per share	—	—	—	(6,452)	—	(6,452)
Current period other comprehensive income, net of tax	—	—	—	—	(2,118)	(2,118)
Pension settlement, net of tax	—	—	—	—	1,398	1,398
Reclassification adjustment to net income, net of tax	—	—	—	—	79	79
Balance, December 31, 2023	$ 5,883	$ 1,566	$ 28,672	$ 355,873	$ (9,654)	$ 382,340
Stock-based compensation	**164**	**—**	**5,668**	**—**	**—**	**5,832**
Purchase of treasury shares	**(317)**	**—**	**—**	**(9,627)**	**—**	**(9,944)**
Net income	**—**	**—**	**—**	**33,741**	**—**	**33,741**
Cash dividends on Class A and Class B common stock: $0.9000 per share	**—**	**—**	**—**	**(6,624)**	**—**	**(6,624)**
Current period other comprehensive income, net of tax	**—**	**—**	**—**	**—**	**(706)**	**(706)**
Reclassification adjustment to net income, net of tax	**—**	**—**	**—**	**—**	**308**	**308**
Balance, December 31, 2024	**$ 5,730**	**$ 1,566**	**$ 34,340**	**$ 373,363**	**$ (10,052)**	**$ 404,947**

See notes to the Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
NACCO INDUSTRIES, INC. AND SUBSIDIARIES
(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

NOTE 1—Principles of Consolidation and Nature of Operations

The accompanying Consolidated Financial Statements include the accounts of NACCO Industries, Inc.® (NACCO) and its wholly owned subsidiary, NACCO Natural Resources Corporation® (NACCO Natural Resources and with NACCO collectively, the Company, we, our or us). NACCO Natural Resources brings natural resources to life by delivering aggregates, minerals, reliable fuels and environmental solutions through our robust portfolio of businesses. We operate under three business segments: Coal Mining, North American Mining® (NAMining) and Minerals Management. The Coal Mining segment operates surface coal mines for power generation companies. The NAMining segment is a trusted mining partner for producers of aggregates, activated carbon, lithium and other industrial minerals. The Minerals Management segment, which includes the Catapult Mineral Partners (Catapult) business, acquires and promotes the development of mineral interests. Mitigation Resources of North America® (Mitigation Resources) provides stream and wetland mitigation solutions as well as comprehensive reclamation and restoration construction services. In addition, ReGen Resources is pursuing opportunities to develop new power generation resources.

We have items not directly attributable to a reportable segment that are not included in the reported financial results of the operating segment. These items primarily include administrative costs related to public company reporting requirements, including management and board compensation, and the financial results of Bellaire Corporation (Bellaire), Mitigation Resources, ReGen Resources and other developing businesses. Bellaire manages our long-term liabilities related to former Eastern U.S. underground mining activities. Intercompany accounts and transactions are eliminated in consolidation. See Note 15 to the Consolidated Financial Statements for further discussion of segment reporting.

Our operating segments are further described below:

Coal Mining Segment
The Coal Mining segment operates surface coal mines under long-term contracts with power generation companies pursuant to a service-based business model. Coal is surface mined in North Dakota and Mississippi. Each mine is fully integrated with our customer's operations.

As of December 31, 2024, the Coal Mining segment's operating coal mines were: The Coteau Properties Company (Coteau), Coyote Creek Mining Company, LLC (Coyote Creek), The Falkirk Mining Company (Falkirk) and Mississippi Lignite Mining Company (MLMC). Each of these mines supply lignite coal for power generation and delivers our coal production to an adjacent power plant or synfuels plant under a long-term supply contract. While MLMC’s coal supply contract contains a take or pay provision, the contract contains a force majeure provision that allows for the temporary suspension of the take or pay provision during the duration of certain specified events beyond the control of either party; all other coal supply contracts are requirements contracts. Certain coal supply contracts can be terminated early, which would result in a reduction to future earnings.

The MLMC contract is the only coal supply contract in which we are responsible for all operating costs, capital requirements and final mine reclamation; therefore, MLMC is consolidated within our financial statements. MLMC sells coal to its customer at a contractually agreed-upon price which adjusts monthly, primarily based on changes in the level of established indices which reflect general U.S. inflation rates. Profitability at MLMC is affected by customer demand for coal and changes in the indices that determine sales price and actual costs incurred. As diesel fuel is heavily weighted among the indices used to determine the coal sales price, fluctuations in diesel fuel prices can result in significant fluctuations in earnings at MLMC. MLMC's customer operates the Red Hills Power Plant, which supplies electricity to the Tennessee Valley Authority (TVA) under a long-term power purchase agreement. MLMC’s contract with its customer runs through April 1, 2032. TVA’s power portfolio includes coal, nuclear, hydroelectric, natural gas and renewables. The decision regarding which power plants to dispatch is determined by TVA. Reduction in dispatch of the Red Hills Power Plant will result in reduced earnings at MLMC.

During 2023, MLMC received notice from our customer related to a boiler issue at the Red Hills Power Plant that began on December 15, 2023. We assessed MLMC's long-lived assets for impairment and recorded a $65.9 million impairment charge in 2023. See Note 9 to the Consolidated Financial Statements in this Form 10-K for further information on the long-lived asset impairment charge. While this issue has been resolved, it resulted in a reduction in customer demand which had a significant impact on our results of operations during 2024. We recognized income of $13.6 million in 2024 related to business interruption insurance recoveries to partially offset losses related to the boiler outage.

The Sabine Mining Company (Sabine) operates the Sabine Mine in Texas. All production from Sabine was delivered to Southwestern Electric Power Company's (SWEPCO) Henry W. Pirkey Plant (the Pirkey Plant). SWEPCO is an American Electric Power (AEP) company. As a result of the early retirement of the Pirkey Plant, Sabine ceased deliveries and commenced final reclamation on April 1, 2023. Funding for mine reclamation is the responsibility of SWEPCO, and Sabine receives compensation for providing mine reclamation services. Sabine will provide mine reclamation services through September 30, 2026. As of October 1, 2026, SWEPCO has an obligation to acquire all of the capital stock of Sabine and complete the remaining mine reclamation.

At Coteau, Coyote Creek and Falkirk, we are paid a management fee per ton of coal or heating unit (MMBtu) delivered. Each contract specifies the indices and mechanics by which fees change over time, generally in line with broad measures of U.S. inflation. Our customers are responsible for funding all mine operating costs, including final mine reclamation, and directly or indirectly providing all of the capital required to build and operate the mine. This contract structure eliminates exposure to spot coal market price fluctuations while providing income and cash flow with minimal capital investment. Other than at Coyote Creek, debt financing provided by or supported by the customers is without recourse to us. See Note 16 to the Consolidated Financial Statements in this Form 10-K for further discussion of Coyote Creek's guarantees.

Coteau, Coyote Creek, Falkirk and Sabine each meet the definition of a variable interest entity (VIE). In each case, NACCO is not the primary beneficiary of the VIE as we do not exercise financial control; therefore, we do not consolidate the results of these operations within our financial statements. Instead, these contracts are accounted for as equity method investments. We regularly evaluate if there are reconsideration events which could change our conclusion as to whether these entities meet the definition of a VIE and the determination of the primary beneficiary. The income before income taxes associated with these VIEs is reported as Earnings of unconsolidated operations on the Consolidated Statements of Operations and our investment is reported on the line Investments in unconsolidated subsidiaries in the Consolidated Balance Sheets. The mines that meet the definition of a VIE are referred to collectively as the Unconsolidated Subsidiaries. For tax purposes, the Unconsolidated Subsidiaries are included within our consolidated U.S. tax return; therefore, the Income tax benefit line on the Consolidated Statements of Operations includes income taxes related to these entities. See Note 16 to the Consolidated Financial Statements in this Form 10-K for further information on the Unconsolidated Subsidiaries.

We perform contemporaneous reclamation activities at each mine in the normal course of operations. Under all of the Unconsolidated Subsidiaries' contracts, the customer has the obligation to fund final mine reclamation activities. Under certain contracts, the Unconsolidated Subsidiary holds the mine permit and is therefore responsible for final mine reclamation activities. To the extent the Unconsolidated Subsidiary performs such final reclamation, it is compensated for providing those services in addition to receiving reimbursement from customers for costs incurred.

NAMining Segment
The NAMining segment provides value-added contract mining and other services for producers of industrial minerals. The segment is a platform for our growth and diversification of mining activities outside of the thermal coal industry. NAMining provides contract mining services for independently owned mines and quarries, creating value for our customers by performing the mining aspects of our customers' operations. This allows customers to focus on their areas of expertise: materials handling and processing, product sales and distribution. As of December 31, 2024, NAMining operates in Florida, Texas, Arkansas, Virginia and Nebraska.

In addition, Sawtooth Mining, LLC (Sawtooth) will be the exclusive provider of comprehensive mining services for the Thacker Pass lithium project in Humboldt County, Nevada. Thacker Pass is owned by a joint venture between Lithium Americas Corp. (TSX:LAC) (NYSE: LAC) and General Motors Holdings LLC. Thacker Pass commenced construction in 2023 and is targeting initial production in 2027. Sawtooth will be reimbursed for costs of mining, capital expenditures and mine closure and will recognize a contractually agreed upon production fee once the mine is operating. In addition to providing comprehensive mining services, Sawtooth is currently assisting with certain construction services and will transport clay tailings once lithium production commences

During 2024 and 2023, NAMining amended and extended existing limestone contracts with two customers and expanded the scope of work with several other customers. New contracts signed in 2024 are expected to be accretive to earnings starting in 2026.

Minerals Management Segment
The Minerals Management segment derives income primarily by leasing our royalty and mineral interests to third-party exploration and production companies, and, to a lesser extent, other mining companies, granting them the rights to explore, develop, mine, produce, market and sell gas, oil, and coal in exchange for royalty payments based on the lessees' sales of those minerals.

The Minerals Management segment owns royalty interests, mineral interests, non-participating royalty interests and overriding royalty interests (collectively mineral and royalty interests).

- Royalty Interest. Royalty interests generally result when the owner of a mineral interest leases the underlying minerals to an exploration and production company pursuant to an oil and gas lease. Typically, the resulting royalty interest is a cost-free percentage of production revenues for minerals extracted from the acreage. A holder of royalty interests is generally not responsible for capital expenditures or lease operating expenses, but royalty interests may be calculated net of post-production expenses, and typically have no environmental liability. Royalty interests leased to producers expire upon the expiration of the oil and gas lease and revert to the mineral owner.
- Mineral Interest. Mineral interests are perpetual rights of the owner to explore, develop, exploit, mine and/or produce any or all of the minerals lying below the surface of the property. The holder of a mineral interest has the right to lease the minerals to an exploration and production company. Upon the execution of an oil and gas lease, the lessee (the exploration and production company) becomes the working interest owner and the lessor (the mineral interest owner) has a royalty interest.
- Non-Participating Royalty Interest (NPRIs). NPRI is an interest in oil and gas production which is created from the mineral estate. The NPRI is expense-free, bearing no operational costs of production. The term non-participating indicates that the interest owner does not share in the bonus, rentals from a lease, nor the right to participate in the execution of oil and gas leases. The NPRI owner does; however, typically receive royalty payments.
- Overriding Royalty Interest (ORRIs). ORRIs are created by carving out the right to receive royalties from a working interest. Like royalty interests, ORRIs do not confer an obligation to make capital expenditures or pay for lease operating expenses and have limited environmental liability; however, ORRIs may be calculated net of post-production expenses, depending on how the ORRI is structured. ORRIs that are carved out of working interests are linked to the same underlying oil and gas lease that created the working interest, and therefore, such ORRIs are typically subject to expiration upon the expiration or termination of the oil and gas lease.

We may own more than one type of mineral and royalty interest in the same tract of land. For example, where we own an ORRI in a lease on the same tract of land in which we own a mineral interest, the ORRI in that tract will relate to the same gross acres as the mineral interest in that tract.

The Minerals Management segment does not currently have any material investments under which we would be required to bear the cost of exploration, production or development. The Minerals Management segment will benefit from the continued development of our mineral properties without the need for investment of additional capital once mineral and royalty interests have been acquired as the capital costs or lease operating expenses are born entirely by the operators or working interest owners.

During 2024 and 2023, Minerals Management invested a total of $19.1 million, including $15.7 million in the fourth quarter of 2024, in Eiger, LLC (Eiger), which holds non-operated working interests in oil and natural gas assets in the Kansas and the Oklahoma portion of the Hugoton basin. This entity meets the definition of a VIE. NACCO is not the primary beneficiary of the VIE as it does not exercise financial control; therefore, we do not consolidate the results of these operations within our financial statements. Instead, this contract is accounted for as an equity method investment. During 2024, we recorded $0.6 million, which represented our share of earnings, as Earnings of unconsolidated operations on the Consolidated Statements of Operations. Our investment is reported on the line Equity method investment in Eiger, LLC in the Consolidated Balance Sheets. Due to a lag in Eiger's financial reporting, earnings or losses from this investment will be recorded on a one quarter lag.

Excluding the Eiger investment described above, total consideration for acquisitions of mineral and royalty interests was $0.7 million and $36.7 million, in 2024 and 2023, respectively. The 2024 acquisitions include 13.7 thousand gross acres and 0.6 thousand net royalty acres. The 2023 acquisitions included 43.4 thousand gross acres and 2.5 thousand net royalty acres.

We also manage legacy royalty and mineral interests located in Ohio (Utica and Marcellus shale natural gas), Louisiana (Haynesville shale and Cotton Valley formation natural gas), Texas (Cotton Valley and Austin Chalk formation natural gas), Mississippi (coal), Pennsylvania (coal, coalbed methane and Marcellus shale natural gas), Alabama (coal, coalbed methane and natural gas) and North Dakota (coal, oil and natural gas). The majority of our legacy reserves were acquired as part of our historical coal mining operations.

Total oil and gas mineral and royalty interests include approximately 198.4 thousand gross acres and 63.9 thousand net royalty acres at December 31, 2024. Net royalty acres are calculated based on our ownership and royalty rate, normalized to a standard 1/8th royalty lease, and assumes a 1/4th royalty rate for unleased acres. See Note 17 for further discussion of Minerals Management.

Other items: At December 31, 2024 and 2023, we had $14.2 million and $6.5 million classified as Assets held for sale, primarily for draglines at NAMining and a building, respectively.

During 2024, we had cash proceeds from the sale of assets held by a qualified intermediary to facilitate tax-deferred exchange transactions under Section 1031 of the Internal Revenue Code. In May 2024, we sold land for $7.0 million and recognized a $4.5 million gain in the Minerals Management segment, which is included on the line (Gain) loss on sale of assets within the accompanying Consolidated Statements of Operations. We structured this transaction in a manner that qualified as a like-kind exchange pursuant to Section 1031 of the Internal Revenue Code and used all of the net proceeds from the sale during the year ended December 31, 2024.

During 2023, our Board of Directors approved the termination of the Combined Defined Benefit Plan (Combined Plan) and participants were offered lump-sum distributions as part of the termination process. As a result of the lump-sum distributions, we recognized a non-cash, pension settlement charge of $1.8 million in 2023 on the line Other, net within the accompanying Consolidated Statements of Operations. See Note 14 to the Consolidated Financial Statements in this Form 10-K for further information on the Combined Plan.

On December 1, 2022, we transferred our ownership interest in Midwest AgEnergy Group, LLC (MAG) to HLCP Ethanol Holdco, LLC. We received cash payments totaling $3.6 million during 2023 in connection with MAG and recognized the gain on the line Other, net within the accompanying Consolidated Statements of Operations.

NOTE 2—Significant Accounting Policies

Use of Estimates: The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and judgments. These estimates and judgments affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities (if any) at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents: Cash and cash equivalents include cash in banks and highly liquid investments with original maturities of three months or less.

Property, Plant and Equipment, Net: Property, plant and equipment are initially recorded at cost. Depreciation, depletion and amortization are provided in amounts sufficient to amortize the cost of the assets, including assets recorded under finance leases, over their estimated useful lives using the straight-line method or the units-of-production method. Buildings and building improvements are depreciated over the life of the asset, which is generally 30 years. Estimated lives for machinery and equipment generally range from three to 15 years. The units-of-production method is used to amortize certain assets based on estimated recoverable tonnages. Repairs and maintenance costs are expensed when incurred, unless such costs extend the estimated useful life of the asset, in which case such costs are capitalized and depreciated. Asset retirement costs associated with asset retirement obligations are capitalized with the carrying amount of the related long-lived asset and depreciated over the asset's estimated useful life.

Royalty Interests in Oil and Natural Gas Properties: We follow the successful efforts method of accounting for royalty and mineral interests. Under this method, costs to acquire mineral and royalty interests in oil and natural gas properties are capitalized when incurred. Acquisitions of royalty interests of oil and natural gas properties are considered asset acquisitions and are recorded at cost. As an owner of mineral and royalty interests and not working interests, we are not required to make capital expenditures and did not make capital expenditures to convert proved undeveloped reserves from undeveloped to developed.

Acquisition costs of proved royalty and mineral interests are amortized using the units of production method over the life of the property, which is estimated using proved reserves. For purposes of amortization, interests in oil and natural gas properties are grouped in a reasonable aggregation of properties with common geological structural features or stratigraphic condition.

We review and evaluate our royalty interests in oil and natural gas properties for impairment when events or changes in circumstances indicate that the related carrying amounts may not be recoverable. Proved oil and gas properties are reviewed for impairment when events and circumstances indicate a potential decline in the fair value of such properties below the carrying value, such as a downward revision of the reserve estimates or lower commodity prices. When such events or changes in circumstances occur, we estimate the undiscounted future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. If the carrying value of the properties is determined to not be recoverable based on the undiscounted cash flows, an impairment charge is recognized by comparing the carrying value to the estimated fair value of the properties.

See Note 17 for further discussion of our royalty and mineral interests.

Long-Lived Assets: We periodically evaluate long-lived assets for impairment when changes in circumstances or the occurrence of certain events indicate the carrying amount of an asset or asset group may not be recoverable. Upon identification of indicators of impairment, we evaluate the carrying value of the asset by comparing the estimated future undiscounted cash flows generated from the use of the asset or asset group and its eventual disposition with the asset's net carrying value. If the carrying value of an asset is considered impaired, an impairment charge is recorded for the amount that the carrying value of the long-lived asset or asset group exceeds its fair value. Fair value is estimated as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Identifying and assessing whether impairment indicators exist, or if events or changes in circumstances have occurred, including assumptions about future power plant dispatch levels, changes in future sales price, operating costs and other factors that impact anticipated revenue and customer demand, requires significant judgment. We determined that indicators of impairment existed at MLMC during the fourth quarter of 2023 and, as a result, MLMC's long-lived assets were reviewed for impairment. We assessed the recoverability of the MLMC asset group and determined that the assets were not fully recoverable when compared to the remaining future undiscounted cash flows from these assets. As a result, we estimated the fair value of the asset group which resulted in a non-cash, long-lived asset impairment charge of $65.9 million in 2023.

See Note 9 for further discussion of our impairment analysis.

Self-insurance Liabilities: We are generally self-insured for medical claims, certain workers’ compensation claims and certain closed mine liabilities. An estimated provision for claims reported and for claims incurred but not yet reported under the self-insurance programs is recorded and revised periodically based on industry trends, historical experience and management judgment. In addition, industry trends are considered within management's judgment for valuing claims. Changes in assumptions for such matters as legal judgments and settlements, inflation rates, medical costs and actual experience could cause estimates to change in the near term.

Revenue Recognition: See Note 3 to the Consolidated Financial Statements for discussion of our revenue recognition.

Stock Compensation: We maintain a long-term incentive program that allow for the grant of shares of Class A common stock, subject to restrictions, as a means of retaining and rewarding selected employees for long-term performance and to increase their ownership in NACCO. Shares awarded under the plans are fully vested and entitle the stockholder to all rights of common stock ownership except that shares may not be assigned, pledged or otherwise transferred during the restriction period. In general, for shares awarded for years ended December 31, 2024 and December 31, 2023, the restriction period ends at the earliest of (i) three years after the participant's retirement date, (ii) three, five or ten years from the award date, or (iii) the participant's death or permanent disability. Pursuant to the plans, we issued 162,670 and 120,649 shares related to the years ended December 31, 2024 and 2023, respectively. After the issuance of these shares, there were 616,681 shares of Class A common stock available for issuance under these plans. Compensation expense related to these share awards was $5.2 million ($4.1 million net of tax) and $4.1 million ($3.3 million net of tax) for the years ended December 31, 2024 and 2023, respectively. Compensation expense represents fair value based on the market price of the shares of Class A common stock at the grant date.

We also have a stock compensation plan for non-employee directors under which a portion of the annual retainer for each non-employee director is paid in restricted shares of Class A common stock. For the year ended December 31, 2024 and 2023, $110,000 ($150,000 for the Chairman) of the non-employee director's annual retainer of $175,000 ($250,000 for the Chairman) was paid in restricted shares of Class A common stock. Shares awarded under the plan are fully vested and entitle the stockholder to all rights of common stock ownership except that shares may not be assigned, pledged, hypothecated or otherwise transferred during the restriction period. In general, the restriction period ends at the earliest of (i) ten years from the award date, (ii) the date of the director's death or permanent disability, (iii) five years (or earlier with the approval of the Board of Directors) after the director's date of retirement from the Board of Directors, (iv) the date the director has both retired from the Board of Directors and has reached age 70, or (v) at such other time as determined by the Board of Directors in their sole and absolute discretion. Pursuant to this plan, we issued 44,731 and 35,965 shares related to the years ended December 31, 2024 and 2023, respectively. In addition to the mandatory retainer fee received in restricted stock, directors may elect to receive shares of Class A common stock in lieu of cash for up to 100% of the balance of their annual retainer, committee retainer and any committee chairman's fees. These voluntary shares are not subject to any restrictions. There were no shares issued under voluntary elections in 2024. Total shares issued under voluntary elections were 1,603 in 2023. After the issuance of these shares, there were 53,748 shares of Class A common stock available for issuance under this plan. Compensation expense related to these awards was $1.3 million ($1.0 million net of tax) and $1.3 million ($1.1 million net of tax) for the years ended December 31, 2024 and 2023, respectively. Compensation expense represents fair value based on the market price of the shares of Class A common stock at the grant date.

Financial Instruments: Financial instruments held by us include cash and cash equivalents, accounts receivable, equity securities, accounts payable, revolving credit agreements and long-term debt.

Fair Value Measurements: We account for the fair value measurement of our financial assets and liabilities in accordance with U.S. generally accepted accounting principles, which defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

A fair value hierarchy requires an entity to maximize the use of observable inputs, where available, and minimize the use of unobservable inputs when measuring fair value.

Described below are the three levels of inputs that may be used to measure fair value:

Level 1 - Quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
Level 2 - Observable prices that are based on inputs not quoted on active markets, but corroborated by market data.
Level 3 - Unobservable inputs are used when little or no market data is available.

The hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The classification of fair value measurements within the hierarchy is based upon the lowest level of input that is significant to the measurement. See Note 9 for further discussion of fair value measurements.

Recently Issued Accounting Standards

Accounting Standards Adopted in 2024: Effective for the year ended December 31, 2024, we adopted ASU No. 2023-07, Segment Reporting (Topic 280), (ASU 2023-07), which enhances reportable segment disclosure requirements in part by requiring entities to disclose significant expenses related to their reportable segments. ASU 2023-07 also requires disclosure of the title and position of the company's Chief Operating Decision Maker (CODM) and how the CODM uses financial reporting to assess segment performance and allocate resources. The adoption of this standard only impacts disclosures and did not have a material impact on our Financial Statements.

Accounting Standards Not Yet Adopted: In December 2023, the Financial Accounting Standards Board (FASB) issued ASU No. 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures (ASU 2023-09), which requires entities to disclose more detailed information about their effective tax rate reconciliation as well as information on income taxes paid. ASU 2023-09 is effective for fiscal years beginning after December 15, 2024. The adoption of this standard only impacts disclosures and is not expected to have a material impact on our Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures (Subtopic 220-40) (ASU 2024-03), which requires entities to disclose disaggregated information about certain income statement expense line items in the notes to their financial statements on an annual and interim basis. ASU 2024-03 is effective for fiscal years beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027, with early adoption permitted. We are currently in the process of evaluating the impact of this ASU on our Financial Statements and related disclosures.

Reclassification: Certain reclassifications have been made to the prior periods' Consolidated Financial Statements to conform to the current period's presentation.

NOTE 3—Revenue Recognition

Nature of Performance Obligations

At contract inception, we assess the goods and services promised in our contracts with customers and identifies a performance obligation for each promised good or service that is distinct. To identify the performance obligations, we consider all of the goods or services promised in the contract regardless of whether they are explicitly stated or are implied by customary business practices.

Each mine or mine area has a contract with our respective customer that represents a contract under ASC 606. For our consolidated entities, our performance obligations vary by contract and consist of the following:

At MLMC, each MMBtu delivered during the production period is considered a separate performance obligation. Revenue is recognized at the point in time that control of each MMBtu of lignite transfers to the customer. Fluctuations in revenue from period to period generally result from changes in customer demand.

At NAMining, the management service to oversee the operation of the equipment and delivery of aggregates or other minerals is the performance obligation accounted for as a series. Performance momentarily creates an asset that the customer simultaneously receives and consumes; therefore, control is transferred to the customer over time. Consistent with the conclusion that the customer simultaneously receives and consumes the benefits provided, an input-based measure of progress is appropriate. As each month of service is completed, revenue is recognized for the amount of actual costs incurred, plus the management fee or fixed fee and the general and administrative fee (as applicable). Fluctuations in revenue from period to period result from changes in customer demand primarily due to increases and decreases in activity levels on individual contracts and variances in reimbursable costs. Revenue from part sales is recognized upon transfer of control of the parts to the customer.

The Minerals Management segment enters into contracts which grant the right to explore, develop, produce and sell minerals controlled by us. These arrangements result in the transfer of mineral rights for a period of time; however, no rights to the actual land are granted other than access for purposes of exploration, development, production and sales. The mineral rights revert back to us at the expiration of the contract.

Under these contracts, granting exclusive right, title, and interest in and to minerals, if any, is the performance obligation. The performance obligation under these contracts represents a series of distinct goods or services whereby each day of access that is provided is distinct. The transaction price consists of a variable sales-based royalty and, in certain arrangements, a fixed component in the form of an up-front lease bonus payment. As the amount of consideration we will ultimately be entitled to is entirely susceptible to factors outside of our control, the entire amount of variable consideration is constrained at contract inception. We believe that the pricing provisions of royalty contracts are customary in the industry. Up-front lease bonus payments represent the fixed portion of the transaction price and are recognized over the primary term of the contract, which is generally three to five years.

Mitigation Resources generates and sells stream and wetland mitigation credits (known as mitigation banking) and provides services to those engaged in permittee-responsible stream and wetland mitigation. Each mitigation credit sale is considered a separate performance obligation. Revenue is recognized at the point in time that control of each mitigation credit transfers to the customer. Fluctuations in revenue from period to period generally result from changes in customer demand. Under the permittee-responsible stream and wetland mitigation model, the contracts are generally structured as a management fee agreement under which Mitigation Resources is reimbursed for all costs incurred in performing the required mitigation plus an agreed profit percentage or a fixed fee. The mitigation services provided is the performance obligation and is accounted for as a series. Performance momentarily creates an asset that the customer simultaneously receives and consumes; therefore, control is transferred to the customer as work is completed. Consistent with the conclusion that the customer simultaneously receives and consumes the benefits provided, an input-based measure of progress is appropriate. As each month of service is completed, revenue is recognized for the amount of actual costs incurred, plus the management fee or fixed fee. Fluctuations in revenue from period to period result from changes in customer demand primarily due to increases and decreases in activity levels of individual contracts and variances in reimbursable costs.

Significant Judgments

Our contracts with our customers in the Coal Mining and NAMining segments contain different types of variable consideration including, but not limited to, management fees that adjust based on volumes or MMBtu delivered. However, the terms of these variable payments relate specifically to our efforts to satisfy one or more, but not all, of the performance obligations (or to a specific outcome from satisfying the performance obligations) in the contract. Therefore, we allocate each variable payment (and subsequent changes to that payment) entirely to the specific performance obligation to which it relates. Management fees, as well as general and administrative fees, are also adjusted based on changes in specified indices (e.g., CPI) to compensate for general inflation changes. Index adjustments, if applicable, are effective prospectively.

In the Minerals Management segment, we have the right to receive revenues from the sale of oil and natural gas through sales of the third-party lessees in which we own a mineral or royalty interest. Revenue is recognized at the point control of the product is transferred from the operator to the purchaser. Those purchasers remit payment to the operator and the operator, in turn, remits payment to us. Receivables from third-party lessees for which we did not receive actual production information, either due to timing delays or due to the unavailability of data at the time when revenues are recognized, are estimated using expected sales volumes and estimated prices. The difference between our estimates and the actual amounts received is recorded in the month that payment is received from the third-party lessee. We typically receive payment for oil and natural gas sales within 90 days of the month of delivery. For the years ended December 31, 2024 and 2023, differences between our estimates and the actual amounts received from operators were immaterial. For the years ended December 31, 2024 and 2023, any changes in estimates were immaterial.

Cost Reimbursement

Certain contracts include reimbursement from customers of actual costs incurred for the purchase of supplies, equipment and services in accordance with contractual terms. Such reimbursable revenue is variable and subject to uncertainty, as the amounts received and timing thereof is highly dependent on factors outside of our control. Accordingly, reimbursable revenue is fully constrained and not recognized until the uncertainty is resolved, which typically occurs when the related costs are incurred on behalf of a customer. We are considered a principal in such transactions and records the associated revenue at the gross amount billed to the customer with the related costs recorded as an expense within cost of sales.

At the Thacker Pass lithium project, in addition to management fee income, the customer will reimburse Sawtooth for certain capital expenditures. Sawtooth will recognize revenue over the estimated useful life of the asset on a straight-line basis as the performance obligation is satisfied over time. In prior years, the customer received a $3.5 million advance from Sawtooth, which is included in the long-term contract asset. The customer will either pay a $4.7 million success fee to Sawtooth upon achieving commercial mining milestones or repay the $3.5 million advance if such commercial mining milestones are not met.

Prior Period Performance Obligations

As discussed above, we record royalty income in the month production is delivered to the purchaser. The expected sales volumes and prices for these properties are estimated and recorded in Trade accounts receivable in the accompanying Consolidated Balance Sheets. The difference between our estimates and the actual amounts received is recorded in the month that payment is received from the third-party lessee. During the years ended December 31, 2024 and 2023, royalty income recognized in the reporting period related to production satisfied in prior reporting periods was immaterial and $1.4 million, respectively.

Disaggregation of Revenue

In accordance with ASC 606-10-50, we disaggregate revenue from contracts with customers into major goods and service lines and timing of transfer of goods and services. We determined that disaggregating revenue into these categories achieves the disclosure objective of depicting how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. Our business consists of the Coal Mining, NAMining and Minerals Management segments as well as Unallocated Items. Revenue included in Unallocated Items is primarily related to Mitigation Resources. See Note 15 to the Consolidated Financial Statements for further discussion of segment reporting.

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

The following table disaggregates revenue by major sources for the years ended December 31:

Major Goods/Service Lines	**2024**	2023
Coal Mining	**$ 68,611**	$ 85,415
NAMining	**119,600**	90,532
Minerals Management	**34,579**	32,985
Unallocated Items	**17,707**	8,459
Eliminations	**(2,789)**	(2,597)
Total revenues	**$ 237,708**	$ 214,794
Timing of Revenue Recognition		
Goods transferred at a point in time	**$ 66,506**	$ 83,273
Services transferred over time	**171,202**	131,521
Total revenues	**$ 237,708**	$ 214,794

Contract Balances

The opening and closing balances of our current and long-term contract assets and liabilities and receivables are as follows:

	Contract balances				
	Trade accounts receivable	Contract asset (current)	Contract asset (long-term)	Contract liability (current)	Contract liability (long-term)
Balance at January 1, 2024	$ 37,429	$ —	$ 3,712	$ 878	$ 1,470
Balance at December 31, 2024	**49,706**	**313**	**3,500**	**484**	**5,119**
Increase (decrease)	$ 12,277	$ 313	$ (212)	$ (394)	$ 3,649

As described above, we enter into royalty contracts that grant exclusive right, title, and interest in and to minerals. The transaction price consists of a variable sales-based royalty and, in certain arrangements, a fixed component in the form of an up-front lease bonus payment. The timing of the payment of the fixed portion of the transaction price is upfront, however, the performance obligation is satisfied over the primary term of the contract, which is generallythree to five years. Therefore, at the time any such up-front payment is received, a contract liability is recorded which represents deferred revenue. The amount of royalty revenue recognized in the years ended December 31, 2024 and December 31, 2023 that was included in the opening contract liability was $0.7 million and $0.8 million, respectively. This revenue consists of up-front lease bonus payments received under royalty contracts that are recognized over the primary term of the royalty contracts, which are generally three to five years.

We expect to recognize $0.5 million in 2025, $0.1 million in 2026 and 2027, $1.0 million in 2028, $2.4 million in 2029 and $1.5 million thereafter related to the contract liability remaining at December 31, 2024. The difference between the opening and closing balances of our contract balances results from the timing difference between our performance and the customer's payment.

We have no contract assets recognized from the costs to obtain or fulfill a contract with a customer.

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

NOTE 4—Inventories

Inventories are summarized as follows:

	December 31	
	2024	2023
Coal	**$ 27,076**	$ 23,784
Mining supplies	**67,532**	53,216
Total inventories	**$ 94,608**	$ 77,000

The weighted average method is used for inventory valuation. During the year ended December 31, 2024 and 2023, we recorded $9.6 million and $7.5 million of inventory impairment charges, respectively, in the line Cost of sales in the accompanying Consolidated Statements of Operations as mining costs exceeded net realizable value of coal inventory at MLMC.

NOTE 5—Property, Plant and Equipment, Net

Property, plant and equipment, net includes the following:

	December 31	
	2024	2023
Coal lands and real estate	**$ 70,766**	$ 58,353
Mineral interests	**69,148**	68,150
Plant and equipment	**317,933**	325,655
Property, plant and equipment, at cost	**457,847**	452,158
Less allowances for depreciation, depletion, amortization and impairment	**198,390**	228,256
	$ 259,457	$ 223,902

Total depreciation, depletion and amortization expense on property, plant and equipment was $24.1 million and $26.4 million during 2024 and 2023, respectively.

During 2023, we recorded a non-cash, long-lived asset impairment charge of $65.9 million. See Note 9 for further discussion of the impairment charge.

NOTE 6—Intangible Assets

We have a coal supply agreement intangible asset which is subject to amortization based on units of production over the term of the lignite sales agreement which expires in 2032. The gross and net balances are set forth in the following table:

	Gross Carrying Amount	**Accumulated Amortization and Impairment**	**Net Balance**
Balance at December 31, 2024			
Coal supply agreement	**$ 84,200**	**$ (78,725)**	**$ 5,475**
Balance at December 31, 2023			
Coal supply agreement	$ 84,200	$ (78,194)	$ 6,006

Amortization expense for intangible assets was $0.5 million and $3.0 million in 2024 and 2023, respectively.

During 2023, we recorded a non-cash, long-lived asset impairment charge of $65.9 million. See Note 9 for further discussion of the impairment charge.

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

NOTE 7—Asset Retirement Obligations

Our obligations associated with the retirement of long-lived assets are recognized at fair value at the time the legal obligations are incurred. Upon initial recognition of a liability, a corresponding amount is capitalized as part of the carrying value of the related long-lived asset and is depreciated either by the straight-line method or the units-of-production method. The liability is accreted each period until the liability is settled, at which time the liability is removed. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Our asset retirement obligations are principally for costs to close our consolidated surface mines and reclaim the land as a result of our normal mining activities. Management's estimate involves a high degree of subjectivity. In particular, the obligation's fair value is determined using a discounted cash flow technique and is based upon mining permit requirements and various assumptions including credit adjusted risk-free-rates, estimates of disturbed acreage, life of the mine, estimated reclamation costs, the application of various environmental laws and regulations and assumptions regarding equipment productivity. We review our asset retirement obligations at each mine site at least annually and makes necessary adjustments for permit changes and for revisions of estimates of the timing and extent of reclamation activities and cost estimates.

The accretion of the liability is being recognized over the estimated life of each individual asset retirement obligation and is recorded in the line Cost of sales in the accompanying Consolidated Statements of Operations. The associated asset is recorded in Property, Plant and Equipment, net in the accompanying Consolidated Balance Sheets. The depreciation of the asset is recorded in the line Cost of sales in the accompanying Consolidated Statements of Operations.

A reconciliation of our beginning and ending aggregate carrying amount of the asset retirement obligations are as follows:

	Coal Mining	Unallocated Items	NACCO Consolidated
Balance at January 1, 2023	$ 28,460	$ 17,542	$ 46,002
Liabilities incurred during the period	1,920	—	1,920
Liabilities settled during the period	(852)	(1,048)	(1,900)
Accretion expense	2,170	1,358	3,528
Revision of estimated cash flows	1,346	1,717	3,063
Balance at December 31, 2023	$ 33,044	$ 19,569	$ 52,613
Liabilities settled during the period	**(6,115)**	**(960)**	**(7,075)**
Accretion expense	**2,530**	**1,510**	**4,040**
Revision of estimated cash flows	**79**	**(130)**	**(51)**
Balance at December 31, 2024	**$ 29,538**	**$ 19,989**	**$ 49,527**

During 2023, we acquired 100% of the membership interests in the Marshall Mine. We received $2.2 million of cash, assumed the asset retirement obligation estimated to be approximately $1.9 million and recognized a gain of approximately $0.3 million in the line Other, net in the accompanying Consolidated Statements of Operations. The asset retirement obligation's fair value was determined using a discounted cash flow technique and is based upon permit requirements and various estimates and assumptions that would be used by market participants, including estimates of disturbed acreage, reclamation costs and assumptions regarding equipment productivity.

Bellaire's legacy liabilities include obligations for water treatment and other environmental remediation that arose as part of the normal course of closing these underground mining operations. Since Bellaire's properties are no longer active operations, no associated asset has been capitalized. Bellaire's asset retirement obligation is included in the table above in the Unallocated Items column.

Prior to 2023, Bellaire established a $5.0 million Mine Water Treatment Trust to provide a financial assurance mechanism in order to assure the long-term treatment of post-mining discharges. The fair value of Bellaire's Mine Water Treatment assets, which are recognized as a component of Equity securities on the Consolidated Balance Sheets, are $12.3 million and $11.2 million at December 31, 2024 and December 31, 2023, respectively, and are legally restricted for purposes of settling the Bellaire asset retirement obligation. See Note 9 for further discussion of the Mine Water Treatment Trust.

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

NOTE 8—Current and Long-Term Financing

Financing arrangements are obtained and maintained at the subsidiary level. NACCO has not guaranteed any borrowings of our subsidiaries.

The following table summarizes our available and outstanding borrowings:

	December 31	
	2024	2023
Total outstanding borrowings:		
Revolving credit agreement	**$ 70,000**	$ 10,000
Other debt	**29,514**	25,956
Total debt outstanding	**$ 99,514**	$ 35,956
Current portion of borrowings outstanding	**$ 4,179**	$ 13,953
Long-term portion of borrowings outstanding	**95,335**	22,003
	$ 99,514	$ 35,956
Total available borrowings, net of limitations, under revolving credit agreement	**$ 169,102**	$ 115,120
Unused revolving credit agreement	**$ 99,102**	$ 105,120
Weighted average stated interest rate on total borrowings	**6.4 %**	6.6 %

Annual maturities of total debt, excluding leases, are as follows:

2025	4,152
2026	8,700
2027	3,130
2028	72,925
2029	1,696
Thereafter	8,827
	$ 99,430

Interest paid on total debt was $5.3 million and $2.4 million during 2024 and 2023, respectively.

In September 2024, NACCO Natural Resources amended its secured revolving line of credit (Facility) to increase the revolving credit commitments to $200.0 million and extend the maturity to September 2028. Borrowings outstanding under the Facility were $70.0 million at December 31, 2024. At December 31, 2024, the excess availability under the Facility was $99.1 million, which reflects a reduction for outstanding letters of credit of $30.9 million.

The Facility has performance-based pricing, which sets interest rates based upon NACCO Natural Resources achieving various levels of debt to EBITDA ratios, as defined in the Facility. Borrowings bear interest at a floating rate plus a margin based on the level of debt to EBITDA ratio achieved. The applicable margins, effective December 31, 2024, for base rate and Term Secured Overnight Financing Rate loans were 1.50% and 2.50%, respectively. The Facility has a commitment fee which is based upon achieving various levels of debt to EBITDA ratios. The commitment fee was 0.40% on the unused commitment at December 31, 2024. During the year ended December 31, 2024 and December 31, 2023, the average borrowing under the Facility was $27.2 million and $6.2 million, respectively, and the weighted-average annual interest rate, including the floating rate margin, was 8.83% and 6.06%, respectively.

The Facility contains restrictive covenants, which require, among other things, NACCO Natural Resources to maintain a maximum net debt to EBITDA ratio of 2.75 to 1.00 and an interest coverage ratio of not less than 4.00 to 1.00. The Facility provides the ability to make loans, dividends and advances to NACCO, with some restrictions based on maintaining a maximum debt to EBITDA ratio of 1.50 to 1.00, or if greater than 1.50 to 1.00, a Fixed Charge Coverage Ratio of 1.10 to 1.00. At December 31, 2024, NACCO Natural Resources was in compliance with all financial covenants in the Facility.

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The obligations under the Facility are guaranteed by certain of NACCO Natural Resources' direct and indirect, existing and future domestic subsidiaries, and is secured by certain assets of NACCO Natural Resources and the guarantors, subject to customary exceptions and limitations.

We have a demand note payable to Coteau, one of the unconsolidated subsidiaries, which bears interest based on the applicable quarterly federal short-term interest rate as announced from time to time by the IRS. At December 31, 2024 and 2023, the balance of the note was $7.7 million and $7.0 million and the interest rate was 4.15% and 5.12%, respectively.

We have ten notes payable that are secured by thirteen specified units of equipment, bear interest at a weighted average rate of 5.50%, and expire at various dates through 2030. One note includes a principal payment of $4.4 million at the end of the term on December 15, 2026. At December 31, 2024 and 2023, the outstanding balances of the notes payable were $21.8 million and $18.8 million, respectively.

NOTE 9—Fair Value Disclosure

Recurring Fair Value Measurements: The following table presents our assets accounted for at fair value on a recurring basis:

		Fair Value Measurements at Reporting Date Using		
Description	December 31, 2024	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Equity securities	**$ 18,663**	**$ 18,663**	**$ —**	**$ —**
	$ 18,663	**$ 18,663**	**$ —**	**$ —**

		Fair Value Measurements at Reporting Date Using		
Description	December 31, 2023	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Equity securities	$ 17,208	$ 17,208	$ —	$ —
	$ 17,208	$ 17,208	$ —	$ —

Bellaire's Mine Water Treatment Trust invests in available for sale securities that are reported at fair value based upon quoted market prices in active markets for identical assets; therefore, they are classified as Level 1 within the fair value hierarchy. The Mine Water Treatment Trust realized a gain of $1.5 million and $1.6 million in the years ended December 31, 2024 and 2023, respectively. See Note 7 for further discussion of Bellaire's Mine Water Treatment Trust.

Prior to 2023, we invested $2.0 million in equity securities of a public company with a diversified portfolio of royalty producing mineral interests. The investment is reported at fair value based upon quoted market prices in active markets for identical assets; therefore, it is classified as Level 1 within the fair value hierarchy. We recognized a gain of $0.3 million and $0.4 million in the years ended December 31, 2024 and 2023, respectively, related to the investment in these equity securities. The change in fair value of equity securities is reported on the line Gain on equity securities in the Other expense (income) section of the Consolidated Statements of Operations.

There were no transfers into or out of Levels 1, 2 or 3 during the year ended December 31, 2024.

Nonrecurring Fair Value Measurements: On December 18, 2023, MLMC received notice from its customer related to a boiler issue at the Red Hills Power Plant that began on December 15, 2023. We determined the reduction in customer demand caused by this issue was an indicator of potential impairment as of December 31, 2023 and, as a result, reviewed MLMC's long-lived assets for impairment.

We assessed the recoverability of the MLMC asset group and determined that the assets were not fully recoverable when compared to the remaining future undiscounted cash flows from the asset group. As a result, we estimated the fair value of the asset group which resulted in a non-cash, long-lived asset impairment charge of $65.9 million. The asset impairment charge was recorded as Long-lived asset impairment charge in the Consolidated Statement of Operations for the year ended December 31, 2023. The $65.9 million relates exclusively to MLMC; however, $60.8 million and $5.1 million were recorded on the Coal Mining segment and the Minerals Management segment, respectively, as certain MLMC land assets were recorded within the Minerals Management segment. The impairment charge was allocated to the long-lived assets of the asset group on a pro rata basis using the relative carrying amount of those assets in relation to their fair value. The analysis for the land and real estate and other property, plant and equipment was calculated using market data for similar assets, which are classified as Level 2 inputs. The analysis of certain other long-term assets was calculated using unobservable inputs with little or no market data, which are classified as Level 3 inputs.

While the boiler issue at the customer's Red Hills Power Plant has been resolved, it resulted in a reduction in customer demand which had a significant impact on our results of operations during 2024. We recognized income of $13.6 million in 2024 related to business interruption insurance recoveries to partially offset losses related to the boiler outage.

Other Fair Value Measurement Disclosures: The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these instruments. The fair values of revolving credit agreements and long-term debt, excluding finance leases, were determined using current rates offered for similar obligations taking into account subsidiary credit risk, which is Level 2 as defined in the fair value hierarchy. The fair value and the book value of revolving credit agreements and long-term debt, excluding finance leases, was $97.9 million and $99.4 million, respectively, at December 31, 2024 and $35.3 million and $35.8 million, respectively, at December 31, 2023.

Financial instruments that potentially subject us to concentration of credit risk consist principally of accounts receivable. Under our mining contracts, we recognize revenue and a related receivable as coal or other aggregates are delivered or predevelopment services are provided. These mining contracts provide for monthly settlements. Our significant credit concentration is uncollateralized; however, historically minimal credit losses have been incurred. To further reduce credit risk associated with accounts receivable, we perform periodic credit evaluations of our customers, but do not generally require advance payments or collateral.

NOTE 10—Leases

We recognize right-of-use assets (ROU assets) and lease liabilities for operating leases of real estate, mining and other equipment that expire at various dates through 2036. The majority of our leases are operating leases. NACCO does not recognize leases with a term of 12 months or less on the balance sheet. Instead, we recognize the related lease expense on a straight-line basis over the lease term. We account for lease and non-lease components as a single lease component. Our lease agreements do not contain lease payments that depend on an index or a rate, as such, minimum lease payments do not include variable lease payments.

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Leased assets and liabilities include the following at December 31:

Description	Location	2024	2023
Assets			
Operating	Operating lease right-of-use assets	**$ 9,661**	$ 8,667
Finance	Property, plant and equipment, net [(a)]	**79**	107
Liabilities			
Current			
Operating	Other current liabilities	**$ 1,973**	$ 1,485
Finance	Current maturities of long-term debt	**27**	28
Non-current			
Operating	Operating lease liabilities	**$ 9,042**	$ 8,782
Finance	Long-term debt	**57**	84

[(a)] Finance leased assets are recorded net of accumulated amortization of less than $0.1 million as of December 31, 2024 and December 31, 2023.

The components of lease expense for the years ended December 31 are as follows:

Description	Location	2024	2023
Lease expense			
Operating lease cost	Selling, general and administrative expenses	**$ 2,191**	$ 1,712
Finance lease cost:			
Amortization of leased assets	Cost of sales	**28**	61
Interest on lease liabilities	Interest expense	**8**	7
Variable lease expense	Selling, general and administrative expenses	**955**	572
Short-term lease expense	Selling, general and administrative expenses	**5,808**	3,214
Total lease expense		**$ 8,990**	$ 5,566

Future minimum finance and operating lease payments were as follows at December 31, 2024:

	Finance Leases	Operating Leases	Total
2025	$ 33	$ 2,769	$ 2,802
2026	33	2,441	2,474
2027	21	1,801	1,822
2028	9	1,822	1,831
2029	—	1,536	1,536
Subsequent to 2029	—	3,940	3,940
Total minimum lease payments	96	14,309	$ 14,405
Amounts representing interest	12	3,294	
Present value of net minimum lease payments	$ 84	$ 11,015	

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As most of our leases do not provide an implicit rate, we determine the incremental borrowing rate based on the information available at the lease commencement date in determining the present value of lease payments. We consider our credit rating and the current economic environment in determining this collateralized rate. The assumptions used in accounting for ASC 842 for the years ended December 31 are as follows:

	2024	2023
Weighted average remaining lease term (years)		
Operating	**6.70**	6.81
Finance	**3.01**	3.97
Weighted average discount rate		
Operating	**8.26 %**	8.13 %
Finance	**8.80 %**	8.69 %

The following table details cash paid for amounts included in the measurement of lease liabilities for the years ended December 31:

	2024	2023
Operating cash flows from operating leases	**$ 2,509**	$ 1,823
Operating cash flows from finance leases	**8**	7
Financing cash flows from finance leases	**25**	786

NOTE 11—Contingencies

Various legal and regulatory proceedings and claims have been or may be asserted against NACCO and certain subsidiaries relating to the conduct of their businesses. These proceedings and claims are incidental to the ordinary course of our business. Management believes that it has meritorious defenses and will vigorously defend us in these actions. Any costs that management estimates will be paid as a result of these claims are accrued when the liability is considered probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, we disclose the nature of the contingency and, in some circumstances, an estimate of the possible loss.

These matters are subject to inherent uncertainties, and unfavorable rulings could occur. If an unfavorable ruling were to occur, there exists the possibility of an adverse impact on our financial position, results of operations and cash flows of the period in which the ruling occurs, or in future periods.

NOTE 12—Stockholders' Equity and Earnings Per Share

NACCO Industries, Inc. Class A common stock is traded on the New York Stock Exchange under the ticker symbol NC. Because of transfer restrictions on Class B common stock, no trading market has developed, or is expected to develop, for our Class B common stock. The Class B common stock is convertible into Class A common stock on a one-for-one basis at any time at the request of the holder. Our Class A common stock and Class B common stock have the same cash dividend rights per share. As the liquidation and dividend rights are identical, any distribution of earnings would be allocated to Class A and Class B stockholders on a proportionate basis, and accordingly the net income per share for each class of common stock is identical. The Class A common stock has one vote per share and the Class B common stock has ten votes per share. The total number of authorized shares of Class A common stock and Class B common stock at December 31, 2024 was 25,000,000 shares and 6,756,176 shares, respectively. Treasury shares of Class A common stock totaling 2,488,013 and 2,335,178 at December 31, 2024 and 2023, respectively, have been deducted from shares outstanding.

Stock Repurchase Program: On November 7, 2023, our Board of Directors approved a stock purchase program (2023 Stock Repurchase Program) providing for the purchase of up to $20.0 million of our outstanding Class A common stock through

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December 31, 2025. NACCO's previous repurchase program (2021 Stock Repurchase Program) would have expired on December 31, 2023 but was terminated and replaced by the 2023 Stock Repurchase Program. During 2024, we repurchased 316,950 shares of Class A Common Stock under the 2023 Stock Repurchase Program for an aggregate purchase price of $9.9 million. During 2023, we repurchased 47,095 shares of Class A Common Stock under the 2021 Stock Repurchase Program for an aggregate purchase price of $1.6 million and 43,872 shares of Class A Common Stock under the 2023 Stock Repurchase Program for an aggregate purchase price of $1.5 million.

The timing and amount of any repurchases under the 2023 Stock Repurchase Program are determined at the discretion of our management based on a number of factors, including the availability of capital, other capital allocation alternatives, market conditions for our Class A common stock and other legal and contractual restrictions. The 2023 Stock Repurchase Program does not require us to acquire any specific number of shares and may be modified, suspended, extended or terminated by us without prior notice and may be executed through open market purchases, privately negotiated transactions or otherwise. All or part of the repurchases under the 2023 Stock Repurchase Program may be implemented under a Rule 10b5-1 trading plan, which would allow repurchases under pre-set terms at times when we might otherwise be restricted from doing so under applicable securities laws.

Stock Compensation: See Note 2 for a discussion of our restricted stock awards.

Earnings per Share: The weighted average number of shares of Class A common stock and Class B common stock outstanding used to calculate basic and diluted earnings per share were as follows:

	2024	2023
Basic weighted average shares outstanding	**7,363**	7,478
Dilutive effect of restricted stock awards	**48**	**N/A**
Diluted weighted average shares outstanding	**7,411**	7,478
Basic earnings (loss) per share	**$ 4.58**	$ (5.29)
Diluted earnings (loss) per share	**$ 4.55**	$ (5.29)

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NOTE 13—Income Taxes

We provide for income taxes and the related accounts under the asset and liability method. Deferred tax assets and liabilities are determined based on the difference between the financial statement and tax bases of assets and liabilities using enacted tax rates expected to be in effect during the year in which the basis differences reverse. Valuation allowances are established when management determines it is more likely than not that some portion, or all, of the deferred tax assets will not be realized.

The components of Income (loss) before income tax benefit and the Income tax benefit for the years ended December 31 are as follows:

	2024	2023
Income (loss) before income tax benefit		
Domestic	**$ 33,637**	$ (64,077)
Foreign	**9**	(81)
	$ 33,646	$ (64,158)
Income tax benefit		
Current income tax provision (benefit):		
Federal	**$ (2,520)**	$ (3,405)
State	**906**	290
Foreign	**2**	(342)
Total current	**(1,612)**	(3,457)
Deferred income tax provision (benefit):		
Federal	**1,373**	(16,467)
State	**144**	(4,647)
Total deferred	**1,517**	(21,114)
	$ (95)	$ (24,571)

We made income tax payments of $5.2 million and $1.4 million during 2024 and 2023, respectively. During the same periods, income tax refunds totaled $1.0 million and $14.9 million, respectively.

The provision for income taxes differs from the amount computed by applying the statutory federal income tax rate to income before the provision for income taxes. A reconciliation of the federal statutory and effective income tax rate for the years ended December 31 is as follows:

	2024	2023
Income (loss) before income tax benefit	**$ 33,646**	$ (64,158)
Statutory taxes at 21.0%	**$ 7,066**	$ (13,473)
State and local income taxes	**556**	(4,392)
Non-deductible expenses	**927**	1,071
Percentage depletion	**(4,683)**	(3,455)
R&D and other federal credits	**(796)**	(109)
Settlements and uncertain tax positions	**(2,273)**	(3,512)
Other, net	**(892)**	(701)
Income tax benefit	**$ (95)**	$ (24,571)
Effective income tax rate	**(0.3)%**	38.3 %

We recorded an income tax benefit of $0.1 million for the year ended December 31, 2024 on income before income tax of $33.6 million, or 0.3%, compared to an income tax benefit of $24.6 million on loss before income tax of $64.2 million, or 38.3%, for the year ended December 31, 2023. The years ended December 31, 2024 and 2023 both included $4.0 million of discrete tax benefits, primarily from the reversal of uncertain tax provisions. Excluding the $4.0 million of discrete tax benefits in each year, the effective income tax rate in 2024 and 2023 was 11.5% and 32.0%, respectively.

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The change in the effective income tax rate for 2024 compared to 2023, excluding the impact of the long-lived asset impairment charge and discrete items, is primarily due to an increase in earnings at entities that do not qualify for percentage depletion. The benefit from percentage depletion is not directly related to the amount of pre-tax income recorded in a period. Accordingly, in periods where income or loss before income tax is relatively small, the proportional effect of the benefit from percentage depletion on the effective tax rate may be significant. When income tax expense is recorded, the benefit from percentage depletion decreases the effective income tax rate, while the effect is to increase the effective income tax rate when a benefit for income taxes is recorded.

A detailed summary of the total deferred tax assets and liabilities in our Consolidated Balance Sheets resulting from differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes is as follows:

	December 31	
	2024	2023
Deferred tax assets		
Lease liabilities	**$ 1,252**	$ 7,083
Tax carryforwards	**12,371**	14,816
Inventories	**6,029**	4,880
Accrued liabilities	**9,430**	9,226
Employee benefits	**3,630**	3,319
Land valuation adjustment	**6,489**	6,378
Partnership investment - development costs	**14,819**	12,565
Other	**7,866**	9,680
Total deferred tax assets	**61,886**	67,947
Less: Valuation allowance	**11,672**	11,783
	50,214	56,164
Deferred tax liabilities		
Lease right-of-use assets	**1,209**	7,429
Depreciation and depletion	**23,731**	23,607
Accrued pension benefits	**10,633**	10,047
Total deferred tax liabilities	**35,573**	41,083
Net deferred asset	**$ 14,641**	$ 15,081

The following table summarizes the tax carryforwards and associated carryforward periods and related valuation allowances where we have determined that realization is uncertain:

	December 31, 2024		
	Net deferred tax asset	Valuation allowance	Carryforwards expire during:
State net operating loss	**$ 15,584**	**$ 14,610**	**2025 - 2044**

	December 31, 2023		
	Net deferred tax asset	Valuation allowance	Carryforwards expire during:
State net operating loss	$ 16,526	$ 14,757	2024-2043

We have a valuation allowance for certain state and foreign deferred tax assets. Based upon the review of historical earnings and the relevant expiration of carryforwards, including utilization limitations in the various state taxing jurisdictions, we believe the valuation allowances are appropriate and do not expect to release valuation allowances within the next twelve months that would have a significant effect on our financial position or results of operations.

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Since 2021, we have participated in a voluntary program with the IRS called Compliance Assurance Process (CAP). The objective of CAP is to contemporaneously work with the IRS to achieve federal tax compliance and resolve all or most issues prior to the filing of the tax return. In general, we operate in taxing jurisdictions that provide a statute of limitations period ranging from three to five years for the taxing authorities to review the applicable tax filings. Our tax returns are under routine examination by various taxing authorities. We have not been informed of any material assessment for which an accrual has not been previously provided and would vigorously contest any material assessment. Management believes any potential adjustment would not materially affect our financial condition or results of operations.

The following is a reconciliation of our total gross unrecognized tax benefits, defined as the aggregate tax effect of differences between tax return positions and the benefits recognized in the financial statements for the years ended December 31, 2024 and 2023. Approximately $0.6 million and $2.8 million of the gross unrecognized tax benefits as of December 31, 2024 and 2023, respectively, relate to permanent items that, if recognized, would impact the effective income tax rate. This amount differs from the gross unrecognized tax benefits presented in the table below due to (1) the deferred tax asset which would be available if the position were not sustained upon audit and (2) the decrease in U.S. federal income taxes which would occur upon the recognition of the state tax benefits included herein.

	2024	2023
Balance at January 1	**$ 6,148**	$ 9,626
Decreases based on lapse of applicable statute of limitations	**(5,396)**	(3,478)
Balance at December 31	**$ 752**	$ 6,148

We record interest and penalties on uncertain tax positions as a component of the income tax provision. We recognized a net benefit of less than $0.1 million in interest and penalties related to uncertain tax positions during 2024 and 2023. The total amount of interest and penalties accrued was $0.2 million as of December 31, 2024 and 2023.

We expect the amount of unrecognized tax benefits will change within the next 12 months; however, the change is not expected to have a significant effect on our financial position, results of operations or cash flows.

NOTE 14—Retirement Benefit Plans

Defined Benefit Plans: We maintain defined benefit pension plans that provide benefits based on years of service and average compensation during certain periods. Prior to 2023, we amended the Combined Plan to freeze pension benefits for all employees. We also amended the Supplemental Retirement Benefit Plan (SERP) to freeze all pension benefits. All of our eligible employees, including employees whose pension benefits are frozen, receive retirement benefits under defined contribution retirement plans.

During 2023, our Board of Directors approved the termination of the Combined Plan and participants were offered lump-sum distributions as part of the termination process. As a result of the lump-sum distributions, we recognized a non-cash, pension settlement charge of $1.8 million on the Other, net line within the accompanying Consolidated Statements of Operations. The $1.8 million charge represents a pro rata portion of the unrecognized net loss recorded in Accumulated other comprehensive loss.

The assumptions used in accounting for the defined benefit plans were as follows for the years ended December 31:

	2024	2023
Weighted average discount rates for pension benefit obligation	**5.39% - 5.49%**	5.02% - 5.04%
Weighted average discount rates for net periodic benefit cost	**5.02% - 5.04%**	5.36% - 5.40%
Expected long-term rate of return on assets for net periodic benefit cost	**5.00%**	7.00%

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Set forth below is detail of the net periodic pension expense for the defined benefit plans for the years ended December 31:

	2024	2023
Interest cost	**$ 1,360**	$ 1,639
Expected return on plan assets	**(1,641)**	(2,751)
Amortization of actuarial loss	**270**	51
Amortization of prior service cost	**58**	58
Settlements	**—**	1,815
Net periodic pension expense	**$ 47**	$ 812

Set forth below is detail of other changes in plan assets and benefit obligations recognized in other comprehensive loss for the years ended December 31:

	2024	2023
Current year actuarial loss	**$ 960**	$ 2,560
Amortization of actuarial loss	**(270)**	(51)
Amortization of prior service cost	**(58)**	(58)
Settlements	—	(1,815)
Total recognized in other comprehensive loss	**$ 632**	$ 636

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

The following table sets forth the changes in the benefit obligation and the plan assets during the year and the funded status of the defined benefit plans at December 31:

	2024	2023
Change in benefit obligation		
Projected benefit obligation at beginning of year	**$ 28,357**	$ 31,722
Interest cost	**1,360**	1,639
Actuarial (gain) loss	**(427)**	2,261
Benefits paid	**(2,610)**	(2,614)
Settlements	**—**	(4,651)
Projected benefit obligation at end of year	**$ 26,680**	$ 28,357
Accumulated benefit obligation at end of year	**$ 26,680**	$ 28,357
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 30,128**	$ 34,485
Actual return on plan assets	**258**	2,452
Employer contributions	**475**	456
Benefits paid	**(2,610)**	(2,614)
Settlements	**—**	(4,651)
Fair value of plan assets at end of year	**$ 28,251**	$ 30,128
Funded status at end of year	**$ 1,571**	$ 1,771
Amounts recognized in the balance sheets consist of:		
Non-current assets	**$ 5,624**	$ 6,068
Current liabilities	**(515)**	(510)
Non-current liabilities	**(3,538)**	(3,787)
	$ 1,571	$ 1,771
Components of accumulated other comprehensive loss consist of:		
Actuarial loss	**$ 12,072**	$ 11,379
Prior service cost	**528**	586
Deferred taxes	**(2,869)**	(2,724)
	$ 9,731	$ 9,241

We recognize as a component of benefit (income) cost, as of the measurement date, any unrecognized actuarial net gains or losses that exceed 10% of the larger of the projected benefit obligations or the plan assets, defined as the corridor. Amounts outside the corridor are amortized over the average expected remaining service of active participants expected to benefit under the retiree medical plans or over the average expected remaining lifetime of inactive participants for the pension plans. The (gain) loss amounts recognized in AOCI are not expected to be fully recognized until the plan is terminated or as settlements occur, which would trigger accelerated recognition. Prior service costs resulting from plan changes are also in AOCI.

Our policy is to make contributions to fund our pension plans within the range allowed by applicable regulations.

We maintain one supplemental defined benefit plan that pays monthly benefits to participants directly out of corporate funds. All other pension benefit payments are made from assets of the pension plans.

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

Future pension benefit payments expected to be paid from assets of the pension plans are:

2025	$	2,750
2026		2,631
2027		2,575
2028		2,514
2029		2,435
2030 - 2034		10,860
	$	23,765

The expected long-term rate of return on defined benefit plan assets reflects management's expectations of long-term rates of return on funds invested to provide for benefits included in the projected benefit obligations. In establishing the expected long-term rate of return assumption for plan assets, we consider the historical rates of return over a period of time that is consistent with the long-term nature of the underlying obligations of these plans as well as a forward-looking rate of return. The historical and forward-looking rates of return for each of the asset classes used to determine our estimated rate of return assumption were based upon the rates of return earned or expected to be earned by investments in the equivalent benchmark market indices for each of the asset classes.

Expected returns for pension plans are based on a calculated market-related value for pension plan assets. Under this methodology, asset gains and losses resulting from actual returns that differ from our expected returns are recognized in the market-related value of assets ratably over three years.

The pension plans maintain investment policies that, among other things, establish a portfolio asset allocation methodology with percentage allocation bands for individual asset classes. The investment policies provide that investments are reallocated between asset classes as balances exceed or fall below the appropriate allocation bands.

The following is the actual allocation percentage and target allocation percentage for the pension plan assets at December 31:

	2024 Actual Allocation	2023 Actual Allocation	Target Allocation Range
Fixed income securities	**99.2 %**	99.1 %	90.0% - 100.0%
Money market funds	**0.8 %**	0.6 %	0.0% - 10.0%
Cash equivalents	**— %**	0.3 %	0.0%

The asset allocation reflects the move into fixed income securities to mitigate volatility prior to the termination of the Combined Plan, currently expected to occur in 2025.

The defined benefit pension plans do not have any direct ownership of NACCO common stock.

The fair value of each major category of our pension plan assets are valued using quoted market prices in active markets for identical assets, or Level 1 in the fair value hierarchy. Following are the values as of December 31:

	Level 1			
	2024		2023	
Fixed income securities	**$**	**28,028**	$	29,866
Money market funds		**223**		181
Cash equivalents		**—**		81
Total	**$**	**28,251**	$	30,128

Postretirement Health Care: We also maintain health care plans which provide benefits to grandfathered eligible retired employees. All of our health care plans have a cap on our share of the costs. The health care plans have network provided benefits which result in cost savings for us. These plans have no assets. Under our current policy, plan benefits are funded at the time they are due to participants.

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

The assumptions used in accounting for the postretirement health care plans are set forth below for the years ended December 31:

	2024	2023
Weighted average discount rates for benefit obligation	**5.26 %**	4.98 %
Weighted average discount rates for net periodic benefit cost	**4.98 %**	5.29 %
Health care cost trend rate assumed for next year	**6.50%**	6.25% - 6.50%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	**4.75%**	4.75%
Year that the rate reaches the ultimate trend rate	**2033**	2029 - 2033

Set forth below is detail of the net periodic benefit expense for the postretirement health care plans for the years ended December 31:

	2024	2023
Service cost	**$ 8**	$ 7
Interest cost	**75**	77
Amortization of actuarial loss	**75**	44
Amortization of prior service credit	**(6)**	(50)
Net periodic benefit expense	**$ 152**	$ 78

Set forth below is detail of other changes in benefit obligations recognized in other comprehensive (income) loss for the years ended December 31:

	2024	2023
Current year actuarial (gain) loss	**$ (49)**	$ 173
Amortization of actuarial loss	**(75)**	(44)
Amortization of prior service credit	**6**	50
Total recognized in other comprehensive (income) loss	**$ (118)**	$ 179

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

The following sets forth the changes in benefit obligations during the year and the funded status of the postretirement health care plans at December 31:

	2024	2023
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,579**	$ 1,551
Service cost	**8**	7
Interest cost	**75**	77
Actuarial (gain) loss	**(49)**	173
Benefits paid	**(195)**	(229)
Benefit obligation at end of year	**$ 1,418**	$ 1,579
Funded status at end of year	**$ (1,418)**	$ (1,579)
Amounts recognized in the balance sheets consist of:		
Current liabilities	**$ (169)**	$ (183)
Noncurrent liabilities	**(1,249)**	(1,396)
	$ (1,418)	$ (1,579)
Components of accumulated other comprehensive loss consist of:		
Actuarial loss	**$ 416**	$ 542
Prior service credit	**—**	(6)
Deferred taxes	**(95)**	(123)
	$ 321	$ 413

Future postretirement health care benefit payments expected to be paid are:

2025	173
2026	182
2027	185
2028	174
2029	166
2030 - 2034	582
	$ 1,462

Defined Contribution Plans: We maintain a defined contribution (401(k)) plan for substantially all employees and provide employer matching contributions based on plan provisions. The plan also provides for a minimum employer contribution. Our matching contributions for these plans were $3.6 million and $3.6 million in 2024 and 2023, respectively.

NOTE 15—Business Segments

Our operating segments are: (i) Coal Mining, (ii) NAMining and (iii) Minerals Management. We determine our reportable segments by first identifying our operating segments, and then by assessing whether any components of these segments constitute a business for which discrete financial information is available and where segment management regularly reviews the operating results of that component. Our President and Chief Executive Officer, who is the CODM, utilizes Operating profit (loss) to evaluate segment performance and allocate resources. Our CODM considers actual, budgeted and forecasted Operating profit (loss) from operations on a monthly basis for evaluating the performance of each segment and making decisions about allocating capital and other resources to each segment.

All financial statement line items below operating profit (other income including interest expense and interest income, the provision for income taxes and net income) are presented and discussed within this Form 10-K on a consolidated basis.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
NACCO INDUSTRIES, INC. AND SUBSIDIARIES
(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

See Note 1 for additional discussion of our reportable segments. All current operations reside in the U.S. The accounting policies of the reportable segments are described in Note 2.

In 2024 and 2023, three customers and two customers, respectively, accounted for more than 10% of consolidated revenue. The following represents the revenue attributable to each of these entities as a percentage of consolidated revenue for those years:

	Percentage of Consolidated Revenue	
Segment	**2024**	2023
Coal Mining customer	**29 %**	40 %
NAMining customer	**24 %**	22 %
NAMining customer	**11 %**	7 %

The following tables provide segment financial information and a reconciliation of segment results to consolidated results for the years ended December 31:

	2024	2023
Revenues		
Coal Mining	**$ 68,611**	$ 85,415
NAMining	**119,600**	90,532
Minerals Management	**34,579**	32,985
Unallocated Items	**17,707**	8,459
Eliminations	**(2,789)**	(2,597)
Total	**$ 237,708**	$ 214,794
Cost of sales		
Coal Mining	**$ 79,375**	$ 108,760
NAMining	**110,821**	83,719
Minerals Management	**5,234**	3,969
Unallocated Items	**15,323**	6,252
Eliminations	**(2,801)**	(2,497)
Total	**$ 207,952**	$ 200,203
Earnings of unconsolidated operations		
Coal Mining	**$ 51,821**	$ 44,633
NAMining	**5,010**	5,361
Minerals Management	**647**	—
Unallocated Items	**(2)**	—
Total	**$ 57,476**	$ 49,994
Operating expenses*		
Coal Mining	**$ 30,358**	$ 92,630
NAMining	**8,017**	8,826
Minerals Management	**1,065**	9,598
Unallocated Items	**25,699**	23,668
Total	**$ 65,139**	$ 134,722

*Operating expenses consist of Selling, general and administrative expenses, Amortization of intangible assets, (Gain) loss on sale of assets and Long-lived asset impairment charges.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
NACCO INDUSTRIES, INC. AND SUBSIDIARIES
(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

	2024	2023
Operating profit (loss)		
Coal Mining	**$ 24,311**	$ (71,342)
NAMining	**5,772**	3,348
Minerals Management	**28,927**	19,418
Unallocated Items	**(23,317)**	(21,461)
Eliminations	**12**	(100)
Total	**$ 35,705**	$ (70,137)
Expenditures for property, plant and equipment and acquisition of mineral interests		
Coal Mining	**$ 8,292**	$ 6,609
NAMining	**30,556**	36,073
Minerals Management	**1,079**	38,881
Unallocated Items	**15,492**	559
Total	**$ 55,419**	$ 82,122
Depreciation, depletion and amortization		
Coal Mining	**$ 9,476**	$ 17,569
NAMining	**9,811**	8,172
Minerals Management	**4,273**	3,067
Unallocated Items	**1,092**	579
Total	**$ 24,652**	$ 29,387

Asset information by segment is not discretely maintained for internal reporting or used in evaluating performance.

NOTE 16—Unconsolidated Subsidiaries

Each of our wholly owned Unconsolidated Subsidiaries, within the Coal Mining and NAMining segments, meet the definition of a VIE. The Unconsolidated Subsidiaries are capitalized primarily with debt financing provided by or supported by their respective customers, and generally without recourse to us. Although we own 100% of the equity and manages the daily operations of the Unconsolidated Subsidiaries, we have determined that the equity capital provided by us is not sufficient to adequately finance the ongoing activities or absorb any expected losses without additional support from the customers. The customers have a controlling financial interest and have the power to direct the activities that most significantly affect the economic performance of the entities. As a result, we are not the primary beneficiary and therefore do not consolidate these entities' financial positions or results of operations. See Note 1 for a discussion of these entities.

The Investment in the unconsolidated subsidiaries and related tax positions totaled $14.1 million and $12.4 million at December 31, 2024 and 2023, respectively. Our risk of loss relating to these entities is limited to our invested capital, which was $5.5 million and $5.0 million at December 31, 2024 and 2023, respectively.

NACCO Natural Resources is a party to certain guarantees related to Coyote Creek. Under certain circumstances of default or termination of Coyote Creek's Lignite Sales Agreement (LSA), NACCO Natural Resources would be obligated for payment of a make-whole amount to Coyote Creek's third-party lenders. The make-whole amount is based on the excess, if any, of the discounted value of the remaining scheduled debt payments over the principal amount. In addition, in the event Coyote Creek's LSA is terminated by Coyote Creek's customers, NACCO Natural Resources is obligated to purchase Coyote Creek's dragline and rolling stock for the then net book value of those assets. To date, no payments have been required from NACCO Natural Resources since the inception of these guarantees. We believe that the likelihood NACCO Natural Resources would be required to perform under the guarantees is remote, and no amounts related to these guarantees have been recorded.

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

Summarized financial information for the unconsolidated subsidiaries is as follows:

	2024	2023
Statement of Operations		
Revenue	**$ 542,643**	$ 610,734
Gross profit	**$ 60,256**	$ 63,646
Income before income taxes	**$ 56,831**	$ 49,994
Net income	**$ 49,284**	$ 43,714
Balance Sheet		
Current assets	**$ 145,655**	$ 124,387
Non-current assets	**$ 816,430**	$ 814,226
Current liabilities	**$ 158,591**	$ 161,606
Non-current liabilities	**$ 798,043**	$ 772,003

Revenue includes all mine operating costs that are reimbursed by the customers of the Unconsolidated Subsidiaries as well as the compensation per ton of coal, heating unit (MMBtu) or ton of limestone delivered. Reimbursed costs have offsetting expenses and have no impact on income before income taxes. Income before income taxes represents the Earnings of the unconsolidated operations within the Coal Mining and NAMining segments.

We received dividends of $48.8 million and $45.8 million from the Unconsolidated Subsidiaries in 2024 and 2023, respectively.

NOTE 17—Supplemental Oil and Gas Disclosures (Unaudited)

The Minerals Management segment derives income primarily by leasing our royalty and mineral interests to third-party exploration and production companies, and, to a lesser extent, other mining companies, granting them the rights to explore, develop, mine, produce, market and sell gas, oil and coal in exchange for royalty payments based on the lessees' sales of those minerals. As an owner of royalty and mineral interests, our access to information concerning activity and operations of our royalty and mineral interests is limited. We do not have information that would be available to a company with working interests in oil and natural gas operations because detailed information is not generally available to owners of royalty and mineral interests. See Note 1, Note 2 and Note 15 for additional discussion of the Minerals Management segment.

Capitalized Oil and Natural Gas Costs

Aggregate capitalized costs related to oil and gas royalty and mineral interests with applicable accumulated depreciation, depletion and amortization at December 31 are as follows:

	2024	2023
Proved developed	**$ 16,720**	$ 16,179
Proved undeveloped	**52,428**	51,971
Proved reserves	**69,148**	68,150
Less: accumulated depreciation, depletion and amortization	**6,061**	3,309
Net royalty interests in oil and natural gas properties	**$ 63,087**	$ 64,841

Oil and Natural Gas Reserves

Total net proved reserves are defined as those natural gas and hydrocarbon liquid reserves to Company interests after deducting all royalties, overriding royalties, and reversionary interests owned by outside parties that become effective upon payout of specified monetary balances. Decline curve analysis was used to estimate the remaining reserves of pressure depletion reservoirs with enough historical production data to establish decline trends. Reservoirs under non-pressure depletion drive mechanisms and non-producing reserves were estimated by volumetric analysis, research of analogous reservoirs, or a combination of both. Reserves have been estimated using deterministic and probabilistic methods. All reserves estimates have been prepared using standard engineering practices generally accepted by the petroleum industry and conform to guidelines developed and adopted by the SEC.

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

The following table presents our estimated net proved oil and natural gas reserves as of December 31 based on the reserve report prepared by Haas & Cobb Petroleum Consultants, our independent petroleum engineering firm. All of our reserves are located in the United States.

	Net reserves as of December 31, 2024		
	Oil (bbl) (1)	**NGL (bbl) (1)**	**Residue gas (Mcf) (2)**
Proved developed	**620,790**	**443,650**	**27,491,840**
Proved undeveloped	**74,400**	**30,280**	**135,830**
Total	**695,190**	**473,930**	**27,627,670**

	Net reserves as of December 31, 2023		
	Oil (bbl) (1)	NGL (bbl) (1)	Residue gas (Mcf) (2)
Proved developed	656,370	380,650	23,596,110
Proved undeveloped	9,020	3,720	26,420
Total	665,390	384,370	23,622,530

(1) Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume.

(2) Mcf. One thousand cubic feet of natural gas at the contractual pressure and temperature bases.

Estimated Proved Reserves

The following table summarizes changes in proved reserves during the year ended December 31, 2024:

	Estimated Proved Reserves		
	Oil (bbl) (1)	**NGL (bbl) (1)**	**Residue gas (Mcf) (2)**
December 31, 2023	665,390	384,370	23,622,530
Purchases	14,005	1,233	29,268
Extensions and discoveries	236,491	85,087	7,040,710
Revisions of previous estimates (3)	(105,479)	63,441	(498,627)
Production	(32,077)	(15,687)	(1,843,911)
Other	(83,140)	(44,514)	(722,300)
December 31, 2024	**695,190**	**473,930**	**27,627,670**

Estimated Proved Undeveloped Reserves (PUDs)

The following table summarizes changes in PUDs during the year ended December 31, 2024:

	Estimated Proved Undeveloped Reserves		
	Oil (bbl) (1)	**NGL (bbl) (1)**	**Residue gas (Mcf) (2)**
December 31, 2023	9,020	3,720	26,420
Purchases	2,208	38	5,237
Extensions and discoveries	69,716	27,902	126,724
Conversions	(3,322)	(1,914)	(10,017)
Revisions of previous estimates (3)	(3,222)	534	(12,534)
December 31, 2024	**74,400**	**30,280**	**135,830**

(1) Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume.

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

(2) Mcf. One thousand cubic feet of natural gas at the contractual pressure and temperature bases.

(3) Revisions of previous estimates include technical revisions due to changes in commodity prices, historical and projected performance and other factors.

As an owner of mineral and royalty interests, we generally do not have evidence of approval of operators' development plans. As a result, proved undeveloped reserve estimates are limited to those relatively few locations for which drilling permits have been publicly filed. As of December 31, 2024, PUD reserves consists of 89 wells in various stages of drilling or completions. As of December 31, 2024, less than 1% of our total proved reserves were classified as PUDs.

Standardized Measure of Discounted Future Net Cash Flows

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the 12-month unweighted average of first-day-of-the-month commodity prices for the periods presented. Future cash inflows are computed by applying applicable prices relating to proved reserves to the year-end quantities of those reserves. Future production and costs are derived based on current costs assuming continuation of existing economic conditions. Federal income tax expenses are deducted from future production revenues in the calculation of the standardized measure using the statutory tax rate. We are subject to certain state-based taxes; however, these amounts are not material. The projections should not be viewed as realistic estimates of future cash flows, nor should the standardized measure be interpreted as representing current value to us. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary.

The following table provides the future net cash flows relating to proved oil and gas reserves based on the standardized measure of discounted cash flows as of December 31, 2024:

	Gross Amounts	Statutory tax rate	Net Amounts
Future cash inflows[3]	**$ 119,534**		
Future production costs	**33,308**		
Future net cash flows before income tax expense	**86,226**	**21 %**	**68,119**
10% discount to reflect timing of cash flows	**(32,580)**	**21 %**	**(25,739)**
Standardized measure of discounted cash flows	**$ 53,646**	**21 %**	**$ 42,380**

The following table provides the future net cash flows relating to proved oil and gas reserves based on the standardized measure of discounted cash flows as of December 31, 2023:

	Gross Amounts	Statutory tax rate	Net Amounts
Future cash inflows[3]	$ 122,286		
Future production costs	27,487		
Future net cash flows before income tax expense	94,799	21 %	74,891
10% discount to reflect timing of cash flows	(33,521)	21 %	(26,481)
Standardized measure of discounted cash flows	$ 61,278	21 %	48,410

(Tabular Amounts in Thousands, Except Per Share, Percentage Data and Oil and Gas Disclosures)

The following summarizes the principal sources of change in the standardized measure of discounted future net cash flows during 2024:

	Gross amounts	
	2024	2023
January 1	$ 61,278	$ 116,526
Purchases	522	11,312
Extensions and discoveries	18,426	11,419
Revisions of previous estimates [3][4]	(20,713)	(61,206)
Conversions	(5,867)	(16,773)
December 31	**$ 53,646**	$ 61,278

[3] Requirements for oil and gas reserve estimation and disclosure require that reserve estimates and future cash flows be based on the average market prices for sales of oil and gas on the first calendar day of each month during the year. The benchmark price for WTI crude oil sold at Cushing, OK during 2024 and 2023 was $75.48 and $78.22 per bbl, respectively. The benchmark price for natural gas delivered at Henry Hub during 2024 and 2023 was $2.13 and $2.64 per MMBTU, respectively. Actual future prices and costs are likely to be substantially different from historical prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

[4] Revisions of previous estimates include technical revisions due to changes in commodity prices, historical and projected performance and other factors.

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS
NACCO INDUSTRIES, INC. AND SUBSIDIARIES
YEAR ENDED DECEMBER 31, 2024 AND 2023

		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts — Describe	Deductions — Describe	Balance at End of Period (A)
	(In thousands)				
2024					
Reserves deducted from asset accounts:					
Deferred tax valuation allowances	**$ 11,783**	**$ (111)**	**$ —**	**$ —**	**$ 11,672**
2023					
Reserves deducted from asset accounts:					
Deferred tax valuation allowances	$ 11,809	$ (26)	$ —	$ —	$ 11,783

(A) Balances which are not required to be presented and those which are immaterial have been omitted.

INSIDER TRADING POLICY
OF NACCO INDUSTRIES, INC.

AND ITS SUBSIDIARIES

August 2024

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NACCO INDUSTRIES, INC.
AND SUBSIDIARIES
INSIDER TRADING POLICY

EXECUTIVE SUMMARY

Introduction

The purpose of this Insider Trading Policy (the "Policy") is to promote compliance with applicable federal securities laws by the directors, officers, employees, agents, and principal stockholders of NACCO Industries, Inc. ("NACCO") and its subsidiaries (collectively, the "Company"), and to help such persons and the Company understand and remain in compliance with insider trading laws and preserve the reputation and integrity of the Company and all persons affiliated with it.

The federal securities laws (the so called "insider trading laws") prohibit all directors, officers, employees, agents and principal stockholders of the Company (and members of the immediate families and households of the foregoing persons) from trading (buying or selling) securities of the Company and securities of any Company Business Partner (as defined below) while in possession of material inside nonpublic information (as defined below). Passing on that material nonpublic information to anyone (including friends and family members) who may trade in the Company's securities is also prohibited.

Federal securities laws may also impose potential civil and criminal sanctions on the Company and its management for failing to take appropriate steps to prevent illegal trading or tipping. These sanctions are in addition to those that may be imposed under other federal or state laws.

Violation of this Policy by any person, regardless of any action taken or not taken by the federal government or securities regulators and regardless of the dollar amount of the trade or the source of the material nonpublic information, may result in disciplinary action against the person up to and including dismissal from the Company.

Applicability

The Policy applies to all of the Company's directors, officers, employees, agents and principal stockholders, as well as their Related Persons (as defined below). The Board of Directors also has adopted additional procedures set forth below that apply to Covered Persons (as defined below) and their Related Persons. These procedures, among other things, require Covered Persons to pre-clear any purchase or sale of securities of the Company with the Senior Vice President, General Counsel and Secretary of NACCO or his or her designee (the "General Counsel").

If there are any questions, they should be addressed to the General Counsel, who can be reached by telephone at (972) 448-5400.

POLICY AND PROCEDURES

Policy

No Insider Trading in Company Securities

The Company's directors, officers, employees, principal stockholders, and agents, and their Related Persons may not buy or sell Company securities, or the securities of any Company Business Partner, while in possession of material nonpublic information about the Company, even if the decision to buy or sell is not based upon the material nonpublic information. For these purposes, any gift of securities to individuals or entities made with the knowledge or expectation that the recipient of the gift will soon sell the securities should be considered in effect a sale for cash followed by a gift of the cash. Such gifts therefore are also subject to the Policy.

Those who are aware of material nonpublic information about the Company are also prohibited from tipping (as defined below) any such information to others, including immediate family and household members or other directors, officers or employees, except for those whose job responsibilities require the information and who have a duty of confidentiality to the Company.

In addition, entities such as trusts or foundations over which a director, officer, employee, principal stockholder or agent has control, may not buy or sell Company securities while the director, officer, employee, principal stockholder or agent is in possession of material, nonpublic information about the Company.

This Policy applies to transactions in the Company's securities, including the Company's common stock, options to purchase common stock, or any other type of securities that the Company may issue, including (but not limited to) preferred stock, convertible debentures and warrants, as well as derivative securities that are not issued by the Company, such as put or call options or swaps relating to the Company's securities.

No Insider Trading in Securities of Company Business Partners

In the course of performing duties for the Company, you may become aware of material nonpublic information about other publicly traded companies with which the Company does business, such as customers, vendors, and partners (each a "Company Business Partner"). No director, officer, employee or their Related Person may use such information to trade, or tip another person to trade, in the securities of a Company Business Partner.

Continuing Obligation Post-Employment

This Policy will continue to apply to any director, officer, employee, principal stockholder or agent whose relationship with the Company terminates as long as the individual possesses material nonpublic information obtained in the course of employment or a relationship with the Company. Such an individual may not trade in Company securities or the securities of any Company Business Partner until that information has become public or is no longer material.

The individuals subject to this Policy have ethical and legal obligations to maintain the confidentiality of information about the Company and not to engage in transactions in the Company's securities while in possession of material nonpublic information. Each individual is responsible for maintaining compliance with this Policy and ensuring that any Related Person whose transactions are subject to this Policy also are in compliance. In all cases, the responsibility for determining whether an individual is in possession of material nonpublic information rests with that individual, and any action by the Company, its legal department or any other employee or director pursuant to this Policy (or otherwise) does not in any way constitute legal advice or insulate an individual from liability under applicable securities laws. You could be subject to severe legal penalties and disciplinary action by the Company for any conduct prohibited by this Policy or applicable securities laws. Each individual who receives this document should review the following policies and procedures carefully.

Definitions

Who is an "Insider"?

The concept of "insider" is broad. Any person who possesses material nonpublic information is considered an insider as to that information. Insiders can include Company directors, officers, employees, principal stockholders, agents, independent contractors and those persons in a special relationship with the Company such as auditors, consultants and attorneys. Insiders also include the Related Persons of persons who are insiders. The definition of an insider is transaction specific; that is, an individual is an insider with respect to each material nonpublic item of which he or she is aware.

What is "Material" Information?

The materiality of information depends upon the circumstances. Information is considered "material" if there is a substantial likelihood that a reasonable investor would consider it important in making a decision to buy, sell or hold a security or where the fact is likely to have a significant effect on the market price of the security. Illegal trades can be made for a profit or to avoid a loss. Material information can be positive or negative and can relate to virtually any aspect of a company's business or to any type of security, debt or equity. There is no bright-line standard for assessing materiality; rather, materiality is based on a comprehensive assessment of all the facts and circumstances, and is often evaluated by enforcement authorities with 20/20 hindsight. Some examples of information that would ordinarily be regarded as material include:

(a) Financial results and financial forecasts, especially unpublished financial results, including estimates of earnings or losses;

(b) Changes in earnings guidance or financial information of the Company as a whole or one or more principal subsidiaries from that previously disclosed to the public;

(c) Payment or omission of a dividend, increases or decreases in the dividend rate or changes in dividend policies;

(d) Pending or proposed mergers, acquisitions, takeovers or other Company transactions (including negotiations regarding such transactions), and any proposed or anticipated changes in the terms of any such transaction;

(e) Significant increases or decreases in backlog orders or the award of a significant contract;

(f) Pending or proposed joint ventures;

(g) Significant changes in operations, such as interruption or curtailment of a major production facility;

(h) Introduction of significant new products or the commencement of a significant new business;

(i) Establishment, and the terms, of a program to repurchase the Company's own securities;

(j) Adverse change in liquidity, such as a sharply decreased inflow of collections from sales or the unavailability of needed credit;

(k) Significant changes in management;

(l) The purchase or sale of substantial assets or a significant change in the value of such assets;

(m) Extraordinary borrowings;

(n) Initiation or termination of significant litigation, including settlement negotiations regarding such litigation;

(o) Regulatory or governmental inquiry or investigation of the Company, its management or employees;

(p) Major product recalls;

(q) Declaration of stock splits and stock dividends;

(r) Proposed issuances or new securities, either public or private;

(s) Significant related party transactions; and

(t) Any other significant activity which is not in the ordinary course of business, either because of the nature of the activity or the magnitude of the activity.

The foregoing list is only illustrative; many other types of information may be considered "material" depending on the circumstances. The materiality of particular information is subject to reassessment on a regular basis. In evaluating the materiality of any nonpublic information, consider this common-sense question: Does knowing the information make you want to buy or sell the Company's securities? If it does, the information is likely material. When in doubt, please contact the General Counsel.

What is "Nonpublic" Information?

Information is "nonpublic" if it is not available to the general public. In order for information to be considered public, it must be widely disseminated in a manner making it generally available to investors through a report filed with the Securities and Exchange Commission ("SEC") or through such media as *Dow Jones*, *Reuters Economic Services*, *The Wall Street Journal*, *Associated Press*, *United Press International,* or broadcasts on widely-available radio or television programs. The circulation of rumors, even if accurate, does not constitute effective public dissemination nor is information that is only available to Company employees or to a select group of analysts, brokers and institutional investors. In addition, even after a public announcement of material information, a reasonable period of time must elapse in order for the market to react to the information.

Generally you should allow two full trading days following publication, as a reasonable waiting period before such information is deemed to be public in order to provide the public with sufficient time to absorb the information. Therefore, for example, if an announcement is made before the commencement of trading on a Monday, you may trade in securities of the Company starting on Wednesday of that week, because two full trading days would have elapsed by then. As further examples, if the announcement is made on Monday after trading begins, employees may not trade in securities of the Company until Thursday, and if the announcement is made on Friday after trading begins, you may not trade in securities of the Company until Wednesday of the following week. Note that this restriction is in addition to any other restrictions that apply under this Policy, including the requirement that trades by Covered Persons be pre-cleared.

Who is a "Related Person"?

A "Related Person" includes your spouse, minor children and anyone else living in your household; partnerships in which you are a general partner; corporations in which you either singly or together with other "Related Persons" own a controlling interest; trusts of which you are a trustee, settlor or beneficiary; estates of which you are an executor or beneficiary; or any other group or entity where the insider has or shares with others the power to decide whether to buy or sell securities. Although a person's parent, adult child or sibling may not be considered a Related Person (unless living in the same household), a parent, adult child or sibling may be a "tippee" (as defined below) for securities laws purposes.

Who is a "Covered Person"?

A "Covered Person" is any Company director; officer or direct report of the President, Chief Executive Officer ("CEO"), the Senior Vice President, Chief Operating Officer, Senior Vice President, Chief Financial Officer or the Senior Vice President, General Counsel; any other "exempt" employee employed in the Finance or Accounting Department; or any other person designated by the Board of Directors. The status of a person who becomes a Covered Person continues as such until three (3) months after his or her association with the Company has terminated in its entirety.

What is "Tipping"?

Tipping involves directly or indirectly communicating material nonpublic information to any third party ("tippee") who is not authorized to receive it, including but not limited to Related Persons. Insiders who tip others can be held civilly and criminally liable for insider trading conducted by their tippees. Tippees can also be exposed to civil and criminal liability for insider trading if they trade on the information or tip others about the information. Tipping may occur directly through overt communication of the material nonpublic information or indirectly through signals, code words, or other suggestions to buy or sell securities made while the tipper is in possession of material nonpublic information. It is the Company's policy that insiders are required to keep completely and strictly confidential all material nonpublic information relating to the Company.

Procedures

In order to implement the Company's Policy, the following procedures should be observed:

Disclosure of Material Nonpublic Information

Until publicly released by the Company, material nonpublic information must not be disclosed to anyone, except appropriate persons within the Company or those third parties to whom the Company desires to provide such information and who have a duty of confidentiality to the Company.

Pre-Clearance by Covered Persons

Covered Persons must obtain prior clearance from the General Counsel before they or their Related Persons effect **any** transactions involving securities of the Company (including any gift, loan, pledge, contribution to a trust or other transfer). The General Counsel may not trade in securities of the Company unless the Principal Accounting Officer has approved the trade(s) in accordance with the procedures set forth in this Policy and procedures. Any request for preclearance by the Covered Person should be submitted at least two business days in advance of the proposed transaction, to permit appropriate consideration. The General Counsel is under no obligation to approve a transaction for pre-clearance. If the Covered Person seeking pre-clearance to engage in a transaction is denied, then he or she should refrain from initiating any transaction in Company securities and should not inform any other person of the restriction.

When a request for pre-clearance is made by a Covered Person, the requestor should carefully consider whether he or she may be aware of any material nonpublic information about the Company, and should describe fully those circumstances to the General Counsel.

Each proposed transaction will be evaluated to determine if it raises insider trading or other concerns under the federal or state securities laws and regulations. This evaluation does not create an attorney-client or investment advisory relationship between the General Counsel and the Covered Person. Clearance of a transaction is only valid for the period provided by the General Counsel at the time of notification of the pre-clearance. If the transaction order is not placed within that period, clearance of the transaction must be re-requested. If clearance is denied at any time during the process, the fact of such denial must be kept confidential by the person requesting such clearance.

Additional Procedures for Section 16 Filers

Federal securities laws require the Company's directors, certain officers designated by the Board of Directors, and holders of more than 10% of any class of the Company's equity securities (collectively, "Section 16 Filers") to make certain reports concerning their ownership of and transactions in the Company's securities. Section 16 Filers are also subject to "short-swing" profit restrictions on the sale of Company securities within six months of acquiring them. Accordingly, in addition to the preclearance procedures specified above, Section 16 Filers should, at the time they request approval from the General Counsel to trade, (a) be prepared to report the transaction on an appropriate SEC Form 4 or Form 5, and (b) advise whether he or she has effected transactions in the Company's securities within the previous six months.

Form 144 Reports

The Company's directors and certain officers designated by the Board of Directors are required to file Form 144 with the SEC before making an open market sale of Company securities. This form notifies the SEC of the person's intent to sell Company securities and is publicly available upon filing. Persons subject to this requirement should, at the time they seek approval to trade from the General Counsel, be prepared to comply with SEC Rule 144 and file Form 144, if necessary, at the time of any sale.

No Speculative Transactions

Investing in securities of the Company provides an opportunity to share in the Company's future growth. Investment in the Company and sharing in the growth of the Company, however, does not mean short-range speculation based on fluctuations in the market. Such activities may put the personal gain of the directors, officers, employees, principal stockholders or agents and their Related Persons in conflict with the best interests of the Company and its securityholders.

Directors, executive officers and principal stockholders of the Company are prohibited by the federal securities laws from making any short sale (i.e., sale of securities not owned) or sale against the "box" (i.e., sale of securities owned but not delivered against the sale) of equity securities of the Company. This short-sale rule prohibits sale of any securities not owned at the time of sale.

For the same reason no director, officer or principal stockholder of the Company and no Related Persons shall purchase or sell puts or calls on securities of the Company or otherwise trade in or write options on such securities. Covered Persons and their Related Persons are also prohibited from participating in discussions about the Company, its business or its securities on social media, except as part of their official duties for the Company.

Hedging Transactions

Certain forms of hedging or monetization transactions, such as zero-cost collars and forward sale contracts, allow an individual to lock in much of the value of his or her stock holdings, often in exchange for all or part of the potential for upside appreciation in the stock. These transactions allow the individual to continue to own the covered securities, but without the full risks and rewards of ownership. When that occurs, the individual may no longer have the same objectives as the Company's other shareholders. Therefore, Covered Persons are prohibited from engaging in such transactions.

Margin Accounts and Pledges

Securities held in a margin account may be sold by the broker without the customer's consent if the customer fails to meet a margin call. Covered Persons are prohibited from holding Company securities in margin accounts. Similarly, securities pledged (or hypothecated) as collateral for a loan may be sold in foreclosure if the borrower defaults on the loan. Because a foreclosure sale may occur at a time when the pledgor is aware of material nonpublic information or otherwise is not permitted to trade in Company securities, Covered Persons are prohibited from pledging Company securities as collateral for a loan without prior approval of the General Counsel.

Transactions Under Rule 10b5-1 Plans

SEC Rule 10b5-1 provides an affirmative defense to insider trading liability. To be eligible to rely on this defense, a person must enter into a "Rule 10b5-1 Plan," which is a written plan for trading Company securities that meets the requirements of Rule 10b5-1 and the Company's Rule 10b5-1 Trading Plan Guidelines (attached as Annex A to this Policy). Any Rule 10b5-1 Plan by a Covered Person must be approved by the Company's CEO and General Counsel.

Trading Windows

Many public companies permit trading in their securities during announced open "trading windows." The Company does not utilize trading windows. We believe that the interests of the Company and its Covered Persons are best served by requiring the pre-clearance of all trades by Covered Persons of Company securities, as described in this Policy.

Application of Restrictions

Transactions that a director, officer, employee, principal stockholder or agent believes to be necessary or justifiable for independent reasons (such as the need to raise money for an emergency expenditure) are not exceptions to the foregoing Policy and procedures. Even the appearance of an improper transaction must be avoided. Each individual subject to the foregoing Policy and procedures is expected to be responsible for the compliance of his or her Related Persons. No circumvention of this Policy and procedures is permitted. It is a violation of this Policy to try to accomplish indirectly what is prohibited directly by the Policy and procedures. The short-term benefits you might receive cannot outweigh the potential liability and loss of reputation to you and the Company that may result when you are involved in, or even suspected of, the illegal trading of securities.

Nominated Individuals

From time to time, the Company may also prohibit all or certain Covered Persons from trading securities of the Company because of material developments known to the Company and certain individuals identified by officers of the Company and not yet disclosed to the public. In such event, all such designated Covered Persons may not engage in any transaction involving the purchase or sale of the Company's securities and should not disclose to others the fact of such suspension of trading. The Company would permit trading, subject to the terms of this Policy, after two full trading days have elapsed following the date of public disclosure of the information, or at such time as the information is no longer material.

PENALTIES FOR INSIDER TRADING

Penalties for trading on or communicating material nonpublic information are severe, both for individuals involved in such unlawful conduct and, potentially, the Company. A person can be subject to some or all of the penalties below even if he or she does not permanently benefit from the violation. Penalties include:

- civil injunctions;
- treble damages;
- disgorgement of profits;
- jail sentences of up to 20 years and criminal fines of up to $5.0 million per violation;
- civil fines for the person who committed the violation of up to three times the profit gained or loss avoided, whether or not the person actually benefited;
- civil fines for the Company or other controlling/supervisory person plus, in the case of entities only, a criminal penalty of up to $2.5 million; and
- criminal penalties up to 25 years in prison for knowingly executing a "scheme or artifice to defraud any person" in connection with any registered securities.

In addition, any violation of this Policy and procedures is likely to result in serious sanctions by the Company, including dismissal of the persons involved, whether or not the employee's failure to comply results in a violation of law.

ACKNOWLEDGMENT

All Covered Persons must certify annually in writing that they have read and intend to comply with this Policy. See Annex B.

AMENDMENT

The Board of Directors of the Company reserves the right to amend this Policy and procedures at any time.

INTERPRETATIONS

Any requests for interpretation of the provisions of this Policy and procedures, including the determination of whether or not particular information is “material” or “public” should be referred to the General Counsel.

ANNEX A

NACCO Industries, Inc.
Rule 10b5-1 Trading Plan Guidelines

These guidelines are designed to facilitate the review of pre-arranged trading plans under Rule 10b5-1 ("Rule 10b5-1") of the Securities Exchange Act of 1934 (as amended, the "Exchange Act") submitted to the Chief Executive Officer ("CEO") and General Counsel of the Company for review and pre-approval pursuant to the Company's Insider Trading Policy (the "Policy"). Terms used in these guidelines without definition are as defined in the Policy. The CEO and General Counsel have been authorized by the Board of Directors of the Company to amend these guidelines at any time for the purpose of conforming these guidelines with applicable law, in accordance with legal advice, or the rules and regulations of the Securities and Exchange Commission.

Pre-Arranged Plan Provisions. Each pre-arranged trading plan will be reviewed and pre-approved by the CEO and General Counsel. The CEO and General Counsel will determine whether the proposed pre-arranged trading plan contains the following mandatory terms, unless the CEO and General Counsel recognize that there is an exception in a particular case.

- The plan must expressly affirm an intent to comply with Rule 10b5-1.
- If the person entering into (or modifying) the plan is a director or officer of the Company, the plan must include a certification that, on the date of adoption (or modification) of the plan, the person is not in possession of material nonpublic information about the Company or its securities.
- If the person entering into (or modifying) the plan is a director or officer of the Company, the plan must include a certification that, on the date of adoption (or modification) of the plan, the person is adopting (or modifying) the plan in good faith and not as part of a plan or scheme to evade the prohibitions of Section 10(b) and Rule 10b-5 under the Exchange Act.
- The plan must specify the nature of the transactions (e.g., purchase or sale).
- The plan must not permit the exercise of any subsequent influence over how, when or whether to effect purchases or sales; provided, in addition, that any other person who, pursuant to the plan, did exercise such influence must not have been aware of material nonpublic information when doing so.
- The plan must specify the terms of all transactions (identify the amounts, prices, and dates of proposed transactions).
- If the person entering into (or modifying) the plan is a director or officer of the Company, the plan must provide for a cooling-off period of at least the later of (1) 90 days after the adoption (or modification) of the plan and (2) two

business days following the disclosure of the Company’s financial results in a Form 10-Q or Form 10-K for the completed fiscal quarter in which the plan was adopted (or modified) (but not to exceed 120 days following plan adoption (or modification)), before execution of the first transaction (or next transaction, in the case of a modification) under the plan.

- If the person entering into (or modifying) the plan is not an officer or director of the Company, the plan must provide for a cooling-off period of at least 30 days after adoption (or modification) of the plan before execution of the first transaction (or next transaction, in the case of a modification) under the plan.
- The plan must specify a termination date that is at least six months following the effective date of the plan.
- If the person entering into (or modifying) the plan is an officer or director of the Company, the plan must include reporting compliance provisions, instructing parties effecting transactions to provide timely notification of such transactions to the General Counsel for purposes of assuring compliance with applicable reporting requirements, such as those arising under Rule 144 of the Securities Act of 1933 and Section 16 under the Exchange Act.

Additional Requirements/Considerations. The following requirements and considerations apply in connection with any pre-arranged trading plan, unless the CEO and General Counsel recognize there is an exception in a particular case.

- A plan must be entered into (or modified) in good faith and not as part of a plan or scheme to evade the prohibitions of Section 10(b) and Rule 10b-5 under the Exchange Act.
- Once a plan has been entered into (or modified), the person entering into the plan must act in good faith with respect to such plan throughout the duration of the plan.
- Any modification or change to the amount, price or timing of the purchase or sale of securities underlying a plan will generally be considered a termination of such plan and the adoption of a new plan, which will be subject to the cooling-off periods specified above.
- The plan must be entered into, modified or terminated while the person entering into, modifying, or terminating the plan is not aware of any material nonpublic information regarding the Company and its securities.
- The plan may not be modified or terminated without the prior approval of the CEO and General Counsel, which approvals may require a waiting period, as appropriate.
- The person entering into (or modifying) the plan may generally only have one pre-arranged trading plan in effect and active at any time. However, a person may maintain two separate plans at the same time so long as trading pursuant to the later-commencing plan is not authorized to begin until after all trades under an earlier-commencing plan are completed or have expired without execution (if an individual otherwise terminates the earlier-commencing plan, the later-commencing plan would be subject to a new cooling-off period, as described above).

- If the plan is designed to effect the open-market purchase or sale of the total amount of securities subject to such plan as a single transaction (a "single-trade plan"), the person entering into (or modifying) the plan must not have entered into (or modified) another single-trade plan in the prior 12-month period that also qualified for the affirmative defense under Rule 10b5-1.
- In the case of officers and directors of the Company, the adoption, modification, or termination of a plan, the material terms of a plan (other than price), and transactions pursuant to a plan will be publicly disclosed in accordance with the applicable laws, rules, and regulations of the Securities and Exchange Commission.
- In connection with the entry into (or modification of) a plan, an officer or director should consider, in consultation with the General Counsel, Section 16(b) of the Exchange Act. Most transactions under Rule 10b5-1 trading plans are likely to involve open-market sales or purchases that could be matched with opposite-way transactions within less than six months to produce "short-swing" profits recoverable by the Company under Section 16(b). An officer or director establishing a plan should determine whether there are any potentially matchable transactions in the past, or in the future, that could cause profits from plan transactions to be recovered by the Company under Section 16(b).

ANNEX B

Mr. John D. Neumann
Senior Vice President, General Counsel and Secretary
NACCO Industries, Inc.
5340 Legacy Drive
Building 1, Suite 300
Plano, Texas 75024-3141

Re: **Insider Trading Policy Certification**

Mr. Neumann:

I certify that I have read, understand and agree to adhere to the Insider Trading Policy (the "Policy") of NACCO Industries, Inc. (the "Company") to prevent trading while in possession of material nonpublic information and to prevent the misuse of such information.

Printed Name

Signature

Date

Exhibit 21

SUBSIDIARIES OF NACCO INDUSTRIES, INC.

The following is a list of active subsidiaries as of the date of the filing with the Securities and Exchange Commission of the Annual Report on Form 10-K to which this is an Exhibit. Except as noted, all of these subsidiaries are wholly owned, directly or indirectly.

Name	Incorporation
Bellaire Corporation	Ohio
C&H Mining Company, Inc.	Alabama
Caddo Creek Redevelopment, LLC	Delaware
Caddo Creek Resources Company, LLC	Nevada
Catapult Mineral Partners, LLC	Nevada
Centennial Natural Resources, LLC	Nevada
CoalRidge Properties, LLC	Nevada
The Coteau Properties Company	Ohio
Coyote Creek Mining Company, L.L.C.	Nevada
Crossbow Energy Partners, LLC	Nevada
Demery Resources Company, L.L.C.	Nevada
The Falkirk Mining Company	Ohio
GRENAC, LLC	Delaware (50%)
HS Solar I, LLC	Delaware
HS Solar II, LLC	Delaware
HS Solar III, LLC	Delaware
HS Solar IV, LLC	Delaware
HS Solar V, LLC	Delaware
Liberty Fuels Company, L.L.C.	Nevada
Marshall Mine LLC	Delaware
Mississippi Lignite Mining Company	Texas
Mitigate Alabama, LLC	Nevada
Mitigate Georgia, LLC	Nevada
Mitigate Florida, LLC	Nevada
Mitigate Pennsylvania, LLC	Nevada
Mitigate Tennessee, LLC	Nevada
Mitigate Texas, LLC	Nevada
Mitigation Resources of North America, LLC	Nevada
MitRes Services, LLC	Nevada
NACCO Energy Properties, LLC	Nevada
NACCO Natural Resources Corporation	Delaware
NAM - AGL, LLC	Nevada
NAM - CMX, LLC	Nevada
NAM - Corkscrew, LLC	Nevada
NAM - CSA, LLC	Nevada
NAM - IND, LLC	Nevada
NAM - Little River, LLC	Nevada
NAM - MCA, LLC	Nevada
NAM - MDL, LLC	Nevada
NAM - Newberry, LLC	Nevada
NAM - PBA, LLC	Nevada
NAM - Perry, LLC	Nevada
NAM - QueenField, LLC	Nevada
NAM - Rosser, LLC	Nevada
NAM - SDI, LLC	Nevada
NAM - WFA, LLC	Nevada
NAM - WRQ, LLC	Nevada
NAM - 7D, LLC	Nevada
NoDak Energy Investments Corporation	Nevada
North American Coal Corporation India Private Limited	India
North American Coal, LLC	Nevada
North American Mining, LLC	Nevada
North American Coal Royalty Company	Delaware
Otter Creek Mining Company, LLC	Nevada
Powhatan Development LLC	Delaware (50%)
Red Hills Property Company, L.L.C.	Mississippi

Name	Incorporation
ReGen HS Solar, LLC	Delaware
ReGen Resources, LLC	Delaware
ReGen SR Solar, LLC	Delaware
RRP I, LLC	Delaware
The Sabine Mining Company	Nevada
Sawtooth Mining, LLC	Nevada
SR Solar I, LLC	Delaware
SR Solar II, LLC	Delaware
SR Solar III, LLC	Delaware
SR Solar IV, LLC	Delaware
SR Solar V, LLC	Delaware
SR Solar VI, LLC	Delaware
SR Solar VII, LLC	Delaware
Strata Equipment Solutions, LLC	Nevada
Texas Mitigate Solutions, LLC	Delaware (20%)
Trident Technology Services Group, LLC	Nevada
Trifecta Red Hills I, LLC	Delaware
Trifecta Renewable Solutions, LLC	Delaware
TRU Global Energy Services, LLC	Delaware
TRU Energy Services, LLC	Nevada
Reed Minerals, Inc.	Alabama
Yockanookany Mitigation Resources, LLC	Nevada

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-277013) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(2) Registration Statement (Form S-8 No. 333-256443) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(3) Registration Statement (Form S-8 No. 333-256445) pertaining to the Amended and Restated Non-Employee Directors' Equity Compensation Plan
(4) Registration Statement (Form S-8 No. 333-231316) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(5) Registration Statement (Form S-8 No. 333-231315) pertaining to the Amended and Restated Non-Employee Directors' Equity Compensation Plan,
(6) Registration Statement (Form S-8 No. 333-139268) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(7) Registration Statement (Form S-8 No. 333-166944) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(8) Registration Statement (Form S-8 No. 333-183242) pertaining to the NACCO Industries, Inc. Supplemental Executive Long-Term Incentive Compensation Plan,
(9) Registration Statement (Form S-8 No. 333-217862) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(10) Registration Statement (Form S-8 No. 333-217900) pertaining to NACCO Industries, Inc. Non-Employee Directors' Equity Compensation Plan (Amended and Restated Effective May 9, 2017), and
(11) Registration Statement (Form S-8 No. 333-277013) pertaining to NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan (Amended and Restated Effective March 3, 2023);

of our reports dated March 5, 2025, with respect to the consolidated financial statements and schedules of NACCO Industries, Inc. and Subsidiaries and the effectiveness of internal control over financial reporting of NACCO Industries, Inc. and Subsidiaries included in this Annual Report (Form 10-K) of NACCO Industries, Inc. for the year ended December 31, 2024.

/s/ Ernst & Young LLP

Cleveland, Ohio
March 5, 2025

Exhibit 23.2

Consent of Jefferson King

I consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-277013) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(2) Registration Statement (Form S-8 No. 333-256443) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(3) Registration Statement (Form S-8 No. 333-256445) pertaining to the Amended and Restated Non-Employee Directors' Equity Compensation Plan
(4) Registration Statement (Form S-8 No. 333-231316) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(5) Registration Statement (Form S-8 No. 333-231315) pertaining to the Amended and Restated Non-Employee Directors' Equity Compensation Plan,
(6) Registration Statement (Form S-8 No. 333-139268) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(7) Registration Statement (Form S-8 No. 333-166944) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(8) Registration Statement (Form S-8 No. 333-183242) pertaining to the NACCO Industries, Inc. Supplemental Executive Long-Term Incentive Compensation Plan,
(9) Registration Statement (Form S-8 No. 333-217862) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(10) Registration Statement (Form S-8 No. 333-217900) pertaining to NACCO Industries, Inc. Non-Employee Directors' Equity Compensation Plan (Amended and Restated Effective May 9, 2017), and
(11) Registration Statement (Form S-8 No. 333-277013) pertaining to NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan (Amended and Restated Effective March 3, 2023);

of the references to my name, the use of the SEC S-K 1300 Technical Report Summary, Mississippi Lignite Mining Company – Red Hills Mine, Ackerman, Mississippi (the "Technical Report") and the information derived from the Technical Report, including any quotation from or summarization of the Technical Report, which are included in the Annual Report on Form 10-K.

/s/ Jefferson King

March 5, 2025

Exhibit 23.3

Consent of Benson Chow

I consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-277013) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(2) Registration Statement (Form S-8 No. 333-256443) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(3) Registration Statement (Form S-8 No. 333-256445) pertaining to the Amended and Restated Non-Employee Directors' Equity Compensation Plan
(4) Registration Statement (Form S-8 No. 333-231316) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(5) Registration Statement (Form S-8 No. 333-231315) pertaining to the Amended and Restated Non-Employee Directors' Equity Compensation Plan,
(6) Registration Statement (Form S-8 No. 333-139268) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(7) Registration Statement (Form S-8 No. 333-166944) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(8) Registration Statement (Form S-8 No. 333-183242) pertaining to the NACCO Industries, Inc. Supplemental Executive Long-Term Incentive Compensation Plan,
(9) Registration Statement (Form S-8 No. 333-217862) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(10) Registration Statement (Form S-8 No. 333-217900) pertaining to NACCO Industries, Inc. Non-Employee Directors' Equity Compensation Plan (Amended and Restated Effective May 9, 2017), and
(11) Registration Statement (Form S-8 No. 333-277013) pertaining to NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan (Amended and Restated Effective March 3, 2023);

of the references to my name, the use of the SEC S-K 1300 Technical Report Summary, Mississippi Lignite Mining Company – Red Hills Mine, Ackerman, Mississippi (the "Technical Report") and the information derived from the Technical Report, including any quotation from or summarization of the Technical Report, which are included in the Annual Report on Form 10-K.

/s/ Benson Chow

March 5, 2025

Exhibit 23.4

Consent of Haas & Cobb Petroleum Consultants

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-277013) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(2) Registration Statement (Form S-8 No. 333-256443) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(3) Registration Statement (Form S-8 No. 333-256445) pertaining to the Amended and Restated Non-Employee Directors' Equity Compensation Plan
(4) Registration Statement (Form S-8 No. 333-231316) pertaining to the Amended and Restated Executive Long-Term Incentive Compensation Plan,
(5) Registration Statement (Form S-8 No. 333-231315) pertaining to the Amended and Restated Non-Employee Directors' Equity Compensation Plan,
(6) Registration Statement (Form S-8 No. 333-139268) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(7) Registration Statement (Form S-8 No. 333-166944) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(8) Registration Statement (Form S-8 No. 333-183242) pertaining to the NACCO Industries, Inc. Supplemental Executive Long-Term Incentive Compensation Plan,
(9) Registration Statement (Form S-8 No. 333-217862) pertaining to the NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan,
(10) Registration Statement (Form S-8 No. 333-217900) pertaining to NACCO Industries, Inc. Non-Employee Directors' Equity Compensation Plan (Amended and Restated Effective May 9, 2017), and
(11) Registration Statement (Form S-8 No. 333-277013) pertaining to NACCO Industries, Inc. Executive Long-Term Incentive Compensation Plan (Amended and Restated Effective March 3, 2023);

of the references to our name, the use of the Reserve Report of Catapult Mineral Partners ("Reserve Report") and the information derived from the Reserve Report, including any quotation from or summarization of the Reserve Report, which are included in the Annual Report on Form 10-K.

/s/ Haas & Cobb Petroleum Consultants

March 5, 2025

Exhibit 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ John S. Dalrymple	February 20, 2025
John S. Dalrymple	Date

Exhibit 24.2

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ John P. Jumper	February 20, 2025
John P. Jumper	Date

Exhibit 24.3

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ Dennis W. LaBarre	February 20, 2025
Dennis W. LaBarre	Date

Exhibit 24.4

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ W. Paul McDonald	February 20, 2025
W. Paul McDonald	Date

Exhibit 24.5

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ Michael S. Miller	February 20, 2025
Michael S. Miller	Date

Exhibit 24.6

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ Alfred M. Rankin, Jr.	February 20, 2025
Alfred M. Rankin, Jr.	Date

Exhibit 24.7

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ Matthew M. Rankin	February 20, 2025
Matthew M. Rankin	Date

Exhibit 24.8

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ Roger F. Rankin	February 20, 2025
Roger F. Rankin	Date

Exhibit 24.9

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ Lori J. Robinson	February 20, 2025
Lori J. Robinson	Date

Exhibit 24.10

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ Valerie Gentile Sachs	February 20, 2025
Valerie Gentile Sachs	Date

Exhibit 24.11

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ Robert S. Shapard	February 20, 2025
Robert S. Shapard	Date

Exhibit 24.12

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of NACCO Industries, Inc. hereby appoints Elizabeth I. Loveman as the true and lawful attorney or attorney-in-fact, with full power of substitution and revocation, for the undersigned and in the name, place and stead of the undersigned, to sign on behalf of the undersigned as director of NACCO Industries, Inc., a Delaware corporation, an Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 on Form 10-K for the fiscal year ended December 31, 2024 and to sign any and all amendments to such Annual Report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting to said attorney or attorney-in-fact full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney or attorney-in-fact substitute or substitutes may lawfully do or cause to be done by virtue hereof.

/s/ Britton T. Taplin	February 20, 2025
Britton T. Taplin	Date

Exhibit 31(i)(1)

Certifications

I, J.C. Butler, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of NACCO Industries, Inc.;

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

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

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

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

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 5, 2025

/s/ J.C. Butler, Jr.
J.C. Butler, Jr.
President and Chief Executive Officer
(principal executive officer)

Exhibit 31(i)(2)

Certifications

I, Elizabeth I. Loveman, certify that:

1. I have reviewed this annual report on Form 10-K of NACCO Industries, Inc.;

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

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

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

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

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 5, 2025

/s/ Elizabeth I. Loveman
Elizabeth I. Loveman
Senior Vice President and Controller
(principal financial officer)

Exhibit 32

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of NACCO Industries, Inc. (the "Company") on Form 10-K for the year ended December 31, 2024, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned officers of the Company certifies, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: March 5, 2025

/s/ J.C. Butler, Jr.
J.C. Butler, Jr.
President and Chief Executive Officer
(principal executive officer)

Date: March 5, 2025

/s/ Elizabeth I. Loveman
Elizabeth I. Loveman
Senior Vice President and Controller
(principal financial officer)

Exhibit 95

MINE SAFETY DISCLOSURES

NACCO Industries, Inc. (the “Company”) believes that The North American Coal Corporation and its affiliated mining companies (collectively, “NACoal”) is an industry leader in safety. NACoal has health and safety programs in place that include extensive employee training, accident prevention, workplace inspection, emergency response, accident investigation, regulatory compliance and program auditing. The objectives for NACoal's programs are to eliminate workplace incidents, comply with all mining-related regulations and provide support for both regulators and the industry to improve mine safety.

Under the Dodd-Frank Wall Street Reform and Consumer Protection Act, each operator of a coal or other mine is required to include certain mine safety results in its periodic reports filed with the Securities and Exchange Commission. The operation of NACoal's mines is subject to regulation by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Act"). MSHA inspects NACoal's mines on a regular basis and issues various citations and orders when it believes a violation has occurred under the Mine Act. The Company has presented information below regarding certain mining safety and health matters for NACoal's mining operations for the year ended December 31, 2024. In evaluating this information, consideration should be given to factors such as: (i) the number of citations and orders will vary depending on the size of the mine, (ii) the number of citations issued will vary from inspector to inspector and from mine to mine, and (iii) citations and orders can be contested and appealed, and in that process, are often reduced in severity and amount, and are sometimes vacated.

During the year ended December 31, 2024, neither the Company's current mining operations nor it's closed mines: (i) were assessed any Mine Act section 104(b) orders for alleged failure to totally abate the subject matter of a Mine Act section 104(a) citation within the period specified in the citation; (ii) were assessed any Mine Act section 110(b)(2) penalties for failure to correct the subject matter of a Mine Act section 104(a) citation within the specified time period, which failure was deemed flagrant (i.e., reckless or repeated failure to make reasonable efforts to eliminate a known violation that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury); (iii) received any Mine Act section 107(a) imminent danger orders to immediately remove miners; or (iv) received any MSHA written notices under Mine Act section 104(e) of a pattern of violation of mandatory health or safety standards or of the potential to have such a pattern. In addition, there were no mining-related fatalities at the Company's operations or it's closed mines during the year ended December 31, 2024.

The following table sets forth the total number of specific citations and orders, the total dollar value of the proposed civil penalty assessments that were issued by MSHA, the total number of legal actions initiated and resolved before the Federal Mine Safety and Health Review Commission ("FMSHRC") during the year ended December 31, 2024, and the total number of legal actions pending before the FMSHRC at December 31, 2024, pursuant to the Mine Act, by individual mine at NACoal:

Name of Mine or Quarry [(1)]	Mine Act Section 104 Significant & Substantial Citations [(2)]	Mine Act Section 104(d) Citations	Total Dollar Value of Proposed MSHA Assessment	Number of Legal Actions Initiated before the FMSHRC for the year ended at December 31, 2024[(3)]	Number of Legal Actions Resolved before the FMSHRC for the year ended at December 31, 2024	Number of Legal Actions Pending before the FMSHRC at December 31, 2024[(3)]
Coteau (Freedom Mine)	1	—	$ 1,792	—	—	—
Falkirk (Falkirk Mine)	1	—	2,827	—	—	—
Sabine (South Hallsville No. 1 Mine)	—	—	873	—	—	—
Demery (Five Forks Mine)	—	—	—	—	—	—
Caddo Creek (Marshall Mine)	—	—	—	—	—	—
Coyote Creek (Coyote Creek Mine)	—	—	—	—	—	—
MLMC (Red Hills Mine)	—	—	—	—	—	—
North American Mining Operations:	—	—	—	—	—	—
Alico Quarry	—	—	—	—	—	—
Center Hill Quarry	—	—	—	—	—	—
FEC Quarry	—	—	—	—	—	—
Inglis Quarry	—	—	—	—	—	—
Krome Quarry	—	—	239	—	—	—
SCL Quarry	—	—	—	—	—	—
St. Catherine Quarry	1	—	549	—	—	—
Seven Diamonds Quarry	—	—	—	—	—	—
Central State Aggregates Quarry	—	—	—	—	—	—
Johnson County Quarry	—	—	—	—	—	—
Little River Quarry	—	—	—	—	—	—
Mid Coast Aggregates Quarry	—	—	—	—	—	—
Newberry Quarry	—	—	—	—	—	—
County Line Quarry	—	—	—	—	—	—
Palm Beach Aggregates Quarry	—	—	—	—	—	—
Perry Quarry	—	—	—	—	—	—
Queenfield Mine	—	—	1,358	—	—	—
Rosser Quarry	—	—	239	—	—	—
SDI Aggregates Quarry	—	—	—	—	—	—
West Florida Aggregates Quarry	—	—	—	—	—	—
Titan Corkscrew Quarry	—	—	—	—	—	—
White Rock Quarry - North	1	—	1,970	1	—	1
Ash Grove	—	—	1,253	—	—	—
Sawtooth	—	—	147	—	—	—
Total	4	—	$ 11,247	1	—	1

(1) Bellaire's, Centennial's, Liberty's and Camino Real's closed mines are not included in the table above and did not receive any of the indicated citations.

(2) Mine Act section 104(a) significant and substantial citations are for alleged violations of a mining safety standard or regulation where there exists a reasonable likelihood that the hazard contributed to or will result in an injury or illness of a reasonably serious nature.

(3) The initiated and pending legal actions are contests of citations received and contests of proposed penalties.

SEC S-K 1300 Technical Report Summary
Mississippi Lignite Mining Company – Red Hills Mine
Ackerman, Mississippi

Effective Date: December 31, 2024

Report Date: March 5, 2025

Report Prepared by:

Mississippi Lignite Mining Company

1000 McIntire Road

Ackerman, MS 39735

Signed by Qualified Persons:

Jefferson King, P.E., P.S., SME-RM

Benson Chow, P.G., SME-RM

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Signature and Report Date

The effective date of this Technical Report Summary (TRS) is December 31, 2024.

QP Name	Sections Responsible For	Signature
Jefferson King, P.E., P.S., SME-RM	1.1, 1.4, 1.6, 1.7, 1.8, 1.9, 2.0, 3.0, 4.0, 5.0, 7.3, 7.4, 9.2, 10.0, 12.0, 13.0, 14.0, 15.0, 16.0, 17.0, 18.0, 19.0, 20.0, 22.2, 23.2, 24.0, 25.0	/s/ Jefferson King
Benson Chow, P.G., SME-RM	1.2, 1.3, 1.5, 1.9, 6.0, 7.1, 7.2, 8.0, 9.1, 11.0, 21.0, 22.1, 23.1, 25.0	/s/ Benson Chow

CERTIFICATE OF QUALIFIED PERSON JEFFERSON KING

(a) I am the Engineering Manager at Mississippi Lignite Mining Company's Red Hills Mine in Ackerman, MS; a position I have held since 2022.
(b) This certificate applies to the Technical Report Summary titled, "SEC S-K 1300 Technical Report Summary, Mississippi Lignite Mining Company – Red Hills Mine, Ackerman, Mississippi" with an effective date of December 31, 2024.
(c) I am a Qualified Person (QP) for the purpose of SEC S-K 1300. My qualifications as a QP are as follows:
    a. I am a graduate of Mississippi State University and graduated with a Bachelor of Science in Civil Engineering in 2003, and a Masters of Business Administration in 2005.
    b. I am a Professional Engineer (License Number 18896), a Professional Surveyor (License Number 3033) registered in the state of Mississippi, and a Registered Member of SME (ID 04195446).
    c. My relevant experience is over 19 years for the purpose of the Technical Report Summary. This includes 13 years of mining operations experience, which have all been in the coal industry, and 6 years of consulting experience outside of the mining industry.
    d. As the Engineering Manager for Mississippi Lignite Mining Company's Red Hills Mine, I conduct personal inspections of each mining area described in this Technical Report Summary on a regular basis.
    e. I am responsible for the sections listed in the signature table on page 9 of this Technical Report Summary.
    f. I have read the SEC S-K 1300 Technical Report Summary requirements. The part of the Technical Report Summary for which I am responsible has been prepared in compliance with this requirement.
    g. At the effective date of the Technical Report Summary, to the best of my knowledge, information, and belief, the parts of the Technical Report Summary for which I am responsible, contains all scientific and technical information that is required to be disclosed to make the Technical Report Summary not misleading.

CERTIFICATE OF QUALIFIED PERSON BENSON CHOW

(d) I am the Principal Geologist at NACCO Natural Resources, Plano, TX; a position I held since 2013. I have been employed by NACCO Natural Resources since 1999.

(e) This certificate applies to the Technical Report Summary titled, "SEC S-K 1300 Technical Report Summary, Mississippi Lignite Mining Company – Red Hills Mine, Ackerman, Mississippi" with an effective date of December 31, 2024.

(f) I am a Qualified Person (QP) for the purpose of SEC S-K 1300. My qualifications as a QP are as follows:

a. I am a graduate of Mississippi State University with a Bachelor of Science in Geosciences and I graduated in 1998.
b. I am a Registered Professional Geologist of the state of Mississippi (License Number 0715) and a Registered Member of SME, ID 4317057.
c. My relevant experience of over 25 years, for the purpose of the Technical Report Summary, includes 8 years of mining operations experience and 17 years of corporate project development experience in various technical roles, of which have been in coal and industrial minerals.
d. As the Principal Geologist for NACCO Natural Resources, I conducted personal inspections of each mining area described in this Technical Report Summary.
e. I am responsible for the sections listed in the signature table on page 9 of this Technical Report Summary.
f. I have read SEC S-K 1300 Technical Report Summary requirements. The part of the Technical Report Summary for which I am responsible has been prepared in compliance with this requirement.
g. At the effective date of the Technical Report Summary, to the best of my knowledge, information, and belief, the parts of the Technical Report Summary for which I am responsible, contains all scientific and technical information that is required to be disclosed to make the Technical Report Summary not misleading.

1. Executive Summary

This Technical Report Summary (TRS) was prepared for the Mississippi Lignite Mining Company (MLMC) to report Mineral Resources and Mineral Reserves for the Red Hill Mine in Choctaw County, Mississippi.

1.1. Property Description and Ownership

NACCO Industries, Inc.® (NACCO) and its wholly owned subsidiary, NACCO Natural Resources Corporation® (NACCO Natural Resources and with NACCO collectively, the Company, we, our or us), bring natural resources to life by delivering aggregates, minerals, reliable fuels and environmental solutions through our robust portfolio of businesses. We operate under three business segments: Coal Mining, North American Mining® and Minerals Management. The Coal Mining segment operates surface coal mines for power generation companies. Coal is surface mined in North Dakota and Mississippi. Each mine is fully integrated with our customer's operations.

The Red Hills Mine, an active lignite surface mine in Mississippi, is operated by our wholly owned subsidiary Mississippi Lignite Mining Company (MLMC). The Red Hills Mine typically supplies 2.6 to 3.2 million tons of lignite per year to the adjacent Red Hills Power Plant (RHPP). Actual production is dictated by customer MMBtu demand. MLMC provides the lignite for the RHPP under a contract that runs until April 1, 2032. Mining dimensions are discussed in Sections 13.1 and 13.3 of this TRS.

MLMC is the exclusive supplier of lignite to the RHPP in Choctaw County, Mississippi under a lignite sales agreement (LSA) with Choctaw Generation Limited Partnership (CGLP) that runs until April 1, 2032. CGLP leases the RHPP from a Southern Company subsidiary pursuant to a leveraged lease arrangement. The RHPP supplies electricity to the Tennessee Valley Authority (TVA) under a long-term Power Purchase Agreement (PPA). TVA’s power portfolio includes coal, nuclear, hydroelectric, natural gas and renewables. The decision regarding which power plants to dispatch is determined by TVA. Reduction in dispatch of the Red Hills Power Plant will result in reduced earnings at MLMC.

MLMC sells coal to CGLP at a contractually agreed-upon price which adjusts monthly, primarily based on changes in the level of established indices which reflect general U.S. inflation rates. MLMC is responsible for all operating costs, capital requirements and final mine reclamation. Profitability at MLMC is affected by customer demand for coal and changes in the indices that determine sales price and actual costs incurred. Additional discussion of material contracts is provided in Section 16.

The Life of Mine (LOM) plan used in this TRS report covers the period from January 1, 2025 through April 1, 2032 as the LOM plan assumes the RHPP will not continue to operate after the expiration of the current LSA with CGLP and the expiration of the existing PPA between TVA and CGLP in April 2032.

The Red Hills Mine is located approximately 7 miles northwest of Ackerman, Mississippi in Choctaw County, which is approximately 120 miles northeast of Jackson, Mississippi. The entrance to the mine is by means of a paved road located approximately 1 mile west of MS Highway 9 with its location at approximately 33^{o} 22’ 26.3”N and 89^{o} 13’ 23.5”W.

MLMC owns in fee approximately 8,090 acres of surface interest and 5,150 acres of coal interest. MLMC holds leases granting the right to mine approximately 5,423 acres of coal interests and the right to utilize approximately 4,890 acres of surface interests. MLMC holds subleases under which it has the right to mine approximately 1,683 acres of coal interest. Most of the leases held by MLMC have terms extending 50 years, and can be further extended by the continuation of mining operations.

1.2. Geology and Mineralization

The Red Hills Mine is in the Wilcox Group of Mississippi which is the most prolific lignite-bearing stratum in the state of Mississippi. The formations within the Wilcox Group and the underlying Midway Group consist of sands, silts, clay, and lignite which were deposited during Paleogene time, approximately 66 to 23 million years ago. Deposition occurred in a cyclical manner representing a transition from a transgressive sequence of valley fill, marginal marine strata to predominantly regressive, nonmarine, deltaic strata.

During each depositional geologic sequence, organic material was repeatedly buried by sediment in an ideal, oxygen-free environment. This ideal environment was attributed to the humid, subtropical conditions and high water-table of wetlands present during Paleogene time which prevented plant matter from decaying prior to burial. The oxygen-free environment combined with heat and pressure from continual deposition of overlying sediments allowed for the formation of peat and further mineralization of lignite over time by undergoing a process known as humification and biochemical gelification.

The average thickness of the Wilcox section containing the mineable lignite seams at the Red Hills Mine and surrounding area is approximately 140 feet. Mineable lignite seams may be as thin as 1-foot and typically do not exceed 5-feet in thickness. Currently, five primary lignite seams are targeted for mining.

The local structural geology for the Red Hills Mine follows the regional structure with a northwest-southeast strike dipping to the southwest. The lignite seams are gently undulating due to differential compaction of the underlying sediments.

1.3. Status of Exploration

Exploration programs described in this TRS have considered the stratigraphic nature of the mineralization for the determination of hole spacing, drilling and sampling method, and quality analyses in order to geologically map and evaluate the structural and quality characteristics of the lignite deposit. The Red Hills Mine lignite deposit is evaluated on a seam-by-seam basis. Drilling exploration data including geologic lithologies, qualities, and hole locations have been compiled in an electronic, geologic database.

From 1975 through 1980 drilling campaigns were completed under the sole direction of Phillips Coal Company (Phillips). Since 1997, independent drilling and geophysical logging contractors have operated under the guidance and direction of MLMC.

Over 1,500 drill holes including pilot holes, coal core holes, overburden holes, geotechnical holes, and monitoring wells have been drilled within the Red Hills Mine lignite deposit. Drilling campaigns conducted at the mine have comprised largely of rotary wash drilling methods. Drill holes were geophysically logged for natural gamma, density, caliper, and resistivity responses to obtain data related to the subsurface structure. Coal core samples collected for quality analyses were sent to independent commercial laboratories for testing.

1.4. Development and Operations

The Red Hills Mine is a multiple lignite seam surface mining operation which typically supplies 2.6 to 3.2 million tons of lignite per year to the adjacent RHPP. Actual annual production is dictated by customer demand. The RHPP supplies electricity to TVA under a long-term PPA. MLMC's customer's demand for coal is driven by the decision of which power plants to dispatch as determined by TVA. An increase in the number of days TVA dispatches the RHPP would increase demand. A decrease in the number of days TVA dispatches the RHPP would reduce demand.

The lignite at the Red Hills Mine surface mining operation is uncovered using dragline, dozer push, and conventional truck and shovel mining methods due to the proximity of the lignite to the surface and the physical characteristics of the deposit. Lignite is mined using a surface miner or a hydraulic backhoe to load a fleet of end dump haul trucks and is directly shipped to the RHPP or the lignite stockpile. The overall average ROM quality of the mined lignite seams meets the required power plant quality specifications. Therefore, no mineral processing is performed by MLMC.

The Red Hills Mine began operations in Mine Area 1 and has transitioned to Mine Area 3. Both Mine Areas are located in the MS-005 permit area. Initial development of the Red Hills Mine began in 1998, with full production and commercial deliveries commencing in 2002. Boxcut construction for Mine Area 3 began in 2021 where mining will continue until April 1, 2032. The Red Hills Mine has, or is currently constructing, all supporting infrastructure for mining operations within the permitted areas.

The Red Hills Mine employs a staff and workforce of approximately 200 employees with fluctuations in employment levels for changes in demand at the RHPP or special projects such as the final reclamation work taking place in Mine Area 1.

1.5. Mineral Resource Estimate

The Mineral Resources in this TRS have been estimated by applying a series of geologic and physical limits as well as high-level mining and economic constraints. The mining and economic constraints were limited to a level sufficient to support reasonable prospect for economic extraction of the estimated Mineral Resources. The potential for economic extraction is justified by the terms of the existing LSA with the RHPP that runs through April 2032.

The QP based the Mineral Resource estimates for the Red Hills Mine on a stratigraphic geologic model generated from the verified drilling exploration data. For a lignite seam to be considered a Mineral Resource by the QP, the seam must have a minimum of ten coal core samples for quality estimation, a maximum ash cutoff of 30% and a minimum calorific value cutoff of 4,000 BTU/lb, both on an as-received moisture basis, and a minimum thickness of 1 foot. Mineral Resources were then further defined for each identified lignite seam by applying projected pit shells based on physical constraints, including but not limited to lease and fee coal boundaries, and a maximum cumulative stripping ratio of 18:1 based on an assumed lignite sales price of $34.02 per ton.

Mineral Resources were divided into three categories of Measured, Indicated, or Inferred and were ranked by increasing level of confidence. The Mineral Resource categorization applied by the QP included the consideration of the type and amount of data per drill hole and the variography of quality and structural continuity among holes with the C Seam present and cored. Measured Mineral Resources are defined as tonnages which meet the general resource requirements and fall within an area where the distance from a core hole is less than or equal to 2,667 feet. Indicated Mineral Resources are defined as tonnages which meet the general resource requirements and fall within an area where the distance from a core hole is greater than 2,667 feet and less than or equal to 5,333 feet. Inferred Mineral Resources are defined as tonnages which meet the general resource requirements and fall within an area where the distance from a core hole is greater the 5,333 feet and less than or equal to 8,000 feet.

Mineral Resources as of December 31, 2024 are shown in Table 1.1, and are reported as in-situ tons such that no adjustments were made to account for mining recovery or losses. Mineral Resources are reported exclusive of in-situ Mineral Reserves.

Table 1.1 Mineral Resource Estimates as of December 31, 2024

Red Hills Mine	Resource Classification	Tonnage (Kt)	Quality (As-Received)			
			Calorific Value (Btu/lb)	Moisture (%wt)	Ash (%wt)	Sulfur (%wt)
Mine Area 2	Measured	4,400	5,200	44.6	13.0	0.6
	Indicated	400	5,180	44.1	13.6	0.6
	Measured + Indicated	4,700	5,200	44.5	13.0	0.6
	Inferred	0	0	0	0	0
Mine Area 3	Measured	0	0	0	0	0
	Indicated	0	0	0	0	0
	Measured + Indicated	0	0	0	0	0
	Inferred	100	5,200	45.5	12.0	0.5
Total Resources	Measured	4,400	5,200	44.6	13.0	0.6
	Indicated	400	5,180	44.1	13.6	0.6
	Measured + Indicated	4,700	5,200	44.5	13.0	0.6
	Inferred	100	5,200	45.5	12.0	0.5

Notes:

1. Mineral Resource Estimate has been prepared by a qualified person employed by NACCO NR as of December 31, 2024
2. Mineral Resources that are not Mineral Reserves do not have demonstrated economic viability and there is no certainty that all or any part of such Mineral Resources will be converted into Mineral Reserves.
3. Mineral Resources are in-situ and exclusive of 22.9 million tons (Mt) of Mineral Reserves.
4. Mineral Resources are reported using an economic cutoff of $34.02 per ton coal.
5. Resources are presented with a minimum 1 foot seam thickness, a maximum as-received moisture basis ash content of 30%, and a minimum calorific value of 4,000 BTU/lb on an as-received moisture basis.
6. Resources are estimated using Vulcan Software.
7. Tonnages and qualities have been rounded to an accuracy level deemed appropriate by the QP. Summation errors due to rounding may exist.

In the opinion of the QP it is important to note that additional exploration may positively or negatively affect Mineral Resource estimates. Additionally, Mineral Resource estimates may be materially affected by a change in the assumptions including general mining costs and land control. New regulations may also impose additional economic factors, delays to future permit renewals, or restrictions to physical estimation boundaries.

At the time of this TRS, the QP is not aware of any specific factors that would materially affect the Mineral Resource estimates presented herein.

1.6. Mineral Reserve Estimate

The Mineral Reserves in this TRS were determined to be the economically mineable portion of the Measured and Indicated Mineral Resources after the consideration of modifying factors related to the mining process, which convert Measured Resources to Proven Mineral Reserves and Indicated Resources to Probable Mineral Reserves. Inferred Mineral Resources were not considered for Mineral Reserves.

Parameters for mining dilution, minimum mining thickness, and minimum parting thickness were applied by the QP to the geologic model to create the Mineral Reserve model. Mining pits were projected based on current mining equipment operating parameters and a maximum cumulative stripping ratio of 14:1, over the entire area evaluated, based on an estimated average price per ton of $34.41. Mining pits were then sectioned into 500-foot blocks; adjusting endwall blocks as necessary. Blocks were reviewed by the QP to ensure quality thresholds were met. Recovery rates were applied to the lignite tonnages by seam and then the blocks were sequenced based on a projected total delivered heat requirement measured in million British Thermal Units (MMBTU) through the LOM plan to determine the Measured and Indicated Resources that would be converted to Proven and Probable Mineral Reserves. The details of the LOM plan are shown in Table 1.2.

Table 1.2 LOM Production Schedule

	2025	**2026**	**2027**	**2028**
Delivered Coal (000 tons)	2,800	2,700	2,700	2,800
Delivered MMBTU (000)	27,700	27,700	27,700	27,700
Calorific Value, Btu/lb	5,010	5,040	5,050	5,020
Total Overburden Material (000 CY)	33,900	35,200	36,200	31,600

	2029	**2030**	**2031**	**2032**	**Total**
Delivered Coal (000 tons)	2,800	2,800	2,700	700	**20,000**
Delivered MMBTU (000)	27,700	27,700	27,700	6,900	**200,800**
Calorific Value, Btu/lb	5,020	5,040	5,100	5,140	**5,000**
Total Overburden Material (000 CY)	34,700	36,400	39,600	8,100	**255,700**

This disclosure of Mineral Reserves is based upon the QP's opinion that the LOM plan and cost estimates have been completed to a Pre-feasibility (PFS) level of accuracy, as defined in 17 Code of Federal Regulations (CFR) Part 229.1300, which includes and supports the QP's determination of Mineral Reserves.

The Red Hills Mine Mineral Reserve, as of December 31, 2024, is shown in Table 1.3.

Table 1.3 Mineral Reserve Estimate as of December 31, 2024

Red Hills Mine	Reserve Classification	Tonnage (Kt)	Quality: Calorific Value (Btu/lb)	Quality: Moisture (%wt)	Quality: Ash (%wt)	Quality: Sulfur (%wt)
Mine Area 3	Proven	17,300	5,090	43.3	14.9	0.6
	Probable	4,700	5,080	43.1	15.1	0.6
	Total	22,000	5,080	43.3	14.9	0.6
Stockpile & Silos	Proven	900	5,090	43.5	15	0.5
Total Reserves Stockpile & Silos	Proven	18,200	5,090	43.3	14.9	0.6
	Probable	4,700	5,080	43.1	15.1	0.6
	Total	22,900	5,090	43.3	14.9	0.6

Notes:

1. Mineral Reserve Estimate have been prepared by a qualified person employed by MLMC as of December 31, 2024.
2. Mineral Reserves use an economic cutoff of a maximum cumulative stripping ratio of 14:1. There are some instances where the stripping ratio for a single year could exceed 14:1, but the average for the entire area evaluated is less than 14:1.
3. Historical coal recovery rates at Red Hills Mine have been applied to generate the Mineral Reserve tonnages.
4. Mineral Reserves are estimated using Vulcan Software.
5. Tonnages and qualities have been rounded to an accuracy level deemed appropriate by the QP. Summation errors due to rounding may exist.

The QP's opinion on risks that could potentially affect the Mineral Reserve estimates include changes in customer demand for any reason, including, but not limited to, dispatch of power generated by other energy sources ahead of coal, fluctuations in demand due to unanticipated weather conditions, regulations or comparable policies which could potentially promote planned and unplanned outages at the RHPP, economic conditions, including an economic slowdown that would affect manufacturing and a corresponding decline in the use of electricity, governmental regulations and/or inflationary adjustments. All of which could potentially have a material adverse effect on MLMC's financial condition.

At the time of this TRS, the QP is not aware of any specific factors that would materially affect the Mineral Reserve estimates.

1.7. Economic Assessment

The primary driver in determining the economic viability of the Red Hills Mine was the expected annual operating performance of the RHPP, which was forecasted using two main inputs: the annual projection notice (nomination for MMBtu requirements) received from the RHPP and a comparison to historical prior years actual delivered lignite fuel. The typical annual MMBtu requirement used in the Red Hills LOM Economic Model was approximately 27.7 MMBtu. This resulted in a production schedule of approximately 2.7 million tons (Mt) of dedicated lignite per year each year until LSA contract expiration in April 2032.

LOM operating costs for a plan delivering approximately 27.7 MMBtu per year to the RHPP total approximately $645 million (M). Operating costs included major cost categories for mine development, burden removal, severing of lignite, reclamation, maintenance and handling of stockpiled lignite and delivery to the adjacent RHPP along with the necessary maintenance required to keep all equipment operating safely and efficiently.

Capital costs to fulfill the LSA for a plan delivering approximately 27.7 MMBtu per year to the RHPP are expected to total approximately $31 M. Capital Costs included categories for equipment expenditures, mine development, mitigation, and land acquisitions.

The base price for the dedicated lignite is defined in the LSA and consists of eight indexed components in addition to a power cost component, a pass-through component, a royalty component and a fixed component. The base price in the LOM is evaluated on an annual basis and is determined based on the actual performance of the 8 indexed components specified in the LSA. Over the LOM plan, the average price per ton for lignite delivered and sold is $34.41 providing revenues totaling approximately $685 M. The Red Hills Mine began commercial deliveries in 2001. The sales price over the last three years has averaged approximately $31 as shown in Table 1.4. The forecasted coal price for the LOM is also shown in Table 1.4.

Table 1.4 Historical and Forecasted Coal Price

Historical	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024**	Total*
Tons Sold (000 ton)	3,200	2,600	3,200	3,000	2,400	3,000	2,600	2,500	3,000	3,200	2,900	1,900	33,500
Coal Price $/Ton	20.61	21.61	22.61	23.61	24.61	25.61	26.61	27.61	27.20	29.66	29.14	35.60	30.88

Forecasted	2025	2026	2027	2028	2029	2030	2031	2032	Total
Tons Sold (000 ton)	2,800	2,700	2,700	2,800	2,800	2,800	2,700	700	20,000
Coal Price $/Ton	31.30	34.46	32.86	33.02	34.65	35.99	36.71	41.90	34.41

*Average Coal price $/ton is from 2022-2024.
**During 2024, a mechanical issue impacted one of two boilers at the Red Hills Power Plant. While this issue has been resolved, it resulted in a reduction in customer deliveries in 2024.

During 2023, MLMC received notice from its customer related to a mechanical issue that began on December 15, 2023 and impacted one of two boilers at the Red Hills Power Plant. While this issue has been resolved, it resulted in a reduction in customer demand in 2024. Total deliveries in 2024 were 1.9 million tons. The Company recognized income of $13.6 million in 2024 related to business interruption insurance recoveries that partially offset losses as a result of the boiler outage.

The projected annual cash flow forecast based on the lignite production schedule over the remaining LOM results in a total after-tax cash flow projection of $88 M resulting in a net present value of $58 M after tax at a 10% discount rate.

The Economic Assessment used what could be considered a conservative assumption in light of historical trends, current conditions and expected future developments for delivered fuel to the RHPP of approximately 27.7 MMBtu annually. Therefore, the QP is of the opinion that any downside risks to the economic viability of the project relate primarily to the risk that RHPP takes less than the LOM plan MMBtus, but notes that there is a minimum take provision included in the LSA. Other downside risks considered were the effects of an increase in diesel prices and labor.

The Income Statement and Annual Cash Flows based on the lignite production schedule for the LOM plan, along with the Net Present Value are detailed in Table 1.5. A Discount Rate of 10% was used, as this was consistent with the Red Hills Mine's weighted average cost of capital. The calculation of Net Present Value and Internal Rate of Return are nuanced due to the ongoing nature of this mining operation. As modeled, the cash flows for the period 2025 through 2045 indicate the project is cash flow positive over the remaining life of the project.

In the opinion of the QP, the income statement and cash flow projection based on the LOM plan assumptions as shown in Table 1.5 are reasonable in light of current conditions and expected future developments. As modeled, the future cash flow projection is estimated to be approximately $88 M and the net present value is estimated to be approximately $58 M after tax.

Note that the net present value estimated for this report does not consider previous cash inflows and outflows and is only estimated from 2025 through the remainder of the LOM and therefore does not consider any historical cash flows already realized.

Table 1.5 Summary of Income Statement and Cash Flow for LOM plan delivering approximately 27.7 MMBtu

Income Statement ($M unless noted)	2025	2026	2027	2028	2029
Tons Sold (in thousands)	2,800	2,700	2,700	2,800	2,800
Revenue/Ton	$ 31.30	$ 34.46	$ 32.86	$ 33.02	$ 34.65
Total Revenue	$ 86,582	$ 94,726	$ 90,210	$ 91,124	$ 95,713
Expenses					
Labor, Material Fuel	$ 48,124	$ 47,530	$ 48,433	$ 48,626	$ 50,948
Royalties & Production Taxes	$ 2,685	$ 3,639	$ 4,142	$ 4,009	$ 4,344
Other Expenses	$ 35,598	$ 30,176	$ 29,014	$ 34,386	$ 35,125
Income Taxes	$ (21)	$ (1,606)	$ (1,035)	$ (493)	$ (636)
Net Income	**$ 154**	**$ 11,775**	**$ 7,586**	**$ 3,612**	**$ 4,661**
EBITDA	**$ 11,811**	**$ 26,382**	**$ 21,966**	**$ 17,540**	**$ 19,087**
Capital Expenditures	$ (12,778)	$ (6,653)	$ (1,902)	$ (2,636)	$ (3,671)
Investing Activities	$ 8,485	$ (132)	$ 1,645	$ 4,861	$ 1,060
Financing Activities	$ (4,691)	$ (5,531)	$ (4,678)	$ (4,437)	$ (4,114)
Mine Closing	$ (6,925)	$ (6,739)	$ (1,684)	$ (426)	$ (250)
Income Taxes	$ (21)	$ (1,606)	$ (1,035)	$ (493)	$ (636)
Increase (decrease) in Cash	**$ (4,118)**	**$ 5,722**	**$ 14,313**	**$ 14,410**	**$ 11,477**

Income Statement ($M unless noted)	2030	2031	2032	2033-2045	Total
Tons Sold (in thousands)	2,800	2,700	700	-	20,000
Revenue/Ton	$ 35.99	$ 36.71	$ 41.90	$ -	$ 34.40
Total Revenue	$ 99,062	$ 99,712	$ 28,255	$ -	$ 685,385
Expenses					
Labor, Material Fuel	$ 53,086	$ 55,959	$ 13,824	$ -	$ 366,529
Royalties & Production Taxes	$ 3,525	$ 3,402	$ 623	$ -	$ 26,368
Other Expenses	$ 38,913	$ 27,792	$ 15,638	$ 10,072	$ 256,714
Income Taxes	$ (425)	$ (1,507)	$ 220	$ 1,209	$ (4,293)
Net Income	**$ 3,113**	**$ 11,052**	**$ (1,610)**	**$ (8,863)**	**$ 31,481**
EBITDA	**$ 15,649**	**$ 23,890**	**$ 4,108**	**$ (752)**	**$ 139,681**
Capital Expenditures	$ (1,165)	$ (1,105)	$ (1,016)	$ -	$ (30,925)
Investing Activities	$ 12,156	$ 1,761	$ 19,363	$ 8,918	$ 58,118
Financing Activities	$ (3,682)	$ (3,580)	$ (2,211)	$ (2,684)	$ (35,607)
Mine Closing	$ (119)	$ (123)	$ (13,070)	$ (9,246)	$ (38,583)
Income Taxes	$ (425)	$ (1,507)	$ 220	$ 1,209	$ (4,293)
Increase (decrease) in Cash	**$ 22,414**	**$ 19,336**	**$ 7,393**	**$ (2,557)**	**$ 88,391**

Net Present Value (10%)	**$57,624**
Internal Rate of Return	**235.0%**

1.8. Permitting Requirements

The Red Hills Mine operates under the state of Mississippi Surface Coal Mining and Reclamation Permit MS-005, issued by the Mississippi Department of Environmental Quality (MDEQ) under delegated authority of the United States Department of the Interior, Office of Surface Mining Reclamation Enforcement (OSMRE) Surface Mining Control and Reclamation Act (SMCRA). In addition to the mining permit, MLMC has secured 45 other permit and agreements, including a National Pollutant Discharge Elimination System (NPDES) permit and an Individual Permit issued by the United States Army Corp of Engineers (USCOE). All permits have been secured and continue to be renewed in a timely fashion.

MLMC currently has all permits in place for the Red Hills Mine to operate and adhere to a mine plan projected through April 1, 2032. Barring any regulatory changes out of MLMC's control, the QP does not anticipate hurdles for approval of future renewal applications.

1.9. Qualified Person's Conclusions and Recommendations

In the QP's opinion, the geological data, sampling, modeling, and estimate are carried out in a manner that both represents the data well and mitigates the likelihood of material misrepresentations for the statements of Mineral Resources. Additional drilling and sampling should be performed in Mine Area 3 to better define upper seams qualities while expanding and upgrading mineral resources and reserves. Continue representative splits sampling and testing from coal cores samples to be tested by an independent laboratory different from the testing laboratory.

In the QP's opinion, the operational and mine planning data, LOM Plan, and estimation are carried out in a manner that both represents the data and operational experience and methodology well and mitigates the likelihood of material misrepresentations for the statements of Mineral Reserves. Current additional work that is budgeted in the discounted cash flows (DCF) that the Red Hills Mine will complete include:

- Continue with the exploration drilling program;
- Monitor pit pore pressures in future pit area identified of potential concern;
- Continue to evaluate used equipment to reduce capital costs;
- Continue the current practice of reconciliation of actual to budget lignite recoveries, qualities, and costs;
- Update the LOM plan and economic analyses accordingly.

2. Introduction

This Technical Report Summary (TRS) was prepared for the Mississippi Lignite Mining Company (MLMC), a wholly-owned subsidiary of NACCO Natural Resources Corporation (NACCO NR) which is a wholly-owned subsidiary of NACCO Industries, Inc. (NACCO).

The purpose for which this TRS was prepared is to report Mineral Resources and Mineral Reserves for the Red Hill Mine located in Choctaw County, Mississippi.

The sources of information and data contained in the technical report or used in its preparations were supplied by MLMC and include data used to produce geologic models, Annual and Life of Mine (LOM) plans, production data, environmental support documents, independent technical studies, resource and reserve estimates, cost estimates, and economic analyses. A large portion of the technical information is summarized from active Surface Mining Control and Reclamation Act (SMCRA) permits addressing Title 11 of the Miss. Admin. Code Pt.8, Ch-2, Mississippi Commission on Environmental Quality Regulations Governing Surface Coal Mining, hereby known as the mine permit requirements. Additional references to specific studies and documents are provided in Section 24.0 of this TRS.

Benson Chow, Mineral Resource QP, is a Registered Professional Geologist in the state of Mississippi, License Number 0175 and a Registered Member of the Society for Mining, Metallurgy & Exploration (SME), ID 4317057 and is in good standing with both organizations. He has been involved with the exploration, geology, and mining operations at Red Hills Mine since 1999 and his most recent site visit was on May 7 through 13, 2024. The purpose of this visit was to complete a site visit of the active mining area and to oversee the 2024 drilling campaign. During the visits the QP completed the following task:

- Inspected the active pit areas for Mine Area 1 west, middle and east end of the pit.
- Observed the extraction of the D Seam coal using the Wirtgen in Mine Area 1. Visited the boxcut in Mine Area 3. Performed survey verification of several previously drilled exploration drill holes.
- Verified drill hole collar locations and elevations from the 2011, 2015, and 2021 drilling programs.
- Inspected the active pit area for Mine Area 3
- Oversaw the 2024 drilling campaign

Jefferson King, is serving as the Mineral Reserve QP, a licensed Professional Engineer (License Number 18896), and Land Surveyor (License Number 3033) in the State of Mississippi, and Registered Member of the Society for Mining, Metallurgy & Exploration (SME), ID 04195446. He has had direct involvement with production, technical projects, development of the LOM plan and financial analysis since 2013. He has held various roles in the Engineering department at Red Hills and is currently serving as the Engineering Manager. In the role of Engineering Manager, he has direct involvement with daily production operations and oversight and management of technical projects, and is directly involved in the development of the LOM finances at the Red Hills Mine.

Unless otherwise stated, the terms of reference for this TRS include:

- US English spelling;
- Imperial units of measurement;
- Lignite qualities are presented in weight percent (wt%) and lignite tonnages are present in short tons (2000 lbs);
- Coordinate System is presented in imperial units using the North American Datum 1983 (NAD83);
- Nominal US Dollars as of 2024.

This is the third TRS filed to the United States Securities and Exchange Commission (SEC) for MLMC. The previous TRS was dated March 10, 2023 and titled: "SEC S-K 1300 Technical Report Summary, Mississippi Lignite Mining Company – Red Hills Mine, Ackerman, Mississippi."

Key Acronyms and definitions for this TRS include:

AOP	Annual Operating Plan
AR	As-Received Basis
ARO	Asset Retirement Obligation
ASTM	American Society for Testing and Materials
BCY	Bank Cubic Yard
BMPs	Best Management Practices
BOX	Base of Oxidation
BUD	Beneficial (Ash) Use Determination
Cardno GLS	Cardno Geophysical Logging Services
Century GLS	Century Geophysical Logging Services
CGLP	Choctaw Generation Limited Partnership
COC	Chain of Custody
CRIRSCO	Committee for Mineral Reserves International Reporting Standards
DMRs	Discharge Monitoring Reports
DTM	Digital Terrain Model
EIS	Environmental Impact Statement
FoS	Factor of Safety
GEA	Geotechnical Engineering Associates
gpm	Gallons per Minute
GSE	Great Southern Engineering
HDPE	High Density Polyethylene
Lbs	Pounds
LOM	Life of Mine
LSA	Lignite Sales Agreement
M	Million (dollars)
MA1	Mine Area 1
MA3	Mine Area 3
MDA&H	Mississippi Department of Archives and History
MDEQ	Mississippi Department of Environmental Quality
MDOT	Mississippi Department of Transportation
MLMC	The Mississippi Lignite Mining Company
MMbtu	Metric Million British Thermal Units
MS-002 permit	Surface Mining Control and Reclamation Act (SMCRA) permit MS-002, Renewal 3
MS-004 permit	Surface Mining Control and Reclamation Act (SMCRA) permit MS-004
mg/L	Milligrams per Liter
msl	Mean Sea Level
Mt	Million Tons
MSU	Mississippi State University
MS	Mississippi
MVTL	Minnesota Valley Testing Laboratories, Inc.
NACCO	NACCO Industries, Inc.
NACCO NR	NACCO Natural Resources Corporation
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NRCS	Natural Resources Conservation Service

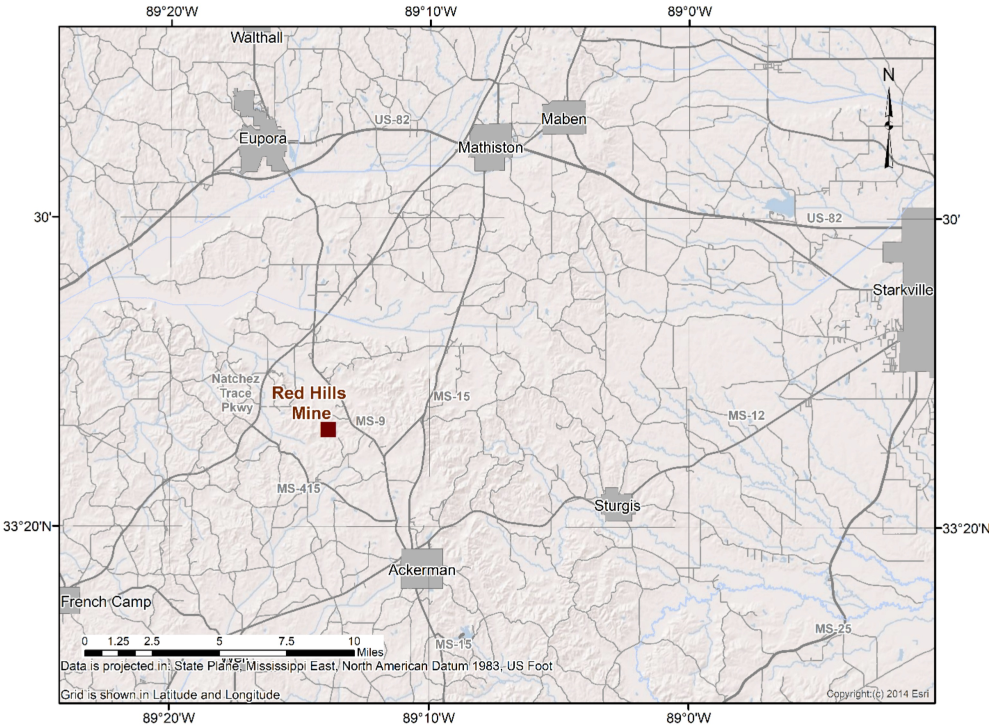
OSMRE	United States Department of the Interior, Office of Surface Mining Reclamation Enforcement
Phillips	Phillips Coal Company
Prox	Proximate
PPA	Power Purchase Agreement
QAR PTP	Proficiency Testing Program by Quality Assurance Resources, LLC
QA/QC	Quality Assurance/Quality Control
QP(s)	Qualified Person(s)
RHPP	Red Hills Power Plant
ROM	Run of Mine
R-O-W	Right of Way
SEC	United States Security and Exchange Commission
SG	Specific Gravity
S-K 1300	SEC's Subpart S-K 1300 (17 CFR Part 229.1300)
SMCRA	Surface Mining Control and Reclamation Act
SPGM	Suitable Plant Growth Material
SPT	Standard Penetration Testing
SWPPP	Storm Water Pollution and Prevention Plan
TDS	Total Dissolved Solids
TRS	Technical Report Summary
TSS	Total Suspended Solids
TVA	the Tennessee Valley Authority
USCOE	United States Corps of Engineers
USCS	Unified Soil Classification System
USGS	United States Geological Survey
WOTUS	Waters of the United States

3. Property Description

3.1. Property Location

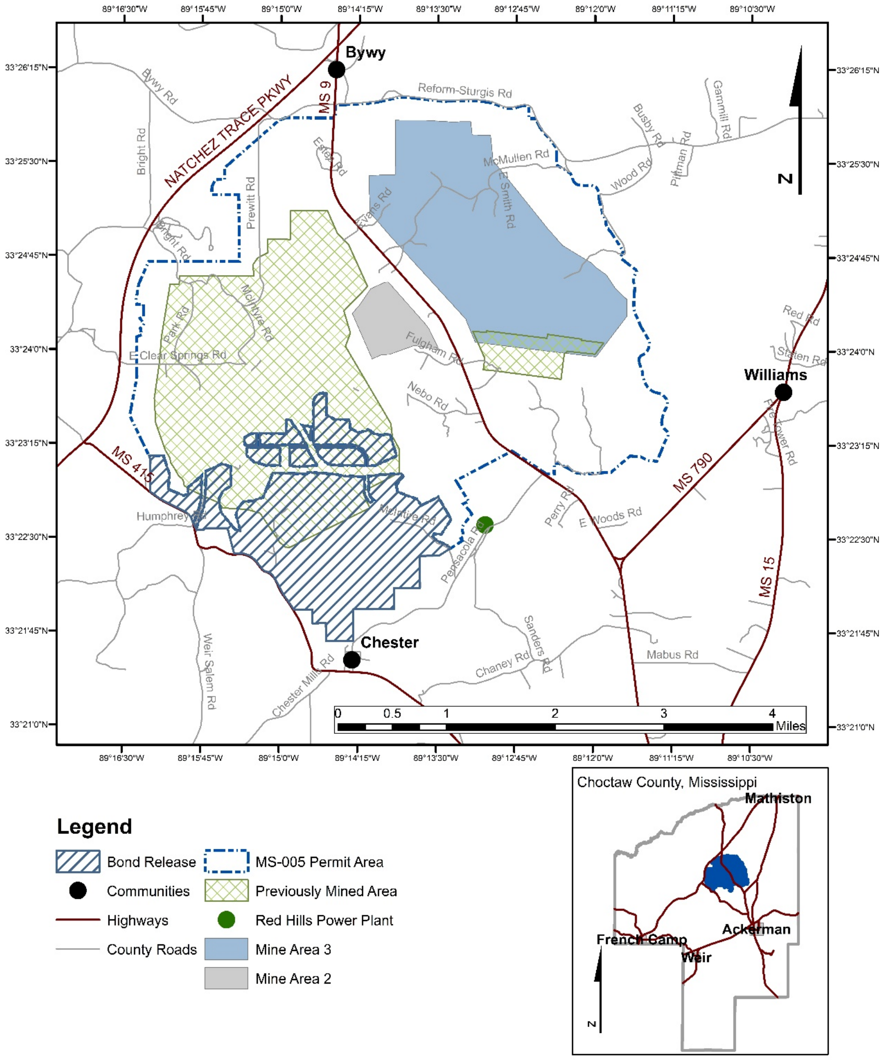
The Red Hills Mine is an operating lignite surface mine located approximately 7 miles northwest of Ackerman, Mississippi, in Choctaw County, which is approximately 120 miles northeast of Jackson, Mississippi (Figure 3.1).

Figure 3.1 Regional Location Map



The entrance to the mine is by means of a paved road that is located approximately 1 mile west of MS Highway 9 and can be found at 33° 22’ 26.3” N and 89° 13’ 23.5” W. The general location of the Red Hills Mine is shown in Figure 3.2. The RHPP is adjacent to the Red Hills Mine.

Figure 3.2 Location of the Red Hills Mine



3.2. Property Area

The Red Hills Mine is encompassed by one permit area, MS-005 as indicated in Figure 3.2. Both mineral resource areas, Mine Area 2 and Mine Area 3, fall within the MS-005 permit area. Mine Area 3 includes Mineral Reserves. Mine Area 2 is a small, permitted auxiliary pit which may be used for tons to supplement the mine plan, but is not currently sequenced in the LOM plan, and as such only includes Mineral Resources, not Mineral Reserves. Mine Area 2 is 202 acres, and Mine Area 3 is 2,060 acres.

MLMC holds leases granting the right to mine approximately 5,423 acres of coal interests and the right to utilize approximately 4,890 acres of surface interests. In addition to leases with independent landowners, MLMC owns in fee approximately 8,090 acres of surface interest and 5,150 acres of coal interest. MLMC holds subleases under which it has the right to mine approximately 1,683 acres of coal interest.

3.3. Leases and Mineral Rights

The name or number and expiration date of each title, claim, mineral right, lease, or option under which MLMC or an affiliated NACCO company has or will have the right to hold or operate on the property is described on Table 3.1 and Table 3.2.

The leases, sub-leases and fee acquisitions were obtained by land acquisition staff employed by Phillips and the Company. Most of the leases held by MLMC have terms extending 50 years and can be further extended by the continuation of mining operations. The surface and mineral leases and associated sub-leases held by MLMC require payments specified by lease agreement to retain the property. Typically, a standard production royalty rate of $0.50 per ton of lignite mined is tied to the leases. Royalties are estimated monthly based on surveyed mined tons and are paid to the landowners on a quarterly basis. In addition to production royalties, payments related to landowner leases may also include surface damage payments and/or advanced royalties.

Table 3.1 Identification of Leases

Lease Id	Lease Type	Lease Date	Lease Expiration Date
955-900002	Coal Lease	12/31/2013	12/30/2038
955-900003	Coal Lease	12/31/2013	12/30/2038
955-900004	Coal Lease	12/31/2013	12/30/2038
955-900005	Coal Lease	12/31/2013	12/30/2038
955-900006	Coal Lease	12/31/2013	12/30/2038
955-900007	Coal Lease	12/31/2013	12/30/2038
955-900008	Coal Lease	12/31/2013	12/30/2038
955-900009	Coal Lease	12/31/2013	12/30/2038
955-900010	Coal Lease	12/31/2013	12/30/2038
955-900011	Coal Lease	12/31/2013	12/30/2038
955-900012	Coal Lease	12/31/2013	12/30/2038
955-900013	Coal Lease	12/31/2013	12/30/2038
955-900014	Coal Lease	12/31/2013	12/30/2038
955-900015	Coal Lease	12/31/2013	12/30/2038
955-900016	Coal Lease	12/31/2013	12/30/2038
955-900017	Coal Lease	12/31/2013	12/30/2038
955-900018	Coal Lease	12/31/2013	12/30/2038

955-900019	Coal Lease	12/31/2013	12/30/2038
955-900023	Coal Lease	7/10/2015	7/9/2040
955-900024	Coal Lease	7/10/2015	7/9/2040
955-900025	Coal Lease	7/10/2015	7/9/2040
955-900026	Coal Lease	7/10/2015	7/9/2040
955-900027	Coal Lease	7/10/2015	7/9/2040
955-900028	Coal Lease	7/10/2015	7/9/2040
955-900029	Coal Lease	7/10/2015	7/9/2040
955-900030	Coal Lease	10/26/2015	10/25/2040
955-900031	Coal Lease	10/26/2015	10/25/2040
955-900032	Coal Lease	5/6/2016	5/5/2041
955-900033	Coal Lease	10/1/2017	9/30/2042
955-900038	Coal Lease	6/1/2019	5/31/2044
955-900042	Coal Lease	8/1/2022	7/31/2047
955-900043	Coal Lease	9/1/2023	8/31/2048
955-900044	Coal Lease	9/1/2023	8/31/2048
955-900045	Coal Lease	5/15/2024	5/14/2049
955-900046	Coal Lease	6/25/2024	6/24/2049
956-929485	Coal Lease	5/9/1975	5/8/2025
956-929508	Coal Lease	5/14/1975	5/13/2025
956-929588	Coal Lease	3/5/1981	3/4/2031
956-929589	Coal Lease	6/16/1975	6/15/2025
956-929597	Coal Lease	6/24/1975	6/23/2025
956-929599	Coal Lease	5/12/1975	5/11/2025
956-929603	Coal Lease	6/26/1975	6/25/2025
956-929646	Coal Lease	6/2/1975	6/1/2025
956-929743	Coal Lease	5/14/1975	5/13/2025
956-929744	Coal Lease	6/11/1975	6/10/2025
956-929745	Coal Lease	6/11/1975	6/10/2025
956-929748	Coal Lease	5/22/1978	5/21/2028
956-929749	Coal Lease	8/7/1975	8/6/2025
956-929750	Coal Lease	8/4/1975	8/3/2025
956-929751	Coal Lease	6/17/1975	6/16/2025
956-929755	Coal Lease	8/7/1975	8/6/2025
956-929757	Coal Lease	8/25/1975	8/24/2025
956-929759	Coal Lease	8/27/1975	8/26/2025
956-929801	Coal Lease	10/24/1974	10/23/2025
956-929802	Exploration Contract & Coal Lease	10/30/1974	10/29/2025
956-929803	Coal Lease	9/4/1975	9/3/2025
956-929835	Exploration Contract & Coal Lease	10/24/1974	10/23/2025
956-929839	Coal Lease	9/15/1975	9/14/2025
956-929841	Coal Lease	9/15/1975	9/14/2025
956-929842	Coal Lease	9/24/1975	9/23/2025

956-929910	Exploration Contract & Coal Lease	10/11/1974	10/10/2025
956-929911	Exploration Contract & Coal Lease	10/28/1974	10/27/2025
956-929955	Coal Lease	9/25/1975	9/24/2025
956-929956	Coal Lease	9/26/1975	9/25/2025
956-929957	Coal Lease	9/20/1975	9/19/2025
956-929958	Coal Lease	10/2/1975	10/1/2025
956-929959	Coal Lease	10/3/1975	10/2/2025
956-930068	Coal Lease	10/13/1975	10/12/2025
956-930187	Coal Lease	10/7/1975	10/6/2025
956-930280	Coal Lease	12/18/1975	12/17/2025
956-930367	Coal Lease	12/16/1975	12/15/2025
956-930413	Coal Lease	2/27/1976	2/26/2026
956-930414	Coal Lease	2/27/1976	2/26/2026
956-930474	Coal Lease	1/26/1976	1/25/2026
956-930480	Coal Lease	2/3/1976	2/2/2026
956-930482	Coal Lease	2/25/1976	2/24/2026
956-930483	Coal Lease	2/19/1976	2/18/2026
956-930488	Coal Lease	3/18/1976	3/17/2026
956-930493	Coal Lease	3/10/1976	3/9/2026
956-930494	Coal Lease	3/17/1976	12/31/2036
956-930495	Coal Lease	3/22/1976	3/21/2026
956-930497	Coal Lease	3/23/1976	3/22/2026
956-930499	Coal Lease	3/18/1976	3/17/2001*
956-930500	Coal Lease	3/8/1976	3/7/2026
956-930501	Coal Lease	3/31/1976	3/30/2026
956-930513	Coal Lease	4/21/1976	4/20/2026
956-930514	Coal Lease	4/21/1976	4/20/2026
956-930515	Coal Lease	4/13/1976	4/12/2026
956-930516	Coal Lease	5/1/1976	4/30/2026
956-930530	Coal Lease	5/4/1976	5/3/2026
956-930593	Coal Lease	3/16/1976	3/15/2026
956-931123	Coal Lease	4/11/1978	4/10/2028
956-931124	Coal Lease	4/11/1978	4/10/2028
956-931250	Coal Lease	8/14/1978	8/13/2028
956-931266	Coal Lease	1/19/1983	1/18/2008*
956-931267	Coal Lease	1/21/1983	1/20/2008*
956-931308	Coal Lease	6/25/1980	6/24/2030
956-931314	Coal Lease	7/31/1980	7/30/2030
956-931316	Coal Lease	8/12/1980	8/11/2030
956-931317	Coal Lease	9/11/1980	9/10/2030
956-931318	Coal Lease	9/18/1980	9/17/2030
956-931323	Coal Lease	10/8/1980	10/7/2030
956-931395	Coal Lease	7/29/1981	7/28/2031

956-931396	Coal Lease	8/24/1981	8/23/2031
956-931397	Coal Lease	8/24/1981	8/23/2031
956-931398	Coal Lease	2/10/1982	2/9/2032
956-931409	Coal Lease	7/31/1981	7/30/2031
956-931484	Coal Lease	5/10/1982	5/9/2032
956-931485	Coal Lease	5/10/1982	5/9/2032
956-931524	Coal Lease	10/8/1982	10/7/2032
956-931537	Coal Lease	12/13/1982	12/12/2032
956-931579	Coal Lease	5/2/1983	5/1/2008*
956-931677	Coal Lease	5/17/2000	5/16/2050
956-931705	Coal Lease	7/16/2001	7/15/2026
956-931706	Coal Lease	10/6/2005	10/5/2030
956-931708	Coal Excavation Lease	12/10/2007	12/9/2047
956-931709	Coal Lease	3/22/2010	3/21/2035
956-931710	Coal Lease	5/25/2011	5/24/2061
956-931711	Coal Lease	12/20/2012	12/19/2062
956-931712	Coal Lease	12/17/2012	12/16/2062
956-931713	Coal Lease	12/20/2012	12/19/2062
956-931714	Coal Lease	9/11/2013	9/10/2063
956-931716	Coal Lease	12/20/2013	12/19/2063
956-931718	Lignite Mining Lease	9/25/2013	9/24/2063
956-931719	Coal Lease	12/20/2013	12/19/2063
956-931723	Coal Lease	4/19/2016	4/18/2066
956-931724	Coal Lease	9/9/2016	9/8/2066
956-931728	Coal & Lignite Lease Agreement	11/14/2017	11/13/2047
956-931729	Coal Lease	11/16/2017	11/15/2067
956-931730	Lignite Mining Lease	12/18/2017	12/17/2067
956-931734	Coal Lease	9/28/2018	9/27/2043
956-931735	Coal Lease	1/23/2019	1/22/2044
956-931737	Coal Lease	3/13/2019	3/12/2069
956-931738	Coal Strip Mining Lease	10/25/2019	10/24/2034
956-931741	Protective Lease		
956-931742	Coal Lease	1/31/2021	1/30/2071
956-931743	Coal Lease	6/25/2021	6/24/2071
956-931746	Coal Lease	10/20/2023	10/19/2073

*Lease continued past expiration by annual payment.

Table 3.2 Identification of Acquisitions

Agreement Id	Agreement Type	Agreement Date	Agreement Expiration Date
957-MLC001	Warranty Deed	8/19/1998	8/18/2097
957-MLC002	Coal Warranty Deed	10/1/1997	12/31/2099
957-MLC003	Warranty Deed	9/17/1998	9/16/2097
957-MLC004	Warranty Deed	12/22/2000	12/21/2999
957-MLC005	Warranty Deed	9/20/2001	9/19/2100
957-MLC006	Warranty Deed	10/12/1998	12/31/2099
957-MLC007	Warranty Deed	10/1/2001	9/30/2100
957-MLC008	Warranty Deed	1/22/2002	1/21/2101
957-MLC009	Warranty Deed	1/22/2002	1/21/2101
957-MLC010	Warranty Deed	10/29/1996	10/28/2096
957-MLC011	Warranty Deed	6/1/1999	6/1/2099
957-MLC012	Warranty Deed	1/5/1999	1/5/2098
957-MLC013	Coal and Lignite Deed	7/8/2005	7/7/2104
957-MLC014	Special Warranty Deed	4/2/1998	4/1/2097
957-MLC015	Special Warranty Deed	8/11/1998	8/10/2097
957-MLC016	Warranty Deed	9/5/1998	12/31/2099
957-MLC017	Warranty Deed	1/24/2000	1/24/2099
957-MLC018	Warranty Deed	8/19/1998	8/19/2097
957-MLC019	Warranty Deed	1/24/2000	1/23/2099
957-MLC020	Warranty Deed	8/17/1998	8/16/2098
957-MLC021	Warranty Deed	6/30/1998	6/29/2097
957-MLC022	Warranty Deed	3/11/1998	3/10/2098
957-MLC023	Warranty Deed	2/25/2003	2/24/2102
957-MLC024	Warranty Deed	11/10/1998	11/9/2097
957-MLC025	Warranty Deed	11/24/1998	11/23/2097
957-MLC026	Warranty Deed	5/14/1999	5/13/2098
957-MLC027	Warranty Deed	4/8/1999	4/7/2098
957-MLC028	Warranty Deed	4/22/1999	4/22/2999
957-MLC029	Warranty Deed	7/7/1999	7/6/2098
957-MLC030	Warranty Deed	5/2/2003	5/1/2102
957-MLC031	Warranty Deed	5/5/2003	5/4/2102
957-MLC032	Warranty Deed	5/2/2003	5/1/2102
957-MLC033	Warranty Deed	7/8/2003	7/7/2102
957-MLC034	Warranty Deed	3/17/2004	12/31/2099
957-MLC035	Warranty Deed	7/16/2004	7/15/2103
957-MLC036	Warranty Deed	11/15/2004	12/31/2999
957-MLC037	Warranty Deed	2/18/2005	12/31/2999
957-MLC038	Warranty Deed	2/23/2005	2/22/2104
957-MLC039	Warranty Deed	4/8/2005	4/7/2104
957-MLC040	Warranty Deed	2/28/2006	2/27/2105

957-MLC041	Warranty Deed	6/28/2007	6/28/2106
957-MLC042	Warranty Deed	7/26/2006	7/25/2105
957-MLC043	Warranty Deed	10/28/2006	10/27/2105
957-MLC044	Warranty Deed	10/28/2006	10/27/2105
957-MLC045	Warranty Deed	10/27/2006	10/26/2105
957-MLC046	Warranty Deed	8/1/2007	7/31/2106
957-MLC047	Warranty Deed	11/20/2007	11/19/2106
957-MLC048	Special Warranty Deed	11/7/2007	11/6/2106
957-MLC049	Warranty Deed	11/26/2007	11/25/2106
957-MLC050	Warranty Deed	6/13/2008	12/31/2099
957-MLC051	Warranty Deed	9/4/2008	12/31/2099
957-MLC052	Warranty Deed	4/23/2009	12/31/2999
957-MLC053	Warranty Deed	12/21/2010	12/31/2999
957-MLC054	Warranty Deed	5/25/2011	12/31/2999
957-MLC055	Special Warranty Deed	6/27/2011	12/31/2999
957-MLC056	Special Warranty Deed	7/3/2011	12/31/2999
957-MLC057	Special Warranty Deed	7/8/2011	12/31/2999
957-MLC058	Warranty Deed	10/13/2011	12/31/2999
957-MLC059	Warranty Deed	10/13/2011	12/31/2999
957-MLC060	Warranty Deed	12/30/2011	12/31/2999
957-MLC061	Warranty Deed	7/17/2012	12/31/2099
957-MLC062	Warranty Deed	7/13/2012	12/31/2099
957-MLC063	Warranty Deed	7/13/2012	12/31/2099
957-MLC064	Warranty Deed	9/20/2012	12/31/2099
957-MLC065	Warranty Deed	12/6/2012	12/31/2999
957-MLC066	Warranty Deed	12/6/2012	12/31/2099
957-MLC067	Warranty Deed	12/3/2012	12/31/2099
957-MLC068	Warranty Deed	4/3/2013	12/31/2099
957-MLC069	Warranty Deed	12/20/2012	12/31/2099
957-MLC070	Warranty Deed	12/17/2012	12/31/2099
957-MLC071	Warranty Deed	12/14/2012	12/31/2099
957-MLC072	Warranty Deed	12/14/2012	12/31/2099
957-MLC073	Warranty Deed	12/20/2012	12/31/2099
957-MLC074	Warranty Deed	12/20/2012	12/31/2099
957-MLC075	Warranty Deed	10/5/2012	12/31/2099
957-MLC076	Warranty Deed	4/3/2013	12/31/2099
957-MLC077	Warranty Deed	5/3/2013	12/31/2099
957-MLC078	Warranty Deed	6/13/2013	12/31/2999
957-MLC079	Warranty Deed	6/14/2013	12/31/2099
957-MLC080	Warranty Deed	9/11/2013	12/31/2099
957-MLC081	Special Warranty Deed	12/31/2013	12/31/2999
957-MLC082	Special Warranty Deed	12/31/2013	12/31/2099
957-MLC084	Warranty Deed	12/20/2013	12/31/2099

957-MLC085	Quit Claim Deed	7/10/2015	12/31/2099
957-MLC086	Quit Claim Deed	7/10/2015	12/31/2999
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957-MLC092	Quit Claim Deed	7/10/2015	12/31/2099
957-MLC094	Quit Claim Deed	7/10/2015	12/31/2099
957-MLC095	Quit Claim Deed	7/10/2015	12/31/2099
957-MLC096	Quit Claim Deed	10/26/2015	12/31/2099
957-MLC097	Quit Claim Deed	10/26/2015	12/31/2099
957-MLC098	Quit Claim Deed	10/26/2015	12/31/2099
957-MLC099	Quit Claim Deed	5/6/2016	12/31/2099
957-MLC100	Quit Claim Deed	9/1/2016	12/31/2099
957-MLC101	Quit Claim Deed	9/1/2016	12/31/2099
957-MLC102	Quit Claim Deed	9/1/2016	12/31/2099
957-MLC103	Quit Claim Deed	6/1/2017	12/31/2099
957-MLC105	Quit Claim Deed	5/15/2024	12/31/2099
957-MLC109	Quit Claim Deed	10/1/2017	12/31/2099
957-MLC111	Quit Claim Deed	6/1/2019	12/31/2099
957-MLC112	Quit Claim Deed	4/1/2020	12/31/2099
957-MLC121	Quit Claim Deed	8/1/2022	12/31/2099
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609-RML064	Warranty Deed	12/31/2013	12/31/2099
609-RML065	Warranty Deed	12/31/2013	12/31/2999
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609-RML067	Warranty Deed	12/31/2013	12/31/2099
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609-RML076	Warranty Deed	12/31/2013	12/31/2099
609-RML077	Warranty Deed	12/31/2013	12/31/2099
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609-RML080	Warranty Deed	12/31/2013	12/31/2099
609-RML081	Special Warranty Deed	9/10/2013	12/31/2999
609-RML082	Warranty Deed	9/10/2013	12/31/2099
609-RML084	Warranty Deed	7/10/2015	12/31/2099
609-RML085	Warranty Deed	12/20/2013	12/31/2099
609-RML086	Warranty Deed	12/20/2013	12/31/2999
609-RML087	Warranty Deed	12/20/2013	12/31/2099
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609-RML091	Warranty Deed	2/21/2014	12/31/2099
609-RML092	Warranty Deed	7/21/2014	12/31/2099
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609-RML097	Warranty Deed	6/25/2015	12/31/2099
609-RML098	Warranty Deed	6/25/2015	12/31/2099
609-RML099	Warranty Deed	8/12/2015	12/31/2099
609-RML100	Warranty Deed	4/8/2016	12/31/2099
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609-RML102	Warranty Deed	5/8/2016	12/31/2099
609-RML103	Warranty Deed	9/9/2016	12/31/2099
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609-RML125	Warranty Deed	1/11/2021	12/31/2099

609-RML126	Warranty Deed	6/15/2021	12/31/2099
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609-RML128	Warranty Deed	11/18/2021	12/31/2099
609-RML129	Warranty Deed	12/23/2021	12/31/2099
609-RML130	Warranty Deed	02/07/20222	12/31/2099
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609-RML171	Warranty Deed	10/31/2023	12/31/2099
609-RML172	Warranty Deed	12/26/2023	12/31/2099
609-RML173	Warranty Deed	3/14/2024	12/31/2099

3.4. Significant Encumbrances to the Property

The Red Hills Mine currently has no significant encumbrances to the property. No mining permit violations have been issued at the Red Hills Mine in the past ten years. One NOV was issued in April 2020 for a water quality exceedance that was determined to not be the fault of Red Hills Mine and no further action was required. A second NOV was issued in June, 2022 for a water sampling violation. Both NOVs were not related to the mining permit. Permitting requirements are discussed in Section 17.0 of this TRS.

3.5. Significant Factors and Risks

MLMC has not identified any significant risks that may affect the right or ability to perform work on the property. However, if a lease were to expire and MLMC had not yet noticed this property for disturbance by mining activities, the landowner may choose not to release this property for mining.

3.6. Registrant Royalties and Interests

Discussed in Section 3.3 of this TRS.

4. Accessibility, Climate, Local Resources, Infrastructure, and Physiography

4.1. Physiography, Topography and Vegetation

The Red Hills Mine, located in Choctaw County, Mississippi, is part of the "red hills phase" of the North Central Hills physiographic province. The region is characterized by dissected upland hills and relatively wide flats in the major stream drainages. The maximum relief of the Red Hills Mine is approximately 280 feet (msl), with the elevation ranging from 360 feet (msl) in the Big Bywy drainage in the north to nearly 640 feet (msl) in the Tertiary upland ridge tops in the southeastern area of the Red Hills Mine.

The Soil Survey of Choctaw County indicate the land-use of the county is approximately 73-percent commercial forestland. Vegetative baseline studies of the permitted areas further indicate the prominent vegetation of the Red Hills Mine to be forested pine plantations along with managed pine habitats which include prepared clearcuts and areas with young, planted pine. Other vegetative designations include deciduous forest, grassland, cropland, and residential lawns.

4.2. Accessibility

Local access to the Red Hills Mine is by way of Highway 9 between Ackerman, Mississippi and Eupora, Mississippi which connects to Pensacola Road that leads to the Red Hills Mine paved access road. Pensacola Road connects with Highway 9 approximately 5 miles north of Ackerman, MS. The mine road is approximately 1 mile west from Highway 9 along Pensacola Road.

Travel to the Red Hills Mine by air is possible using the Jackson-Medgar Wiley Evers International Airport in Jackson, Mississippi, approximately 104 miles south of the mine, and then using ground transportation, traveling via Highway 25, Highway 15, and Highway 9. Alternatively, the Golden Triangle Regional Airport is a smaller airport approximately 50 miles from the Red Hills Mine by means of Highway 82 west, Highway 15 south, and Highway 9 north.

The Red Hills Mine is in close proximately to river ports of the Tennessee-Tombigbee Waterway and the Mississippi River. The Lowndes County Port is approximately 60 miles east of the mine. The Port of Greenville is approximately 135 miles west of the mine, and the Port of Vicksburg, approximately 150 miles southwest of the mine. All ports are connected by major state and federal highways.

In additional to transportation via roadways, air and waterways, the Kansas City Southern (KCS) railroad has a depot located approximately 5 miles south of the mine in Ackerman and is accessible by Highway 9 and Highway 15.

4.3. Climate

The climate of the Red Hills Mine varies seasonally with a warm, humid summer and a generally mild, humid winter. The Red Hills Mine operates through all seasons. Heavy precipitation events may temporarily slow production. Nearby Ackerman, Mississippi has the following climate (Climate in Ackerman, Mississippi, 2024):

- 56 inches of rain annually, on average
- One inch of snow per year
- 96 days per year with some sort of precipitation
- 217 sunny days per year
- Temperatures: July High: 90°F; January Low: 31°F

4.4. Local Resources and Infrastructure

The towns of Ackerman, Eupora, Starkville, Louisville, Kosciusko, and numerous smaller communities are within a 40-mile radius of the Red Hills Mine and provide a vast employment base. Furthermore, Mississippi State University (MSU) is located approximately 30 miles east of the mine in Starkville. MLMC has a history of partnership with MSU as well as the local community colleges for science, technology, engineering, and mathematics (STEM) research and skilled trades training.

The Red Hills Mine sources power for mine office facilities and operations from 4-County Electric Power Association, and water for the mine office facilities from the Reform Water Association. Fuel for equipment is supplied by a local vendor. Most supplies to operate the mine are within the region. The Red Hills Mine has, or is currently constructing, all supporting infrastructure for mining operations through the LOM plan. See Section 15.0 of the TRS for further detail pertaining to the mine specific infrastructure.

5. History of the Property

The Red Hills Mine began operations in the MS-002 permit area in Mine Area 1 and is currently mining in Mine Area 3 within the MS-005 permit area. Initial development of the Red Hills Mine began in 1998, with full production and commercial deliveries commencing in 2002. Boxcut construction for Mine Area 3 began in 2021 where mining will continue through April 2032. The Red Hills Mine has, or is currently constructing, all supporting infrastructure for mining operations within the permitted areas.

Excluding the partial year of 2001 and 2024 (due to plant issues), the average tons sold from 2002-2024 was 3.1 million tons/year. Table 5.1 shows the historical production for Red Hills Mine.

Table 5.1 Historical Production

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Tons Sold (000 ton)	500	2,900	3,700	3,600	3,600	3,600	3,400	3,000	3,700	3,600	2,700	3,100

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Tons Sold (000 ton)	3,200	2,600	3,200	3,000	2,400	3,000	2,600	2,500	3,000	3,200	2,900	1,900

5.1. Previous Operations

There are no previous mining operations on the Red Hills Mine property.

5.2. Exploration and Development History Prior to MLMC

Original exploration of the Red Hills Mine area was conducted by Phillips from 1975 to 1980. Phillips contracted independent drilling services to drill and geophysically log over 800 boreholes. The data collected from the Phillips' drilling exploration was the basis of the Red Hills Project, which included the Red Hills Mine and the RHPP.

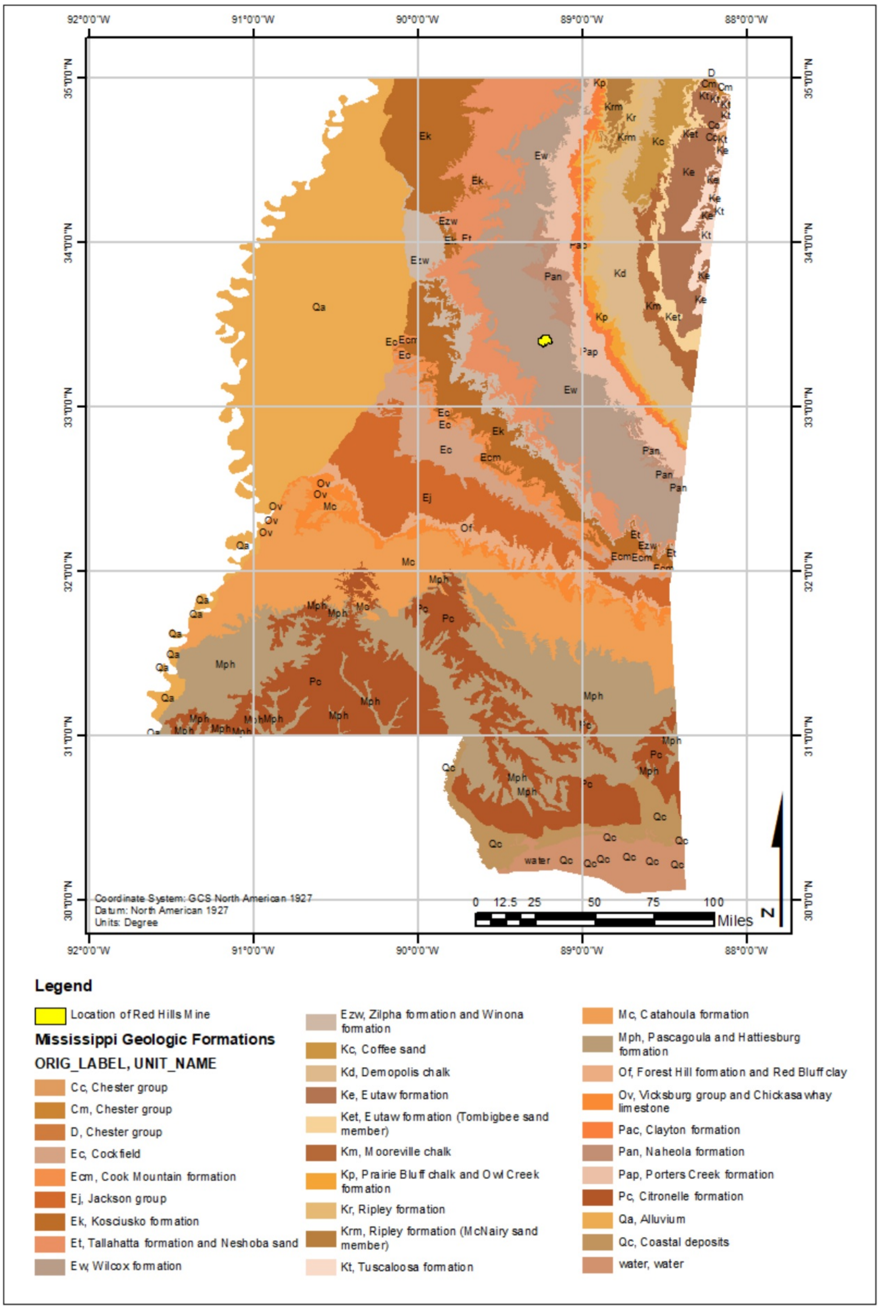
6. Geological Setting, Mineralization and Deposit

6.1. Geology

6.1.1. Regional Geology

The Red Hills Mine is in the Wilcox Group of Mississippi (Figure 6.1) which is the most prolific lignite-bearing stratum in the state of Mississippi. The Wilcox Group and underlying Midway Group were deposited during Paleogene time; 66 to 23 million years ago. The most prominent characteristics of the Wilcox Group formations are the cyclical deposition and lateral persistence of the lithologic units, especially the lignite seams. The stratigraphy of the Wilcox Group is depicted on Figure 6.2. The section from the Gravel Creek Member through the Tuscahoma Formation represents a transition from a transgressive sequence of valley fill, marginal marine strata (lower Gravel Creek) to predominantly regressive, nonmarine, deltaic strata (upper Gravel Creek through the Tuscahoma).

Figure 6.1 Geologic Formations of Mississippi (Dicken, Nicholson, Horton, Foose, & Mueller, 2005)



During each depositional geologic sequence, organic material was repeatedly buried by sediment in an ideal, oxygen-free environment. This ideal environment was attributed to the humid, subtropical conditions and high water-table of wetlands present during Paleogene time which prevented plant matter from decaying prior to burial. The oxygen-free environment combined with heat and pressure from continual deposition of overlying sediments allowed for the formation of peat and further mineralization of lignite over time by undergoing a process known as humification and biochemical gelification.

The regional structural geology is fairly consistent. The regional strike is northwest-southeast. The strata are nearly flat lying, dipping to the southwest at only 25 to 35 feet per mile. No evidence of any significant faulting has been observed in the region.

6.1.2. Local and Property Geology

The average thickness of the Wilcox section containing the mineable lignite seams at the Red Hills Mine and surrounding area is approximately 140 feet (Figure 6.2). Vertical repetition of the geological characteristics results in a straightforward depositional setting facilitating comprehensive analysis of the geological, as well as the geochemical, geotechnical, and geohydrological baseline conditions of the Red Hills Mine.

Following the regional geology, trends in lignite seam sulfur content at the Red Hills Mine support a geologic transition from marine to nonmarine environments. Increased sulfur values are generally associated with marine influences. The C-seam marks a transition from higher sulfur below to lower sulfur contents above.

The local structural geology for the Red Hills Mine also follows the regional structure with a northwest-southeast strike dipping to the southwest. The lignite seams are gently undulating due to differential compaction of the underlying sediments. Small, localized faults have been encountered within the lignite seams while mining through Mine Area 1, and are anticipated to be encountered in Mine Area 3. These faults have been discontinuous and the seam displacement has typically been less than 10 feet. The faults have not materially affected mining or production at the Red Hills Mine.

Since mining began, no unique or especially significant geological features, formations, or paleontological resources have been identified at the Red Hills Mine. No known workings of active, inactive, or abandoned underground mines have been identified. Additionally, no fatal flaws related to geological conditions have been identified.

6.2. Mineral Deposit Type

The Red Hills Mine is solely focused on mining lignite from the project area. Details on the geological units encountered at the Red Hills Mine are described below and shown in Figure 6.1:

6.2.1. Gravel Creek Member

The top of the Gravel Creek Member of the Nanafalia Formation (Wilcox Group) lies just below the C-seam and includes a thin sand layer directly beneath the C-seam. The C-seam is currently the lowest lignite seam stratigraphically mined. However, upon further exploration, the B-seam may be mined in the future, particularly in areas with low laying terrain within Mine Area 3.

A basal sand unit, of up to 100 feet in thickness or more, characterizes the Gravel Creek Member. From the limited drill hole data that extends through this member, it appears that these sand units can be fairly widespread, but also may be completely absent. On the geophysical logs and limited cuttings data, the sand unit typically appears to be fairly massive and poorly- to well-sorted, fine- to medium-grained sand. These sand units, along with the sands in the underlying Coal Bluff Formation (Midway Group) are often referred to as the Lower Wilcox aquifer.

Above this basal sand are interbedded silt, clay, sand and lignite (A-seam). Due to the relative depth, anticipated lower quality, and closer proximity to the basal sands, the A-seam is not currently considered a resource targeted for mining.

6.2.2. Grampian Hills Member

Five of the six lignite seams recovered at Red Hills Mine are contained in the Grampian Hills Member of the Nanafalia Formation (Wilcox Group). The formation conformably overlies the Gravel Creek Member and consists of interbedded and interlaminated clays, silts, sands, and lignite. Overall, the section is relatively sand poor.

The clays and silts are typically finely interlaminated. Munsell color varies from dark gray (N 4/ to N 5/) to greenish gray (10BG 5/1). Immediately below the lignite seams, the color is dark grayish brown (10YR 4/2) due to the presence of carbonaceous fragments. These carbonaceous layers often contain lignitized plant roots establishing an autochthonous origin for the peats that formed the lignite seams.

The sands are light gray (2.5Y 7/1) to gray (N 5/) or greenish gray (5GY 5/1). The pale greenish-gray color of many of the sands and silts is a distinctive feature of this unit. Typically, the sands are very-fine-grained, and commonly interbedded with silts and clays. One exception is the tabular sand bed between the D-seam and C-seam. The sand units between the D-seam and G-seam are typically silty, infrequent, lenticular, and probably represent narrow sand channels in the crevasse splay sequences that were penecontemporaneous with peat accumulation. Sand and silty sands compact much less than silts and clays. This phenomenon is probably the chief cause of the gentle structural undulations found in the lignite seams.

Cemented horizons, commonly referred to as “hard streaks”, are also associated with the sand units. These indurated zones are most abundant within the sand channels and the silty, sandy natural levee deposits flanking the channels. The thickness of these hard streaks ranges from less than one foot to about two feet. These zones are cemented with calcite, silica, iron oxide, or siderite, and are suggestive of periods of sub-areal oxidizing conditions during deposition. Modern analogies in the natural levee deposits of the Mississippi Delta have been noted.

The color of the lignite seams ranges from black (N 2.5/) to very dark gray (10Y 3/1). Occasional layers of carbonaceous clay or zones of clay clasts increase the ash content of the lignite. The minimum thickness for recovery is one foot. The maximum thickness of the lignite seams is about eight feet.

6.2.3. Tuscahoma Formation

The Tuscahoma Formation (Wilcox Group) conformably overlies the Grampian Hills Member of the Nanafalia Formation. The basal portion of this formation is the uppermost stratum to be disturbed by mining. The base of the Tuscahoma is marked by a predominantly sandy, often coarse-grained unit with a variable thickness of 10 feet to 110 feet. The variability is due to the occurrence of contemporaneously bedded clay, silt, and lignite. Laterally, these sands grade into finer grained overbank deposits including lignite seams. The overbank facies of the Tuscahoma are essentially identical to the descriptions for the Grampian Hills Member described above.

The H-seam, which is the uppermost seam that will be consistently recovered, lies at the base of the Tuscahoma. Because of its relatively high stratigraphic position, the H-seam is restricted to the upland areas above approximately 450 feet in elevation within the Red Hills Mine. Other lignite seams lying above the H-seam, including the H2-seam and the I-seam, may be encountered on occasion and are mined when seam thickness and quality are sufficient.

6.3. Stratigraphic Column

A typical stratigraphic column is shown on Figure 6.2 while a planer view of two cross sections is included on Figure 6.3. Geologic cross section E-W2 and geologic cross section C-C' are included as Figure 6.4 and Figure 6.5, respectively. The cross-sections were constructed primarily based on the drill hole geophysical logs supplemented with lithology descriptions from the drill cuttings, as well as the data from the core holes. The stratigraphic framework of the geologic cross sections follows the detailed surface mapping and subsurface investigations completed by the MDEQ, Office of Geology.

Figure 6.2 Stratigraphic Column of the Red Hills Mine

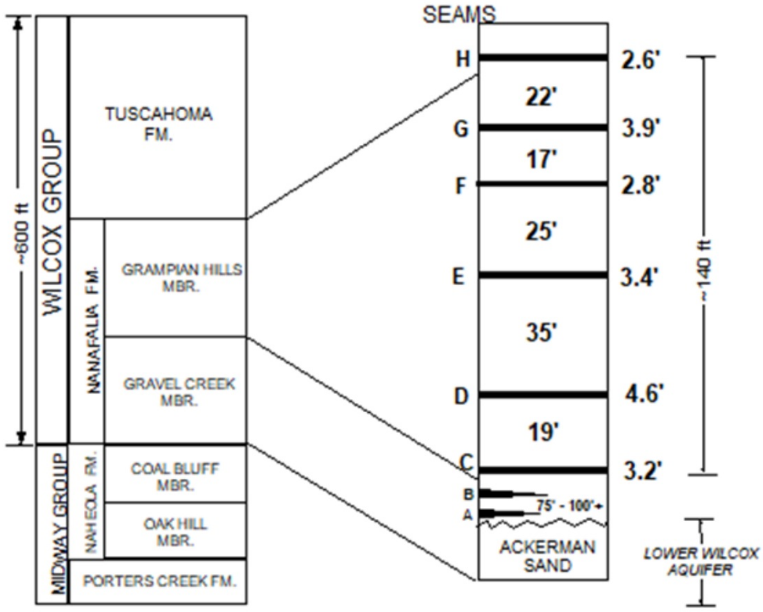


Figure 6.3 Geologic Cross Sections planer reference

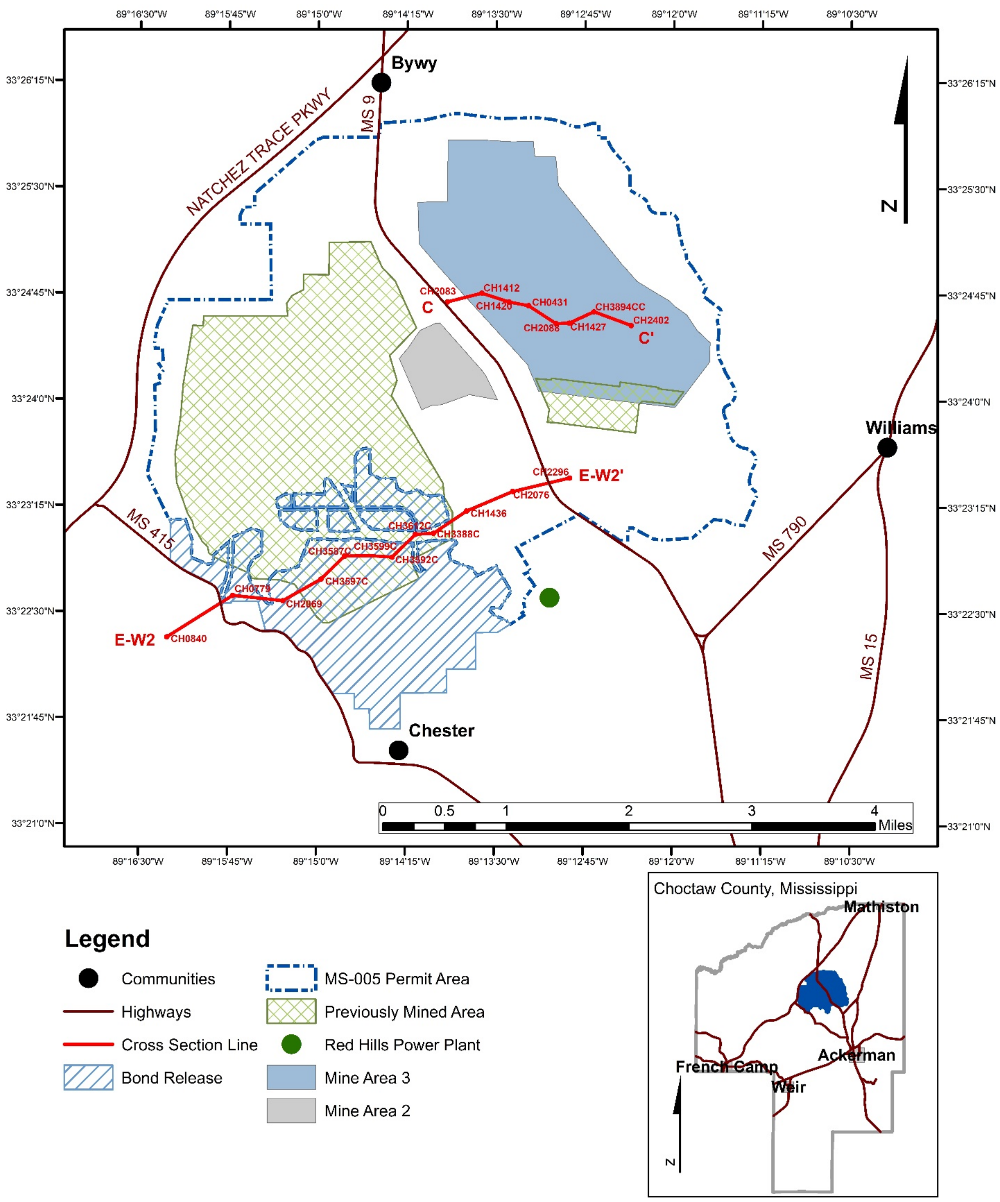


Figure 6.4 Geologic Cross Section E-W2 (Excerpted from SMCRA permit MS-005, Appendix 2509-6)

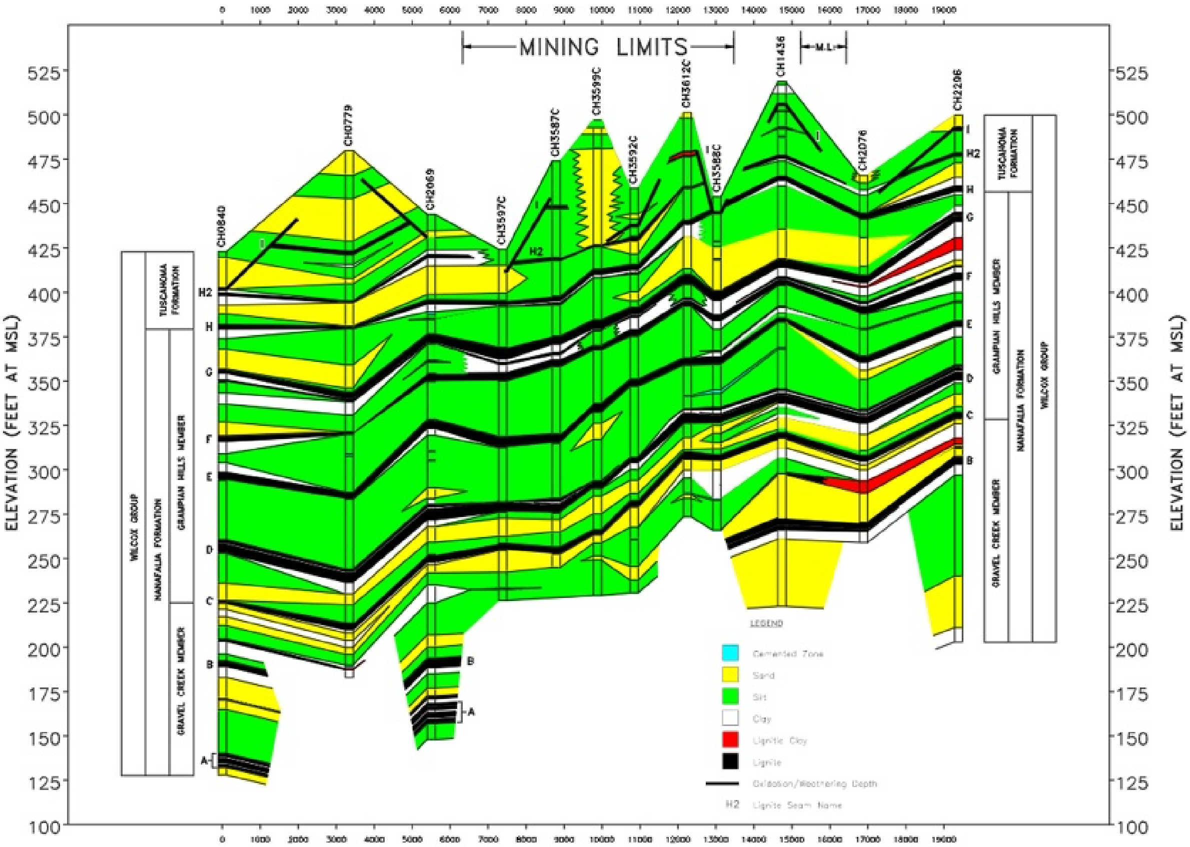
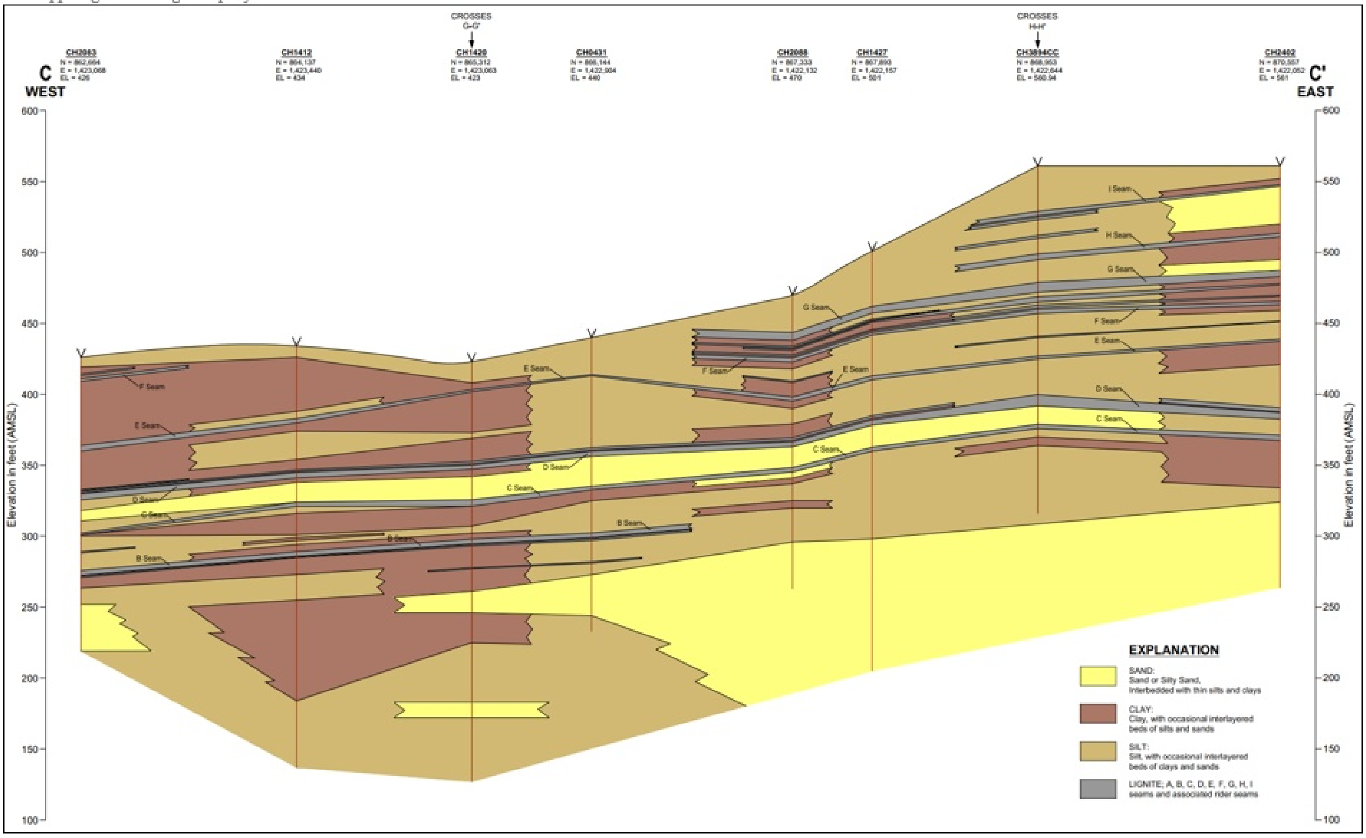


Figure 6.5 Geologic Cross Sections C-C' (Excerpted from SMCRA permit MS-005, Appendix 2509-6)



7. Exploration

7.1. Exploration

No exploration work other than drilling and associated geophysical logging has been conducted at the Red Hills Mine. Geophysical logging is discussed with drilling in Section 7.2 of this TRS.

7.2. Drilling Exploration

Data collected during drilling exploration programs at the Red Hills Mine is the sole information available for modeling the lignite deposit for the determination of Mineral Resources. Coal core drilling following the U.S. Geological Survey's (USGS) guidance for sampling coal for chemical analysis is the exclusive method used by Red Hills Mine for modeling quality of the lignite deposit. The Red Hills Mine lignite deposit is evaluated on a seam by seam basis. Drilling exploration data including geologic lithologies, qualities, and hole locations have been compiled electronically in Excel files. Cross sections produced from drill hole data are shown in Section 6.3 of this TRS. The information below summarizes the various drilling programs.

7.2.1. Drilling Type and Extent

Drilling exploration programs conducted at the Red Hills Mine have comprised largely of rotary wash drilling methods. Historically, MLMC has contracted independent drilling services and geophysical logging services to operate under the guidance and direction of MLMC. Drill holes completed at the Red Hills Mine are vertical in orientation and have been broken into four categories which are described below. A drill hole location map for the Red Hills Mine is presented in Figure 7.1.

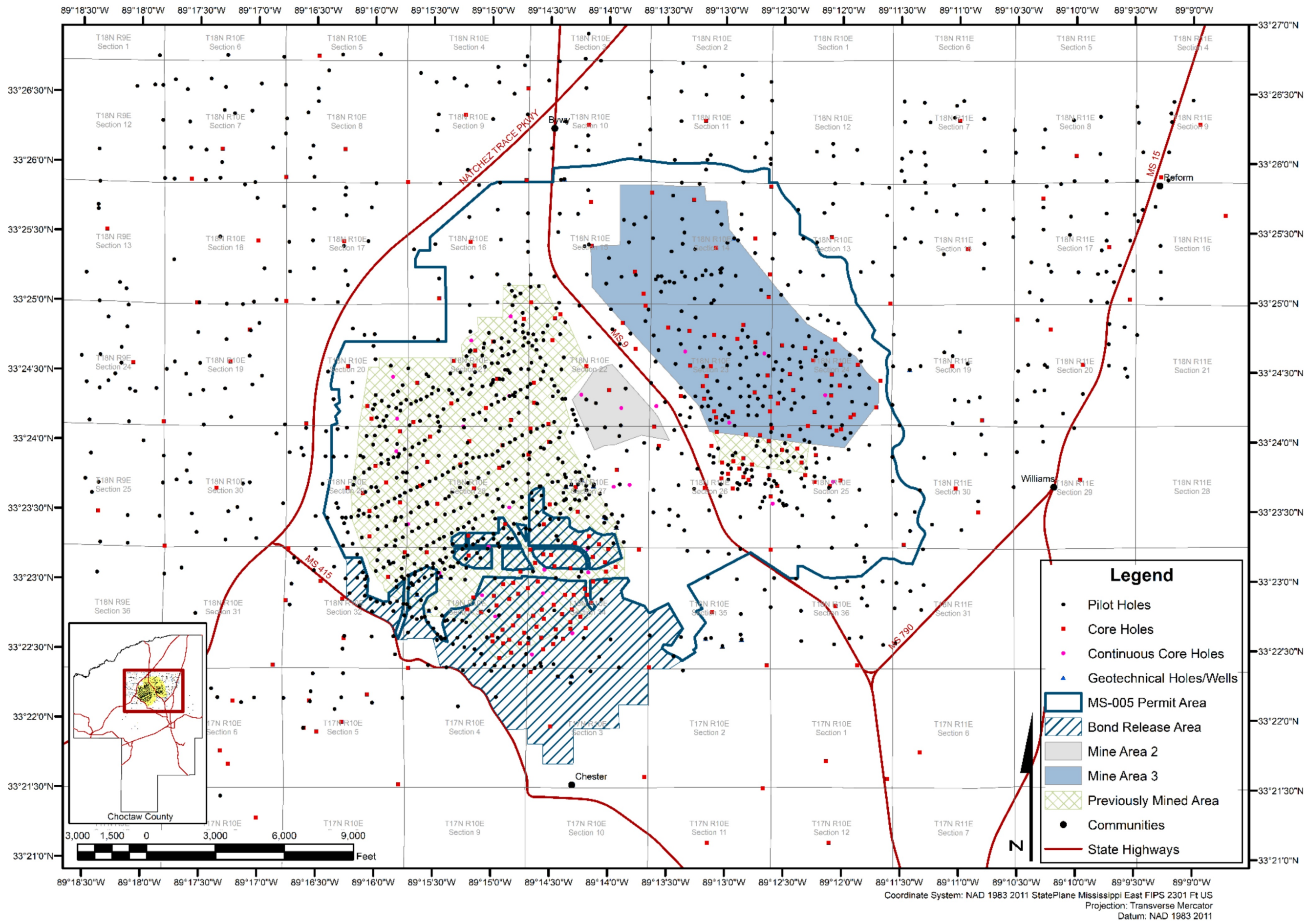
Exploratory drill holes, also referred to as pilot holes, typically range in size from 4.0 to 4.5-inches outer hole diameter (od) and terminate at a minimum of 10-feet below the lowest targeted lignite seam as specified by the geologist. Drill hole cuttings are typically recovered by the driller, in accordance with established drilling and sampling protocols, on a 5 or 10-foot interval and are described by the geologist. All pilot holes are geophysically logged by an independent geophysical logging contractor for natural gamma, density, caliper, and resistivity responses. Related drilling data has been reviewed by the QP for inclusion in the geologic model.

Coal core holes to collect samples for quality testing are advanced next to pilot holes at specified locations in accordance with protocols described herein. Core holes are typically 6.5-inches (od) or 4.25-inches (od) with a respective sample diameter of 3-inches (od) or 2.125-inches (od). Samples are collected with a double core barrel or Shelby tube sampler. Coring intervals are determined by the geologist based on the pilot hole's geophysical log and cuttings descriptions. Core holes terminate 10-feet below the lowest targeted lignite seam. Typically, coal cores from the drilling campaigns at the Red Hills Mine are fully recovered. The minimum core recovery accepted is 90-percent (see Section 8 for discussion on sample preparation). Coal core data have been reviewed by the QP for inclusion in the geologic model.

Overburden core holes, or continuous cores, are drilled following protocols similar to the coal cores as described above. Rather than specifying specific intervals to collect coal cores for quality testing, overburden cores are advanced in continuous ten-foot core sections using a double core barrel or Shelby tube sampler from top of hole to bottom of hole such that the geologist can log and sample burdens in addition to lignite. Burden (overburden and interburden) samples are shipped to a separate independent soil laboratory for geochemical analysis. Overburden cores require 75-percent total run recovery for soil analysis, while coal core intervals require a minimum of 90-percent recovery within continuous core runs, such that parameters outlined for coal core collection previously are maintained. Data specific to the coal cores collected during these continuous core sampling programs have been reviewed by the QP for inclusion in the geological model.

The fourth, and final, category of drill holes are comprised of geotechnical holes and monitoring wells which have been geophysically logged and extend through multiple coal seams. These drill holes follow the parameters outlined for pilot holes and available data has been reviewed by the QP.

Figure 7.1 Location of Drill Holes



7.2.2. General Drilling Procedures

Details may vary with each exploration program and are discussed in the next subsection, however general procedures for drilling at Red Hills Mine include:

- Identification of land control; acquire drilling leases for properties not owned or previously leased and noticed.
- Site preparation.
- Rotary wash drilling by an independent drilling contractor; typically, cuttings are collected every 5-feet until a depth of 30-feet is reached then cuttings are collected every 10-feet to final depth.
- Geologist logs description of cuttings including depth, texture, general color.
- Independent contractor geophysically logs drill hole for natural gamma, density, caliper, and resistivity.
- Geologist reviews geophysical log.
- Hole determined complete and abandoned by independent drilling contractor in accordance with state regulatory requirements.
- Survey drill hole collar location.

To continue with a coal core hole:

- Coring intervals are determined by the geologist from pilot hole geophysical log.
- Coal core drilling by an independent drilling contractor.
- Core extracted from barrel by independent drilling contractor and placed in logging tray.
- Geologist cleans core sample of drilling mud, measures the core length and identifies the roof and floor. If an acceptable length of core is not recovered, independent drilling contractor may attempt to retrieve the remaining core from the current hole. If no success, the core run interval will be "re-cored" as an additional core hole. After sufficient attempts have been made to re-core the interval, the geologist may accept a core recovery of 90-percent.
- Geologist logs the core including depths, fractures, texture, color, and characteristics of the lignite.
- Geologist double bags and double tags sample.
- Once all intervals are cored, independent contractor geophysically logs drill hole.
- Geologist reviews geophysical log.
- Hole determined complete and abandoned by independent drilling contractor in accordance with state regulatory requirements.
- Survey drill hole collar location.

Additional drilling tasks include:

- Maintaining daily drilling report and record of collected samples.
- Proper storage of lignite core samples in secure location of the mine office and transfer to the warehouse to prepare for shipment to laboratory.

Samples are sent to laboratories independent of NACCO for analyses. Table 7.1 list testing laboratories and certifications/accreditations held used in the preparation of information contained in this TRS.

Table 7.1 Independent Testing Laboratories

Laboratory	Location	Services	Certification/Accreditation
Aquaterra Engineering, LLC.	Jackson, MS	Independent geotechnical services	Unknown
Burns Cooley Dennis, Inc.	Ridgeland, MS	Independent geotechnical services	AASHTO
Core Laboratories, Inc.	Tyler, TX	Independent analytical services	Unknown
ETC Laboratory (Waypoint Analytical)	Memphis, TN	Independent analytical services	NELAP
Geoscience Engineering, LLC.	Jackson, MS	Independent geotechnical services	Unknown
Inter-Mountain Laboratories, Inc.	College Station, TX	Independent analytical services	Unknown
Minnesota Valley Testing Laboratories, Inc.	Bismarck, ND	Independent analytical services	ISO 17025
Mississippi State Chemical Laboratory	Mississippi State, MS	Independent analytical services	ISO/IEC 17025:2017
Pritchard Engineering	Columbus, MS	Independent geotechnical services	Unknown
Soil Engineering Testing	Bloomington, MN	Independent geotechnical services	AASHTO
Standard Laboratories, Inc.	Casper, WY	Independent analytical services	ISO 17025
Terracon	Jackson, MS	Independent geotechnical services	AASHTO

7.2.3. Drilling Exploration Programs

Numerous drilling exploration programs have been conducted at the Red Hills Mine. Over 1,500 exploration holes have been drilled. 330 of those drill hole locations were sampled for coal quality testing. Table 7.2 and the text below describes the various drilling programs at Red Hills to date.

Table 7.2 Exploration Drilling Summary

Program	Year	Drilling Contractor	Geophysical Logging Contractor	Type of Drill Holes			Information from Drill Holes			Average Linear Core Recovery (%)
				Pilot Holes	Coal Core Holes	Total Drill Holes	Holes with Geophysical Log	Holes with Core Log	Holes with Lab Analysis	
1975- 1980	1975- 1980	Various Contractors [1]	Century Geophysical	715	105	**820**	817	102	103	99.50
1997- 1998	1997	Diversified Drilling Services [2,3]	Century Geophysical	20	23	**43**	43	23	23	100.00
	1998			-	16	**16**	16	16	16	100.00
2000- 2008	2000	Diversified Drilling Services [3]	Century Geophysical	-	15	**15**	15	15	12	99.50
	2003			-	22	**22**	22	22	-	99.50
	2006			83	8	**91**	91	8	8	100.00
	2007			22	-	**22**	22	-	-	-
	2008			34	-	**34**	34	-	-	-
2009- 2015	2009	Aquaterra [3,4]	Century Geophysical	43	-	**43**	43	-	-	-
	2011	Terricon [3,4]		41	16	**57**	57	16	16	100.00
	2013		Cardno GLS	11	6	**17**	17	-	6	100.00
	2014			25	6	**31**	31	6	6	100.00
	2015			20	10	**30**	30	10	10	100.00
2016	2016	Liberty Fuels	Cardno GLS	32	2	**34**	34	2	2	100.00
2017	2017	Great Southern Engineering [5] (GSE)	Cardno GLS	7	-	**7**	7	-	-	-
2018- 2024	2018	MHC X-Ploration Corporation [6]	Marshal Miller and Associates (Formerly Cardno)	47	20	**67**	67	20	20	100.00
	2019		Century Geophysical	27	21	**48**	48	21	21	100.00
	2021		Marshal Miller and Associates	48	11	**59**	59	11	11	100.00
	2022			25	10	**35**	35	10	10	100.00
	2023			16	21	**37**	37	21	21	100.00
	2024			13	18	**31**	31	18	18	100.00
Total				**1,229**	**330**	**1,559**	**1,556**	**321**	**303**	**99.78**

Notes:
1 Contracted by Phillips Coal Company; included Diversified Drilling Services
2 Pilot Holes include Geotechnical Holes
3 Core Holes include Continuous Core Holes
4 Pilot Holes include Geotechnical Holes and Monitoring Wells
5 Core data excluded from model due to uncertainty in drilling method
6 Pilot Holes include Monitoring Wells

<u>1975 - 1980</u>

From 1975 to 1980 Phillips conducted drilling exploration activities. Independent drilling contractors including Diversified Drilling Services and Century Geophysical Logging Services (Century GLS) completed this work using rotary wash drilling methods. Initial hole spacing in 1975 and 1976 averaged three quarters of a mile. In 1979 and 1980, the general spacing of drill holes averaged 1500-feet, however spacing still exceeded a half mile in areas.

All drill holes were geophysically logged, and field logs were maintained to describe the geology. Coal cores collected during these drilling campaigns had an average linear core recovery of 99.8% and were analyzed by Core Laboratories, Inc. in Tyler, Texas. The method used to survey these drill hole locations is unknown.

These data were the basis for the characterization of the lignite deposit to justify the Red Hills Project including the Red Hills Mine and the RHPP. Despite uncertainty in how these early drill holes were surveyed, the data collected by Phillips has remained fairly consistent when compared to current fill-in drilling and quality analyzed during active mining operations. The QP has evaluated the reliability of the drilling data provided by Phillips including review of geophysical logs, field logs, and coal quality certificates. Drill holes deemed reliable, such that at minimum lithology could be verified by a geophysical log have been used to model the lignite structure, and core holes in which the quality data could be verified by laboratory reports were used to model lignite quality. Scanned drilling files acquired from Phillips are securely stored in NACCO NR corporate office.

<u>1997-1998</u>

In 1997 and 1998, MLMC conducted a drilling exploration program which primarily increased the drill hole density of the first 5-year mining block in the MS-002 permit area to an average spacing of 1000-feet or less. 12 of the 59 drill holes were distributed across the northern portion of the permit area and largely consisted of continuous cores in which soil geochemistry was evaluated in addition to lignite quality. Phillips personnel oversaw drilling activities. Drilling activities consisted of rotary wash methods and was performed by Diversified Drilling Services and Century GLS. Geophysical logs, field logs, and lab results were maintained for each hole during this program. The average coal core recovery rate from 1997 through 1998 was 100%. Coal cores were analyzed by Core Laboratories, Inc. in Tyler, Texas. Collar surveys were obtained by handheld GPS units. It is unknown to what accuracy these surveys were obtained. However, the QP feels the data is appropriate for use in the geologic model after comparison of the collar elevations with the pre-mine topography.

<u>2000-2008</u>

From 2000 through 2008 Diversified Drilling Services and Century GLS were contracted by MLMC to drill over 180 holes using rotary wash methods. Hole types included pilots, coal cores, and continuous cores which increased the hole density, again to an average spacing of 500-feet, within the MS-002 permit area immediately ahead of active mining. Geologists from MLMC oversaw these drilling activities and logged core samples. The average coal core recovery rate from 2000 through 2008 was 99.9%. Core samples were shipped to Standard Laboratories in Casper, Wyoming for analysis. Collar surveys were originally obtained by Trimble units connected to a known base station, followed by Leica survey equipment for a brief period until Topcon Hyper V Rovers with RTK correction tied to a known GPS base were established in 2007.

Upon the QP’s review of drilling data completed from 2000 to 2008, copies of the laboratory analysis for the 22 core holes in 2003 were not available to check the quality inputs stored in the electronic, geologic database. The QP contacted Standard Laboratories for copies of the original quality reports. However, the time of record exceeded the laboratory’s holding period of seven years and copies were not available. The QP then compared the related quality of the drilling database to the associated month end reconciliation reports and found that modeled tonnages in the area of the 2003 drilling were representative of the actual mined tonnage as shipped to the RHPP. As such, it is the QP’s opinion that the quality values documented in the electronic, geologic database for these 22 holes are representative of the deposit.

2009-2015

From 2009 through 2015, MLMC contracted Aquaterra Engineering, LLC (Aquaterra), a Terracon Company, which fully transitioned to Terracon in 2011 to perform drilling exploration work. Century GLS and Cardno Geophysical Logging Services (Cardno GLS) were contracted by MLMC to geophysically log the drill holes. Approximately 180 holes were drilled including pilots, coal cores, continuous cores, and monitoring wells. The majority of drilling was once again focused in the MS-002 permit area ahead of mining operations to achieve an average drill hole density of 1000-feet or less. However, in 2015, MLMC also began fill-in drilling within Mine Area 3 where the next mine area was projected to be in full operation in 2023. The extent of work for Mine Area 3 included 6 continuous core holes and 3 monitoring well locations. Geologists from MLMC oversaw these drilling activities and logged core samples which were shipped to Standard Laboratories in Casper, Wyoming for analysis. The average coal core recovery rate from 2009 through 2015 was 100%. Collar surveys were obtained by Topcon Hyper V Rovers with RTK correction tied to a known GPS base.

2016

In 2016, Liberty Fuels, another subsidiary of the Company, conducted drilling services for MLMC under a mutual cost reimbursement agreement. Cardno GLS was contracted to geophysically log the drill holes. 34 holes were drilled using rotary wash methods within Mine Areas 1 and 3. Two core holes were drilled successfully during this program targeting the F-seam and C-seam quality in Mine Area 3. Due to poor core recovery on multiple attempts, no other seams were sampled for quality during this program. Geologists from MLMC oversaw these drilling activities and logged core samples which were shipped to Standard Laboratories in Casper, Wyoming for analysis. The coal core recovery of the sampled F- and C-seams in 2016 was 100%. Collar surveys were obtained by Topcon Hyper V Rovers with RTK correction tied to a known GPS base.

2017

In 2017, MLMC contracted Great Southern Engineering (GSE) to collect lignite cores for quality assessment using sonic drilling methods, but due to uncertainty in the representative quality from excessive heating and fracturing of the coal cores during the sample collection process, the QP determined these coal core data would be excluded from the geologic model. 7 pilot holes in advance of these coal cores were conducted by Geotechnical Engineering Associates (GEA) using rotary wash methods. Century GLS geophysically logged these holes. Collar surveys were obtained by Topcon Hyper V Rovers with RTK correction tied to a known GPS base. Information related to the pilot holes in advance of these coal core holes, including geophysical logs and cuttings descriptions were evaluated by the QP and included in the geologic model to further define the structure of the lignite deposit.

2018-2024

From 2018 to 2024, MLMC contracted MHC X-Ploration Corporation, Century GLS, and Marshall Miller and Associates (previously Cardno GLS) to drill and geophysically log approximately 277 pilot holes, coal core holes, and a monitoring well. The holes were drilled using rotary wash methods and were located in the MS-005 permit area. These holes increased the drill hole density in the resource area. The drilling activities included the mine area east of Highway 9 as well as additional exploration outside the currently permitted areas. Geologists from MLMC oversaw these drilling activities and logged core samples which were shipped to Standard Laboratories in Casper, Wyoming for analysis. The average coal core recovery rate from 2018 through 2024 was 100%. Collar surveys were obtained by Topcon Hyper V Rovers with RTK correction tied to a known GPS base. While discussed and displayed in figures, 2024 drilling was not included for resource and reserve calculation since the drilling was infill production and results were not material to global mineral resources estimates.

7.2.4. Qualified Person Opinion – Drilling Exploration

The drilling campaigns completed from 2015 through 2024 in conjunction with the original exploration conducted by Phillips chiefly influence the Red Hills Mine Mineral Resource estimations discussed in Section 11.

As described in the above drilling programs, MLMC does plan exploration activities to attain an average 500-foot drilling density for the four-year projection ahead of active mining operations. Every effort is made to locate holes as closely as possible to maintain this average spacing but due to terrain/site conditions, permit restrictions, or site access the distance between holes may deviate from the 500-foot target. This drilling density is optimal for day-to-day operations to capture the gentle undulation of the lignite seams. Identifying these slight differences in roof elevations is key to optimizing lignite recovery efforts, particularly on the thinner seams.

However, as a whole, it should be noted for the purpose of Mineral Resource estimations and LOM projections, the QP has determined a high level of confidence in the resource classification distances. This confidence comes from the continuity of the lignite seams including both lithologic and quality characteristics, as well as the ability to compare modeled seam projections to active and historical mining operations. Slight structural changes are defined in the tighter drill hole spacing, but these localized structural anomalies tend to not effect quality nor materially affect the structure. Further justification of drill hole distances specific to Mineral Resource Classifications is discussed in Section 11.

Physical constraints such as stream buffers and unnavigable terrain may affect the consistency in drill hole spacing. Additionally, drilling exploration for later years does not always land within fully permitted areas which may limit the extent of disturbance allowed.

7.3. Hydrogeologic Characterization

7.3.1. Surface Water

Beginning in 1996, surface water monitoring sites were established and monitored by Mississippi State University (MSU) under the direction of MLMC within the various streams and tributaries surrounding and intersecting the Red Hills Mine. Baseline flow rates collected by MSU were compared to selected USGS stations within the vicinity of the study area watershed and were analyzed to characterize general runoff conditions. Surface water flow measurements were performed at the monitoring stations using the velocity-area method. As recommended by the USGS, if the depth of flow was greater than two feet, a two-point method of measuring average velocity was used.

To further characterize study area watersheds, rainfall-runoff simulations were performed for storm events with a duration of 24 hours and different return periods. These simulations were performed using the U. S. Army Corps of Engineers HEC-1 flood hydrograph model. Necessary HEC-1 model input includes watershed area, specified rainfall loss and runoff methods, and a design precipitation event. The Soil Conservation Service (SCS) method, now the Natural Resources Conservation Service (NRCS), for abstractions utilizing a curve number (CN), was chosen as the loss rate method, and a SCS/NRCS idealized unit hydrograph was used to model watershed runoff response, as study area watersheds are generally small. Modeled precipitation events were obtained from the U. S. Weather Bureau’s Technical Paper No. 40.

Based on baseline flow data, the average runoff for the Red Hills Mine was determined to be approximately 1.25 cfs/square mile of drainage area.

Surface water samples from each monitoring site were collected and analyzed for physical and chemical parameters including pH, conductivity, total dissolved solids (TDS), sulfate, chloride, total suspended solids (TSS), iron, manganese, nitrates, dissolved trace metals, coliforms, acidity, alkalinity, and various organic pollutants. All of the monitoring sites exhibited waters with very similar water quality and with very small seasonal variations. Averages of general water quality results from baseline data include a pH of 6.9 s.u., conductivity of 55 umohos/cm, TDS of 54 mg/l, and TSS of 8 mg/l. Laboratory analytical analysis for samples taken from the monitoring sites for baseline water quality was conducted by Inter-Mountain Laboratories, Inc. Surface water samples were analyzed by EPA approved methods current at the time of sample collection.

7.3.2. Groundwater

In 1996 and 1997 MLMC contracted R.W. Harden & Associates to conduct hydrogeologic studies focusing on groundwater. Work conducted included construction of test wells, sampling of groundwater chemistry, measurement of potentiometric surfaces, and testing of the aquifers.

The primary water bearing strata at the Red Hills Mine is within the Wilcox group, which is composed primarily of fine-grained deposits of interbedded clay, sandy clay and silt. Sand thicknesses were acquired from geophysical log data gathered during the early Phillip's exploration drilling programs and test well installation for initial characterization of aquifers within the Red Hills Mine.

Approximately 43 test wells were installed as part of the initial studies (Figure 7.2). Water levels were measured quarterly in all test wells constructed to determine potentiometric surface of various sand units. Aquifer testing, including pump tests and slug tests, was conducted in 15 of the test wells to study the more permeable horizons in the overburden and underburden of the mine. The testing indicated transmissivities ranging from 0.2 to 16,600 gallons per day per foot and provided a range of hydraulic conductivities ranging from 0.004 to 31 feet per day. Horizons with higher hydraulic conductivity were generally associated with the coarser sand units in the underburden. Aquifer test results in overburden sands generally show lower transmissivities because only thin sand layers are present and are typically of finer and siltier texture.

Laboratory hydraulic conductivity tests were conducted on clay samples taken from boreholes drilled in the permit area. Results from eight permeability tests indicated, as is typical of Wilcox clay units, that hydraulic conductivities of these clays were low, ranging from 1 x 10-7 to 9.4 x 10-9 centimeters per second, and thus, clay units acted as confining layers to the stratigraphically lower Wilcox sand units. Results of these tests indicated little or no vertical hydraulic communication between sand units separated by clay strata. The layers of clay, predominant in the overburden and underburden materials, act effectively as confining layers. This was confirmed by the results of the laboratory hydraulic conductivity tests indicating low values for these clays.

Natural groundwater movement rates, in both water-table and artesian areas, are very slow and range from a few feet to 50 feet per year in the more permeable sand zones. Vertical hydraulic communication between sand zones is known to be small when separated by low hydraulic conductivity clays. This was demonstrated by the amount of rejected recharge during aquifer testing, indicating little seepage into adjoining beds downdip, and pumping-test data, indicating essentially no influence on drawdown between overlying and underlying sand zones.

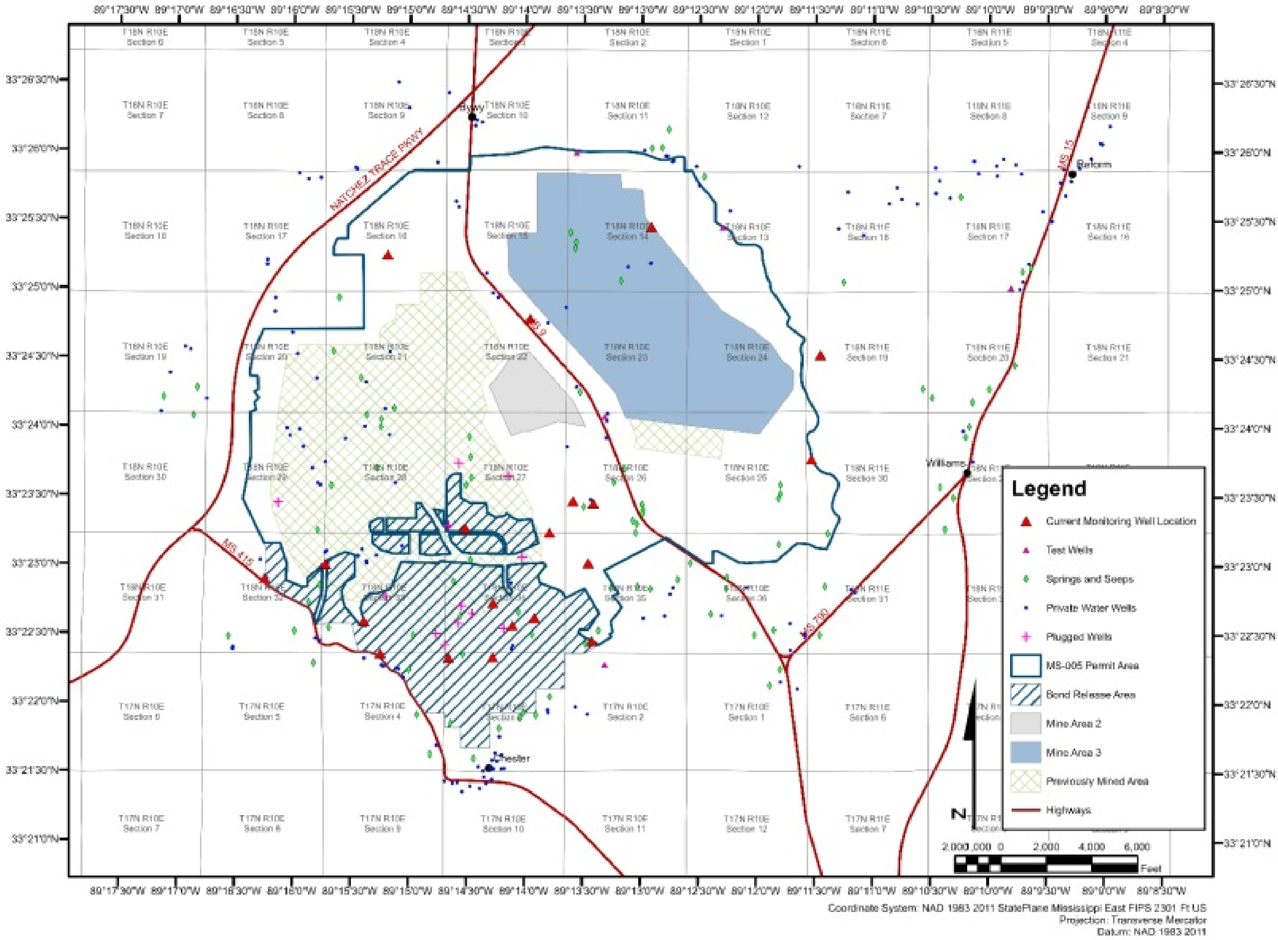
Twelve months of water well, monitoring well and spring groundwater quality data was collected by MSU from 21 test wells in 1997 for alkalinity, hardness, total suspended solids (TSS), major cations/anions and select metals. Water samples collected for analyses were analyzed by an independent laboratory, ETC Laboratory, in Memphis, TN. Groundwater samples were analyzed by EPA approved methods current at the time of sample collection. Groundwater quality results from the Wilcox sands is fresh with average total dissolved solids concentrations less than 300 milligrams per liter (mg/L) and minor to moderate iron and manganese concentrations thought to be naturally occurring.

No formal QA/QC document was available for the initial baseline data. However, use of duplicate samples and blanks were noted by the QP upon review of laboratory reports, chain of custody (COC) forms, and field notes related to the data collected by MSU and R.W. Harden & Associates.

7.3.3. Qualified Person Opinion – Hydrogeologic Characterization

The hydrogeology of the Red Hills Mine has been well studied. MLMC has continued to gain an understanding of the water bearing units during mining, established groundwater and surface water monitoring programs, fill-in drilling, and installation of new monitoring wells. In the QP’s opinion, these additional observations and collected data from the past 20 years of mining align with the results of the original surface water quantity measurements, aquifer tests, hydraulic conductivity tests, and water quality results.

Figure 7.2 Groundwater Map



7.4. Geotechnical Studies

7.4.1. Early Geotechnical Studies

Geotechnical soil drilling has been carried out at the property during several investigations. The most notable studies concerning baseline geotechnical properties are described below.

In 1997, Burns Cooley Dennis, Inc. conducted a study to establish ground conditions and geotechnical properties for the various formations in the Red Hills project area. Three geotechnical boreholes to a maximum depth of 70 feet were completed using a 6-inch diameter short-flight earth auger to a depth of 10-feet followed by rotary wash methods to final depth. Each boring was sampled to a depth of 60-feet, drilled an additional 10-feet then geophysically logged by Century GLS. All soils encountered during drilling were classified with respect to material composition and consistency or density by a geotechnical/geological engineer.

Following the previous investigation in 1997, Geoscience Engineering, LLC. completed four cored holes (including an initial pilot hole) drilled to depths ranging from 170 to 360 feet at a 6-inch diameter. The pilot holes and core holes were advanced using rotary wash methods. Soil Samples were collected using a double core barrel.

In 2004, Aquaterra Engineering, LLC. completed eight soil borings using rotary wash methods to a maximum depth of 200 feet. Each soil boring was advanced with a 4-inch diameter drill bit. The soil sampling program included the collection of both disturbed and undisturbed soil samples. The samples were collected at various depths. Relatively undisturbed samples were obtained by pushing a 3-inch diameter, Shelby tube sampler to collect soil samples for geotechnical laboratory testing. Locations of geotechnical borings are shown on Figure 7.3.

The typical geotechnical borehole log included the following geotechnical descriptions and records of the samples collected during investigation:

- Lithology: Descriptions of the lithology (typically sandy silts, silts and clayey silts) are recorded for each stratigraphic interval in conjunction with a soil type in accordance with the Unified Soil Classification System (USCS). The soil types encountered by Burns Cooley Dennis, Inc., 1997 at the boring locations include clayey sands (SC), silty sands (SM), slightly silty sands (SP-SM), silty and sandy clays (CL), clays (CH) and lignite.
- Consistency/Relative Density: Aquaterra Engineering, LLC., 2004 determined the relative strength estimates of the sample by hand penetrometer readings. In the more granular conditions at this site and at locations where the very dry nature of the surface soils prevented undisturbed sampling, Standard Penetration Testing (SPT) was performed.
- Sample Type and Laboratory Data: The soil borings included various samples collected during the geotechnical investigations. The Aquaterra Engineering investigation (2004) collected piston (Shelby tube) samples (2.0 to 2.5 feet in length) at nominal 10-foot intervals. The piston samples are considered to be relatively “undisturbed” samples and suitable for laboratory testing such as the various strength tests. The index properties determined were the moisture content, Atterberg limits, and grain size determination. The laboratory investigation by burns Colley Dennis, Inc., 1997, included unconfined compression tests, consolidated and unconsolidated undrained triaxial compression tests, water content determination, shear strengths, mechanical sieve analysis, proctor compaction tests, and chemical/corrosion testing. The laboratory investigation by Geoscience Engineering, LLC., 1997 determined the undrained shear strength, unconfined compression test, drained shear strength, moisture content, Atterberg limits, consolidation, and grain size analysis of site materials.

The geotechnical reports available for the QP's review did not document QA/QC protocols and procedures followed by the independent contractor at time of testing and sample collection, however the laboratory standards were indicated. The typical laboratory tests performed in the three investigations described above were performed in accordance with the relevant American Society for Testing and Materials (ASTM) standards at independent certified laboratories and include the following:

Soil Index properties:

- Moisture content determination – ASTM D 2216, ASTM D 4959
- Atterberg limit determination – ASTM D 4318
- Consolidation tests – ASTM D 2435
- Grain size determination – ASTM D 422 and ASTM D 1140

Soil Strength properties:

- Direct shear strength tests – ASTM D 3080
- Consolidated shear strength tests – ASTM D 3080
- Unconfined compression tests – ASTM D 2166
- Unconsolidated undrained triaxial tests – ASTM D 2850
- Consolidated undrained triaxial compression tests – ASTM D 4767

In the QP's opinion the laboratory testing methods completed to determine the geotechnical soil parameters are appropriate for the purpose of detailed pit design outlined in Section 13.5 of this TRS.

Further detail concerning pit design and ground control parameters related to geotechnical studies and additional geotechnical studies related to pore water pressures and effects on pit stability are discussed in Section 13.0 Mining Methods.

7.4.2. Buffer Block Study

In 2011, the Company conducted an additional geotechnical study to determine the design parameters for a buffer block left between future mine area boxcuts directly adjacent to previously mined pits at the Red Hills Mine. The Company contracted Terracon, an independent geotechnical company, to drill, sample, and conduct laboratory testing for 8 soil borings within the area of interest (Figure 7.3). Century Geophysical, an independent contractor, geophysically logged the bore holes.

The soil sampling program included the collection of both disturbed and undisturbed soil samples. Relatively undisturbed samples were obtained by pushing a three-inch diameter, Shelby tube sampler a distance of two feet into the soil in general accordance with ASTM D1587.

After the Shelby tube was removed from the boring, the sample was carefully extruded in the field and visually classified. Relative strength estimates of the sample were obtained by penetrometer readings. Disturbed portions of the sample were discarded and the undisturbed sample was placed in a protective container for transportation to the laboratory. An additional portion of the sample was placed in a plastic jar to minimize moisture loss during transport to the laboratory and to aid in visual classification of the sample.

In more granular conditions, the standard penetration test (SPT) was performed. In this case, representative disturbed samples were obtained in cohesionless soils by driving a 2-inch OD split-spoon sampler a distance of 18 inches into the soil with blows from a 140-pound hammer falling a distance of 30-inches (ASTM D 1586).

Representative samples removed from the split spoon sampler and placed in plastic jars to minimize moisture loss provided a sample for laboratory testing.

At selected boring locations, auger samples were also collected to allow collection of soils for classification purposes only. In this case, the sample was retrieved directly from the auger being used to advance the boring. The auger sample was placed in a plastic jar to minimize moisture loss during transport to the laboratory.

The soil samples were delivered to the Terracon laboratory for testing. Laboratory test assignments were made by the Company. Laboratory testing was accomplished to determine index and strength properties of the soils encountered. These procedures are listed below.

- Index properties: Moisture content (ASTM D2216), Atterberg Limits (ASTM D4318), Grain Size Determination (ASTM D422 and D1140), and Standard Effort Compaction Test (ASTM D 698)
- Strength Tests: Unconfined Compression (ASTM D2166), Consolidated Undrained Triaxial Compression (ASTM D4767), Unconsolidated Undrained Triaxial Compression (ASTM D2850), Direct Shear Test (ASTM D3080)
- Permeability Tests (ASTM D5084 and ASTM 2434)

All soils were visually classified and in accordance with criteria stipulated by Unified Soil Classification System (USCS).

During the soil boring advancement and sampling operation, observations for free groundwater was not made because the rotary wash technique was used for the entire boring advancement. Therefore, groundwater levels were not determined. However, ground water information from existing monitoring wells and on-site ground water management programs was available.

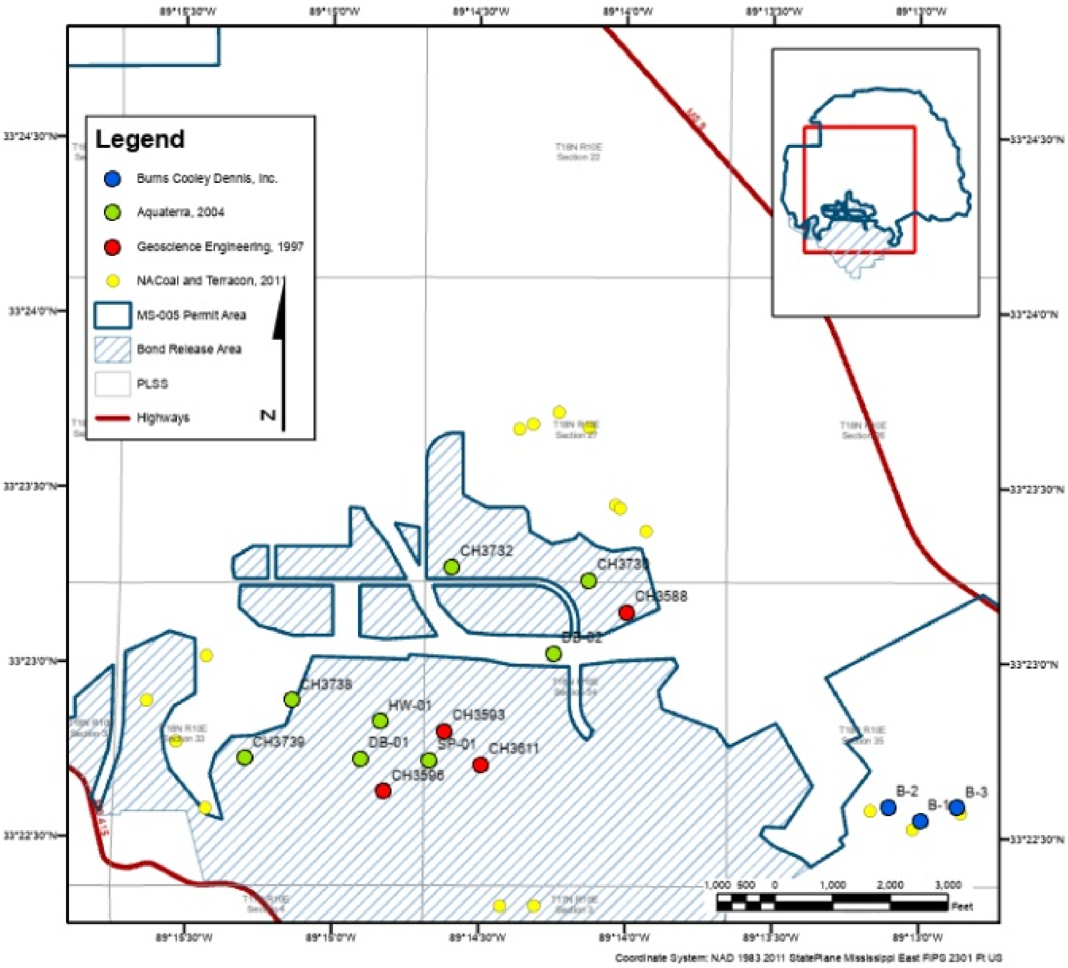
Using the results of the laboratory tests and field observations, the Company conducted a slope stability analysis using the computer program Slope W and a method called Morgenstern-Price to obtain likely factors of safety for opening up a boxcut adjacent to a previously mined pit. Three scenarios for block widths between mine areas were analyzed including a 500-foot block, 250-foot block, and 100-foot block. All scenarios initially assumed 41-degree slopes on either side of the buffer block. All three scenarios resulted in a recommendation that the low wall of a new boxcut adjacent to a previously mined area should be no steeper than 30-degrees to prevent instability and increase the factor of safety near the low wall slope to 1.3.

In the QP's opinion the drilling, sampling, testing, and analysis completed were appropriate to establish low wall pit parameters for opening up a box cut for a new mine area adjacent to a previously mined pit. In the current LOM plan, this parameter only applies to the Mine Area 2 boxcut.

7.4.3. Qualified Person Opinion – Geotechnical Studies

Subsurface conditions and geologic units encountered have remained fairly consistent since mining commenced in 2000. Overburden core holes in which individual sections of burden were collected and tested for physical and geochemical properties, as described previously under drilling exploration, have been evenly distributed throughout the permitted mine areas and continually serve as an indicator for soils to be encountered ahead of mining. Furthermore, the geologic structural data acquired from geophysical logs during drilling campaigns indicate consistent depths between burdens and lignite seams among other subsurface characteristics. Special situations, such as deep pore water pressures described in Section 13.0 of this TRS, have led to additional geotechnical studies specific to the issue encountered while mining. However, the general pit parameters defined by the above studies have not warranted a need for further studies from the continued information obtained from drilling exploration and active mining operations. The QP understands that additional geotechnical studies may be required on an as needed basis to address special conditions that may be encountered in future mining. These conditions will be monitored and addressed as needed as mining progresses.

Figure 7.3 Location of Geotechnical Borings



8.

8. Sample Preparation, Analysis, and Security

8.1. Sample Collection and Shipment

The Red Hills Mine lignite deposit is evaluated on a seam-by-seam basis. As a regular practice in the coal industry, lignite cores are bagged and sent to the independent coal testing laboratory. The procedures at the Red Hills Mine for current and historical sample collection are summarized below.

Core runs are specified by the geologist by referencing the geophysical log of the pilot hole. As coal seams rarely exceed 6 feet in thickness, a single 10-foot core run can typically capture a full lignite seam. Once a specified core run is brought to the surface, the geologist observes the drillers extract the lignite sample from the double barrel core to ensure the integrity of the sample is maintained, and to verify the top and the bottom of the coal core run. The core sample is transferred from the core barrel to a core cradle (i.e. halved pvc pipe) and is carried to the geologist's work station. The geologist washes excess drilling mud from the core sample with water, verifies the roof and floor of the lignite core is present and checks the expected coal seam thickness referenced from the pilot hole's geophysical log to determine coal core recovery. If full core recovery cannot be verified, the driller may attempt to retrieve the remainder of the lignite core run from the current hole. If no successful attempt is made to recover the remaining lignite, the driller must re-core the lost interval in a new adjacent core hole to achieve a minimum of 90-percent recovery.

Upon verifying recovery of the core run, logs the lignite run. A typical log describes:

- "to" and "from" depths of burdens and lignite;
- joints and fractures at specified depths;
- characteristics of burden above and below the lignite core;
- roof and floor of lignite seam (i.e. sharp or gradational);
- presence of pyrite or petrified wood;
- observations of clay or sands imbedded in the lignite core;
- and any other prominent characteristics.

After the geologist describes the core run, the entire lignite section is double bagged and double tagged. Tags include the date, mine identifier, hole ID, seam ID, and "to" and "from" intervals. Double bagging preserves the moisture of the sample, and double tagging safeguards the identification of the sample from the field through transportation to the independent laboratory. Historically, Red Hills Mine has not photographed coal cores prior to bagging samples, but starting with the 2022 drilling campaign, photographs of core samples are performed as a regular QA/QC practice in logging core samples.

Lignite cores may be split into multiple samples for the following reasons:

- Prominent roof, floors, or partings within a continuous seam;
- Identification of composition concentrations (i.e. to determine if sulfur trends toward top, middle or bottom of seam).

Total core runs are shipped for analysis following industry standards, thus split samples in the context of a retained sample are not stored at the Red Hills Mine. Lignite tends to be a high moisture coal which oxidizes rapidly and does not have a long shelf life once removed from the ground. If core split samples were retained, they would not be representative of in-situ coal properties over time.

After samples are bagged, they are stored in a dry, shaded area until the geologist returns to the mine office. Core samples are then securely stored in the office until transferred by the geologist to specified pallet boxes in the warehouse to be shipped to the independent laboratory. The warehouse is climate controlled, such that the samples are not kept in a hot environment that could adversely affect the quality results. Furthermore, the Red Hills Mine office and warehouse is secured with user specified fob access and camera surveillance.

Prior to shipping the samples, the geologist reviews each sample against the field records and the chain-of-custody (COC). The date, mine identifier, hole ID, seam ID, and "to" and "from" intervals are verified. In addition to the COC included in the physical shipping container, a copy is emailed to the laboratory manager to notify that a shipment is in route. Copies of the COC forms for coal cores shipped from 2015 through 2021 were available for the QP to review. Coal core samples are shipped to the independent laboratory via insured freight with tracking information.

8.2. Sample Preparation and Analysis

Minimum analyses of coal cores include short proximate (ash, calorific value (BTU/lb), sulfur, moisture) and specific gravity. These parameters are the primary quality inputs used to model the Red Hills Mine lignite deposit. Additional analyses of coal cores may include mineral analysis of ash, trace elements, ash fusion, and forms of sulfur. Historically, full proximate, ultimate analysis, and grindability have been requested on a specialized basis. However, these parameters are not modeled or currently relevant for consideration in Mineral Resource estimations.

As mentioned in Section 7, coal cores collected by Phillips in the early years of exploration were sent to Core Laboratories, Inc., an independent laboratory in Tyler, Texas. QA/QC information related to these samples was not provided to MLMC by Phillips when data was acquired in 2000. However, the QP was able to review laboratory certificates to verify quality data related to these core holes.

Since 2000, Red Hills Mine has sent lignite core samples to Standard Laboratories, Inc. (Standard), an independent laboratory in Casper, Wyoming for analyses. Standard is a certified ANAB Accredited and ISO 17025 accredited laboratory for coal including typical lignite coals.

The Mineral Resources QP toured the Standard Laboratories facility in Casper, Wyoming on June 24, 2021. The QP reviewed procedures for chain of custody, QA/QC, and observed laboratory processes and found the operation to be clean, well-managed, and professionally operated. No concerns were noted.

Short proximate parameters, as used to define Mineral Resources and Reserves, are tested at the Casper laboratory location. Other tests at the Casper location include, but are not limited to, mineral analysis of ash and ash fusion. Lignite core samples requesting trace mineral analysis and forms of sulfur analyses are completed by the Freeburg, IL Standard laboratories location from sample splits prepared at the Casper location.

The laboratory ASTM standards used at the Casper location are listed in Table 8.1. A modification to ASTM D3302/D3302M-18 Total Moisture is completed at Standard. Due to lignite having a higher moisture content and faster oxidation rate than higher rank coals, the temperature limit for air-drying was modified to reduce the drying time. Minimal to no evidence of bias was noted in any of the parameters (TM, Dry Ash, AR BTU/lb, MAF Btu) in any of the modified drying times and temperature combinations.

Table 8.1 List of ASTM standards for Standard Laboratories, Casper location

Specific Tests and/or Properties Measured	Specification, Standard, Method, or Test Technique	Items, Materials or Product Tested	Key Equipment or Technology
Ash in the Analysis Sample	ASTM D 3174	Coal	Furnace
Calorific Value	ASTM D5865	Coal	Calorimeter
Carbon, Hydrogen, and Nitrogen	ASTM D5373	Coal	Elemental Analyzer
Equilibrium Moisture	ASTM D1412	Coal	Waterbath Method
Free-Swelling Index	ASTM D720	Coal	Electric Method
Fusibility of Ash	ASTM D1857	Coal	Furnace
Grindability of Coal	ASTM D409/D409M (MOD)	Coal	Grindability Machine
Loss on Ignition	ASTM 7348	Coal	Oven/Furnace
Major and Minor Elements	ASTM D6349	Coal	ICP-OES, Mixed Acid Digestion
Mercury	ASTM D6722	Coal	Direct Combustion Analysis
Moisture in the Analysis Sample	ASTM D3173	Coal	Oven
Moisture (Total)	ASTM D3302/D3302M (MOD)	Coal	Commercial Method
Preparing Samples for Analysis	ASTM D2013/D3302M (MOD)	Coal	Crusher/Pulverizer
Sulfur (Total)	ASTM D4239	Coal	Furnace
Volatile Matter	ASTM D7582	Coal	TGA
Water Soluble Alkali Content	ASTM D8010 Method A	Coal	ICP-OES

8.2.1. Receiving Dock/Sample Storage Room

The receiving dock doubles as the sample storage room and is climate controlled (ventilated and heat). Casper, WY has a moderate summer climate, with cold winters that can be mitigated with heaters. From the receiving dock and storage room there is access to the sample prep room and main laboratory.

During non-operational hours Standard is locked down with an active alarm system including door, window and motion detectors which is monitored by a local company.

Once a shipment is received, the shipment is logged and opened then the number of individual samples are logged along with the date and time. Each sample is cross referenced with the COC and is then weighed using certified balances. Paper records including Standard Laboratories logs, COC's, and any additional paperwork received in the shipment are transferred to an electronic database at this point.

Once samples are logged, they are stored in this storage room until there is available space in the prep room. It was noted there is a slight potential for moisture loss during this storage period. MLMC acknowledges this potential and, as such, double bags samples in the field to preserve as much in-situ moisture as possible.

Retained pulverized and dried 60-mesh samples are also stored in this room. These samples can be retested within 6 months for selective parameters. Due to the sample being dry and potential for oxidation moisture parameters and Btu/lb cannot be retested. Standard contacts and verifies with the client prior to disposal of retains.

8.2.2. Prep Room

The prep room is a temperature-controlled room (AC and Heat) accessible from the receiving dock. Within the prep room samples are crushed to 8-mesh size using a Holmes crusher and are then run through a Holmes riffler. Pulverizer screens and rifflers are inspected daily, before and after each batch. The distance between the riffler fin spread is regularly checked in accordance with ASTM standards. An air hose is used to clean out after each sample to mitigate contamination. It was noted that the prep room was very clean. No visible residual material was observed in the riffler.

8-mesh samples are divided into 1000 g per tray following ASTM standards using calibrated balances. Additional sample material is placed in a bag which then has the air mechanically removed and heat sealed for storage in a separate room off of the prep room. The same storage process is used for round robin samples. Similar to the retained samples, Standard verifies with the client prior to disposal of sample splits.

Prepared 1000 g trays are placed in one of three air dry units for overnight drying following the modified standards discussed previously. Drying time and temperatures are regulated on the air-dry units. Certified thermometers are used which also indicate minimum and maximum temperature values to ensure there is no exceedance of the max allowable temperature. Temperature gauges are certified annually, and additional checks are performed quarterly.

Once air-drying is complete and samples are re-weighed and logged. Dried samples are pulverized to 60-mesh and split samples are obtained with a Holmes sample riffle. Split samples are stored in pre-labeled high-density polyethylene (HDPE) bottles with foam lined caps.

8.2.3. Laboratory Testing

After the prep room process, 60-mesh split bottles are transferred to the main portion of the laboratory where they are first run through a mixing wheel for 10 minutes to ensure a homogeneous sample. All equipment maintains logs of processes and results. This portion of the laboratory is climate controlled (AC and heat).

Review of all analysis results is by the laboratory manager, or assistant laboratory manager. Review includes but is not limited to identification of outliers, and comparison of results with historical information by site, if available. The laboratory manager may request a rerun on a sample if needed.

8.3. Quality Control Procedures

There is currently no formal program in place at Red Hills Mine for the inclusion of blanks, standards, or field duplicates. However, Standard completes several internal QA/QC checks to verify samples and a pulverized duplicate reference laboratory audit was initiated for the 2024 drilling campaign.

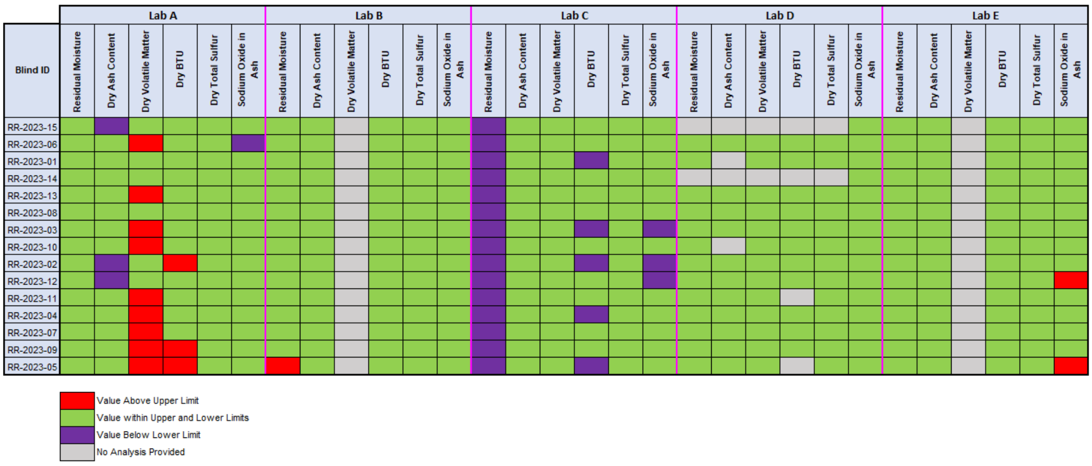
8.3.1. Laboratory Round Robin

Standard participates in a monthly round robin coal testing program including 32 other laboratories. A 4-mesh program and an 8-mesh program are included in this round robin. In addition to the monthly round robin coal program, a formal Proficiency Testing Program by Quality Assurance Resources, LLC (QAR PTP) which includes a 4-mesh program and 8-mesh program is also completed monthly. If there is an error or out of tolerance reported, an investigation is immediately completed. Upon investigation, corrective action will be taken to remediate the issue and additional training will be completed if deemed necessary. Trainings were documented. The most current QAR PTP results were posted and personally reviewed by the QP and the Company's principal geologist during the lab visit.

Along with the above programs, internally at Standard, a daily short proximate testing program was in place.

In 2023, Standard also participated in a lignite (coal) specific round robin testing program facilitated by the Company including five laboratories that were used by various Company mine locations. The round robin consisted of eleven samples of which three were sourced from Red Hills Mine and the remaining were sourced from other Company mine locations. In addition to the eleven samples, there was one duplicated created for each mine site which increased the total number of samples to fifteen samples. The fifteen samples were blind labeled RR-2023-01 through RR-2023-15. The various sampling locations provided a range of samples with variability in moisture, ash, sulfur and sodium. The labs participating in the round robin were provided dried 60-mesh splits of all fifteen samples. Total moisture was not included in this round robin with the dried 60-mesh samples. The general results are summarized in Figure 8.1. Standard is labeled "Laboratory D" and all results fell within ASTM Range. However, Lab D was not able to report 14 (19%) of the 75 values due to internal control processes that self-reported these samples as having not met the laboratory's QAQC standards. While it is not ideal to not report 19% of the samples, the remaining 81% of the samples were in compliance.

Figure 8.1 NACCO 2023 Round Robin Program Summary. (NACCO, 2023)



8.3.2. Reference Laboratory Audit

Red Hills Mine initiated a reference laboratory audit for pulverized duplicate samples for the 2024 drilling campaign. Thirty-one random samples were selected for the audit. Standard Laboratories prepared the 8 mesh reference splits and sent the splits to MVTL for testing. Analytes and ASTM testing methods are listed on Table 8.2.

Table 8.2 Reference Audit Analytes and ASTM Testing Methods

Laboratory	Total Moisture As Received Moisture Basis (wt. %)	Total Ash Dry Basis (wt. %)	Total Sulfur Dry Basis (wt. %)	Heat Content Dry Basis (BTU/lb)
Standard Laboratories	D3302 (M)	D3174	D4239	D5865
MVTL	D7582	D7582	D4239	D5865

Comparison of the ASTM Reproducibility Limit (R) results were varied with total ash and sulfur having the most samples that reported outside of the ASTM Reproducibility Limits. Results of the reference laboratory audit including ASTM Reproducibility Limits are shown in Figure 8.2 through Figure 8.5 with samples outside of ASTM Reproducibility Limits noted in the table and below.

Total moisture had one sample reporting outside of the reproducibility limit but resulted with reproducibility above 95% probability.

Heat content had two sample results outside of the reducibility limits but still had a reproducibility probability of 94%.

Total ash and total sulfur resulted with four samples outside the reproducibility limits for each analyte. Total ash cannot be directly compared between the two laboratories since the sample testing methods are not the same between the laboratories while total sulfur was tested by both laboratories using the same testing methods as shown on Table 8.2. The failures in total sulfur samples were unexpected since both laboratories reported total sulfur ranges within the reproducibility limits during the 2023 round robin testing. Both laboratories are ISO 17025 accredited and each laboratory has its own QAQC policies and procedures and participates in inter-laboratory round robin testing. A third reference laboratory will be introduced into the 2025 Reference Laboratory Audit to further investigate the total sulfur failures.

Figure 8.2 Reference Laboratory Audit Results for Total Moisture (As Received)

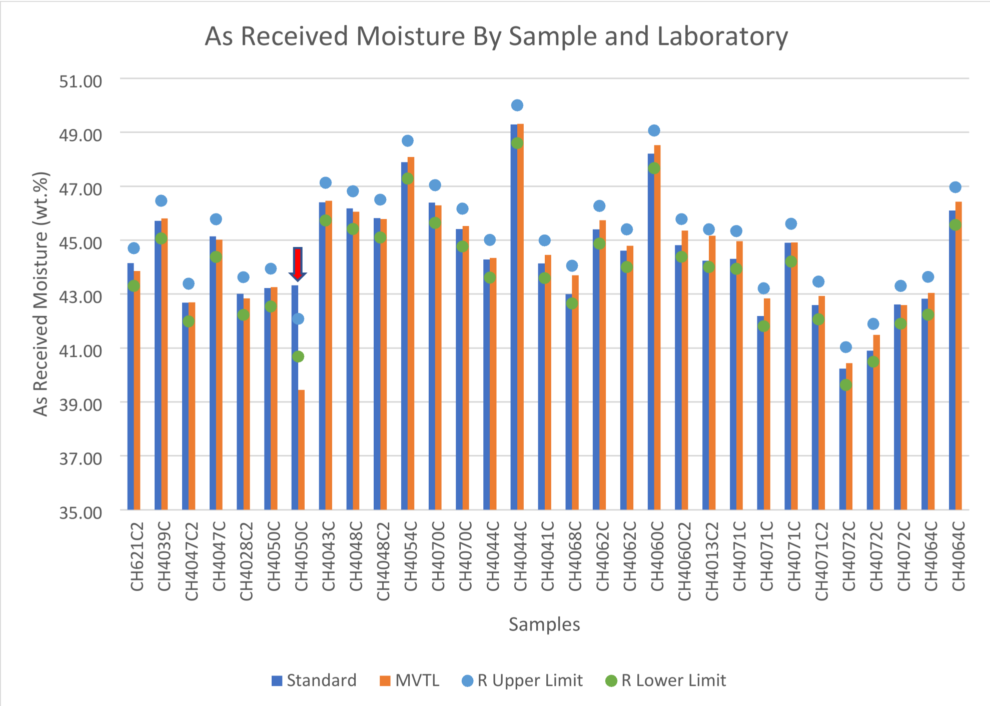


Figure 8.3 Reference Laboratory Audit Results for Ash Content (Dry)

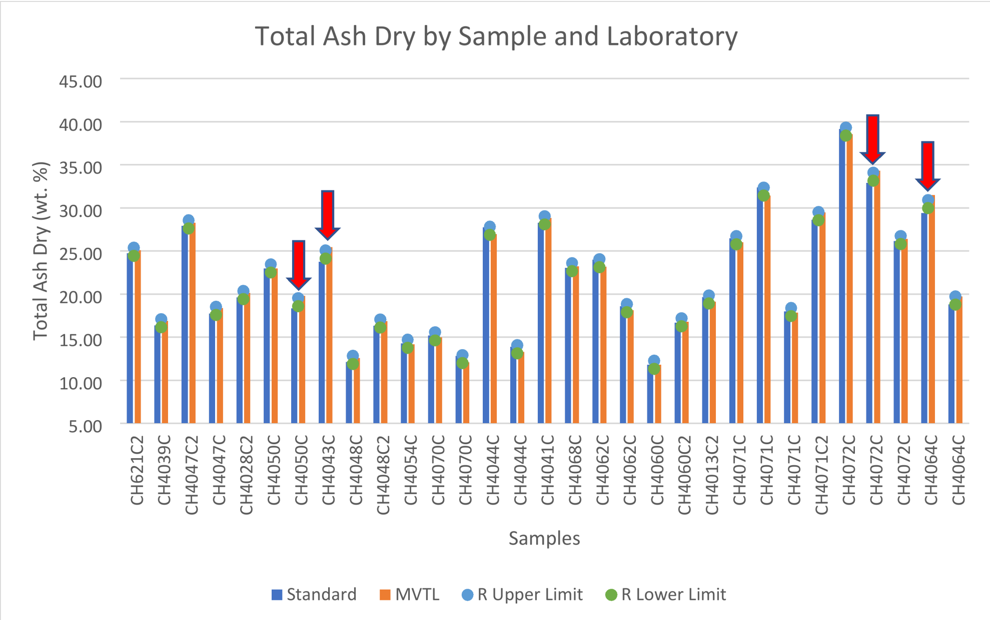


Figure 8.4 Reference Laboratory Audit Results for Total Sulfur (Dry)

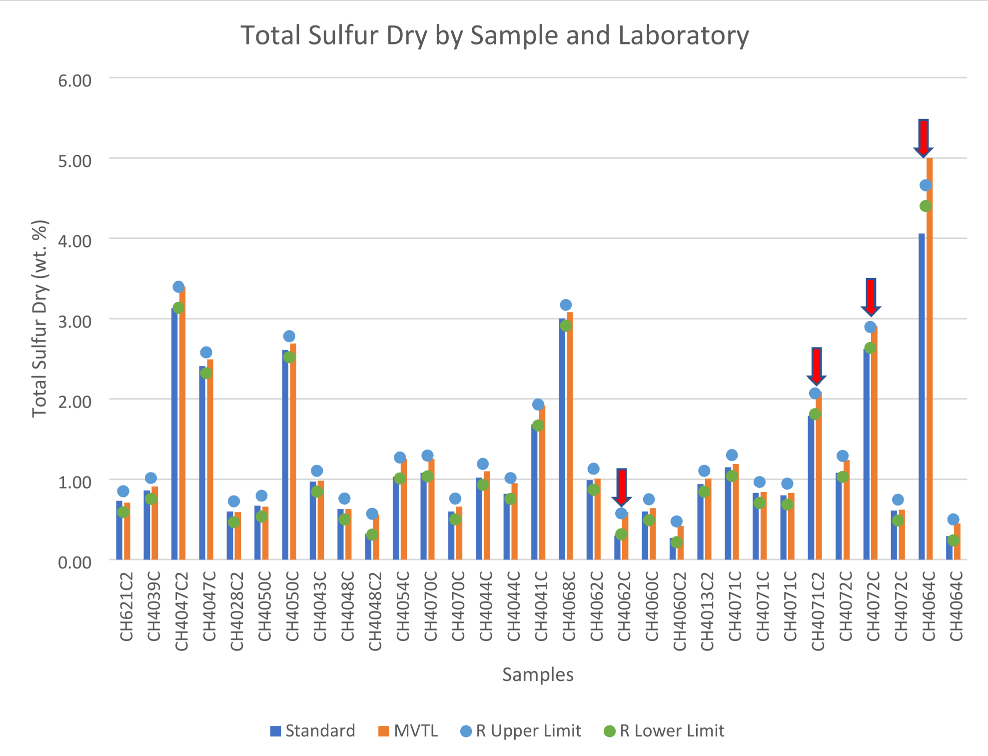
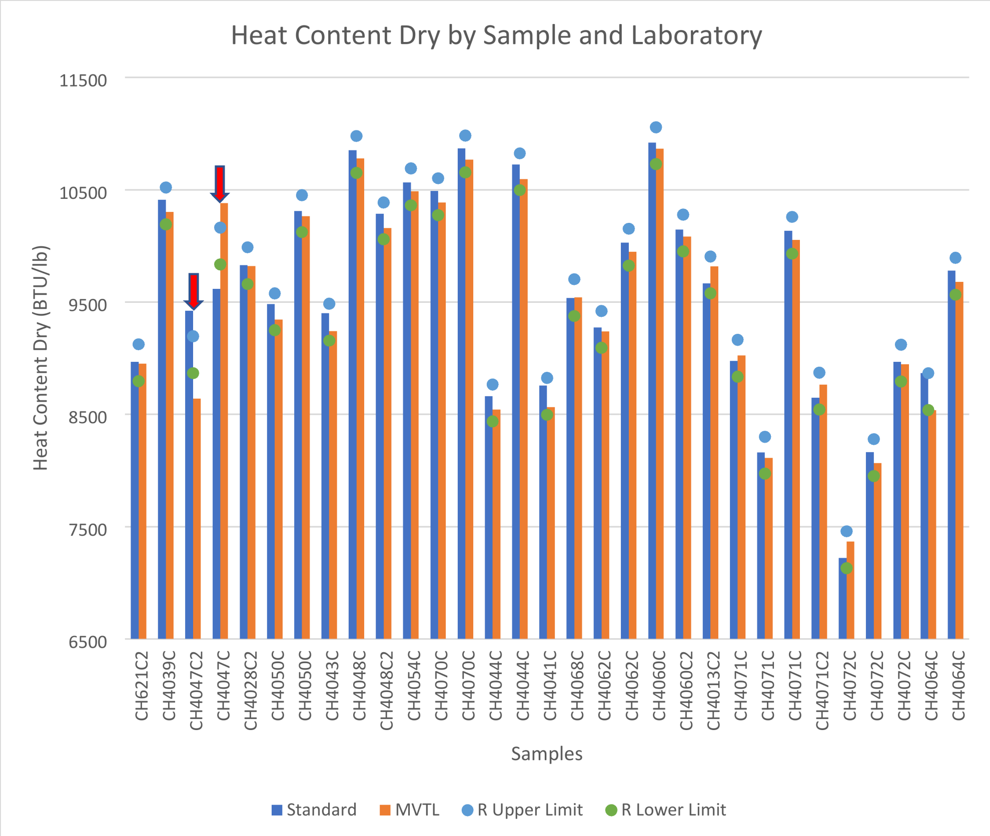


Figure 8.5 Reference Laboratory Audit Results for Heat Content (dry)



Historic laboratory results from Standard Laboratories have been consistent with expected ranges and past round robin testing results. Subsequent drilling campaigns will provide additional samples to look for trends or if these failures were isolated to this drilling campaign

8.4. QP Statement on the Adequacy of Sample Preparation, Security and Analytical Procedures

Although no formal written procedure existed until 2024 for the process to collect coal samples at the Red Hills Mine, the consistency in core collection from one drilling program to the next has been thoroughly documented. Through records review and personal observation of numerous drilling campaigns, it is the QP's opinion that historic coal core collection has remained consistent with U.S. Geological Survey's (USGS) guidance for sampling coal for chemical analysis. The process of double bagging and tagging the cores in addition to multiple checkpoints to log samples from field to shipment to the laboratory further ensures the integrity and security of each sample is maintained.

Additionally, in the QP's opinion the methodologies used by Standard Laboratories are within ASTM standards for sample preparation, process of sample splitting and reduction, general quality control, and security of samples to ensure that validity and integrity of samples is upheld. Although 19% of samples from Standard Laboratories were not able to be reported for the Laboratory Round Robin testing due to noncompliance with internal QAQC, the QP has confidence that the analytical results from Standard Laboratories have met their laboratory's QAQC and are acceptable for use in the estimation of Mineral Resources. Reproducibility failures for total sulfur for the Reference Laboratory Audit between Standard and MVTL will continue to be monitored and evaluated. Total sulfur results reported by both laboratories are within expected historic ranges reported at Red Hills Mine and do not pose a concern to the QP.

9. Data Verification

9.1. Data Verification Procedures for Mineral Resources

9.1.1. QP Site Visit

Benson Chow, Mineral Resource QP, is a Registered Professional Geologist in the state of Mississippi, License Number 0175 and a Registered Member of SME, ID 4317057 and is in good standing with both organizations. He has been involved with the exploration, geology, and mining operations at Red Hills Mine since 1999 and his most recent site visit was on May 7 through 13, 2024. The purpose of this visit was to complete a site visit of the active mining area and to oversee the 2024 drilling campaign. During the visits the QP completed the following task:

- Inspected the active pit areas for Mine Area 1 west, middle and east end of the pit.
- Observed the extraction of the D Seam coal using the Wirtgen in Mine Area 1. Visited the boxcut in Mine Area 3. Performed survey verification of several previously drilled exploration drill holes. Figure 9.1 shows Mine Areas 1 and 3 inspection and the survey verification of several exploration drill holes. Table 9.1 outlines the holes verified and the variance in northing, easting and elevation.
- Verified drill hole collar locations and elevations from the 2011, 2015, and 2021 drilling programs.
- Inspected the active pit area for Mine Area 3
- Overseen the 2024 drilling campaign

Figure 9.1 Resource QP Site Visit Photographs

West End of Mine Area 1 Pit

Middle of Mine Area 1 Pit mining D Seam

West End of Mine Area 3

Surveying hole CH3783CC

Surveying hole CH3890C

Surveying hole CH3890CC

Table 9.1 Resource QP Drill Hole Survey Verification

	Resource Model			Carlson Surveyor 2 Data Collector with Sokkia GRX3 Receiver			Difference			Comment
Hole Id	Northern	Eastern	Elevation	Northern	Eastern	Elevation	Northern	Eastern	Elevation	
CH3783CC	1420860	860986	409	1420850	860979	408	10	7	1	
CH3890C	1425269	858337	405	1425268	858337	405	0	0	0	No hole found but survey lath found
CH3890CC	1420357	864251	467	1420357	864250	466	0	1	0	
3580LW4	1427671	867643	559	1427670	867647	560	0	-4	0	Placard on well shroud labeled as 3280-LW4
CH3895CC	1420826	871604	481	1420826	871604	481	0	0	0	No hole or survey lath found

9.1.2. Verification of Drill Hole Data and Geologic (Mineral Resource) Model

The drilling database for the Red Hills Mine was organized into three Excel files related to lithology intervals, collar survey, and quality. The files encompassed the geologic modeling inputs including lithology picks, total depth of hole, base of oxidation (weathering), hole coordinates, and coal core quality data. A secondary compilation of drilling data was created to verify completeness of data related to each drill hole including the file location of geologist field logs and laboratory certificates or reports for core quality, and details of each drilling program such as contractors who performed the work and year drilled.

The drilling files were saved on the MLMC network drive which contains the geologic model and has limited access by engineering and geology at MLMC.

Once the drilling database was compiled, a series of routine data integrity checks were performed by the QP on the database to check for common errors and omissions. The QP visually inspected the database after updates were made, then conducted a second data validation check using Maptek Vulcan software. The validation checks included, but were not limited to, the following:

- Verified each hole has a unique collar location.
- Verified the total hole depth on the collar table matches the total depth on the lithology table.
- Verified the from and to depths on the lithology table and quality table increase down hole.
- Verified for overlapping intervals in the lithology table based on from and to depths.
- Verified the from and to depths on the quality table match the associated seam depths on the lithology table.

For any errors or omissions reported, the QP reviewed the geophysical logs, field logs, and quality reports related to the specified holes to reconcile the differences.

After the initial checks were performed, the QP identified any holes in close proximity to other holes such as twinned or re-drilled holes. If two drill holes fell within 50-foot of one another, the data from the two holes was reviewed. The hole with the highest confidence and most complete data was selected to be included in the model. After database checks and reconciliations were completed, the QP completed the modeling process which is detailed in Section 11.1 of this TRS.

The QP reviewed and validated the constructed geological model using various checks between drill hole data and modeled horizons. Drill hole locations were randomly selected to verify modeled values of each horizon and were found to be representative of the imported drill hole data. Additional visual inspection of the model included review of various consecutive cross sections as well as isopach maps of the modeled structure and quality. Newly modeled grids were also compared to previous models. Changes in modeled values were minor and isolated to areas where new drilling data had been included from recent exploration programs. Anomalies were reviewed against the original drill hole data, any errors in the drilling database were reconciled and the model was reconstructed.

It is the QP's opinion that the analytical results from the coal cores collected during MLMC's exploration programs are consistent with actual as-delivered quality from the active mining operations at the Red Hills Mine. This opinion was based on comparison of historical quality projected from the geologic model for the annual operating plans to actual as-delivered quality indicated by the customer's (Red Hills Power Plant) independent laboratory, Standard Laboratories, Evansville, IN. It is also the QP's opinion that the modeled structure of the lignite seams is consistent with active mining operations based on comparisons of modeled seam thickness and trends against actual surveyed seam thicknesses and trends.

The QP found the geologic model for Mineral Resource estimation was a reasonable and reliable representation of the geologic structure and quality of the lignite seams (horizons) at the Red Hills Mine.

9.1.3. Verification of the Reasonable Prospect for Economic Extraction to Support Mineral Resource Estimation

The Red Hills Mine has acquired data related to mine development and production within the local lignite deposit over an extended operational history. The QP verified the assumptions made for the estimation of Mineral Resources were well within accuracy required for an initial assessment (IA) level of study based on actual historical metrics and a contract period defined by the LSA with the RHPP. Data referenced for verification included actual month end reconciliations, production reports, and mine permit requirements. The potential for economic extraction is justified by the terms of the existing LSA with the RHPP through April 2032.

9.1.4. Limitations on Data Verification for Mineral Resources

Representatives of MLMC or the Company were not involved in the original drilling exploration programs conducted by Phillips prior to 1997. MLMC obtained the collar surveys, geophysical logs, coal core analyses, and geologist field logs for each hole from Phillips, but was unable to observe the drilling, sampling, or sample preparation related to these data. The largest uncertainty lies in the method of the collar survey of the early data drilled from 1975 to 1980. It is unknown to what degree these holes were surveyed. Collar elevations for these early drill holes were plotted against a topographic digital terrain model (DTM) contoured at 5-foot intervals and checked for discrepancies. All plotted drill hole locations fell appropriately within the respective contour interval.

MLMC, historically, has contracted Diversified Drilling Services and Century GLS, contractors used by Phillips for the early exploration, to perform in-fill drilling programs, such that MLMC has gained familiarity in these contractors' drilling and downhole mapping methods. Furthermore, comparisons of new drilling data to the older Phillips data have been completed as fill-in drilling progresses ahead of mining. These comparisons, and the level of documentation Phillips provided upon acquisition of the coal assets translates to a level of confidence in these data to use in the geologic modeling for Mineral Resource estimation. Nonetheless, there is still some uncertainty related to the Phillips drill hole data which the QP has considered in the determination Mineral Resource estimations as discussed in Section 11 of this TRS.

Additionally, as discussed previously in Section 7.2 of this TRS, the QP was also unable to verify laboratory records for the 22 coal cores collected in 2003 as included in the drilling database. The QP reached out to the independent laboratory for copies of the original quality reports. However, the time of record exceeded the laboratory's holding period of seven years and copies were not available. The QP then compared the related quality of the drilling database to the associated month end reconciliation reports and found that modeled tonnages in the area of the 2003 drilling were representative of the actual mined tonnage as shipped to the RHPP. After this comparison, the QP determined the uncertainty in the modeled 2003 quality would not materially affect the Mineral Resource estimations.

9.1.5. QP's Statement of Adequacy of Data for Mineral Resources

Data disclosed in this TRS used for the preparation of geologic models for the purpose of Mineral Resource estimations at the Red Hills Mine have been verified by the QP. The QP has been involved with the collection of these data during drilling exploration programs since 1999. These data include drill hole surveys, geophysical logs, coal core quality, and other relevant test data. Procedures discussed previously in this section were used by the QP to reconcile any discrepancies upon review of the available data. In addition to a substantial geologic database, historical data since the mine opened the original boxcut in 2000 was available to the QP to review to ensure appropriate mining costs were applied to estimate Mineral Resources.

It is the QP's opinion that the data provided for this TRS is sufficient for the determination of Mineral Resources at the Red Hills Mine.

9.2. Data Verification Procedures for Mineral Reserves

9.2.1. QP Site Visit

Jefferson King, is serving as the Mineral Reserve QP, a licensed Professional Engineer (License Number 18896), a Land Surveyor (License Number 3033) in the State of Mississippi, and a Registered Member of SME (ID 04195446). He has had direct involvement with production, technical projects, development of the LOM plan and financial analysis since 2013. He has held various roles in the Engineering department at Red Hills and is currently serving as the Engineering Manager. In the role of Engineering Manager, he has direct involvement with daily production operations and oversight and management of technical projects, and is directly involved in the development of the LOM finances at the Red Hills Mine.

9.2.2. Verification of Hydrogeology Data

Groundwater and surface water studies were conducted on the Red Hills Mine site, as described in Section 7.3 of this TRS, and used to develop mine plans as described in Section 13 of this TRS. The QP has reviewed the findings of these studies and believes they are thorough, complete and provide the necessary information for the start-up and ongoing operation of the Red Hills Mine. Sampling and modelling techniques used in the studies were adequate and completed in a professional manner for a PFS level assessment of the hydrology/hydrogeology. The locations of the surface water sampling sites and monitoring/test well locations are adequate for the MS-005 permit area. The Red Hills Mine has operated for over 20 years and is continuously gaining an improved understanding of how the groundwater and surface water impacts mining operations along with environmental compliance.

9.2.3. Verification of Geotechnical Data

Several geotechnical studies were initially conducted on the Red Hills Mine site as described in Section 7.4 of this TRS and subsequent studies conducted and described in Section 13.1 of this TRS. These studies have been reviewed by the QP and they provided the basis for the mine plan designs. Sampling and modelling techniques used in the studies were adequate and completed in a professional manner for a PFS level assessment of the geotechnical parameters. It is the opinion of the QP that the geotechnical studies reviewed have been consistent with conditions experienced in the field from the active mining operation and are adequate for use in the MS-005 permit area.

9.2.4. Verification of Cut-off Grade, Dilution Assumptions and Modifying Factors

The QP reviewed the cut-off grade, dilution assumptions, and all modifying factors for completeness and reasonableness and found them to be consistent with the realized results from the active mining operation.

Quality reject specifications from the LSA are the basis for determining the cut-off grades. While the cut off grades vary from the LSA reject specifications any coal that meets the cut off grades can ultimately be blended with other coal seams to meet the LSA requirements. The QP has reviewed the cut-off grades and LSA and in his opinion these have been properly established.

Dilution parameters are reasonable and have been verified by comparing projected to actual as-delivered quality data which confirms the established dilution parameters are a good representation of final results. Recovery rates have been refined over the course of operating the Red Hills Mine and are constantly being compared to actual recoveries for verification.

Modifying factors used in pit designs, as described in Section 13 of this TRS, have remained consistent since mine inception with limited changes. The modifying factors have been reviewed by the QP and consistently applied in the mine design process.

It is the opinion of the QP that the cut-off grade, dilution assumptions and modifying factors are adequate for purposes of determining Mineral Reserves.

9.2.5. Verification of Ultimate Pit Configuration

The ultimate pit configuration is defined by physical constraints including permitted boundaries and related offsets and buffers, and areas where the stripping ratio exceeds economic limits. It is the opinion of the QP that the ultimate pit configuration has been properly defined and is adequate for purposes of determining Mineral Reserves.

9.2.6. Verification of Cost Estimate, Pricing Assumptions, and Economic Analysis

The QP has reviewed annual historical values for all costs, pricing assumptions and economic analysis to be reasonable for future projections, which will continue to be refined annually as more data is collected from ongoing operations, to improve the accuracy of the projections. This information has been used to support parameters used during mine planning.

9.2.7. Workforce, Staffing and Equipment

The QP considers that reconciliations of staffing and workforce requirements, actual equipment capacities and productivities have been appropriately considered while establishing the needs of executing the mine plan. The Red Hills Mine is an active, on-going operation and the staffing, workforce, and equipment requirements are well established. Ultimately the required staffing, workforce, and equipment needs are driven by the dispatch of the RHPP.

9.2.8. Environmental Factors

The QP has worked closely with the Red Hills Mine Environmental Manager and has helped develop the site closure and reclamation plans and the related costs. Proper monitoring programs to meet mine permit requirements are in place. Field work has been observed routinely by nature of the QP’s on-site role to verify the conditions and assumptions that underscore the environmental data used in this TRS.

9.2.9. Limitations on Data Verification for Mineral Reserves

It is the opinion of the QP that there are no limitations to data verification for Mineral Reserves.

9.2.10. QP's Statement of Adequacy of Data for Mineral Reserves

The QP has verified the data disclosed, including prior technical studies used in the development of the modifying factors, cut-off grade, ultimate pit configuration, mine design, schedule, workforce and staff requirements, equipment needs, environmental factors, cost assumptions, pricing assumptions and economic analysis. The QP has been involved with the collection and use of this data since 2013 while being employed at the Red Hills Mine. Red Hills Mine has established internal policies and controls to manage the environmental, regulatory and social or community aspects for the mining operations. These are periodically reviewed by the QP and other managers at the Red Hills Mine and the Company's management for their effectiveness in a culture which follows the principle of continuous improvement. The QP is of the opinion that a reasonable level of verification has been completed and that no material issues have been left unidentified in the course of collecting and analyzing the data described in this report.

It is the QP's opinion that the data provided for this TRS is sufficient for the determination of Mineral Reserves at the Red Hills Mine.

10. Mineral Processing

It was identified early on that the Red Hills Mine and power plant project would only be viable if the fuel source could be used as a direct feed ROM fuel source. Therefore, no washability tests for processing or metallurgical tests were conducted.

11. Mineral Resource Estimates

This section contains forward-looking information related to the Mineral Resource estimates for the Red Hills Mine. The material factors that could cause actual results to differ from the conclusions, estimates, designs, forecasts or projections include geological modeling, grade interpolations, cutoff parameters, lignite price estimates, mining cost estimates, and mine design parameters.

11.1. Key Assumptions, Parameters and Methods

The QP developed the stratigraphic geologic model for Mineral Resource estimation using Maptek Vulcan software. All verified drilling data as of January 01, 2024 was considered for inclusion in the model. Key assumptions, parameters and methods to estimate Mineral Resources are discussed herein. In-fill drilling has been completed through 2024, however has not been included in the current geological model. In the opinion of the QP, the drill holes from the 2024 program are in-fill and will not materially affect the Mineral Resource estimates stated in this TRS.

11.1.1. Horizons

The structure of the Red Hills Mine deposit is determined by "to" and "from" depth picks from geophysical logs and geologist's drill hole field logs correlated to the drill hole collar survey. Depth picks represent the roof or floor of a lignite seam which define each horizon or domain.

Laboratory results for split cores are reviewed prior to inclusion in the geologic database for modeling. Quality results for all split samples to identify composition concentrations are identified as a continuous seam in the geologic database. The weighted average is computed in the modeling process, which allows for a single composite value for each lignite seam per drill hole.

Roofs, floors and parting samples that meet a minable quality and thickness (see Table 11.1) are identified as part of the associated seam and are modeled in the same manner as the split samples described previously. Roofs, floors and partings that do not meet a minable quality or thickness are included in the geologic database as a point of record, but are not modeled with a seam identifier, and thus the quality and thickness of those sample splits are not composited with the associated seam.

Table 11.1 Quality (as-received basis) and Thickness Limits

Parameter	Minimum	Maximum
Calorific Value, Btu/lb	4,000	N/A
Ash, %wt	N/A	30.0
Thickness, feet	1.0	N/A

Table 11.2 presents the stratigraphic horizons modeled. Horizons considered for Mineral Resource estimates are indicated with an asterisk. Modeled horizons were required to have a minimum of ten coal core samples in the drilling database to be considered. The QP found a minimum of 10 coal core samples provided the statistical confidence to characterize the quality of a lignite seam.

Table 11.2 Stratigraphic Horizons

HORIZON ID	SEAM NAME	AVERAGE THICKNESS
COJ	J-Seam	1.7
CI2	I2-Seam	1.1
COI	I-Seam	1.6
CI1	I1-Seam	1.1
CH2	H2-Seam	1.4
COH*	**H-Seam***	**2.5**
CH1	H1-Seam	1.2
CG2	G2-Seam	1.4
COG*	**G-Seam***	**3.0**
CG1	G1-Seam	1.2
CG3	G3-Seam	1.3
CF2	F2-Seam	1.0
COF*	**F-Seam***	**2.8**
CF1	F1-Seam	1.4
CE2	E2-Seam	0.9
COE*	**E-Seam***	**3.5**
CD6	D6-Seam	1.1
CD4	D4-Seam	1.3
CD2	D2-Seam	1.2
COD*	**D-Seam***	**3.2**
CC2	C2-Seam	0.9
COC*	**C-Seam***	**3.0**
CC1	C1-Seam	1.0
CB2	B2-Seam	1.1
COB	B-Seam	3.1
CB1	B1-Seam	1.5
CB3	B3-Seam	1.0

***** Indicates horizon with an average drill hole quality and an adequate number of core samples which meet the limits for consideration as a Mineral Resource.

11.1.2. Quality Parameters and Density Determination

The quality parameters modeled in the resource model are calorific value (Btu/lb), moisture (wt%), ash (wt%), and sulfur (wt%); typical Short Proximate analysis reported on an as-received (AR) moisture basis. The minimum and maximum quality constraints which determine feasibility to be categorized as a Mineral Resource are also listed in Table 11.1.

In addition to the quality grids, each lignite seam (horizon) has a modeled density grid. Specific Gravity (SG) analysis is regularly tested on lignite core samples. Modeled SG values by horizon are converted to a density grid in the modeling process by converting grams per cubic centimeter (g/cm^3) to tons per cubic foot (tons/ft^3) such that: SG * Density of Water (62.43 lb/ft^3) * 2000 lb/ton.

11.1.3. Modeling Process

After the QP verified the drilling data following procedures outlined in Section 9.1 of this TRS, the stored drill hole data encompassing geologic lithology picks, quality data, and collar surveys was imported into the modeling software.

Once the drilling data was imported, a preliminary topographic surface was created by triangulation of an electronic contour map of the pre-mining topography of the Red Hills Mine and surrounding area. A 50 by 50-foot grid surface was then applied to the triangulated surface. Surveyed drill holes were modeled using inverse distance with a grid cell of 50-feet to create a second topographic grid. Differences in the surface produced by the surveyed drill holes are added to the preliminary topographic surface to create the designed topographic surface of the area to be modeled.

The lithology and location tables were then referenced by the modeling program and the structural model was developed. The lignite horizons were correlated and modeled using 50-foot grid cells. During the modelling process, lithologic data were extrapolated from ten surrounding drill holes using an inverse distance squared calculation to infill the grids where appropriate.

The base of oxidation (BOX) depth determined from drill cuttings and continuous (overburden) cores was modeled to provide the limit for suitable plant growth material (SPGM) for operations. This limit also generalizes the base of weathering in that lignite above this depth has been partially oxidized and typically exhibits unacceptable quality characteristics. The depth of the BOX layer was modeled by the grid calculation method using 50-foot grid cells and the extrapolated depth of the BOX from drill hole to drill hole. Lignite seams were then subcropped based on the BOX and lignite seams above the BOX were removed from the model.

The structural model was validated based on geological cross sections and isopach maps of the seam roofs and floors that were created, and checked by the QP. Any errors identified in the lithologic descriptions were reconciled.

Lignite quality was then modeled for the entire deposit. As described above, quality data was first composited for each lignite seam by drill hole. As with the structural model, the quality model uses 50-foot grid cells to model quality of the deposit. Drill holes missing quality data employed an inverse distance squared calculation to assign averaged values from ten surrounding drill holes.

In-situ tonnages for the lignite seams were estimated within Maptek Vulcan by applying a formula to each horizon by the area, thickness, density, and real/extrapolated quality values (i.e. modeled parameters).

11.1.4. Justification of Modeling Methods

Historically, geologic models at the Red Hills Mine have been generated using inverse distance methods. The models have proved to be consistent with field conditions (structure and quality), which is likely attributed to the simplistic, stratigraphic geology of the region as described in Section 6.0 of this TRS. Geologic units are laterally consistent with generally graded quality. Use of inverse distance methods has proven to be robust in continuous stratigraphic deposits. The QP did not see a need for MLMC to alter geologic modeling methods.

11.1.5. Limits and Constraints on the Mineral Resource Estimates

The Mineral Resources presented in Table 11.4 were estimated by applying a series of geologic and physical limits in addition to mining and economic constraints which meet the level of accuracy required for an initial assessment (IA). The potential of economic extraction is justified by the terms of the existing LSA contract and are clearly defined through April 2032. Key constraints used by the QP to determine Mineral Resource estimates are summarized below. Details pertaining to physical constraints are discussed further within Sections 3 and 17 of this TRS. Mining and economic constraints specific to Mineral Resource estimates are discussed herein.

Geologic Constraints:

- Modeled roof and floors of each lignite seam (horizon);
- Base of oxidation (BOX);

Physical Constraints:

- Topography surface;
- Lease and fee coal boundaries;
- Surveys of mined out tonnages as of December 31, 2024;
- Offsets from unleased land tracts and occupied dwellings;
- Buffers from state and federal parks;
- Existing roads and highways, major utilities, and major surface infrastructure without prior agreements for relocation or temporary closure;
- Stream offsets for Waters of the US (WOTUS) that fall outside of mitigation permits.

Mining and Economic Constraints:

- Resource categorization parameters based on distance from point of observation and drill hole sample count criteria;
- Resource pit shells developed from general mine design parameters and reasonable unit costs used to determine the max cumulative strip ratio for the tonnage to be economical;
- Stated in-situ without any mining loss, dilution or other modifying factors applied;
- Stated exclusive of Mineral Reserves;
- Limits on quality and thickness parameters presented in Table 11.1.

11.1.6. Generation of Pit Shells for Mineral Resource Estimates

Resource pit shells were projected and confirmed to meet the supply requirements of the LSA.

The QP determined the maximum reasonable cumulative stripping ratio was 18:1 for the Red Hills Mine deposit assuming a lignite sales price based on the LSA of $34.02 per ton as of December 31, 2024. Assumptions of mining costs were based on knowledge of surface mining methods in a simple multi-seam, stratigraphic deposit.

Two pit shells were identified for Mineral Resource estimates. Mine Area 2 and Mine Area 3 pit shells fall within the MS-005 permit area.

The geologic model was used to create a stripping ratio map of the deposit. Recovery of tonnage was assumed to be 100-percent. No dilution factors were applied. The C-seam was assumed by the QP to be the lowest potentially mined lignite seam. Highwalls and endwalls were projected up from the lowest mineable seam to the topography at 40-degrees, an angle appropriate for surface mining in soft materials. Preliminary pit shells were determined by the QP based on the maximum cumulative stripping ratio, then modified for any physical constraints.

11.2. Mineral Resource Estimates

11.2.1. Basis for Mineral Resource Estimate

The basis of the Mineral Resource estimates for the Red Hills Mine deposit and the methods in which they were prepared are summarized for this item. The S-K 1300 regulations (17 CFR 229.1300) define a Mineral Resource as:

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

Following definitions presented in 17 CFR 229.1300 and guidance from the Committee for Mineral Reserves International Reporting Standards (CRIRSCO), Mineral Resources are divided into three categories as listed below and are ranked by increasing level of confidence. Mineral Resources are reported as in-situ tons such that no adjustments have been made to account for mining recovery or losses.

Measured Mineral Resources are defined as a Mineral Resource for which quantity and quality are estimated on the basis of conclusive geological evidence and sampling such that the geologic certainty of the Mineral Resource is sufficient to allow the QP to apply modifying factors in detail to support detailed mine planning and final evaluation of the economic viability of the deposit. Measured Mineral Reserves have the greatest confidence defined by the QP, and may be converted to a Proven Mineral Reserve.

Indicated Mineral Resources are defined as a Mineral Resource for which quantity and quality are estimated on the basis of adequate geological evidence and sampling such that the QP can apply modifying factors in sufficient detail to support mine planning and evaluation of the economic viability of the deposit. These Mineral Resources may be converted to a Probable Mineral Reserve. Indicated Mineral Resources have a moderate level of confidence determined by the QP, and could be upgraded to a Measured Mineral Resource with further exploration.

Inferred Mineral Resources are defined as a Mineral Resource for which quantity and quality are estimated on the basis of limited geological evidence and sampling. Geological evidence is sufficient to imply but not verify geological and quality continuity. Inferred Mineral Resources have the lowest level of confidence determined by the QP.

The QP based the Mineral Resource estimates presented in Table 11.3 for the Red Hills Mine on a stratigraphic geologic model generated from the verified drilling exploration data presented in Section 7.2 of this TRS. The choice of stratigraphic modeling is due to the lateral persistence and continuous extent of the lignite seams.

11.2.2. Mineral Resource Statement

The categorized Mineral Resources reported in Table 11.3 are exclusive of in situ Mineral Reserves. The effective date of Mineral Resource estimates is December 31, 2024.

Table 11.3 Mineral Resource Estimates

Red Hills Mine	Resource Classification	Tonnage (Kt)	Quality (As-Received)			
			Calorific Value (Btu/lb)	Moisture (%wt)	Ash (%wt)	Sulfur (%wt)
Mine Area 2	Measured	4,400	5,200	44.6	13.0	0.6
	Indicated	400	5,180	44.1	13.6	0.6
	Measured + Indicated	4,700	5,200	44.5	13.0	0.6
	Inferred	0	0	0.0	0.0	0.0
Mine Area 3	Measured	0	0	0.0	0.0	0.0
	Indicated	0	0	0.0	0.0	0.0
	Measured + Indicated	0	0	0.0	0.0	0.0
	Inferred	100	5,200	45.5	12.3	0.5
Total Resources	Measured	4,400	5,200	44.6	13.0	0.6
	Indicated	400	5,180	44.1	13.6	0.6
	Measured + Indicated	4,700	5,200	44.5	13.0	0.6
	Inferred	100	5,200	45.5	12.0	0.5

Notes:

1. Mineral Resource Estimate has been prepared by a qualified person employed by NACCO NR as of December 31, 2024
2. Mineral Resources that are not Mineral Reserves do not have demonstrated economic viability and there is no certainty that all or any part of such Mineral Resources will be converted into Mineral Reserves.
3. Mineral Resources are in-situ and exclusive of 22.9 million tons (Mt) of Mineral Reserves.
4. Mineral Resources are reported using an economic cutoff of $34.02 per ton.
5. Resources are presented with a minimum 1 foot seam thickness, a maximum as received moisture basis ash content of 30%, and a minimum calorific value of 4000 BTU/lb on an as received moisture basis cutoffs.
6. Resources are estimated using Vulcan Software.
7. Tonnages and qualities have been rounded to an accuracy level deemed appropriate by the QP. Summation errors due to rounding may exist.

11.3. Cut-off Quality, Assumed Cost and Sales Price

Quality limits were previously discussed with Table 11.1 and in subsection Limits and Constraints on the Mineral Resource Estimates under Section 11.1 of this TRS.

Assumed cost and sales price to determine Mineral Resources was previously defined by the stripping ratio and discussed in subsection Generation of Pit Shells for Mineral Resource Estimates of Section 11.1 of this TRS.

11.4. QP's Classification of Mineral Resources

The Mineral Resource categorization applied by the QP includes the consideration of quality and thickness by seam and by drill hole and the spatial distribution of drill holes. Mineral Resources presented in this TRS were estimated and categorized as Measured, Indicated, or Inferred.

Table 11.2 identified the lignite seams for initial consideration of a Mineral Resource by the QP. The indicated seams had a minimum of ten coal core samples for quality estimation, and an average coal core sample quality which fell within the limits provided in Table 11.1. Mineral Resources were then further defined by the three identified resource pit shells.

As discussed in Section 7.2 all drill holes within the Red Hills Mine deposit obtained structural data related to the lignite seams, where a portion of these drill holes also included quality data from the collection of coal core samples. As such, the QP determined it would be appropriate that the defined distances for Mineral Resource categories were supported by the ash variography of the C Seam. C Seam is the stratigraphically deepest and most spatially consistent seam within the deposit and represents the basal seam of the LOM plan. A histogram of the ash distribution has been included as Figure 11.1 which shows a typical positive skew distribution of ash samples for C Seam. Figure 11.2 shows the variogram developed for C Seam ash which displays the continuity of the ash content within the C Seam. A range of 8,000 feet can be estimated from this C Seam ash variogram. Samples beyond the range are no longer considered to have a correlation.

Figure 11.1 C Seam Ash Histogram

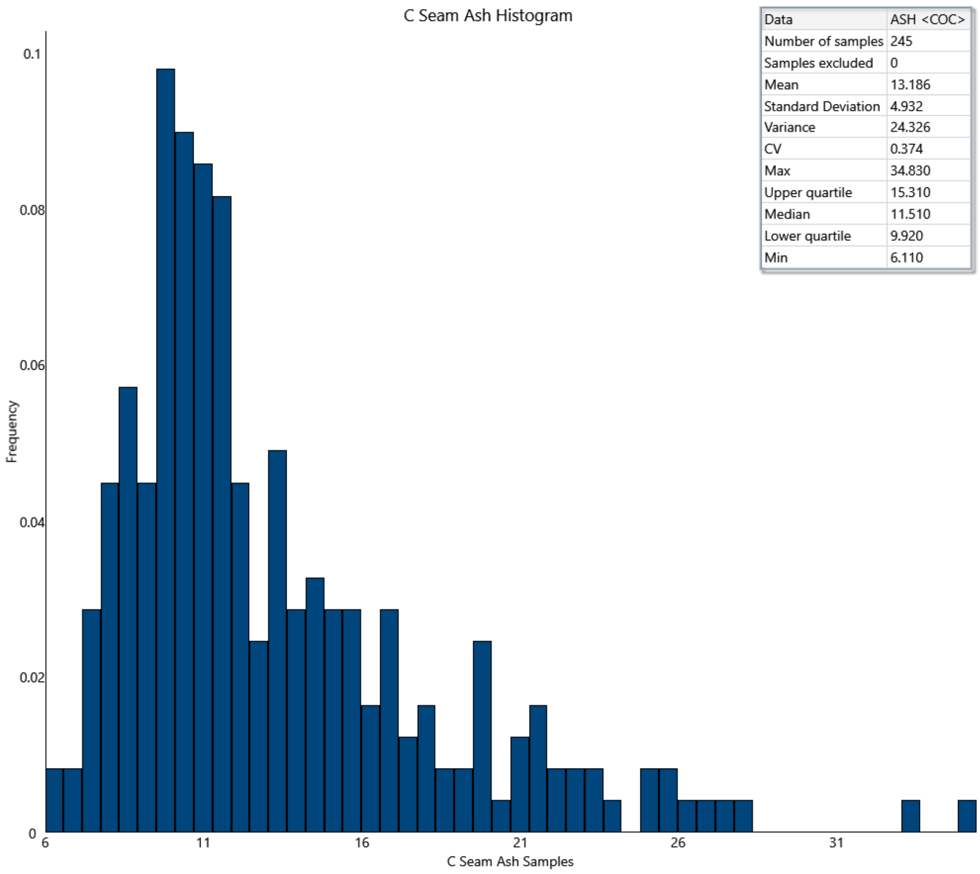
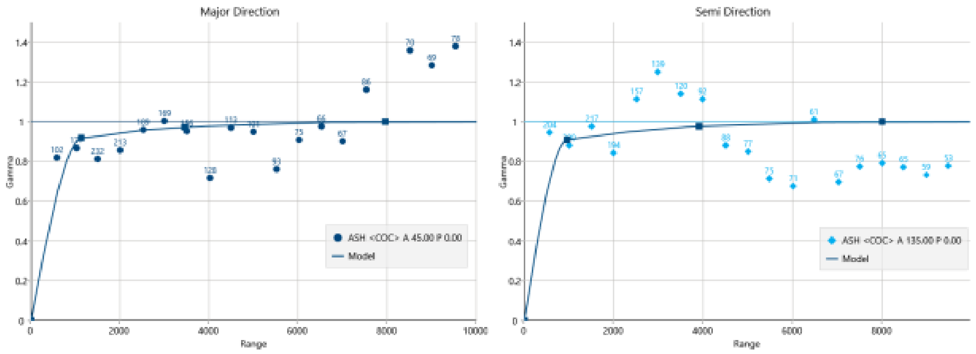
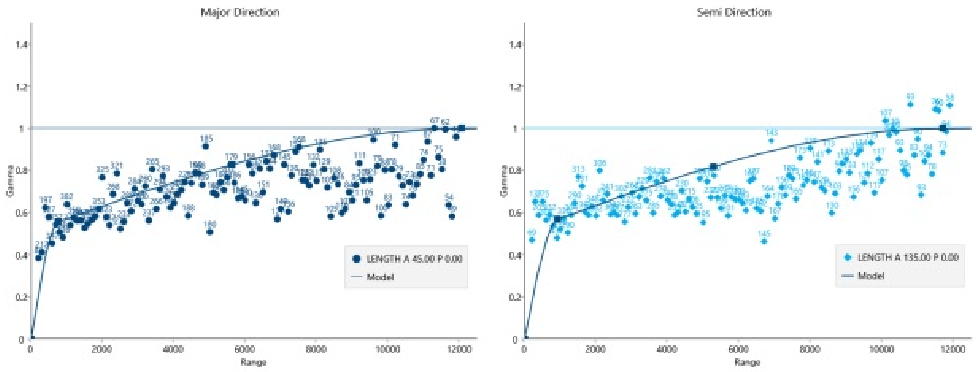


Figure 11.2 C Seam Ash Variogram



A variogram of C Seam thickness was developed to show the continuity of the structural thickness of the C Seam and has been included as Figure 11.3. A range of 12,000 feet can estimated from the C Seam thickness variogram.

Figure 11.3 C Seam Thickness Variogram



The QP has determined that a maximum classification distance of 8,000 feet is appropriate for the deposit by analyzing the variogram ranges from the C Seam ash and comparing this range with the variogram range for the C Seam thickness. The C Seam ash variogram range distance is conservative and is within the 12,000 feet range for the structural thickness continuality of the C Seam. Potential overstating of reserves is mitigated by using the C Seam ash variogram range with the shorter distance when compared with the larger C Seam thickness range.

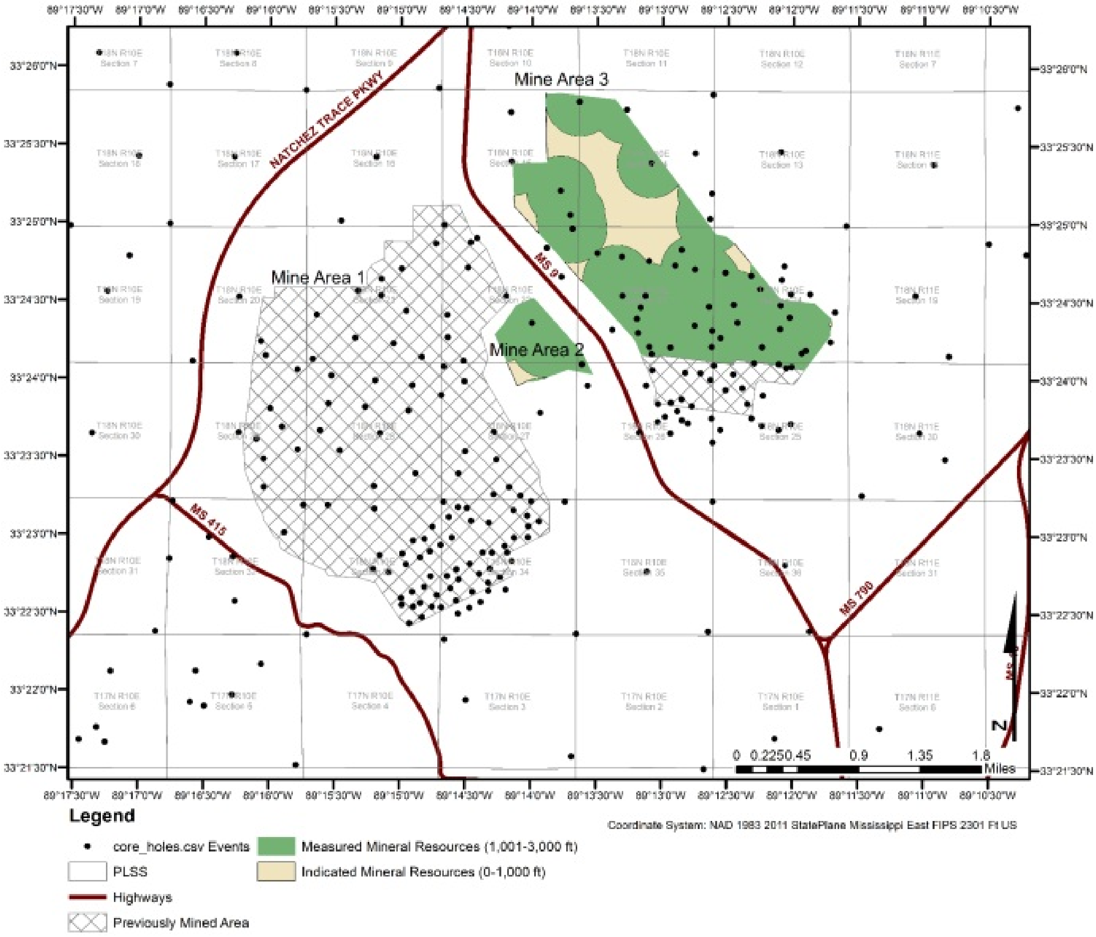
After review, the QP determined distances from core holes of 2,667 feet, 5,333 feet, and 8,000 feet are appropriate for categorization of Mineral Resources as Measured, Indicated, or Inferred, respectively (Table 11.4). These classification distances are applied to each seam by only using holes where each representative seam was sampled for quality as points of reference.

Table 11.4 Mineral Resource Categories – distances from C Seam Ash Variogram

Mineral Resource Category	Lower Distance (Ft)	Upper Distance (Ft)
Measured	0	2,667
Indicated	2,668	5,333
Inferred	5,334	8,000

As stated previously, all Mineral Resource tonnages meet the minimum of 10 samples per seam for estimation, meet the quality limits, and fall within a defined resource pit shell. The distinguishing factor between Measured, Indicated, and Inferred Resources is the distance of the resource from a core hole as described below and shown in Figure 11.4. Please note that Figure 11.4 is only for the C Seam, as an example, individual maps and influence polygons were compiled for each individual seam and those were utilized for the Mineral Resource estimate.

Figure 11.4 Red Hills Mine Mineral Resource Classification for C Seam



Measured Mineral Resources are defined as tonnages which meet the general resource requirements and fall within an area where the distance from a core hole is less than or equal to 2,667 feet. An extensive amount of fill-in drilling has occurred in areas where core holes have been drilled at a distance within 1,000-feet of each other. At this distance, much of the structural data has been tightened to a density of 500-feet or less. Most of this drilling data was collected by MLMC using known sampling methods and surveying methods. Due to the level of control and oversight during collection of this drilling data, the resulting resource estimates have a high level of confidence by the QP and a low level of uncertainty.

Indicated Mineral Resources are defined as tonnages which meet the general resource requirements and fall within an area where the distance from a core hole is greater than 2,667 feet and less than or equal to 5,333 feet. While a portion of this data still relies on some of the early exploration data collected by Phillips, much of the area has been filled-in with data collected by MLMC using known sampling methods and surveying methods. While some uncertainty still exists in this data due to the influence of the early Phillips drilling, a moderate level of confidence in this data has been applied by the QP from more recent fill-in drilling.

Inferred Mineral Resources are defined as tonnages which meet the general resource requirements and fall within an area where the distance from a core hole is greater the 5,333 feet and less than or equal to 8,000 feet. Modeled values at this distance require a large amount of interpolation from drilling data collected in the early exploration stage conducted by Phillip's from 1975 through 1980 and, as such, holds the greatest uncertainty in sample collection and survey methods. Fill-in drilling, including twinned holes would increase the confidence in these data.

11.5. Uncertainty in the Mineral Resource Estimate

The drilling methods, sampling methods, hole survey, sample storage and preparation, and data processing for the Phillips holes are unknown and cannot be verified. More recent drilling appears to agree with the results of the original Phillips drilling. Risk associated with using the Phillips data is considered minimal since the newer data validates the Phillips drilling and sampling methods, sample storage, and data testing and processing. This is considered a low risk of uncertainty for all Mineral Resource classifications.

Geological uncertainties exist in the modeled limits of the coal seams. Although there are over 1,500 holes drilled and used to model this deposit, but subcropping of seams have been encountered in the Mine Area 1 that were not identified in any exploratory drilling campaign. These areas have been small and limited in aerial extent. Measured and Indicated classifications have a low risk to its resources due to the high density of sampling. Inferred class has a moderate level of risk of uncertainty to the geologic modeling.

Resource estimation distances were derived from a statistical analysis of C Seam as-received ash content and C Seam thickness. Variograms were developed for ash and thickness and the ranges were determined for each variogram. The variogram range for ash is estimated at 8,000 feet while thickness range is estimated at 12,000. By selecting the more conservative distance for the Inferred classification the QP believes that all there is a low risk of uncertainty for all Mineral Resource classifications.

Table 11.5 shows a tabular summary of the resource classification uncertainty.

Table 11.5 Resource Classification Uncertainty Summary

Uncertainty Type	Measured Uncertainty	Indicated Uncertainty	Inferred Uncertainty
Drilling	Low	Low	Low
Sampling	Low	Low	Low
Data Processing and Handling	Low	Low	Low
Hole Survey	Low	Low	Low
Geological Modeling	Low	Low	Moderate
Geostatistical Analysis	Low	Low	Low
Mineral Resource Estimate	Low	Low	Low

11.6. QP's Opinion on Potential Influences Affecting Mineral Resource Estimates

Due to the contract provisions of the LSA, factors including contract term or likelihood of economic extraction, lignite sales price, and quality parameters/limits have far less risk of being affected than a mineral sold on the open market. Nonetheless some risks still need to be addressed.

Additional exploration may positively or negatively affect Mineral Resource estimates. Furthermore, Mineral Resource estimates may be materially affected by a change in the assumptions including general mining costs and land control. New regulations may impose additional economic factors, delays to future permit renewals, or restrictions to physical estimation boundaries.

The QP is not aware of any specific factors that would currently materially affect the prospect of economic extraction.

12. Mineral Reserve Estimates

This section contains forward-looking information related to the Mineral Reserve estimates for the Red Hills Mine. The material factors that could cause actual results to differ from the conclusions, estimates, designs, forecasts or projections include geological modeling, grade interpolations, cutoff parameters, lignite price estimates, mining cost estimates, and final pit shell limits such as more detailed exploration drilling or final pit slope angle.

12.1. Key Assumptions, Parameters, and Methods

To develop the estimate of Mineral Reserves, modifying factors were applied to Measured and Indicated Resources. Inferred Mineral Resources were not considered for Mineral Reserves. The following modifying factors were applied using key assumptions, parameters and methods to convert Mineral Resources to Proven and Probable Mineral Reserves.

12.1.1. Stripping Ratio and Pit Limits

The maximum stripping ratio for Mineral Reserves was determined from analysis of historical and future costs compared to the estimated base sales price per MMBtu as defined in the LSA through April 1, 2032 as described in Section 19 of this TRS. The cost and price per MMBtu establish the maximum allowable cumulative stripping ratio limit of 14:1, which is averaged over the LOM plan. MLMC has historically found this stripping ratio to provide the necessary economic mining cost compared to selling price. The base price for the dedicated lignite is defined in the LSA with the estimated average price per ton of $34.41 for lignite delivered and sold over the LOM plan. All costs were escalated at various rates based on the forward-looking Consumer/Producer Price Index with budgeted 2025 costs used as the base year. The maximum allowable cumulative stripping ratio establishes the pit limits within the Mineral Resource pit shells.

Stripping ratios remain relatively consistent across the MS-005 permit area with the exception of high stripping ratios along the east side of the permit area which defines the eastern boundary of mining.

12.1.2. Lignite Quality

Lignite that was unable to be blended to meet the quality specifications as outlined in the LSA (Table 11.1) was eliminated from consideration and not included in reserve estimates.

12.1.3. Modeled Mining Parameters

The geologic model used for estimation of Mineral Resources was modified to account for the minimum mining thickness of 1-foot and dilution parameters as described in Section 13.2 and Table 13.3 of this TRS. Additionally, seams with a parting thickness of less than 6-inches were composited.

12.1.4. Assumptions and Modifying Factors

The following key assumptions, parameters and modifying factors were used by the QP to estimate the recoverable Proven and Probable Reserves contained within the LOM:

- All recoverable lignite required to fulfill the contractual obligations of the LSA is contained within the LOM plan pit extents;
- Geological structure and quality model are as described in Section 11 of this TRS;
- Only Measured and Indicated Resources were included;
- Maximum cumulative stripping ratio 14:1 (averaged over LOM plan);

- Mining production rates on a cubic yard and per ton basis remain relatively consistent with historical performance;
- Mining costs on a unit basis remain relatively consistent with historical performance;
- Depth of weathering (base of oxidation) as defined by Section 11 of this TRS;
- Minimum minable lignite thickness: 1.0 feet;
- Minimum parting thickness before seams are composited: 6.0 inches;
- Maximum depth of mining: approximately 320 feet;
- The Mineral Reserves fall within the Mineral Resource pit shells which have clearly defined physical constraints;
- Mining dilution parameters defined in Table 13.3 ROM Dilution Parameters;
- Lignite density defined by seam from coal core drilling data and modified by dilution parameters and approximately 80 lb/ft^3;
- Recovery rates by seam as presented in Table 13.4;
- Quality limits as defined by the LSA and presented in Table 11.1 were applied after dilution has been accounted for, and;
- Forecasted annual power plant MMBtu requirements.

12.1.5. Method

The RHPP provides a forecast of MMBtu requirements to MLMC on an annual basis. MLMC compares this forecast to historical plant requirements to develop a workplan of MMBtu demand for the LOM. The LOM plan assumes the RHPP will not continue to operate after the expiration of the current contract with CGLP on April 1, 2032.

To develop the LOM plan, modifying factors including minimum mining thickness, minimum parting thickness, and mining dilution parameters were applied to the geologic (Mineral Resource) model within Maptek Vulcan to create the Mineral Reserve model.

MLMC engineers then project mining pits within Maptek Vulcan. Projections were directed to the topography from the lowest mineable lignite seam. The mining pit width is 170’ based on the current mining equipment operating parameters. The mining pit length varies based on mining pit limits. Highwalls are projected at 42-degrees. Endwalls are projected at 40-degrees with the allowance for a 150-foot wide bench to establish haul roads. Final pit extents were limited by a maximum cumulative stripping ratio of 14:1 (average over the LOM plan). Further justification of pit design parameters is provided in Section 13 of this TRS.

Once mining pits were projected, volumes, tonnages, and associated quality parameters were exported from Maptek Vulcan. The blocks were exported as volume for burden horizons and as tons for lignite horizons. The QP reviewed the exported quality for each lignite horizon block to ensure quality thresholds were met. Any lignite block that did not meet the minimum quality parameters was not considered a Mineral Reserve and the associated block was considered waste material (burden block). The exported data was then sequenced and the overburden blocks were then assigned to the appropriate mining fleet to perform the work. The first step in sequencing was to apply recovery rates to lignite tonnages by seam.

Once the above modifying factors were applied, the sequencing program allotted lignite tonnages and burden volumes to the four major operational fleets of truck and shovel, dozer push, dragline, and lignite load and haul by period based on the workplan MMBtu requirements. The sequencer creates an output of volumes by fleet, including rehandle volumes, and projected tonnages and qualities by period.

This output then flowed through a series of steps to estimate equipment hours based on equipment production rates for each necessary piece of equipment. Calculations also included adjustments for:

- Equipment mechanical, operational, and weather availabilities;
- Fleet capacity including limiting production factors;
- Variations in haulage routes;
- Assumptions for crew sizes and;
- New and/or retiring equipment.

The output of allotted volumes, lignite tonnages, quality, and equipment hours by period were the inputs for the Red Hills Mine financial model. These inputs flow through the financial model, which was developed and refined by MLMC based on actual performance, along with escalated inputs for cost estimates for labor, materials and supplies, fuel and other cost components to generate cost projections for the LOM plan. In addition to general operating costs, contemporaneous reclamation, royalties, mine closure, and capital projects were projected and escalated accordingly. It is the opinion of the QP that the final LOM plan and related projected MMBtu costs and forecasted pricing justify the selection of the maximum cumulative stripping ratio and supports the conversion of Measured and Indicated Mineral Resources to Mineral Reserves.

12.2. Mineral Reserve Statement

Based on the LOM plan and modifying factors discussed above, the Red Hills Mine contains the economically minable Mineral Reserves listed in Table 12.1. The Mineral Reserves include approximately 20.0 Mt of ROM lignite, with an average calorific value of 5,000 Btu/lb, moisture content of 43.3 %wt., ash content of 15.3 %wt., and sulfur content of 0.6 %wt. The point of reference for Mineral Reserves is as delivered to the stockpile and RHPP silos as of December 31, 2024.

Table 12.1 Mineral Reserve Estimates

			Quality			
Red Hills Mine	**Reserve Classification**	**Tonnage (Kt)**	**Calorific Value (Btu/lb)**	**Moisture (%wt)**	**Ash (%wt)**	**Sulfur (%wt)**
Mine Area 3	Proven	17,300	5,090	43.3	14.9	0.6
	Probable	4,700	5,080	43.1	15.1	0.6
	Total	22,000	5,080	43.3	14.9	0.6
Stockpile & Silos	Proven	900	5,090	43.5	15.0	0.5
Total Reserves	Proven	18,200	5,090	43.3	14.9	0.6
	Probable	4,700	5,080	43.1	15.1	0.6
	Total	22,900	5,090	43.3	14.9	0.6

Notes:

1. Mineral Reserve Estimate has been prepared by a qualified person employed by MLMC as of December 31, 2024.
2. Mineral Reserves use an economic cut-off of a maximum cumulative stripping ratio of 14:1. There are some instances where the stripping ratio for a single year could exceed 14:1, but the average for the entire area evaluated is less than 14:1.
3. Historical coal recovery rates at Red Hills Mine have been applied to generate the Mineral Reserve tonnages.
4. Mineral Reserves are estimated using Vulcan Software.
5. Tonnages and qualities have been rounded to an accuracy level deemed appropriate by the QP. Summation errors due to rounding may exist.

12.3. Cut-off Quality and Sales Price

Cut-off quality and price were previously discussed in Section 12.1 under subsection Stripping Ratio and Pit Limits.

12.4. Mineral Reserve Classification

This Item discloses the Mineral Reserve estimates for the Red Hills Mine based on the QP's detailed evaluation of the modifying factors as applied to indicated or measured mineral resources, which demonstrate economic viability of the Red Hills Mine property. The estimated Mineral Reserves are in accordance with the definitions of "Mineral Reserve" as described by the S-K 1300 regulations (17 CRF 229.1300) as:

"A coal reserve is the economically mineable part of a Measured or Indicated coal resource demonstrated by at least a Preliminary Feasibility Study, which includes information on mining, processing, economic and other relevant factors that demonstrate, at the time of reporting, that economic extraction can be justified."

Following definitions presented in 17 CFR 229.1300, and guidance from the Committee for Mineral Reserves International Reporting Standards (CRIRSCO), Mineral Reserves are divided into two categories as listed below and are ranked by increasing level of confidence.

Proven Mineral Reserve is the economically mineable part of a measured mineral resource and can only result from conversion of a measured mineral resource. A Proven Mineral Reserve implies a high degree of confidence in the Modifying Factors.

Probable Mineral Reserve is the economically mineable part of an indicated and, in some cases, a measured mineral resource. The confidence in the Modifying Factors applying to a Probable Mineral Reserve is lower than that applying to a Proven Mineral Reserve.

The reference point at which Mineral Reserves are defined, is the point of sale to the RHPP, which is after two 20k ton storage silos following the truck dump hopper.

This disclosure of Mineral Reserves is based upon the qualified person's opinion that the LOM plan has been completed to a PFS level of accuracy, as defined in 17 CFR Part 229.1300, which includes and supports the qualified person's determination of Mineral Reserves.

The LOM plan included annual stripping and lignite production qualities and quantities. Annual production costs were estimated based on the mine plan quantities, surface mining methods, equipment fleets in use, and unit prices that have been proven by historical production at the Red Hills Mine. The current mining methods, used at the Red Hills Mine since inception, are planned to continue until enough lignite reserve is depleted to fulfill the contractual obligations of the LSA for fuel supply to the RHPP.

12.5. Multiple Commodity Mineral Reserve

The Red Hills Mine is a single commodity Mineral Reserve.

12.6. QP's Opinion on Risk Factors that could Affect Mineral Reserve Estimates

The Red Hills Mine began commercial deliveries in 2002. Since this is a well-established operation, the deposit, mining, and environmental aspects of the Project are very well understood. The knowledge for the Red Hills Mine is based on the collective experience of personnel from MLMC's site operations and technical disciplines gained since mine inception. This knowledge is supported by years of production data and observations at the Red Hills Mine.

The LOM plan included annual stripping and lignite production qualities and quantities. Production costs were estimated based on the mine plan quantities, surface mining methods, equipment fleets in use, and unit prices that have been proven by historical production at the Red Hills Mine. The current mining methods, used at the Red Hills Mine since inception, are planned to continue until enough of the lignite reserve is depleted to fulfill the contractual obligations of the LSA for fuel supply to the RHPP.

With this said, there are some risks that could materially affect Mineral Reserve estimates. Risks include changes in customer demand for any reason, including, but not limited to, dispatch of power generated by other energy sources ahead of coal, fluctuations in demand due to unanticipated weather conditions, regulations or comparable policies which could potentially promote planned and unplanned outages at the RHPP, economic conditions, including an economic slowdown that would affect manufacturing and a corresponding decline in the use of electricity, governmental regulations and/or inflationary adjustments. All of which could potentially have a material adverse effect on MLMC's financial condition.

Other risks include unforeseen changes in the LOM plan from additional exploration, changes in land control and new regulations that could delay future permit renewals or restrictions to physical mining boundaries.

At the time of this TRS, the QP is not aware of any specific factors that would currently materially affect the prospect of economic extraction.

Uncertainty in the Mineral Resource estimates was previously discussed in in subsection Uncertainty in the Mineral Resource Estimate in Section 11.5 of this TRS.

13. Mining Methods

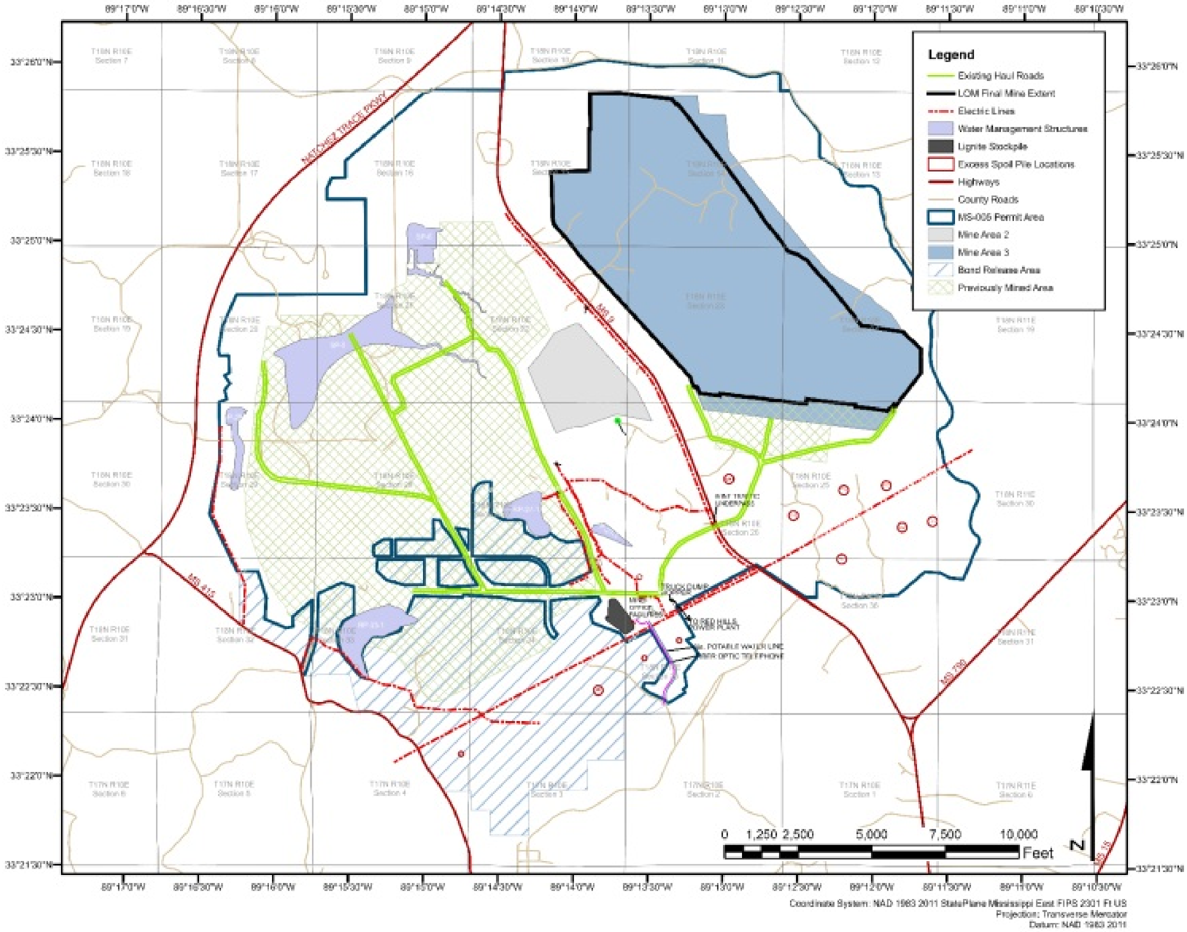
This section contains forward-looking information related to the mining methods for the Red Hills Mine. The material factors that could cause actual results to differ from the conclusions, estimates, designs, forecasts or projections include mine design parameters, production rates, equipment selection, and personnel requirements.

The Red Hills Mine began commercial deliveries in 2002. Since this is an established operation, the deposit, mining, and environmental aspects of the project are very well understood. The geological knowledge is based on the collective experience of personnel from MLMC operations, geology, engineering, environmental, and other disciplines gained during years of lignite mining at Red Hills Mine and other mining operations in the United States.

The lignite at Red Hills Mine surface mining operation is recovered using dragline, dozer push, and conventional truck and shovel mining methods due to the proximity of the lignite to the surface and the physical characteristics of the deposit. Mining operations progress in a five-step process, which includes clear and grub, overburden and interburden removal, lignite production, spoil backfill and grading, and reclamation. In the development phase, drainage and water control were established, and then the required infrastructure consisting of power, mine office and maintenance facilities, lignite stockpile facilities, and roadways were established.

The Red Hills Mine began operations in Mine Area 1 (MA1) and has transitioned to Mine Area 3 (MA3). Both MA1 and MA3 are located in the MS-005 permit area. The initial boxcut construction for MA3 began in 2021 and mining in this area will continue until April 1, 2032. Figure 13.1 presents the layout of the Red Hills Mine and identifies the total area to be affected over the mine.

Figure 13.1 Layout of the Red Hills Mine



13.1. Geotechnical and Hydrological Considerations

13.1.1. Pit Design

The initial geotechnical parameters for the design of the pit slopes was provided in the Geoscience Engineering report completed in 1997 and Aquaterra report completed in 1994 to define soil index properties and soil strength parameters as discussed previously in Section 7.4 of this TRS. The early geotechnical studies were the basis of the pit design which is fully detailed in the Red Hills Mine Ground Control Plan and summarized herein.

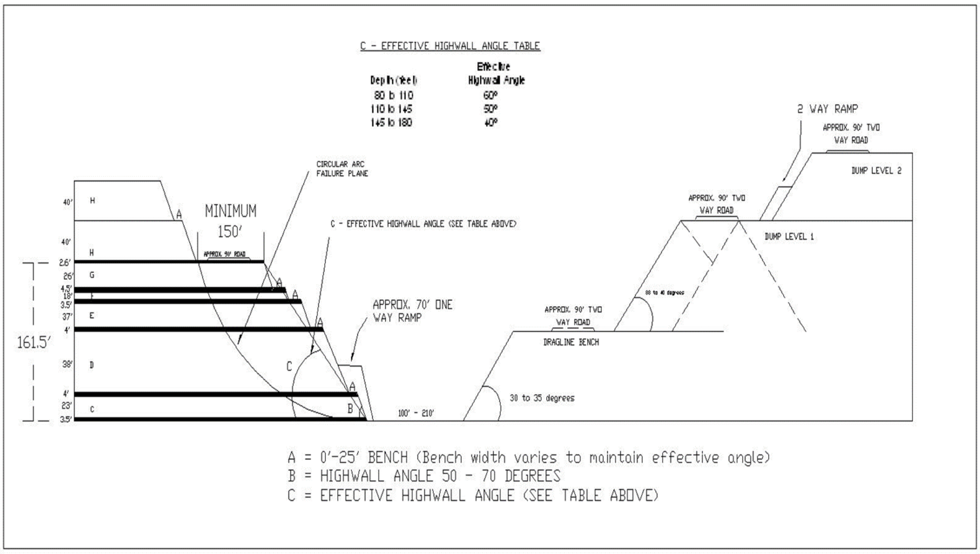
To determine highwall stability, a circular arc failure approach has been utilized. A minimum FoS of 1.2 was estimated using the Modified Bishop Method for each highwall configuration that will be encountered by the mine. Due to the depth and multiple seam nature of the lignite deposit, benching will be required to allow for continuous burden removal and lignite mining. For individual slopes less than 80 feet, the highwall angle is stable up to 70 degrees. Between 80 and 180 feet, the effective slope angle decreases with a linear relationship from 60 to 40 degrees as shown in Table 13.1.

Table 13.1 Effective highwall angle by depth

Depth (ft)	Effective Highwall Angle
80 to 110	60 degrees
110 to 145	50 degrees
145 to 180	40 degrees

For slopes greater than 180 feet, benching is required. Figure 13.2 illustrates the combination of highwall slopes and safety benches that are used to meet the effective slopes outlined above. In general, the truck and shovel operating level is located 150 to 160 feet above the pit floor and naturally creates a bench with a minimum width of 150 feet. When benches and offsets are accounted for pits may range from 100 to 210 feet in width. Initial design assumes a 170-foot pit width.

Figure 13.2 Typical Pit Configuration for plan at steady state. (Mississippi Lignite Mining Company, 2023)



Low wall or spoil side angles were based on the type of materials found throughout the mine area, an angle-of-repose of 33 degrees was recommended by geotechnical studies. MLMC's digging plan reduces the effective spoil angle to 33 degrees or less by allowing for an operating bench on the spoil side of the pit.

As a whole, Red Hills Mine pits are designed with an effective highwall angle of approximately 42 degrees, effective endwall angles of approximately 40 degrees, and effective low wall angles of 33 degrees or less.

Mining has been ongoing at the Red Hills Mine since 1998 and the design methodology for the pit slopes has been satisfactory as evidenced by each pit progression. Due to the stratigraphic nature of the Red Hills Mine geology, which is checked by regular drilling exploration programs ahead of mining, repetition of geologic units leads to consistency in applying geotechnical parameters.

The Company and MLMC engineering have made minor adjustment to the pit design since 1998. However, these adjustments are primarily for optimization, to address new equipment specifications or additional ramps to reduce haul distances. Other adjustments include additional benching in the highwall where topography is higher or the depth to the C-seam increases to establish ramps and functional road systems. This additional benching also increases the FoS of the highwall by reducing the overall effective angle in these instances. Optimization of drainage is another factor that greatly influences the pit design.

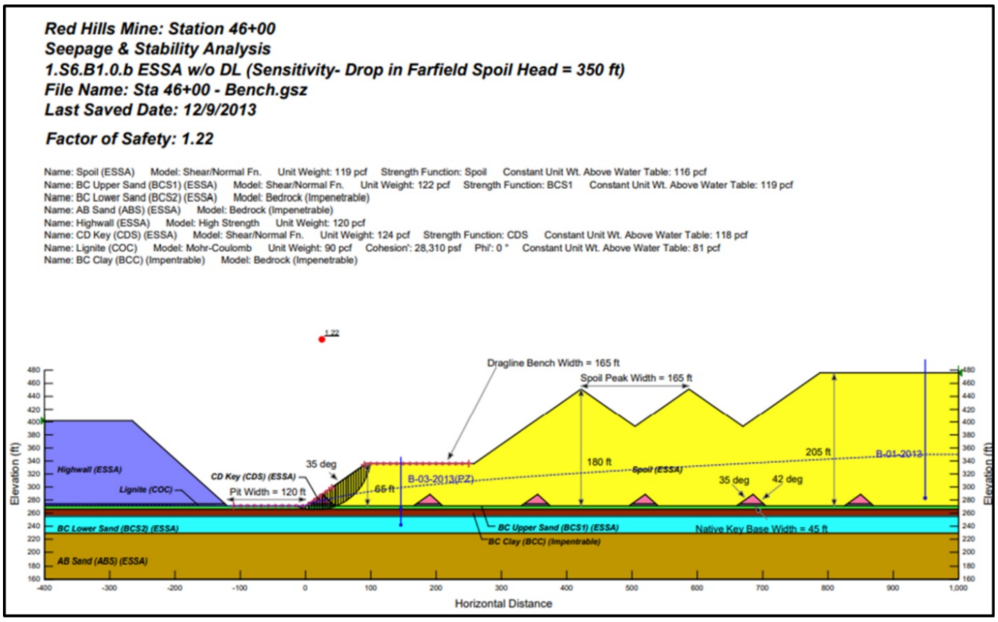
13.1.2. Spoil Stability Studies

The bulk of geotechnical studies at the Red Hills Mine since 2004 pertain to spoil stability which influence operation plans for production and reclamation. Two types of spoil failures have been observed at the mine. The first type comprised of a rotational failure occurring at the toe of the dragline bench with radial cracks extending into the bench toward the spoil piles. The second bench failure type observed at the mine included heaving of the C-seam followed by a slump failure. There were several spoil studies performed using software packages developed by

GEO-SLOPE International, and RocScience. Some of the pit slope analyses can be found in the report, titled "Design Report for Red Hills Mine Slope Stability Study" by Barr Engineering (Barr), 2014; "Red Hills Slope Stability Mitigation Test Plan" by Aquaterra, 2010; and "Red Hills Mine Slide Investigation" by Aquaterra, 2009.

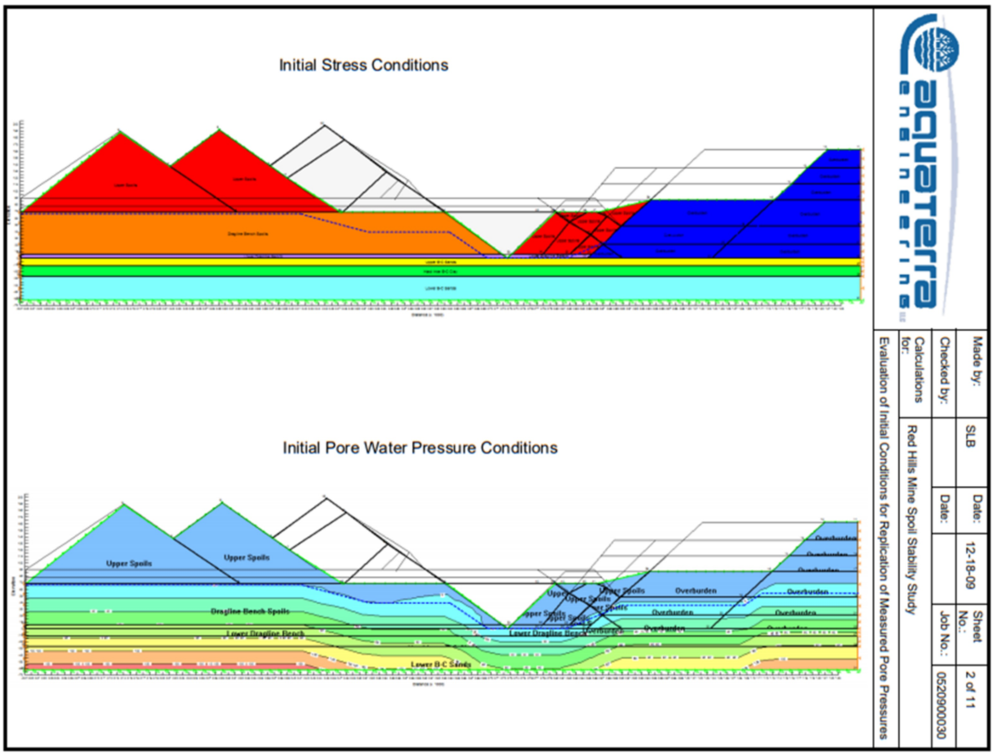
The report, "Design Report for Red Hills Mine Slope Stability Study," by Barr analyzed seepage conditions and slope stability of the levee setback and US Army Corps of Engineers (USACE) defined conditions with software created by GEO-SLOPE International Ltd. The integrated software suite is called GeoStudio 2012, which includes SEEP/W and SLOPE/W. SEEP/W is a finite element program that analyzes groundwater seepage within porous materials like rock and soil for traditional steady-state flow or transient analyses. The computed pore-water pressures and corresponding phreatic surface can then be imported into SLOPE/W for analysis. SLOPE/W uses limit equilibrium methods to perform slope stability analyses. An example of a slope stability analysis done by Barr is presented in Figure 13.3.

Figure 13.3 Soil Stability Assessment. (Barr Engineering, 2014)



The report "Red Hills Slope Stability Mitigation Test Plan" by Aquaterra tried to determine changes in stresses and pore pressures during the mining operation. A 2-D coupled stress-pore pressure model was conducted using the Sigma/W application as developed by GEO-SLOPE International. The Sigma/W program provides a finite element mesh analysis stresses and deformations within the subsurface soils sing transient loads. An example of a slope stability analysis is presented in Figure 13.4.

Figure 13.4 Slope Stability Study (Aquaterra Engineering, LLC., 2010)



To help remediate the potential rotational bench failures, the truck-shovel operation does not dump material within the first two spoil peaks from the active pit, and spoil piles are not to exceed 90-feet in height above the dragline bench height. Furthermore, extra attention is given to ensure water is not stored in spoil valleys for a prolonged period. In addition, the work area is inspected by shift supervisors and fleet leadmen for cracking, heaving, flowing groundwater, or any other abnormal conditions prior to starting work in an area, and following any precipitation or freeze/thaw event. The inspection requirements are specified as part of MLMC's safeguards under the Ground Control Plan. A certified person must document inspections of the work areas during each shift and after every rain, freeze, or thaw. Dragline operators and groundmen are continuously monitoring bench and spoil conditions as they dig.

Potential heaving of the C-seam followed by a slump failure was attributed to the ground water recharge and increased pore pressures due to seepage from three sand seams below the C-seam. These failures are described in depth in the Barr and Aquaterra reports. Based on these studies, earthquake drains, and dewatering well systems were implemented to address the increased head pressure from the lower aquifers. These systems were installed by registered drillers immediately following the severance of the C-seam. More details on these systems were provided in the "Red Hills Slope Stability Mitigation Test Plan" report. MLMC engineers continued to install earthquake drains for a few pits once the B-seam came back into existence. Once the earthquake drains were retired, MLMC then continued to monitor the pore pressures below the dragline bench as mining progressed with wireline piezometers for a few pits and noted no pressure changes. Although earthquake drains are not anticipated for MA3, MLMC will continue to monitor spoil stability for indications of conditions that would warrant installation of earthquake drains. This assumption is based on cross referencing sand thickness maps with the B-seam existence limits and projected pits. Pore pressures below bench grade will be monitored leading into this area of interest with the installation of wireline piezometers, followed by the installation of earthquake drains with the mining progression if deemed necessary by MLMC engineers.

A dewatering well system was installed annually ahead of mining from 2008 through 2014. As discussed in the hydrogeology portion of Section 7.3 of this TRS, the upper stratigraphic sands of the Wilcox sediments which are mined through are minor. The systems MLMC put into place were a recommendation from a geotechnical study with the idea that the groundwater flow, although minimal, was contributing to the saturation of the spoils contributing to spoil side failures. This system was discontinued as mining pits advanced and moved out of the area with the geological conditions that were producing these types of failures.

13.1.3. Excess Spoil Piles

In addition to pit design and spoil stability, regulations governing the permanent placement of excess spoil require geotechnical studies to ensure stability of the placed material. In 1999, Pritchard Engineering, Inc. carried out the geotechnical investigation to gather soil index properties and soil strength properties which were then used as inputs by the Company to perform a stability study under static and seismic conditions for the excess spoil piles in Mine Area 1, which at the time were in the MS-002 permit area. MLMC is in the process of constructing excess spoil piles for Mine Area 3, which is located in the MS-005 permit area. As mining operations continue in the MS-005 permit area, a geotechnical study of similar parameters will be conducted to assess the stability of the spoil piles in the MS-005 permit area. Due to the similarity of the pre-mine topography for the new excess spoil piles, similar soil characteristics/chemistry, the lateral extensiveness of the geology in the region, and furthermore an extended history of operating heavy equipment in various dump conditions, MLMC does not anticipate major changes to the mine plan from future geotechnical investigations of the excess spoil piles. Existing and proposed excess spoil pile locations are shown on Figure 13.1.

13.2. Lignite Production Rate, Mine Life, Mining Dimensions and Dilution and Recovery Factors

13.2.1. Production Rate

The Red Hills Mine typically supplies 2.6 to 3.2 million tons of lignite per year to the adjacent RHPP. Actual production is dictated by customer MMBtu demand. The details of the LOM plan are shown in Table 13.2.

Table 13.2 LOM Production Schedule

	2025	2026	2027	2028
Delivered Coal (000 tons)	2,800	2,700	2,700	2,800
Delivered MMBTU (000)	27,700	27,700	27,700	27,700
Calorific Value, Btu/lb	5,010	5,040	5,050	5,020
Total Overburden Material (000 CY)	33,900	35,200	36,200	31,600

	2029	2030	2031	2032	Total
Delivered Coal (000 tons)	2,800	2,800	2,700	700	**20,000**
Delivered MMBTU (000)	27,700	27,700	27,700	6,900	**200,800**
Calorific Value, Btu/lb	5,020	5,040	5,100	5,140	**5,000**
Total Overburden Material (000 CY)	34,700	36,400	39,600	8,100	**255,700**

13.2.2. Mine Life

MLMC provides the lignite for the RHPP under a contract that runs until April 1, 2032.

13.2.3. Mining Dimensions

Mining dimensions are discussed in Sections 13.1 and 13.3 of this TRS.

13.2.4. Haulroad Design

Haul roads and spoil ramps are typically designed to a minimum width of 90 feet to allow for two-way traffic. In some circumstances, one-lane roads may be established with proper signage. Highwall ramps are designed to a width of 70 feet, and dragline walkways must be a minimum of 120 feet wide.

13.2.5. Mining Dilution

ROM tonnages at the Red Hills Mine meet the following conditions:

- Minimum mining thickness: 1.0 ft;
- Maximum burden depth: approximately 320 feet;
- Average lignite density: approximately 80 lb/ft^3

The base of weathering, which closely aligns with the depth of the BOX as described in Section 11 of this TRS may affect lignite recovery. Special considerations for lignite above this depth must be considered as it may have been partially oxidized and typically exhibits unacceptable quality characteristics for the power plant.

Mining dilution was initially determined from statistical analysis of coal core data collected from 1975 through 1997. During the 2011 drilling exploration program, roof and floor samples were collected and analyzed for each coal seam to verify dilution parameters used in modeling. The drilling data was compared to actual as-delivered quality data and confirmed that the original dilution parameters remained applicable. Dilution parameters are applied to all lignite seams and are listed in Table 13.3.

Table 13.3 ROM Dilution Parameters

Structural (Roof and Floor)	
Loss (ft)	0.25
Gain (ft)	0.083

Quality (Roof and Floor)	
Density (lb/ft^3)	85.4
Calorific Value (Btu/lb)	1859
Moisture (%wt)	26.48
Ash (%wt)	53.98
Sulfur (%wt)	0.26

13.2.6. Recovery Factors

Recovery rates of individual coal seams are presented in Table 13.4 and were determined from various comparisons between surveyed severed tons, haul truck payloads, delivered tons to RHPP, and modeled tons accounting for dilution and minimum mining thickness. The low recovery of C-seam is due to a swath of lignite that is up to 50-feet wide that is left in the pit to assist with stabilizing the spoil and dragline bench.

Table 13.4 Recovery Rates by Seam

Seam	Recovery Rate
H	71%
G	84 %
F	97 %
E	90 %
D	100 %
C	67 %

13.3. Requirements for Stripping and Backfilling

The Red Hills Mine is a multiple lignite seam surface mining operation.

The primary burden removal units for a typical mining sequence at the Red Hills Mine include:

- one 82-cubic yard electric-powered walking dragline;
- one 41-cubic yard electric rope shovel;
- a fleet of 150-ton and 200-ton end-dump haul trucks and;
- four large track-type push dozers.

Lignite is severed and loaded by a surface miner or hydraulic backhoe.

Figure 13.5 through Figure 13.7 illustrate typical pit layouts to show the mining process. Similar mining processes will be followed in MA3 for production and reclamation. Figures are not to scale.

First, the truck and shovel fleet remove overburden to an elevation which approximates the first minable lignite seam; this will be the G or H seam. This overburden material is hauled to fill in the topography to final grade during the reclamation process. Truck and shovel operations may be required to remove other interburdens and rehandle material depending on sequencing/production and reclamation planning.

Following removal of the H and G seams, the dozers push the interburden, which overlies the F-seam, into the previously mined pit. This process is repeated through successive lignite seams until the accumulated interburden has reached a point where it is level across the pit. This typically occurs at or near the E-seam elevation.

Finally, the dragline sits spoil side on a bench primarily constructed from the material the dozers pushed and then removes both the D-seam and C-seam interburdens.

Figure 13.5 Pit Layout - Truck and shovel operation. (Mississippi Lignite Mining Company, 2019)

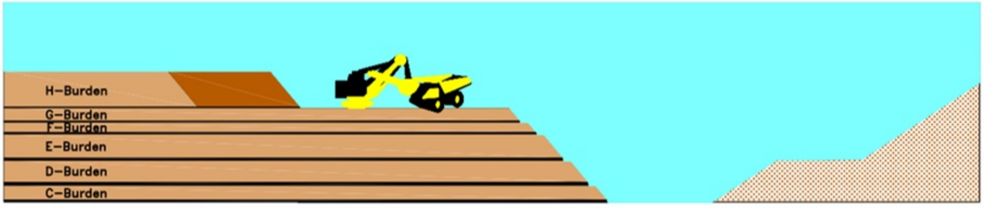


Figure 13.6 Pit Layout - Dozer operation. (Mississippi Lignite Mining Company, 2019)

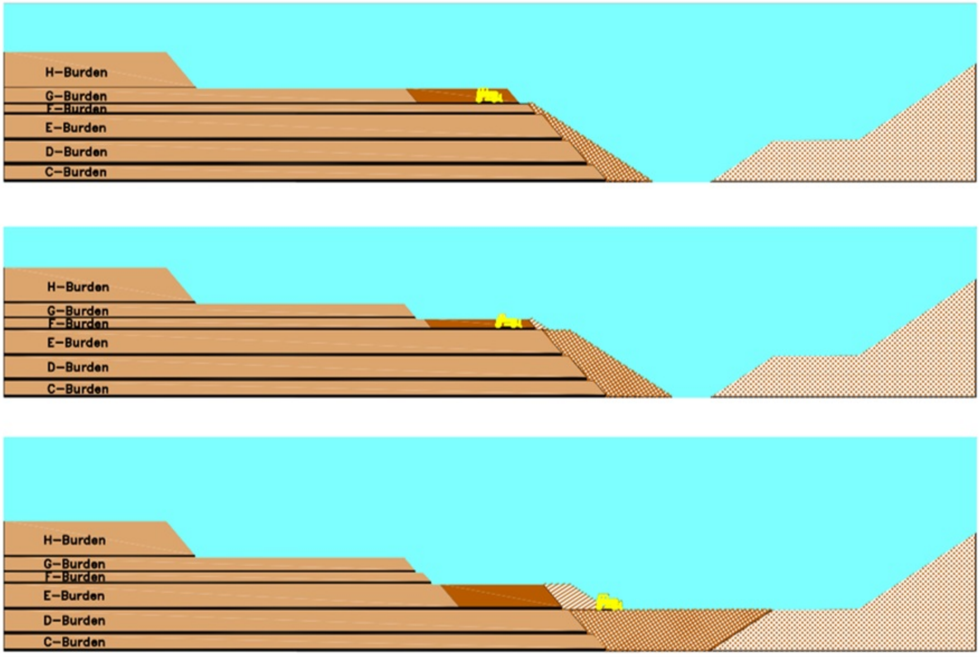
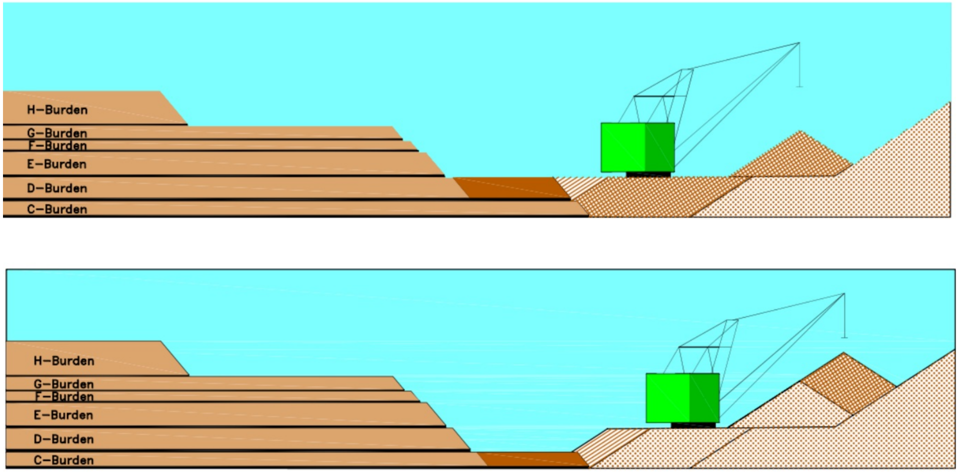


Figure 13.7 Pit Layout - Dragline operation. (Mississippi Lignite Mining Company, 2019)



Rough backfilling and grading of reclamation are accomplished using dozers as the haul trucks dump material between the dragline spoils. Hydraulic backhoes may be used to rehandle spoil material that exceeds final grade. In accordance with the mine permit requirements, a minimum of 4 feet of suitable plant growth material (SPGM), or red oxidized soil that meets textural parameters, must be placed on top of the gray unoxidized material in the dump unless otherwise approved. MLMC follows an approved final grading plan using a "balanced acreage" approach in that the same reclaimed areas must be brought up to grade within 29-months of lignite removal. This plan is approved for both permitted areas.

Previously in MA1, mining progresses through three to four pits per year. Due to a shorter pit length in MA3, MLMC anticipates mining five to seven pits per year.

13.4. Major Equipment and Personnel

A list of major and auxiliary equipment used at the Red Hills Mine is presented in Table 13.5. The equipment at the Red Hills Mine is well maintained, in good physical condition and is either updated or replaced periodically with newer models to maintain reliability and to keep up with technological advancements.

As equipment wears out, MLMC evaluates what replacement option will be the most cost-efficient, including the evaluation of both new and used equipment.

Table 13.5 Major and primary auxiliary equipment list

Unit(s)	Equipment	Approximate Production Rates	Major Fleet
1	Marion 8200 Dragline	3200 yd3 per hour	Dragline
1	P&H 2800 Electric Rope Shovel	2100 yd3 per hour	Truck and Shovel (T-S)
1	Wirtgen 4200 Surface-miner	2000 tons per hour	Lignite
1	CAT 6040 Hydraulic Backhoe	1800 yd3 per hour	T-S/Lignite Support
2	CAT 6040 Hydraulic Shovel	1800 yd3 per hour	T-S Support
1	CAT 5230 Hydraulic Shovel	1400 yd3 per hour	Lignite
1	Komatsu PC2000 Hydraulic Backhoe	1200 yd3 per hour	T-S/Lignite Support
4	CAT D-11 Tractors	850 yd3 per hour	Dozer Push
5	CAT D-10 Tractors		Dragline/Dump Support
1	CAT D-8 LGP Tractor		Auxiliary Support
3	CAT D-6 LGP Tractor		Ash Placement
1	CAT 844 Rubber Tire Tractor		T-S Support
12	CAT 789 A, B, C, & D End-Dump Trucks	200-ton payload	T-S and Lignite Haul
4	CAT 785 A & B End-Dump Trucks	150-ton payload	T-S and Lignite Haul
3	CAT 773 Side-Dump Ash Train	140-ton payload	Ash Placement
2	CAT 24 Class Motor Grader		Road/Reclamation Grading
2	CAT 16 Class Motor Grader		Road/Reclamation Grading
1	21,000 Gallon CAT 777 Water Truck		Dust Suppression
1	32,000 Gallon CAT 785 Water Truck		Dust Suppression
3	3-5 yd3 CAT Backhoes		Auxiliary Support
4	40 Tons CAT ADT trucks	40-ton payload	Auxiliary Support

At normal operating levels, the Red Hills Mine on average employs +/-200 personnel (**Table 13.6**).

Table 13.6 MLMC Personnel

STAFF		WORKFORCE	
Full Time	42	Production	101
Interns/Co-ops	1 or 2	Maintenance	55
		Warehouse	5
		Temporary	Varies

14. Processing and Recovery Methods

The overall average quality of the mined lignite seams meets the quality specifications stated in the LSA without beneficiation. No mineral processing is performed by MLMC.

15. Infrastructure

The Red Hills Mine public utility lines and facilities locations are presented in**Figure 15.1** showing the mine infrastructure and details of the mine facilities.

MLMC purchases power from 4-County Electric Power Association, a cooperative of the TVA. A 69kV line runs parallel to the TVA 500kV line from the Highway 9 Right-of-Way (R-O-W) to the mine office substation. This line then continues past the office to feed the RP-27-1 transformer and the Pump Building transformer.

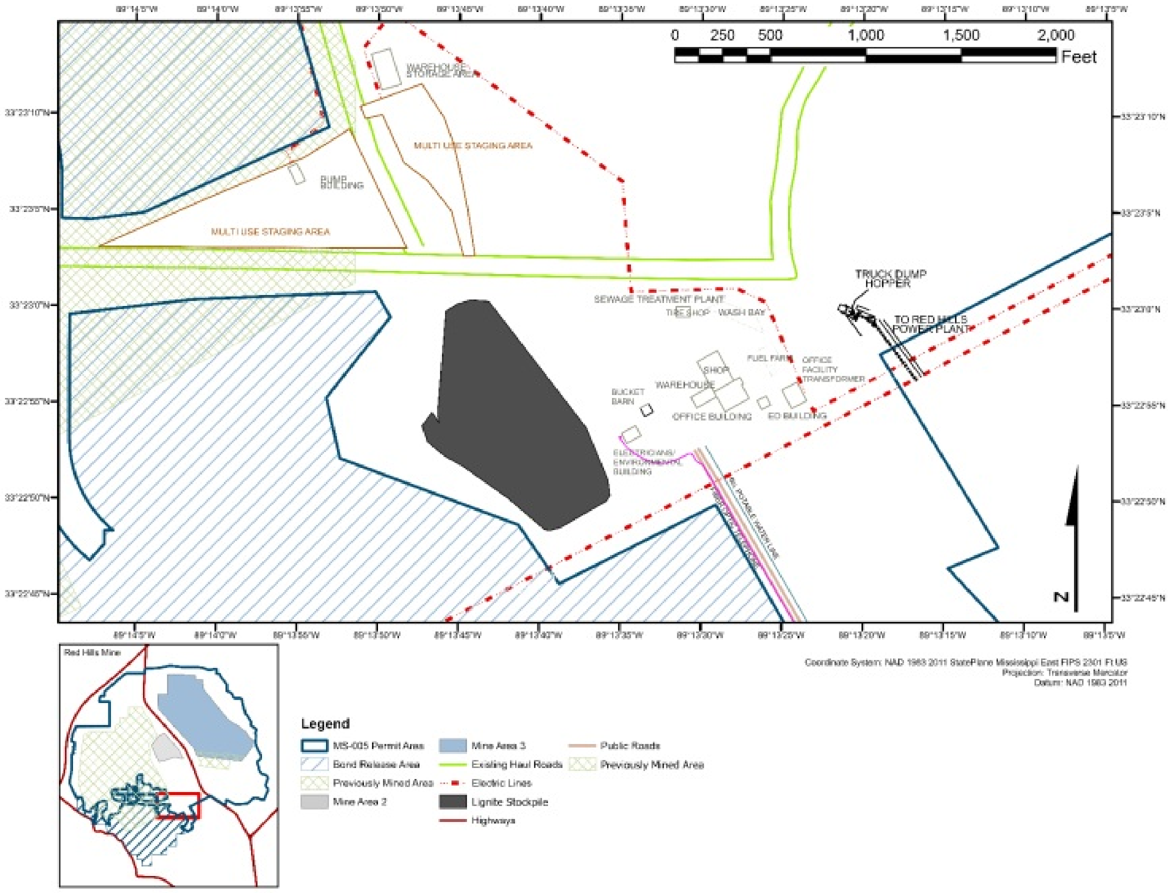
A second 69kV line runs north along the west R-O-W of Highway 9 to feed the dragline substation currently in use. This dragline substation will be used for the remainder of the MS-005 permit area. MLMC has bored under Highway 9 to feed dragline cable to the east side of the highway.

Water for the mine office facilities is supplied by the Reform Water Association via a 6-inch line which runs along the R-O-W of McIntire Road. A registered groundwater well sourced from the Lower Wilcox aquifer feeds the equipment wash bay, boot wash, irrigation, and fire hydrants.

The Red Hills Mine has a sanitary waste treatment plant with a permitted NPDES outfall. This is an active sludge treatment plant. Onsite sedimentation ponds are permitted for Beneficial Water Use and serve as the water source for dust suppression

There are no leach pads or tailings ponds at the Red Hills Mine. Lignite is mined and transported to a stockpile or to the customer's hopper. Public roads are not used for the transport of lignite to the RHPP. Mine site haul routes are depicted in Figure 13.1 and Figure 15.1. To transport lignite from the active pit to the lignite stockpile or the customer's hopper, an overpass for Highway 9 traffic has been constructed northeast of the Hopper. Mine traffic generally travels below the Highway 9 traffic via an underpass. A secondary haul route will be available via the dragline deadhead road. This is an at-grade crossing approximately 1,300 feet southeast of the overpass/underpass. The highway department must be notified in advance to detour traffic around this at-grade crossing; therefore, this crossing will only be used to mobilize large equipment or emergency use.

Figure 15.1 Red Hills Mine Facilities Map



16. Market Studies

This section contains forward-looking information related to the market studies for the Red Hills Mine. The material factors that could cause actual results to differ from the conclusions, estimates, designs, forecasts or projections include plant dispatch rate, plant availability rate, fuel pricing, and other commodity pricing.

16.1. Markets

The primary market for the Red Hills Mine lignite is the adjacent RHPP for which the mine was developed. The Red Hills Mine is a mine-mouth operation where the lignite is delivered directly to the power plant. The Red Hills Mine is a high moisture, low calorific value fuel, which precludes transporting the lignite as a viable option to expand market share, thus no known marketing studies have been conducted for the Red Hills Mine. The LOM plan assumes the RHPP will not continue to operate after the expiration of the current LSA with CGLP and the expiration of the existing PPA between TVA and CGLP on April 1, 2032. The Red Hills Mine is expected to begin final reclamation in April 2032. The Company and MLMC have made efforts to identify specialty niche markets for the lignite with limited success.

16.2. Material Contracts

Red Hills Mine is a fully developed and functioning mining operation. All aspects of the mining, haulage and delivery of lignite to the RHPP are defined in the LSA between CGLP and MLMC. The RHPP supplies electricity to the TVA under a long-term PPA. CGLP leases the RHPP from a Southern Company subsidiary pursuant to a leveraged lease arrangement. The LOM plan assumes the RHPP will not continue to operate after the expiration of the current LSA with CGLP and the expiration of the existing PPA between TVA and CGLP on April 1, 2032.

Red Hills Mine is an active operation and all material contracts are in place for the continued operation of the mine. The Red Hills Mine is a mine-mouth project where the lignite is delivered directly to the power plant using off highway haul trucks.

The base price for the dedicated lignite is defined in the LSA and consists of eight indexed components in addition to a power cost component, a pass-through component, a royalty component and a fixed component. The base price in the LOM plan is evaluated on an annual basis and is determined based on the actual performance of the 8 indexed components specified in the LSA. Over the LOM plan, the average price per ton for lignite delivered and sold is $34.41 providing revenues totaling approximately $685 M. The Red Hills Mine began commercial deliveries in 2001. The sales price over the last three years has averaged $31 as shown in Table 16.1. The forecasted coal price for the LOM is also shown in Table 16.1.

Table 16.1 Historical and Forecasted Coal Price

Historical	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024**	Total*
Tons Sold (000 ton)	3,200	2,600	3,200	3,000	2,400	3,000	2,600	2,500	3,000	3,200	2,900	1,900	33,500
Coal Price $/Ton	20.61	21.61	22.61	23.61	24.61	25.61	26.61	27.61	27.20	29.66	29.14	35.60	30.88

Forecasted	2025	2026	2027	2028	2029	2030	2031	2032	Total
Tons Sold (000 ton)	2,800	2,700	2,700	2,800	2,800	2,800	2,700	700	20,000
Coal Price $/Ton	31.30	34.46	32.86	33.02	34.65	35.99	36.71	41.90	34.41

*Average Coal Price $/Ton is from 2022-2024.
**During 2024, a mechanical issue impacted one of two boilers at the Red Hills Power Plant. While this issue has been resolved, it resulted in a reduction in customer deliveries in 2024.

17. Environmental Studies, Permitting, and Plans, Negotiations, or Agreements with Local Individuals or Groups

17.1. Environmental and Baseline Studies

In July, 1998, a final Environmental Impact Statement (EIS) was issued for the Red Hills Power Project. The impacts of the Red Hills Mine were considered during this process. This EIS evaluated anticipated impacts associated with mining at the Red Hills Mine. The EIS evaluated project impacts to the following resources:

- Air Resources
- Geology
- Soils
- Groundwater Resources
- Surface Water Resources
- Aquatic Ecology
- Streams and Wetlands
- Terrestrial Ecology
- Threatened and Endangered Species
- Land Use
- Cultural and Historical Resources
- Socioeconomics
- Environmental Justice
- Transportation Facilities
- Public Health
- Hazardous and Solid Waste
- Noise
- Recreation
- Visual Resources

The EIS evaluated these areas individually for the action and no action alternatives as well as cumulative impacts for past, present and proposed actions. A Record of Decision (ROD) was issued August 8, 1998 by the TVA that detailed the decision to build the Red Hills Mine. The EIS encompasses all areas within the currently approved Surface Mine Control and Reclamation Act (SMCRA) permits.

The results of the geological baseline studies are detailed in Section 6 of this report. Additionally, the results of the surface and groundwater baseline studies and geotechnical studies are documented in Sections 7.3 and 7.4, respectively. In addition, the Red Hills Mine completed baseline assessments of the area soils, prime farmlands, land uses, biological resources, threatened and endangered species, and cultural resources which were used to support the mining permits continuously issued by the Mississippi Department of Environmental Quality (MDEQ) since 1998.

17.2. Waste Disposal, Site Monitoring and Water Management

17.2.1. Waste Disposal

No processing of lignite occurs at the Red Hills Mine; therefore, no lignite processing or tailing wastes have been or will be generated.

17.2.2. Site Monitoring

The Red Hills Mine is required to conduct routine groundwater, surface water and soil sampling in accordance with SMCRA and NPDES permit requirements. Surface and groundwater monitoring occur both within the active mine area as well as in adjacent, undisturbed areas upstream and downstream of the active mining operations. Red Hills Mine also conducts routine soil sampling to ensure the reclaimed environment meets regulatory chemical and textural requirements. The water and soil data are submitted to MDEQ in accordance with permit requirements.

Red Hills Mine will continue to monitor surface water, groundwater, and soils in accordance with all permit requirements until such time mining and reclamation activities are complete and MDEQ has released the entire project from the reclamation performance bond requirements. This release can only happen once Red Hills Mine has quantitatively demonstrated that the reclaimed areas meet performance criteria detailed in the mining permit. Once the reclamation performance bond is released, the Red Hills Mine will have no further site monitoring requirements.

17.2.3. Water Management

Because rainfall averages more than 55 inches per year, water management is a critical focus at the Red Hills Mine. Prior to initiating mining activities, streams that would otherwise flow through the active mine area are typically rerouted around the perimeter of the mine. This allows the natural hydrologic balance to be maintained except for stormwater that falls within the footprint of the active mine area. Red Hills manages stormwater by constructing large, strategically located sedimentation ponds. The sedimentation ponds are constructed in accordance with permit requirements to retain a 10-year, 24-hour storm event. Once the retained water meets NPDES water quality requirements, the water is released back into the natural system. The results of the NPDES monitoring are reported monthly to MDEQ through the eDMR system.

17.3. Project Permitting Requirements

The Red Hills Mine is operating under the state of Mississippi Surface Coal Mining and Reclamation Permit MS-005. The permit was issued by the Mississippi Department of Environmental Quality (MDEQ) under delegated authority of the United States Department of the Interior, Office of Surface Mining Reclamation Enforcement (OSMRE) under the Surface Mining Control and Reclamation Act (SMCRA).

17.3.1. Permit Status

In addition to the mining permits, the Red Hills Mine is required to obtain and maintain numerous other regulatory permits and approvals (**Table 17.1**).

Table 17.1 Red Hills Mine Permit Summary and Status

Type of Permit	Name and Address of Issuing Authority	Identification Number	Status
State Coal Exploration License	Department of Environmental Quality Office of Geology P. O. Box 20307 Jackson, Mississippi 39289-1307	NA	Issued 08/15/00
State Coal Mining Permit	Department of Environmental Quality Office of Geology P.O. Box 20307 Jackson, Mississippi 39289-1307	MS-002 Renewal 3 MS-004 MS-005	Issued 02/13/18 Issued 02/11/20 Issued 2/02/2023
Mine Identification No.	Mine Safety and Health Administration U. S. Department of Labor District II 1030 London Dr, Suite 400 Birmingham, Alabama 35211	No. 22-00690	Issued 08/26/97
State of Mississippi Water Pollution Control Permit (includes Mining Stormwater Pollution Prevention Plan)	Department of Environmental Quality Office of Pollution Control P. O. Box 10385 Jackson, Mississippi 39289-0385 Issuing Authority: Mississippi Environmental Quality Permit Board	No. MS0054046 No. MSR108199	Modified 02/11/20 Issued 06/15/20
Section 404 Permit	Vicksburg District P. O. Box 60 Vicksburg, MS 39180-0060	No. MVK-2017-257 No. MVK-2016-509	Issued 3/28/18 Modified 7/11/18 Issued 12/21/20
Section 401 State Water Quality Certification	Department of Environmental Quality Office of Pollution Control P. O. Box 10385 Jackson, Mississippi 39289-0385 Issuing Authority: Mississippi Environmental Quality Permit Board	NA	Issued by the Commission for USACE
Exclusion for Rubbish Disposal Activities	Department of Environmental Quality Office of Pollution Control P. O. Box 10385 Jackson, Mississippi 39289-0385	NA	Issued 08/25/98
Mississippi Conditionally Exempt Small Quantity Generator	Department of Environmental Quality Office of Pollution Control P. O. Box 10385 Jackson, Mississippi 39289-0385	MSR000005330	Issued 3/17/99
Spill Prevention Control and Countermeasure Plan	USEPA, Region IV and Department of Environmental Quality Office of Pollution Control P. O. Box 10385 Jackson, Mississippi 39289-0385	NA	Revised 6/11/18

Dragline Boom Height	U.S. Department of Transportation FAA 2300 East Devon Avenue Des Plains, Illinois 60018	NA	Exemption Request Approved 3/3/98
Radio Station Authorization	Federal Communications Commission Wireless Telecommunications Bureau	NA	Issued 10/21/2015
Water Withdrawal Permit for Beneficial Uses for Public Water of the State of Mississippi	Department of Environmental Quality Office of Land and Water Resources P. O. Box 10385 Jackson, Mississippi 39289-0385	No. MS-GW-15160 No. MS-GW-15254 No. MS-SW-02755 No. MS-SW-02791 No. MS-SW-10088 No. MS-SW-10104 No. MS-SW-10150 No. MS-SW-10530	Well (Issued 8/25/98) Well (Re-issued 07/16/2018) R-1 (Re-issued 05/12/2008) P-4-1 (Re-issued 05/12/2008) RP-33-1 (Issued 4/20/2009) P-29-2 (Issued 6/22/2009) RP-27-1 (Issued 8/23/2010) SP-8 (Issued 5/4/2020)
Beneficial Use Determination (BUD)	Department of Environmental Quality Office of Pollution Control P.O. Box 10385 Jackson, Mississippi 39289-0631	BUD 0015 BUD 0099	Issued 12/14/06 Issued 05/04/21
Handheld XRF Analyzer Analytical X-Ray	Mississippi State Department of Health Division of Radiology 3150 Lawson Street Jackson, Mississippi 39213	No. X-326	Issued 09/08/20
Work within TVA Transmission Right-of-Way	TVA Transmission R-O-W Team Tennessee Valley Authority 400 West Summit Hill Drive Knoxville, TN 37902	NA	Issued 03/23/20
Road Closures, Relocations and operations within 100' of Outside Right of Ways	The Choctaw County Board of Supervisors P. O. Box 250 Ackerman, Mississippi 39734	Prewitt Road State HWY 415 State HWY 415 East Clear Springs Rd. East Clear Springs Rd. East Clear Springs Rd. McIntire Road McIntire Road McIntire Road Nebo Road Nebo Road Null Road Null Road Salem-Bywy Road Salem-Bywy Road Salem-Bywy Road Salem-Bywy Road	Issued 08/01/2011 Issued 03/22/04 Issued 03/26/04 Issued 03/22/04 Issued 6/8/2009 Issued 2012 Issued 10/02/05 Issued 2012 Issued 2013 Issued 03/17/03 Issued 2013 Issued 10/02/05 Issued 2013 Issued 03/22/04 Issued 05/24/04 Issued 08/30/04 Issued 04/03/06

		Salem-Bywy Road	Issued 2013
		Salem-Bywy Road	Issued 2015
	MDOT	State HWY 415	Issued 03/26/04
	Post Office Box 2060	State HWY 9	Issued 02/21/20
	Tupelo, Mississippi 38803-2060	State HWY 9	Issued 08/25/21

17.3.2. Reclamation Bond Requirements

MDEQ regulations require the Red Hills Mine post a reclamation performance bond that would allow MDEQ to affect final reclamation of the project in the unlikely event the Red Hills Mine goes out of business. Bonding is estimated based on a worst-case scenario. The amount of the financial security as of December 31, 2024 is $4 M.

17.4. Plans, Negotiations, or Agreements with Local Individuals or Groups

The Red Hills Mine has secured agreements with all third parties that are necessary to conduct mining operations in accordance with applicable law.

17.5. Mine Closure Plans

Following the expiration of the LSA, the mine will be required to complete final remediation in accordance with the detailed plans in the approved mining permit. Final reclamation and closure activities began in Mine Area 1 in 2023 as active mining in this area has been completed. Closure activities in both Mine Area 1 and Mine Area 3 will continue throughout the mine life, with the projected completion of the expanded permit area in 2045. Financial assurance for the ultimate reclamation of facilities is documented in the reclamation plan, and security for costs that will be incurred to execute site closure is provided by a third-party insurer to the State of Mississippi in the form of a surety bond.

17.6. QP's Opinion of Adequacy of Current Plans

MLMC currently has all permits in place for the Red Hills Mine to operate and adhere to a mine plan projected to April 1, 2032. Barring any regulatory changes out of MLMC's control, the QP does not anticipate hurdles for approval of future renewal applications. The QP bases this opinion on the mine's history to meet regulatory requirements. Proper monitoring is ongoing in accordance with permit requirements. Furthermore, appropriate bonding and closure plans are in place.

17.7. Description of any Commitments to Ensure Local Procurement and Hiring

Purchasing strives to place orders with regards to dependability and service records of the supplier, the nature of the guaranty and warranty of the product, its price, and quality. Preference is given to suppliers who are developing new and improved products or equipment, or designing and developing a special product, specifically for the Red Hills Mine. Consideration is also provided to local suppliers near the Red Hills Mine. Suppliers must have a reputation of adhering to specifications and delivery schedules.

Positions at the Red Hills Mine are posted with Mississippi Department of Employment Security for priority availability to all veterans and other job seekers. MLMC also participates with regional state job fairs, recruits on local college campuses, and participates in local community sponsored activities.

18. Capital and Operating Costs

18.1. Operating Costs

Annual operating costs were estimated in conjunction with the mining methods discussed in Section 13. LOM operating costs for a plan delivering approximately 27.7 MMBtu per year to the RHPP are expected to total approximately $645 M from January 2025 through the end of reclamation in 2045 are summarized in Table 18.1.

All costs were estimated to a PFS level of study based on historical costs and performance measures that have been maintained by MLMC since its inception. These costs are reviewed and updated on an annual basis to account for changes in site conditions or the operating plan. This information was then used to estimate the projected future costs included in the LOM plan from January 2025 through the expiration of the LSA on April 1, 2032. All costs were escalated at various rates based on the forward-looking Consumer/Producer Price Index with budgeted 2024 costs used as the base year.

Operating costs included major cost categories for mine development, burden removal, severing of lignite, reclamation, maintenance and handling of stockpiled lignite and delivery to the adjacent RHPP along with the necessary maintenance required to keep all equipment operating safely and efficiently. Direct costs were categorized as expenses directly related to the severing and delivery of lignite. All other general business expenses were categorized as indirect costs. Direct costs included production, maintenance, and staff labor, materials and supplies, fuel, equipment repairs, outside contractors, administration, production taxes and royalties, depletion, depreciation, and amortization (DD&A), inventory adjustments, interest expense, income taxes, and accretion on asset retirement obligations (ARO). Accretion costs are estimated by taking the escalated cash flows of the ARO liability over time and discounting it to its present value as required under U.S. GAAP.

Table 18.1 LOM Operating Costs to deliver approximately 27.7 MMBtu per year

Operating Cost	Cost (M$)
Direct Cost of Sales	$623.24
Indirect Cost of Sales	$22.08
Operating Cost	$645.32

18.2. Capital Costs

Capital Costs were estimated to a PFS level of study based on vendor quotes, historical land purchases, mine development costs, mitigation costs and other costs. Capital costs to fulfil the LSA for a LOM plan delivering approximately 27.7 MMBtu per year to the RHPP are expected to total approximately $31 M from January 2025 through the end of the LSA on April 1, 2032 and are summarized in Table 18.2. Consistent with operating costs, all capital costs were escalated at various rates based on the forward-looking Customer/Producer Price Index using 2024 as the base year. There are risks regarding the estimated capital costs including escalating costs of raw materials, equipment availability or supply chain gaps.

Table 18.2 LOM Capital Costs to deliver approximately 27.7 MMBtu per year

Capital Cost	Cost (M$)
Equipment Expenditures	$18.5
Development	$1.6
Wetlands	$6.8
Reserve/Land Acquisition	$4.0
Capital Cost	$30.9

19. Economic Analysis

This section contains forward-looking information related to the economic analysis for the Red Hills Mine. The material factors that could cause actual results to differ from the conclusions, estimates, designs, forecasts or projections include estimates of mineral resources and reserves, mine production plans, labor and salary rates, mine closure cost, plant dispatch rate, plant availability rate, fuel and other commodity pricing, and royalty, production, or income tax rates.

19.1. Key Assumptions, Parameters and Methods

The primary key assumption to determine the economic viability of the Red Hills Mine was the annual operating performance of the RHPP. The forecasted operating performance of RHPP was determined using two main inputs: the annual projection notice (nomination for MMBtu requirements) received from the RHPP based on projected customer requirements and a comparison to prior years actual delivered lignite fuel to develop the expectation for future MMBtu requirements. The estimated annual MMBtu requirement used in the Red Hills LOM Model was approximately 27.7 MMBtu. This resulted in a production schedule of approximately 2.7 Mt of dedicated lignite per year and was assumed to continue for the full LSA contract term, expiring on April 1, 2032.

The base price for the dedicated lignite is defined in the LSA. This base price consists of eight indexed components in addition to a power cost component, a pass-through component, a royalty component and a fixed component. Over the LOM, the average estimated sales price per ton for lignite delivered and sold is $34.41 providing revenues totaling approximately $685 M.

Key assumptions and methods used to determine the capital and operating costs associated with the production schedule were detailed previously in Section 18.0 Capital and Operating Costs of this TRS.

Additional key assumptions include:

- The LOM production plan was based primarily on surface mining methods including a truck and shovel, dozer push and dragline operations;
- Total number of employees per year was approximately 200, but varies by year depending on the forecasted overburden to be moved and the dispatch of the RHPP. Also included are temporary employees on an as needed basis;
- Diesel price was estimated to be $2.39 per gallon at the beginning of 2025. This price was escalated based on NY Harbor ULSD Futures for 2025, 2026 and 2027. After 2027 a flat 3% escalation was assumed. This projected diesel costs to reach $2.66 per gallon by 2032;
- Revenue $/MMBtu was escalated using the eight indexed components defined in the LSA;
- The economic analysis period of the Red Hills Mine LOM plan was the remaining production operation from January 1, 2025 until April 1, 2032 plus 13 years of post-mining reclamation;
- $0.064/ton sold Reclamation Fee assessed on delivered tons;
- Discount rate of 10% was used to account for cost of capital and;
- 12% estimated effective income tax rate. The effective income tax rate of 12% differs from the U.S. federal statutory rate primarily due to the benefit from percentage depletion. The benefit of percentage depletion is not directly related to the amount of pre-tax income recorded in a period.

19.2. Annual Cash Flows

The Income Statement and Annual Cash Flows based on the lignite production schedule for the LOM plan, along with the Net Present Value are detailed in Table 19.1. A Discount Rate of 10% was used as this was consistent with the Red Hills Mine's weighted average cost of capital. The calculation of Net Present Value and Internal Rate of Return are nuanced due to the ongoing nature of this mining operation. As modeled, the cash flows for the period 2025 through 2045 indicate the project is cash flow positive over the remaining life of the project.

In the opinion of the QP, the income statement and cash flow projection based on the LOM plan assumptions as shown in Table 19.1 are reasonable in light of historical trends, current conditions and expected future developments. As modeled, the future cash flow projection is estimated to be approximately $88 M and the net present value (10%) is estimated to be approximately $58 M after tax.

Note that the net present value estimated for this report does not consider previous cash inflows and outflows and is only estimated from 2025 through the remainder of the LOM.

Table 19.1 Summary of Income Statement and Cash Flow for LOM plan delivering approximately 27.7 MMBtu

Income Statement ($M unless noted)	2025	2026	2027	2028	2029
Tons Sold (in thousands)	2,800	2,700	2,700	2,800	2,800
Revenue/Ton	$ 31.30	$ 34.46	$ 32.86	$ 33.02	$ 34.65
Total Revenue	$ 86,582	$ 94,726	$ 90,210	$ 91,124	$ 95,713
Expenses					
Labor, Material Fuel	$ 48,124	$ 47,530	$ 48,433	$ 48,626	$ 50,948
Royalties & Production Taxes	$ 2,685	$ 3,639	$ 4,142	$ 4,009	$ 4,344
Other Expenses	$ 35,598	$ 30,176	$ 29,014	$ 34,386	$ 35,125
Income Taxes	$ (21)	$ (1,606)	$ (1,035)	$ (493)	$ (636)
Net Income	**$ 154**	**$ 11,775**	**$ 7,586**	**$ 3,612**	**$ 4,661**
EBITDA	**$ 11,811**	**$ 26,382**	**$ 21,966**	**$ 17,540**	**$ 19,087**
Capital Expenditures	$ (12,778)	$ (6,653)	$ (1,902)	$ (2,636)	$ (3,671)
Investing Activities	$ 8,485	$ (132)	$ 1,645	$ 4,861	$ 1,060
Financing Activities	$ (4,691)	$ (5,531)	$ (4,678)	$ (4,437)	$ (4,114)
Mine Closing	$ (6,925)	$ (6,739)	$ (1,684)	$ (426)	$ (250)
Income Taxes	$ (21)	$ (1,606)	$ (1,035)	$ (493)	$ (636)
Increase (decrease) in Cash	**$ (4,118)**	**$ 5,722**	**$ 14,313**	**$ 14,410**	**$ 11,477**

Income Statement ($M unless noted)	2030	2031	2032	2033-2045	Total
Tons Sold (in thousands)	2,800	2,700	700	-	20,000
Revenue/Ton	$ 35.99	$ 36.71	$ 41.90	$ -	$ 34.40
Total Revenue	$ 99,062	$ 99,712	$ 28,255	$ -	$ 685,385
Expenses					
Labor, Material Fuel	$ 53,086	$ 55,959	$ 13,824	$ -	$ 366,529
Royalties & Production Taxes	$ 3,525	$ 3,402	$ 623	$ -	$ 26,368
Other Expenses	$ 38,913	$ 27,792	$ 15,638	$ 10,072	$ 256,714
Income Taxes	$ (425)	$ (1,507)	$ 220	$ 1,209	$ (4,293)
Net Income	**$ 3,113**	**$ 11,052**	**$ (1,610)**	**$ (8,863)**	**$ 31,481**
EBITDA	**$ 15,649**	**$ 23,890**	**$ 4,108**	**$ (752)**	**$ 139,681**
Capital Expenditures	$ (1,165)	$ (1,105)	$ (1,016)	$ -	$ (30,925)
Investing Activities	$ 12,156	$ 1,761	$ 19,363	$ 8,918	$ 58,118
Financing Activities	$ (3,682)	$ (3,580)	$ (2,211)	$ (2,684)	$ (35,607)
Mine Closing	$ (119)	$ (123)	$ (13,070)	$ (9,246)	$ (38,583)
Income Taxes	$ (425)	$ (1,507)	$ 220	$ 1,209	$ (4,293)
Increase (decrease) in Cash	**$ 22,414**	**$ 19,336**	**$ 7,393**	**$ (2,557)**	**$ 88,391**

Net Present Value (10%)	**$57,624**
Internal Rate of Return	**235.0%**

19.3. Sensitivity Analysis

Additional LOM scenarios were modeled to analyze the effect of changes in key assumptions and included in the previous submission of this document. The most significant affect was an increase in the annual MMBtu requirement. A 10% upside case with an increased annual MMBtu requirement by the RHPP to 30,090,235 MMBtu was considered. This scenario is well within the operating capacity of the RHPP, and results in an average increase in cash flows of $2 M on an annual basis. Significant risk from a downside case, where the RHPP takes less than the LOM plan MMBtu's, is protected by a minimum annual take provision included in the LSA.

Additionally, recovery rates were looked at from a sensitivity stand point. Any changes to recovery that occurred over the previous 2 years were analyzed and determined to not be material.

Other key assumptions considered were the effects of an increase in diesel prices and labor. Any increase in the cost of labor or diesel fuel has an offsetting effect on revenue due to the labor and diesel indices used to calculate revenue also increasing. Typically, any additional costs incurred by increased labor and diesel pricing is offset by the adjusted revenue calculation. Ultimately the main factor affecting profitability at MLMC is customer demand.

20. Adjacent Properties

There are no other properties adjacent to the Red Hills Mine. There is no information used in this TRS that has been sourced from adjacent properties. No public drilling information was available or sourced for the development of the geological model.

The drilling and exploration activities at the Red Hills Mine well defines the lignite geology, Mineral Resource estimates and Mineral Reserve estimates. Due to this and the relatively simple geology at the Red Hills Mine, material changes to the Mineral Resource estimates and Mineral Reserve estimates are not likely if adjacent property information is included in future estimates.

21. Other Relevant Data and Information

In the QPs opinion, all material information has been stated in the above sections of this TRS.

22. Interpretations and Conclusions

22.1. Mineral Resources

In the QP's opinion, the geological data, sampling, modeling, and estimate are carried out in a manner that both represents the data well and mitigates the likelihood of material misrepresentations for the statements of Mineral Resources. There are currently no recommendations for Mineral Resources.

22.2. Mineral Reserves

In the QP's opinion, the operational and mine planning data, LOM Plan, and estimation are carried out in a manner that both represents the data and operational experience and methodology well and mitigates the likelihood of material misrepresentations for the statements of Mineral Reserves. There are currently no recommendations for Mineral Reserves.

23. Recommendations

23.1. Mineral Resources

The QP has the following recommendations for additional work:

- Additional coal coring should be performed in Mine Area 3 to better define upper seams qualities while potentially expanding and upgrading mineral resources and reserves. Estimated cost for this recommendation is $2 million.
- Continue secondary laboratory splitting and testing QA/QC program. Estimated cost of $160,000 over the remaining eight full years of production.

23.2. Mineral Reserves

The QP has no recommendations for additional work.

Current work plans that are budgeted in the discounted cash flows (DCF) that the Red Hills Mine will complete include:

- Monitor pit pore pressures in future in pit areas identified of potential concern. No cost is estimated unless conditions arise where additional studies and mitigation controls are needed to address the stability issues.
- Continue to evaluate used equipment to reduce capital costs, reconciliation of actual to budget lignite recoveries, qualities and costs which is part of MLMC's annual operational budgeting process.

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25. Reliance on Information Provided by the Registrant

At time of signing, the QPs for this report are employees of the registrant, and all information was sourced from the registrant or studies commissioned by the registrant.

Exhibit 97.1

POLICY ON RECOUPMENT OF INCENTIVE COMPENSATION

Introduction
The Board of Directors (the "Board") of NACCO Industries, Inc. (the "Company") has adopted this Policy on Recoupment of Incentive Compensation (this "Policy"), which shall apply in certain circumstances in the event of a restatement of financial results by the Company. This Policy shall be interpreted to comply with the requirements of U.S. Securities and Exchange Commission rules and New York Stock Exchange ("NYSE") listing standards implementing Section 954 of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (the "Dodd-Frank Act") and, to the extent this Policy is in any manner deemed inconsistent with such rules, this Policy shall be treated as retroactively amended to be compliant with such rules.

Definitions
17 C.F.R. §240.10D-1(d) defines the terms "Executive Officer," "Financial Reporting Measure," "Incentive-Based Compensation," and "Received." As used herein, these terms shall have the same meaning as in that regulation.

Administration
This Policy shall be administered by the Compensation and Human Capital Committee of the Board (the "Committee"). Any determinations made by the Committee shall be final and binding on all affected individuals. The Committee is authorized to interpret and construe this Policy and to make all determinations necessary, appropriate or advisable for the administration of this Policy, in all cases consistent with the Dodd-Frank Act. The Board may amend this Policy from time to time in its discretion.

Covered Executive Officers
This Policy applies to any current or former Executive Officer of the Company or a subsidiary of the Company who is a current or former Section 16 officer of the Company within the meaning of Rule 16a-1(f) under the Exchange Act. This Policy shall be binding and enforceable against all Executive Officers and their beneficiaries, executors, administrators, and other legal representatives.

Recoupment Upon Financial Restatement
If the Company is required to prepare an accounting restatement due to the material noncompliance of the Company with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements, or that would result in a material misstatement if corrected in the current period or if left uncorrected in the current period (a "Financial Restatement"), the Committee shall cause the Company to recoup from each Executive Officer, as promptly as reasonably possible, any erroneously awarded Incentive-Based Compensation.

No-Fault Recovery
Recoupment under this Policy shall be required regardless of whether the Executive Officer or any other person was at fault or responsible for accounting errors that contributed to the need for the Financial Restatement.

Compensation Subject to Recovery; Enforcement
This Policy applies to all compensation granted, earned or vested based wholly or in part upon the attainment of any Financial Reporting Measure, including but not limited to performance-based cash, stock, options or other equity-based awards paid or granted to the Executive Officer. Compensation that is granted, vests or is earned based solely upon the occurrence of non-financial events, such as base salary or a bonus awarded solely at the discretion of the Board or Committee and not based on the attainment of any financial measure, is not subject to this Policy.

In the event of a Financial Restatement, the amount to be recovered will be the excess of (i) the Incentive-Based Compensation Received by the Executive Officer during the Recovery Period (as defined below) based on the erroneous data and calculated without regard to any taxes paid or withheld, over (ii) the Incentive-Based Compensation that would have been Received by the Executive Officer had it been calculated based on the restated financial information, as determined by the Committee. For purposes of this Policy, "Recovery Period" means the three completed fiscal years immediately preceding the date on which the Company is required to prepare the

Financial Restatement, as determined in accordance with 17 C.F.R. §240.10D-1(b)(1)(ii), or any transition period that results from a change in the Company's fiscal year (as set forth in Section 303A.14(c)(1)(i)(D) of the NYSE Listed Company Manual).

For Incentive-Based Compensation based on stock price or total shareholder return, where the amount of erroneously awarded compensation is not subject to mathematical recalculation directly from the information in the Financial Restatement, the Committee shall determine the amount to be recovered, document such determination and provide such documentation to the NYSE in accordance with 17 C.F.R. §240.10D-1(b)(1)(iii).

The Company may use any legal or equitable remedies that are available to the Company to recoup any erroneously awarded Incentive-Based Compensation, including but not limited to by collecting from the Executive Officer cash payments or shares of Company common stock or by forfeiting any amounts that the Company owes to the Executive Officer. Executive Officers shall be solely responsible for any tax consequences to them that result from the recoupment or recovery of any amount pursuant to this Policy, and the Company shall have no obligation to administer the Policy in a manner that avoids or minimizes any such tax consequences.

No Indemnification

The Company shall not indemnify any Executive Officer or pay or reimburse the premium for any insurance policy to cover any losses incurred by such Executive Officer under this Policy or any claims relating to the Company's enforcement of rights under this Policy.

Exceptions

The compensation recouped under this Policy shall not include Incentive-Based Compensation Received by an Executive Officer (i) prior to beginning service as an Executive Officer or (ii) if he or she did not serve as an Executive Officer at any time during the performance period for that Incentive-Based Compensation. The Committee may determine not to seek recovery from an Executive Officer in whole or part to the extent it determines in its sole discretion that such recovery would be impracticable because (A) the direct expense paid to a third party to assist in enforcing recovery would exceed the recoverable amount (after making a reasonable attempt to recover the erroneously awarded Incentive-Based Compensation and providing corresponding documentation of such attempt to the NYSE), (B) recovery would violate the home country law that was adopted prior to November 28, 2022, as determined by an opinion of home country counsel that is acceptable to the NYSE, or (C) recovery would likely cause the failure of certain tax-qualified retirement plans to meet certain tax-qualification requirements, as described in 17 C.F.R. §240.10D-1(b)(1)(iv).

Other Remedies Not Precluded

The exercise by the Committee of any rights pursuant to this Policy shall be without prejudice to any other rights or remedies that the Company, the Board or the Committee may have with respect to any Executive Officer subject to this Policy, whether arising under applicable law (including pursuant to Section 304 of the Sarbanes-Oxley Act of 2002), regulation or pursuant to the terms of any other policy of the Company, employment agreement, equity award, cash incentive award or other agreement applicable to an Executive Officer. Notwithstanding the foregoing, there shall be no duplication of recovery of the same Incentive-Based Compensation under this Policy and any other such rights or remedies.

Acknowledgment

To the extent required by the Committee, each Executive Officer shall be required to sign and return to the Company the acknowledgement form attached hereto as Exhibit A pursuant to which such Executive Officer will agree to be bound by the terms of, and comply with, this Policy. For the avoidance of doubt, each Executive Officer shall be fully bound by, and must comply with, the Policy, whether or not such Executive Officer has executed and returned such acknowledgment form to the Company.

Effective Date and Applicability

This Policy has been adopted by the Board on November 7, 2023, and shall apply to any Incentive-Based Compensation that is Received by an Executive Officer on or after October 2, 2023.

EXHIBIT A

NACCO INDUSTRIES, INC.
POLICY ON RECOUPMENT OF INCENTIVE COMPENSATION

ACKNOWLEDGEMENT FORM

Capitalized terms used but not otherwise defined in this Acknowledgement Form (this "***Acknowledgement Form***") shall have the meanings ascribed to such terms in the Policy.

By signing this Acknowledgement Form, the undersigned acknowledges, confirms and agrees that the undersigned: (i) has received and reviewed a copy of the Policy; (ii) is and will continue to be subject to the Policy and that the Policy will apply both during and after the undersigned's employment with the Company; and (iii) will abide by the terms of the Policy, including, without limitation, by reasonably promptly returning any recoverable compensation to the Company as required by the Policy, as determined by the Committee in its sole discretion.

Sign: _____________________________
Name: [Employee]

Date: _____________________________

HAAS & COBB
PETROLEUM CONSULTANTS

APPRAISAL OF CERTAIN OIL AND NATURAL GAS INTERESTS

LOCATED IN
Alabama, Louisiana, New Mexico, Ohio, Pennsylvania, Texas, Utah, and Wyoming

OWNED BY
Catapult Mineral Partners, LLC
A NACCO Industries, Inc. Company

AS OF
January 1, 2025

PREPARED FOR
Catapult Mineral Partners, LLC
A NACCO Industries, Inc. Company

HAAS & COBB
PETROLEUM CONSULTANTS

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February 17, 2025

Mr. Brian Larson

Catapult Mineral Partners, LLC A NACCO

Company
5340 Legacy Drive, Suite 300

Plano, TX 75024

Mr. Larson:

As requested, Haas and Cobb Petroleum Consultants (hereinafter referred to as "Haas & Cobb") has prepared an estimate of certain hydrocarbon Reserves owned by "Catapult Mineral Partners, LLC" (hereinafter referred to as "Catapult") , a wholly owned subsidiary of NACCO Industries, Inc. ("NACCO"). The properties contained in this evaluation are located in Alabama, Louisiana, New Mexico, Ohio, Pennsylvania, Texas, Utah, and Wyoming.

Haas & Cobb has completed this report in accordance with the definitions of set forth in Rule 4-10(a) of Regulation S-X of the U.S. Securities and Exchange Commission ("SEC"). With the exception of the exclusion of future income taxes, this evaluation conforms to the FASB Accounting Standards Codification Topic 932, Extractive Industries - Oil and Gas. This report was prepared for Catapult's inclusion as an exhibit in their filing with the SEC, and it is our understanding that it contains 100 percent of their Proved Reserves. It is Haas & Cobb's opinion that the assumptions, data, methods, and procedures used in the preparation of this report are suitable for use in SEC filings.

Production data was generally available through October 31, 2024. As of January 1, 2025 Catapult's net Reserves, future net income ("FNI"), and net present worth discounted at 10 percent per annum ("NPV") have been estimated to be as follows:

TABLE 1

	As of 01/01/2025					
	- Net Reserves		Sales Volumes			
Reserve Class/Cat	**Oil & Condensate (bbl)**	**Wet Gas (Mcf)**	**NGL (bbl)**	**Residue Gas (Mcf)**	**FNI ($)**	**NPV Disc. @ 10% ($)**
Proved Producing	517,150	24,436,510	403,280	21,592,500	65,822,210	39,368,340
Proved Behind Pipe	103,640	6,080,150	40,370	5,899,340	14,610,220	10,551,280
Proved Shut-in	-	-	-	-	-	-
Proved Undeveloped	74,400	288,540	30,280	135,830	5,793,000	3,726,410
Total Proved	**695,190**	**30,805,200**	**473,930**	**27,627,670**	**86,225,430**	**53,646,030**

* Totals in Table 1 may not exactly match values in the attached cash flow summaries and tabular summaries due to computer rounding.

FNI is after deducting estimated operating and future development costs, severance, and ad valorem taxes, but before Federal income taxes. Total net Proved Reserves are defined as those natural gas and hydrocarbon liquid Reserves to Catapult interests after deducting all royalties, overriding royalties, and reversionary interests owned by outside parties that become effective upon payout of specified monetary balances. All Reserves estimates have been prepared using standard engineering practices generally accepted by the petroleum industry and conform to guidelines developed and adopted by the SEC. All hydrocarbon liquid Reserves are expressed in United States barrels ("bbl") of 42 gallons. Natural gas Reserves are expressed in thousand standard cubic feet ("Mcf") at the contractual pressure and temperature bases and include shrinkage adjustment related to field and plant losses.

RESERVES ESTIMATE CLASSIFICATION

The estimates contained in this report have been prepared using standard engineering methods and practices generally accepted by the petroleum industry. The appropriate depth and thoroughness were used to estimate Reserves in conformance with SEC regulations. For more information regarding Reserves classification definitions see Appendix A. A complete discussion of the Reserves classification definitions can be found on the United States Securities and Exchange Commission website (www.sec.gov).

The maximum remaining Reserves life assigned to wells included in this report is 50 years. This report does not include any gas sales imbalances. All volumes are related to commercial production.

The SEC requires a development plan be in place for these assets. As Catapult is a mineral and royalty company, there is some uncertainty in the timing of future completions and development. Haas & Cobb has used professional judgment in forecasting such timing. For the purposes of this report, completed, non-producing and drilled, and uncompleted wells have been classified as Proved Behind Pipe, and locations with an active permit have been classified as Proved Undeveloped. All Proved Undeveloped locations are developed within 5 years.

METHODOLOGY AND DISCUSSION

The Reserves estimates contained in this report have been prepared using standard engineering practices generally accepted by the petroleum industry. Decline curve analysis was used to estimate the remaining Reserves of pressure depletion reservoirs with enough historical production data to establish decline trends. Reservoirs under non-pressure depletion drive mechanisms and non-producing Reserves were estimated by volumetric analysis, research of analogous reservoirs, or a combination of both. Reserves in this report have been estimated using deterministic and probabilistic methods. The appropriate methodology was used, as deemed necessary, to estimate Reserves in conformance with SEC regulations.

COMMODITY PRICES

Pursuant to SEC guidelines, the cash flow projections in this report utilize the unweighted 12-month arithmetic average of the first-day-of month benchmark prices for January 2024 through December 2024. The benchmark price for natural gas is the NYMEX Natural Gas Henry Hub settlement price for each respective month and the benchmark price for hydrocarbon liquids is the price received for West Texas Intermediate ("WTI") crude oil at the Cushing, OK sales point.

The benchmark price for WTI crude oil sold at Cushing, OK during this time period is $75.48 per bbl. For crude oil, the benchmark price is held constant throughout the life of the wells and is adjusted for crude quality, marketing fees, BS&W, purchaser bonuses, and basis differentials, resulting in a weighted average received price of $74.90 per bbl. For natural gas liquids ("NGL"), the WTI crude oil price was held constant throughout the life of the wells and is adjusted for BTU content, plant processing fees, and basis differentials, resulting in a weighted average net price of $20.69 per bbl.

The benchmark price for natural gas delivered at Henry Hub during this time period is $2.13 per MMBTU. The Henry Hub price was held constant throughout the life of the wells and is adjusted for BTU content, marketing costs, and basis differentials, resulting in a weighted average received price of $2.09 per Mcf.

Fees associated with gathering, marketing, processing, and transportation were applied as expenses in this report.

Summary level revenue accounting data for the period of January 1, 2024 through September 30, 2024 was generally used in this evaluation.

OPERATING EXPENSES & CAPITAL COSTS

As Catapult is primarily a mineral and royalty company, it is not burdened by material operating expenses and capital costs. Therefore, Asset Retirement Obligations (“ARO”) have not been included in this evaluation. The lease operating costs used in this evaluation have been included to truncate the commercial life of the property and were estimated based on knowledge of analogous wells producing under similar conditions. The lease operating expenses in this report represent field level operating costs.

Operating expenses and capital costs were not escalated in this evaluation.

DISCLAIMERS

The Proved Reserves presented in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered; and, if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the product prices and the costs incurred in recovering these Reserves may vary from the price and cost assumptions in this report. Because these estimates are based on existing governmental regulations, changes could affect the ability to recover these Reserves. In any case, quantities of Reserves may increase or decrease as a result of future operations.

It should be understood that the financial information supplied by Catapult for 2024 has not yet been audited and has been accepted as represented.

Reserves estimates for individual properties included in this report are only valid when considered within the context of the overall report and should not be considered independently. The future net income and net present value estimates contained in this report do not represent an estimate of fair market value.

All information pertaining to the operating expenses, prices, and the interests of Catapult in the properties appraised has been accepted as represented. It was not considered necessary to make a field examination of the appraised properties. Data used in performing this appraisal were obtained from Catapult, public sources, and our own files. Supporting work papers pertinent to the appraisal are retained in our files and are available to you or designated parties at your convenience.

It was beyond the scope of this Haas & Cobb report to evaluate the potential environmental liability costs from the operation and abandonment of these properties. In addition, no evaluation was made to determine the degree of operator compliance with current environmental rules, regulations, and reporting requirements. Therefore, no estimate of the potential economic liability, if any, from environmental concerns is included in the forecasts presented herein.

Nothing contained in this report is intended to create or confer, or shall be construed as having created or conferred, any rights in any third party, and all claims, rights, remedies, and obligations of Haas & Cobb or Catapult, as the case may be, in connection with this report shall accrue or apply solely to Haas & Cobb or Catapult. For all purposes of this paragraph, the term "third party" means any party other than Catapult or Haas & Cobb, including without limitation Catapult's owners, prospective investors, lenders or prospective lenders, partners or prospective partners, and vendors or other service providers. Without the express written consent of Haas & Cobb, only Catapult is entitled to rely on this report and any information, conclusions, and/or opinions contained herein.

Haas & Cobb is independent with respect to Catapult as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE.

The technical persons primarily responsible for conducting this Report meets the requirements regarding qualifications, independence, objectivity, and confidentiality, as defined by the SPE Standards. Franklin Stagg, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at Haas & Cobb since 2016 and has over 9 years of industry experience.

GENERAL INFORMATION

Attached are summary tables of economic analysis of predicted future performance. Other tables identify the properties appraised with summary Reserves and the economic factors applicable to each. A list of tables is included.

We appreciate this opportunity to have been of service and hope that this report will fulfill your requirements.

[Remainder of page intentionally left blank. Signature page follows.]

Respectfully submitted,

Haas & Cobb Petroleum Consultants F-26129

Franklin W. Stagg, P.E.
February 17, 2025

Appendix

Appendix A
Definitions of Oil and Gas Reserves - Securities and Exchange Commission

The list of definitions below were compiled by Haas & Cobb. They represent selected definitions from the Securities and Exchange Commission's Rule 4-10 document. This document was amended on January 14, 2009, and the definitions below reflect the changes resulting from the amendment. Comprehensive versions of Rule 4-10 and the amendments to Rule 4-10 can be obtained online at http://www.gpoaccess.gov/ .

(a) **Definitions.** The following definitions apply to the terms listed below as they are used in this section:

(1) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

(2) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(3) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(4) *Proved oil and gas reserves*. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil(HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(5) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(6) *Reliable technology*. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(7) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e. , absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e. , potentially recoverable resources from undiscovered accumulations).

(8) *Undeveloped oil and gas reserves* . Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

LIST OF ECONOMIC TABLES

Cash Flow Summaries

TABLE 2 Total

Production and Economic Projection

As of: 1/1/2025

Year	Wells	Estimated 8/8 Prod. Oil (Mbbl)	Estimated 8/8 Prod. Gas (MMcf)	Net Reserves Volume Oil (Mbbl)	Net Reserves Volume Wet Gas (MMcf)	Plant Net Sales Volume NGL (Mbbl)	Plant Net Sales Volume Residue Gas (MMcf)	Oil ($/bbl)	NGL ($/bbl)	Res. Gas ($/Mcf)
2025	2,218	64,246.60	384,043.61	109.72	6,929.26	55.70	6,279.74	74.99	20.76	2.14
2026	2,276	52,295.55	334,558.78	109.86	4,903.91	56.47	4,473.96	75.08	20.45	2.10
2027	2,273	32,663.87	234,836.27	68.52	2,978.17	43.40	2,673.78	75.00	20.53	2.09
2028	2,265	23,800.94	182,417.27	48.81	2,160.13	33.88	1,930.84	74.98	20.66	2.08
2029	2,260	18,715.19	148,486.71	37.82	1,679.16	28.03	1,500.05	74.98	20.71	2.07
2030	2,249	15,472.43	125,380.03	31.13	1,367.35	23.98	1,220.53	74.98	20.73	2.07
2031	2,239	13,169.59	108,315.95	26.47	1,145.39	20.90	1,021.58	74.97	20.75	2.06
2032	2,229	11,469.73	95,340.37	23.04	982.23	18.52	875.29	74.96	20.75	2.06
2033	2,219	10,088.68	84,559.74	20.26	850.42	16.49	757.09	74.95	20.76	2.06
2034	2,209	9,005.55	75,992.83	18.09	748.24	14.85	665.51	74.94	20.76	2.05
2035	2,198	8,114.34	68,819.65	16.31	665.51	13.47	591.45	74.94	20.77	2.05
2036	2,189	7,387.61	62,880.40	14.86	597.90	12.32	531.11	74.93	20.78	2.05
2037	2,177	6,728.24	57,296.18	13.54	537.67	11.25	477.37	74.93	20.78	2.05
2038	2,159	6,174.87	52,714.90	12.44	487.60	10.34	432.69	74.93	20.79	2.05
2039	2,148	5,685.45	48,650.51	11.47	442.92	9.52	392.78	74.92	20.80	2.05
Sub-T		285,018.66	2,064,293.20	562.36	26,475.85	369.11	23,823.77	75.00	20.67	2.09
After		64,495.35	579,116.68	132.83	4,329.35	104.82	3,803.90	74.84	20.92	2.04
Total		349,514.01	2,643,409.88	695.19	30,805.21	473.92	27,627.67	74.97	20.73	2.08
Cum.		417,682.32	3,020,479.08							
Ult.		767,196.33	5,663,888.96							

0.00% Lease Shrinkage and 10.31% Plant Shrinkage

Year	Company Future Gross Revenue Oil (M$)	Company Future Gross Revenue NGL (M$)	Company Future Gross Revenue Gas (M$)	Company Future Gross Revenue Other (M$)	Company Future Gross Revenue Total (M$)	Prod & Adv Taxes Prod Tax (M$)	Prod & Adv Taxes Adv Tax (M$)	Revenue after Sev & Adv (M$)
2025	8,228.66	1,156.52	13,424.35	0.00	22,809.53	1,403.55	677.81	20,728.16
2026	8,248.41	1,155.03	9,374.83	0.00	18,778.26	1,020.28	621.03	17,136.95
2027	5,138.82	891.17	5,579.43	0.00	11,609.42	591.89	407.21	10,610.33
2028	3,660.16	699.93	4,013.07	0.00	8,373.16	408.92	307.19	7,657.05
2029	2,835.58	580.54	3,107.34	0.00	6,523.46	308.99	246.47	5,968.00
2030	2,334.33	497.08	2,521.63	0.00	5,353.04	247.86	206.13	4,899.06
2031	1,984.16	433.66	2,106.10	0.00	4,523.92	205.86	176.52	4,141.54
2032	1,727.23	384.34	1,801.54	0.00	3,913.12	175.69	154.12	3,583.31
2033	1,518.83	342.26	1,556.33	0.00	3,417.42	151.84	135.49	3,130.10
2034	1,355.97	308.37	1,366.68	0.00	3,031.01	133.54	120.76	2,776.72
2035	1,222.48	279.69	1,213.57	0.00	2,715.74	118.82	108.60	2,488.32
2036	1,113.57	255.92	1,088.78	0.00	2,458.28	106.91	98.61	2,252.76
2037	1,014.74	233.81	977.93	0.00	2,226.48	96.31	89.53	2,040.64
2038	931.99	214.94	885.92	0.00	2,032.85	87.53	81.89	1,863.43
2039	859.54	198.01	803.87	0.00	1,861.42	79.86	75.04	1,706.52
Sub-T	42,174.48	7,631.27	49,821.37	0.00	99,627.12	5,137.84	3,506.40	90,982.89
After	9,940.92	2,193.16	7,772.32	0.00	19,906.40	841.26	791.50	18,273.64
Total	52,115.40	9,824.43	57,593.69	0.00	119,533.52	5,979.10	4,297.90	109,256.53

Year	Deductions Lease Net Costs (M$)	Deductions Net Investments (M$)	Deductions Trans. Costs (M$)	Deductions Net Profits (M$)	Future Net Income Before Income Taxes Undiscounted Annual (M$)	Future Net Income Before Income Taxes Undiscounted Cumulative (M$)	Discounted Ann @ 10.00% (M$)	Disc. Cum. Annual @ 10.00% (M$)
2025	0.40	0.00	3,810.15	0.00	16,917.61	16,917.61	16,161.81	16,161.81
2026	0.52	0.00	3,259.92	0.00	13,876.51	30,794.13	12,069.56	28,231.37
2027	0.52	0.00	2,133.41	0.00	8,476.39	39,270.52	6,702.69	34,934.06
2028	0.52	0.00	1,644.66	0.00	6,011.87	45,282.39	4,318.42	39,252.48
2029	0.51	0.00	1,336.41	0.00	4,631.08	49,913.47	3,022.22	42,274.69
2030	0.50	0.00	1,123.71	0.00	3,774.85	53,688.32	2,238.97	44,513.66
2031	0.50	0.00	964.45	0.00	3,176.59	56,864.91	1,712.60	46,226.26
2032	0.50	0.00	842.52	0.00	2,740.28	59,605.19	1,342.77	47,569.04
2033	0.50	0.00	739.86	0.00	2,389.73	61,994.91	1,064.36	48,633.40
2034	0.50	0.00	658.41	0.00	2,117.80	64,112.72	857.47	49,490.87
2035	0.50	0.00	591.14	0.00	1,896.68	66,009.40	698.12	50,189.00
2036	0.50	0.00	535.68	0.00	1,716.57	67,725.97	574.32	50,763.32
2037	0.50	0.00	485.29	0.00	1,554.85	69,280.82	472.87	51,236.19
2038	0.50	0.00	442.81	0.00	1,420.12	70,700.93	392.64	51,628.83
2039	0.50	0.00	404.36	0.00	1,301.65	72,002.59	327.19	51,956.02
Sub-T	7.51	0.00	18,972.79	0.00	72,002.59	72,002.59	51,956.02	51,956.02
After	15.51	2.09	4,033.20	0.00	14,222.83	14,222.83	1,690.01	1,690.01
Total	23.02	2.09	23,006.00	0.00	86,225.42	86,225.42	53,646.03	53,646.03

Present Worth Profile (M$)

FW 5.00% :	64,661.40
FW 8.00% :	57,359.92
PW 10.00% :	53,646.03
PW 12.00% :	50,555.36
PW 15.00% :	46,757.90
PW 20.00% :	41,925.65

TABLE 3

Production and Economic Projection

As of: 1/1/2025

Proved Producing Rsv Class & Category

Year	Wells	Estimated 8/8 Prod. Oil Mbbl	Estimated 8/8 Prod. Gas MMcf	Net Reserves Volume Oil Mbbl	Net Reserves Volume Wet Gas MMcf	Plant Net Sales Volume NGL Mbbl	Plant Net Sales Volume Residue Gas MMcf	Oil $/bbl	NGL $/bbl	Res. Gas $/Mcf
2025	2,072	46,944.73	295,756.52	87.75	5,237.67	53.13	4,606.21	74.92	20.69	2.16
2026	2,067	29,444.88	208,087.29	57.15	3,224.14	40.53	2,850.42	74.93	20.71	2.13
2027	2,063	21,760.04	161,034.73	42.84	2,296.98	32.94	2,036.41	74.92	20.71	2.11
2028	2,055	17,288.77	131,225.87	34.33	1,764.78	27.71	1,566.81	74.91	20.70	2.09
2029	2,050	14,236.09	109,737.81	28.43	1,411.11	23.68	1,253.54	74.90	20.70	2.08
2030	2,039	12,087.93	94,096.14	24.23	1,167.13	20.62	1,037.02	74.89	20.70	2.08
2031	2,029	10,473.67	82,101.34	21.06	987.21	18.19	877.07	74.89	20.70	2.07
2032	2,019	9,239.01	72,745.84	18.62	852.13	16.24	756.77	74.88	20.70	2.07
2033	2,009	8,204.96	64,822.46	16.56	741.04	14.54	657.69	74.87	20.69	2.06
2034	1,999	7,378.51	58,448.47	14.92	654.08	13.15	580.12	74.87	20.69	2.06
2035	1,988	6,687.16	53,044.32	13.55	583.14	11.96	516.89	74.86	20.70	2.06
2036	1,979	6,116.77	48,525.20	12.41	524.71	10.97	464.96	74.86	20.70	2.06
2037	1,967	5,591.20	44,203.53	11.36	472.29	10.03	418.36	74.86	20.70	2.06
2038	1,949	5,145.87	40,661.34	10.47	428.50	9.23	379.41	74.85	20.71	2.06
2039	1,938	4,747.95	37,491.97	9.68	389.09	8.51	344.30	74.85	20.71	2.05
Sub-T		205,347.55	1,501,982.83	403.36	20,734.00	311.42	18,346.00	74.90	20.70	2.11
After		54,469.27	427,010.59	113.79	3,702.51	91.86	3,246.51	74.75	20.82	2.05
Total		259,816.82	1,928,993.42	517.15	24,436.51	403.28	21,592.50	74.87	20.73	2.10
Cum.		417,502.26	3,018,822.20							
Ult.		677,319.08	4,947,815.62							

0.00% Lease Shrinkage and 11.64% Plant Shrinkage

Year	Company Future Gross Revenue Oil M$	NGL M$	Gas M$	Other M$	Total M$	Prod & Adv Taxes Prod Tax M$	Adv Tax M$	Revenue after Sev & Adv M$
2025	6,575.02	1,099.11	9,931.15	0.00	17,605.28	1,024.00	549.99	16,031.29
2026	4,282.04	839.50	6,057.95	0.00	11,179.49	592.79	388.58	10,198.12
2027	3,209.86	682.08	4,287.80	0.00	8,179.74	407.45	301.71	7,470.58
2028	2,571.45	573.68	3,278.20	0.00	6,423.34	306.49	245.63	5,871.22
2029	2,129.19	490.23	2,611.04	0.00	5,230.45	242.10	204.71	4,783.65
2030	1,814.84	426.84	2,152.93	0.00	4,394.61	198.94	174.70	4,020.97
2031	1,577.23	376.39	1,816.23	0.00	3,769.84	167.80	151.51	3,450.53
2032	1,394.43	336.05	1,564.11	0.00	3,294.58	144.78	133.42	3,016.39
2033	1,240.24	300.84	1,357.42	0.00	2,898.50	126.12	117.98	2,654.40
2034	1,116.99	272.12	1,195.97	0.00	2,585.09	111.59	105.62	2,367.88
2035	1,014.04	247.54	1,064.62	0.00	2,326.21	99.78	95.30	2,131.13
2036	928.83	227.03	956.73	0.00	2,112.59	90.11	86.75	1,935.74
2037	850.11	207.75	860.21	0.00	1,918.06	81.40	78.89	1,757.76
2038	783.50	191.18	779.70	0.00	1,754.37	74.13	72.25	1,607.99
2039	724.58	176.20	707.28	0.00	1,608.06	67.73	66.23	1,474.10
Sub-T	30,212.35	6,446.55	38,621.35	0.00	75,280.24	3,735.22	2,773.26	68,771.76
After	8,506.15	1,912.89	6,667.59	0.00	17,086.63	711.94	688.76	15,685.93
Total	38,718.50	8,359.44	45,288.93	0.00	92,366.87	4,447.16	3,462.02	84,457.69

Year	Deductions Lease Net Costs M$	Net Investments M$	Trans. Costs M$	Net Profits M$	Future Net Income Before Income Taxes Undiscounted Annual M$	Undiscounted Cumulative M$	Discounted Ann @ 10.00% M$	Disc. Cum. Annual @ 10.00% M$
2025	0.12	0.00	2,838.80	0.00	13,192.37	13,192.37	12,642.89	12,642.89
2026	0.12	0.00	2,095.87	0.00	8,102.13	21,294.50	7,046.82	19,689.71
2027	0.12	0.00	1,658.82	0.00	5,811.64	27,106.13	4,591.90	24,281.60
2028	0.12	0.00	1,363.08	0.00	4,508.02	31,614.15	3,236.44	27,518.04
2029	0.11	0.00	1,141.12	0.00	3,642.42	35,256.57	2,376.42	29,894.47
2030	0.11	0.00	975.63	0.00	3,045.23	38,301.80	1,805.94	31,700.40
2031	0.11	0.00	846.13	0.00	2,604.29	40,906.09	1,403.91	33,104.32
2032	0.11	0.00	744.32	0.00	2,271.96	43,178.05	1,113.21	34,217.52
2033	0.11	0.00	656.68	0.00	1,997.62	45,175.67	889.67	35,107.20
2034	0.11	0.00	586.34	0.00	1,781.43	46,957.10	721.25	35,828.45
2035	0.11	0.00	527.73	0.00	1,603.29	48,560.40	590.12	36,418.56
2036	0.11	0.00	479.05	0.00	1,456.58	50,016.97	487.32	36,905.88
2037	0.11	0.00	434.47	0.00	1,323.18	51,340.16	402.41	37,308.29
2038	0.11	0.00	396.69	0.00	1,211.19	52,551.35	334.87	37,643.16
2039	0.11	0.00	362.20	0.00	1,111.80	53,663.15	279.46	37,922.62
Sub-T	1.69	0.00	15,106.92	0.00	53,663.15	53,663.15	37,922.62	37,922.62
After	1.64	0.00	3,525.23	0.00	12,159.06	12,159.06	1,445.72	1,445.72
Total	3.33	0.00	18,632.15	0.00	65,822.21	65,822.21	39,368.34	39,368.34

Present Worth Profile (M$)

FW 5.00% :	48,154.46
FW 8.00% :	42,304.85
PW 10.00% :	39,368.34
PW 12.00% :	36,948.46
PW 15.00% :	34,008.76
PW 20.00% :	30,328.47

TABLE 4

Production and Economic Projection

As of: 1/1/2025

Proved Behind Pipe Rsv Class & Category

Year	Wells	Estimated B/B Prod. Oil Mbbl	Estimated B/B Prod. Gas MMcf	Net Reserves Volume Oil Mbbl	Net Reserves Volume Wet Gas MMcf	Plant Net Sales Volume NGL Mbbl	Plant Net Sales Volume Residue Gas MMcf	Oil $/bbl	NGL $/bbl	Res. Gas $/Mcf
2025	90	11,398.80	72,348.28	18.44	1,683.22	1.73	1,671.89	75.52	23.20	2.09
2026	120	10.979.29	85.854.33	27.04	1.633.30	11.00	1.601.69	74.87	19.06	2.05
2027	121	6,021.90	47,465.94	15.39	649.06	7.05	622.07	74.81	19.27	2.04
2028	121	3,608.55	32,058.69	8.52	371.88	3.68	352.86	74.83	19.83	2.04
2029	121	2,468.47	23,844.46	5.30	249.73	2.42	237.78	74.97	20.23	2.04
2030	121	1,867.39	19,100.05	3.83	185.23	1.78	176.34	75.03	20.53	2.04
2031	121	1,490.68	15,945.63	2.97	145.54	1.39	138.45	75.07	20.76	2.04
2032	121	1,236.24	13,721.91	2.41	119.19	1.14	113.28	75.09	20.94	2.04
2033	121	1,046.17	11,981.94	2.01	99.84	0.95	94.81	75.11	21.09	2.04
2034	121	905.40	10,653.63	1.71	85.68	0.82	81.30	75.13	21.22	2.03
2035	121	795.64	9,585.59	1.49	74.76	0.71	70.89	75.14	21.33	2.03
2036	121	709.66	8,729.93	1.32	66.28	0.63	62.82	75.15	21.42	2.03
2037	121	635.88	7,969.25	1.17	59.09	0.56	55.97	75.16	21.50	2.03
2038	121	576.23	7,343.27	1.05	53.31	0.51	50.48	75.17	21.57	2.03
2039	121	525.54	6,803.71	0.95	48.48	0.46	45.89	75.17	21.63	2.03
Sub-T		44,265.84	373,406.59	93.61	5,524.59	34.80	5,376.53	75.04	19.98	2.06
After		5,627.13	94,467.53	10.04	555.56	5.56	522.81	75.19	21.98	2.03
Total		49,892.97	467,874.12	103.64	6,080.15	40.37	5,899.34	75.05	20.26	2.06
Cum.		0.00	0.00							
Ult.		49,892.97	467,874.12							

0.00% Lease Shrinkage and 2.97% Plant Shrinkage

Year	Company Future Gross Revenue Oil M$	NGL M$	Gas M$	Other M$	Total M$	Prod & Adv Taxes Prod Tax M$	Adv Tax M$	Revenue after Sev & Adv M$
2025	1,392.60	40.06	3,491.06	0.00	4,923.73	366.69	120.95	4,436.09
2026	2,024.68	209.63	3,289.08	0.00	5,523.40	324.62	176.67	5,022.11
2027	1,151.17	135.84	1,271.97	0.00	2,558.97	140.52	82.41	2,336.05
2028	637.46	72.96	720.45	0.00	1,430.87	75.98	47.87	1,307.03
2029	397.18	48.87	485.01	0.00	931.05	48.32	32.25	850.49
2030	287.31	36.44	359.43	0.00	683.18	34.73	24.20	624.25
2031	222.90	28.84	282.03	0.00	533.78	26.66	19.24	487.88
2032	181.09	23.79	230.65	0.00	435.52	21.42	15.91	398.18
2033	150.82	20.05	192.96	0.00	363.83	17.66	13.45	332.72
2034	128.84	17.30	165.41	0.00	311.55	14.95	11.63	284.97
2035	111.99	15.17	144.18	0.00	271.34	12.88	10.22	248.24
2036	98.96	13.50	127.71	0.00	240.17	11.30	9.11	219.76
2037	87.95	12.07	113.76	0.00	213.78	9.97	8.17	195.65
2038	79.14	10.92	102.57	0.00	192.63	8.91	7.41	176.32
2039	71.77	9.95	93.22	0.00	174.94	8.03	6.76	160.14
Sub-T	7,023.88	695.40	11,069.48	0.00	18,788.75	1,122.65	586.24	17,079.86
After	754.68	122.31	1,058.94	0.00	1,935.93	82.24	79.79	1,773.90
Total	7,778.56	817.71	12,128.42	0.00	20,724.69	1,204.89	666.03	18,853.76

Year	Deductions Lease Net Costs M$	Net Investments M$	Trans. Costs M$	Net Profits M$	Future Net Income Before Income Taxes Undiscounted Annual M$	Undiscounted Cumulative M$	Discounted Ann @ 10.00% M$	Disc. Cum. Annual @ 10.00% M$
2025	0.27	0.00	966.44	0.00	3,469.37	3,469.37	3,276.66	3,276.66
2026	0.40	0.00	1,135.81	0.00	3,885.90	7,355.27	3,375.35	6,652.01
2027	0.40	0.00	456.89	0.00	1,878.76	9,234.03	1,488.01	8,140.02
2028	0.40	0.00	269.09	0.00	1,037.54	10,271.58	746.71	8,886.73
2029	0.40	0.00	185.72	0.00	664.37	10,935.95	434.03	9,320.75
2030	0.40	0.00	140.35	0.00	483.51	11,419.45	286.99	9,607.74
2031	0.40	0.00	111.86	0.00	375.63	11,795.08	202.62	9,810.37
2032	0.40	0.00	92.66	0.00	305.12	12,100.21	149.58	9,959.94
2033	0.40	0.00	78.37	0.00	253.95	12,354.16	113.14	10,073.09
2034	0.40	0.00	67.82	0.00	216.76	12,570.92	87.79	10,160.87
2035	0.40	0.00	59.60	0.00	188.24	12,759.15	69.30	10,230.17
2036	0.40	0.00	53.18	0.00	166.18	12,925.33	55.61	10,285.78
2037	0.40	0.00	47.69	0.00	147.56	13,072.89	44.88	10,330.67
2038	0.40	0.00	43.26	0.00	132.66	13,205.56	36.68	10,367.35
2039	0.40	0.00	39.53	0.00	120.22	13,325.77	30.22	10,397.57
Sub-T	5.82	0.00	3,748.27	0.00	13,325.77	13,325.77	10,397.57	10,397.57
After	13.87	2.09	473.50	0.00	1,284.44	1,284.44	153.71	153.71
Total	19.69	2.09	4,221.77	0.00	14,610.22	14,610.22	10,551.28	10,551.28

Present Worth Profile (M$)

FW 5.00% :	12,051.86
FW 8.00% :	11,077.81
PW 10.00% :	10,551.28
PW 12.00% :	10,094.10
PW 15.00% :	9,505.63
PW 20.00% :	8,708.50

TABLE 5

Production and Economic Projection

As of: 1/1/2025

Proved Shut-In Rsv Class & Category

		Estimated 8/8 Prod.		Net Reserves Volume		Plant Net Sales Volume				
Year	Wells	Oil Mbbl	Gas MMcf	Oil Mbbl	Wet Gas MMcf	NGL Mbbl	Residue Gas MMcf	Oil $/bbl	NGL $/bbl	Res. Gas $/Mcf
2025	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-T		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
After		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cum.		180.06	1,656.88							
Ult.		180.06	1,656.88							

0.00% Lease Shrinkage and 0.00% Plant Shrinkage

	Company Future Gross Revenue					Prod & Adv Taxes		Revenue
Year	Oil M$	NGL M$	Gas M$	Other M$	Total M$	Prod Tax M$	Adv Tax M$	after Sev & Adv M$
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-T	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
After	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

	Deductions				Future Net Income Before Income Taxes			
Year	Lease Net Costs M$	Net Investments M$	Trans. Costs M$	Net Profits M$	Undiscounted Annual M$	Undiscounted Cumulative M$	Discounted Ann @ 10.00% M$	Disc. Cum. Annual @ 10.00% M$
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-T	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
After	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Present Worth Profile (M$)

PW 5.00% :	0.00
PW 8.00% :	0.00
PW 10.00% :	0.00
PW 12.00% :	0.00
PW 15.00% :	0.00
PW 20.00% :	0.00

TABLE 6

Production and Economic Projection

As of: 1/1/2025

Proved Undeveloped Rsv Class & Category

Year	Wells	Estimated 8/8 Prod. Oil Mbbl	Estimated 8/8 Prod. Gas MMcf	Net Reserves Volume Oil Mbbl	Net Reserves Volume Wet Gas MMcf	Plant Net Sales Volume NGL Mbbl	Plant Net Sales Volume Residue Gas MMcf	Oil $/bbl	NGL $/bbl	Res. Gas $/Mcf
2025	56	5,903.07	15,938.82	3.53	8.36	0.84	1.63	73.98	20.53	1.31
2026	89	11.871.38	40,617.16	25.67	46.48	4.94	21.85	75.65	21.44	1.27
2027	89	4.881.93	26,335.61	10.29	32.12	3.42	15.29	75.62	21.44	1.29
2028	89	2,903.62	19,132.71	5.97	23.47	2.49	11.18	75.60	21.42	1.29
2029	89	2,010.63	14,904.45	4.09	18.32	1.94	8.74	75.58	21.41	1.29
2030	89	1,517.10	12,183.84	3.07	14.99	1.58	7.16	75.56	21.40	1.29
2031	89	1,205.24	10,268.98	2.44	12.64	1.33	6.05	75.55	21.39	1.30
2032	89	994.48	8,872.62	2.01	10.92	1.15	5.24	75.54	21.39	1.30
2033	89	837.55	7,755.34	1.69	9.54	1.00	4.59	75.53	21.39	1.30
2034	89	721.63	6,890.73	1.46	8.48	0.89	4.08	75.52	21.39	1.30
2035	89	631.55	6,189.74	1.28	7.61	0.79	3.67	75.51	21.38	1.30
2036	89	561.19	5,625.28	1.14	6.91	0.72	3.34	75.50	21.38	1.30
2037	89	501.16	5,123.40	1.02	6.29	0.65	3.04	75.50	21.38	1.30
2038	89	452.77	4,710.29	0.92	5.78	0.60	2.80	75.49	21.38	1.30
2039	89	411.97	4,354.82	0.84	5.35	0.55	2.59	75.49	21.38	1.30
Sub-T		35,405.27	188,903.78	65.39	217.26	22.89	101.24	75.52	21.38	1.29
After		4,398.95	57,638.56	9.01	71.28	7.39	34.59	75.50	21.37	1.32
Total		39,804.23	246,542.34	74.40	288.54	30.28	135.83	75.51	21.38	1.30
Cum.		0.00	0.00							
Ult.		39,804.23	246,542.34							

0.00% Lease Shrinkage and 52.93% Plant Shrinkage

Year	Company Future Gross Revenue Oil M$	NGL M$	Gas M$	Other M$	Total M$	Prod & Adv Taxes Prod Tax M$	Adv Tax M$	Revenue after Sev & Adv M$
2025	261.04	17.34	2.14	0.00	280.52	12.86	6.87	260.79
2026	1,941.68	105.90	27.79	0.00	2,075.38	102.88	55.78	1,916.72
2027	777.79	73.25	19.66	0.00	870.70	43.92	23.09	803.69
2028	451.25	53.29	14.41	0.00	518.95	26.45	13.69	478.80
2029	309.21	41.45	11.30	0.00	361.95	18.57	9.52	333.86
2030	232.17	33.80	9.27	0.00	275.25	14.19	7.22	253.84
2031	184.03	28.42	7.84	0.00	220.29	11.39	5.77	203.13
2032	151.72	24.50	6.79	0.00	183.01	9.49	4.79	168.74
2033	127.77	21.36	5.95	0.00	155.09	8.06	4.05	142.98
2034	110.13	18.94	5.30	0.00	134.37	6.99	3.51	123.87
2035	96.45	16.98	4.77	0.00	118.20	6.16	3.08	108.95
2036	85.78	15.40	4.34	0.00	105.52	5.50	2.75	97.26
2037	76.68	14.00	3.96	0.00	94.64	4.94	2.47	87.23
2038	69.35	12.84	3.65	0.00	85.84	4.49	2.24	79.12
2039	63.19	11.86	3.38	0.00	78.42	4.10	2.04	72.28
Sub-T	4,938.26	489.32	130.55	0.00	5,558.13	279.97	146.90	5,131.26
After	680.09	157.96	45.79	0.00	883.84	47.08	22.95	813.81
Total	5,618.35	647.28	176.34	0.00	6,441.97	327.05	169.84	5,945.08

Year	Deductions Lease Net Costs M$	Net Investments M$	Trans. Costs M$	Net Profits M$	Future Net Income Before Income Taxes Undiscounted Annual M$	Undiscounted Cumulative M$	Discounted Ann @ 10.00% M$	Disc. Cum. Annual @ 10.00% M$
2025	0.00	0.00	4.92	0.00	255.87	255.87	242.26	242.26
2026	0.00	0.00	28.23	0.00	1,888.49	2,144.36	1,647.39	1,889.65
2027	0.00	0.00	17.70	0.00	785.99	2,930.36	622.79	2,512.43
2028	0.00	0.00	12.49	0.00	466.31	3,396.67	335.27	2,847.71
2029	0.00	0.00	9.57	0.00	324.29	3,720.96	211.77	3,059.47
2030	0.00	0.00	7.73	0.00	246.11	3,967.06	146.04	3,205.52
2031	0.00	0.00	6.46	0.00	196.67	4,163.73	106.07	3,311.58
2032	0.00	0.00	5.54	0.00	163.19	4,326.93	79.99	3,391.57
2033	0.00	0.00	4.82	0.00	138.16	4,465.09	61.55	3,453.12
2034	0.00	0.00	4.26	0.00	119.61	4,584.70	48.44	3,501.56
2035	0.00	0.00	3.81	0.00	105.15	4,689.85	38.71	3,540.26
2036	0.00	0.00	3.45	0.00	93.82	4,783.66	31.39	3,571.65
2037	0.00	0.00	3.13	0.00	84.10	4,867.77	25.58	3,597.23
2038	0.00	0.00	2.86	0.00	76.26	4,944.02	21.09	3,618.32
2039	0.00	0.00	2.64	0.00	69.64	5,013.66	17.50	3,635.82
Sub-T	0.00	0.00	117.60	0.00	5,013.66	5,013.66	3,635.82	3,635.82
After	0.00	0.00	34.48	0.00	779.34	779.34	90.59	90.59
Total	0.00	0.00	152.08	0.00	5,793.00	5,793.00	3,726.41	3,726.41

Present Worth Profile (M$)

PW 5.00% :	4,455.09
PW 8.00% :	3,977.26
PW 10.00% :	3,726.41
PW 12.00% :	3,512.80
PW 15.00% :	3,243.51
PW 20.00% :	2,888.68

Tabular Summaries

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
Proved Producing Rsv Class & Category													
21202 VECTOR 19 A 1 - 1	*P-DP*	0.02	0.00	0.00	1.68	0.00	0.00	0.00	0.14	0.00	1.54	0.99	12.67
44 MAGNUM 9-4 H 1LS - H 1LS	*P-DP*	0.40	0.06	0.36	30.72	1.61	0.71	0.00	2.55	0.00	30.50	15.68	50.00
44 MAGNUM 9-4 H 1WA - H 1W	*P-DP*	0.17	0.07	0.41	13.14	1.82	0.80	0.00	1.33	0.00	14.43	8.16	45.11
44 MAGNUM 9-4 H 1WB - H 1W	*P-DP*	0.11	0.11	0.63	8.64	2.83	1.24	0.00	1.23	0.00	11.48	6.18	40.15
44 MAGNUM 9-4 H 2WA - H 2W	*P-DP*	0.29	0.07	0.42	22.23	1.86	0.81	0.00	1.99	0.00	22.90	11.84	50.00
44 MAGNUM 9-4 H 2WB - H 2W	*P-DP*	0.18	0.06	0.36	13.87	1.62	0.71	0.00	1.34	0.00	14.86	8.13	46.37
44 MAGNUM 9-4 H 3WA - H 3W	*P-DP*	0.31	0.09	0.56	23.37	2.49	1.09	0.00	2.21	0.00	24.73	13.73	47.18
ABIGAIL 218-219 UNIT 1H - 1H	*P-DP*	0.02	0.02	0.02	1.25	0.50	0.02	0.00	0.23	0.00	1.54	0.81	40.18
ACKERLY BROWN 9 1 - 1	*P-DP*	0.02	0.00	0.01	1.49	0.05	0.02	0.00	0.13	0.00	1.43	0.88	32.29
ADAMCHIK 4 - 4	*P-DP*	0.00	0.00	3.78	0.00	0.00	5.32	0.00	0.50	0.00	4.82	2.54	50.00
ADAMCHIK 5 - 5	*P-DP*	0.00	0.00	3.02	0.00	0.00	4.24	0.00	0.40	0.00	3.84	2.03	50.00
ADAMCHIK 7 - 7	*P-DP*	0.00	0.00	4.86	0.00	0.00	6.83	0.00	0.64	0.00	6.19	3.10	50.00
ADAMEK UNIT 2H - 2H	*P-DP*	0.31	0.51	2.52	22.93	9.18	4.88	0.00	3.31	0.00	33.68	18.09	50.00
ADAMS EAST H 23-26 4208H - 4	*P-DP*	0.03	0.02	0.07	2.53	0.33	0.14	0.00	0.30	0.00	2.70	1.40	42.97
ADAMS EAST H 23-26 4408H - 4	*P-DP*	0.08	0.03	0.12	5.84	0.56	0.24	0.00	0.63	0.00	6.01	3.08	50.00
ADAMS WEST A 23-26 4301H - 4	*P-DP*	0.16	0.12	0.41	11.80	1.99	0.83	0.00	1.50	0.00	13.12	6.51	50.00
ADAMS WEST B 23-26 4202H - 4	*P-DP*	0.01	0.01	0.02	0.85	0.10	0.04	0.00	0.10	0.00	0.89	0.56	23.74
ADAMS WEST B 23-26 4402H - 4	*P-DP*	0.03	0.03	0.09	2.47	0.45	0.19	0.00	0.32	0.00	2.78	1.52	41.65
ADAMS WEST D 23-26 4304H - 4	*P-DP*	0.03	0.22	0.75	2.22	3.59	1.50	0.00	1.13	0.00	6.18	2.79	50.00
ADAMS WEST E 23-26 4205H - 4	*P-DP*	0.01	0.03	0.10	1.09	0.48	0.20	0.00	0.22	0.00	1.56	0.88	33.39
ADAMS WEST E 23-26 4405H - 4	*P-DP*	0.03	0.04	0.15	2.60	0.72	0.30	0.00	0.41	0.00	3.21	1.73	44.70
ADAMS WEST G 23-26 4307H - 4	*P-DP*	0.04	0.13	0.46	3.05	2.18	0.91	0.00	0.83	0.00	5.32	2.71	50.00
ADMIRAL 4-48 47 1H - 1H	*P-DP*	0.10	0.05	0.32	7.58	1.06	0.43	0.00	0.86	0.00	8.21	3.99	50.00
AGGIE THE BULLDOG 39-46 A 1	*P-DP*	0.41	0.08	0.38	30.81	1.70	0.51	0.00	2.87	0.00	30.15	16.75	26.41
AGGIE THE BULLDOG 39-46 A 1	*P-DP*	0.90	0.52	2.52	68.18	11.35	3.39	0.00	9.26	0.00	73.66	42.09	40.41
AGGIE THE BULLDOG 39-46 A 1	*P-DP*	0.74	0.22	1.05	56.54	4.72	1.41	0.00	5.88	0.00	56.78	32.64	31.77
AGGIE THE BULLDOG 39-46 A 1	*P-DP*	0.70	0.15	0.74	52.90	3.34	1.00	0.00	5.09	0.00	52.15	29.61	31.24
AGGIE THE BULLDOG 39-46 B 2	*P-DP*	0.64	0.31	1.50	48.44	6.76	2.02	0.00	6.08	0.00	51.14	35.87	24.63
AGGIE THE BULLDOG 39-46 B 2	*P-DP*	0.19	0.22	1.06	14.78	4.75	1.42	0.00	2.88	0.00	18.07	11.91	21.92
AGGIE THE BULLDOG 39-46 C 3	*P-DP*	0.49	0.92	4.46	37.09	20.05	5.98	0.00	10.33	0.00	52.78	34.38	23.78
AGGIE THE BULLDOG 39-46 C 3	*P-DP*	0.31	0.07	0.32	23.40	1.43	0.43	0.00	2.23	0.00	23.02	14.62	21.30
AGGIE THE BULLDOG 39-46 C 4	*P-DP*	0.50	0.19	0.92	38.08	4.14	1.24	0.00	4.33	0.00	39.13	25.26	25.05
AGGIE THE BULLDOG 39-46 D	*P-DP*	0.50	0.29	1.42	37.81	6.38	1.90	0.00	5.17	0.00	40.93	23.73	27.48
AGGIE THE BULLDOG 39-46 D	*P-DP*	0.18	0.54	2.64	13.98	11.85	3.54	0.00	5.53	0.00	23.83	14.64	26.96

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
AGGIE THE BULLDOG 39-46 D	*P-DP*	0.52	0.22	1.07	39.73	4.83	1.44	0.00	4.71	0.00	41.29	25.58	32.27
AGGIE THE BULLDOG 39-46 D	*P-DP*	0.57	0.82	4.00	43.36	17.97	5.36	0.00	9.99	0.00	56.70	31.41	29.47
AGGIE THE BULLDOG 39-46 E 6	*P-DP*	0.43	0.20	0.98	32.42	4.39	1.31	0.00	4.01	0.00	34.10	21.69	23.82
AGGIE THE BULLDOG 39-46 E 7	*P-DP*	0.76	0.54	2.63	57.40	11.81	3.53	0.00	8.65	0.00	64.08	35.70	32.28
AGGIE THE BULLDOG 39-46 E 7	*P-DP*	0.99	0.29	1.43	74.95	6.42	1.92	0.00	7.86	0.00	75.42	43.10	40.53
AGGIE THE BULLDOG 39-46 E 7	*P-DP*	0.87	0.23	1.13	65.99	5.06	1.51	0.00	6.70	0.00	65.87	39.28	32.14
AGGIE THE BULLDOG 39-46 E 7	*P-DP*	0.52	0.85	4.16	39.14	18.69	5.58	0.00	9.96	0.00	53.45	34.80	24.46
ALEX TAMSULA 2 - 2	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALEX TAMSULA 4 - 4	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALLMAN 24 1H - 1H	*P-DP*	0.30	1.16	7.17	22.90	23.58	9.62	0.00	8.59	0.00	47.51	25.03	45.81
ALLRED UNIT B 08-05 5AH - 5A	*P-DP*	0.04	0.01	0.09	3.39	0.38	0.17	0.00	0.33	0.00	3.62	2.23	30.13
ALLRED UNIT B 08-05 5BH - 5B	*P-DP*	0.01	0.03	0.18	0.95	0.80	0.35	0.00	0.24	0.00	1.87	1.28	15.58
ALLRED UNIT B 08-05 5MH - 5M	*P-DP*	0.05	0.04	0.25	3.71	1.12	0.49	0.00	0.51	0.00	4.81	2.62	41.55
ALLRED UNIT B 08-05 5SH - 5S	*P-DP*	0.05	0.04	0.21	3.87	0.94	0.41	0.00	0.48	0.00	4.74	2.57	42.25
ALLRED UNIT B 08-05 6AH - 6A	*P-DP*	0.08	0.05	0.28	6.05	1.27	0.56	0.00	0.71	0.00	7.17	3.88	47.32
ALLRED UNIT B 08-05 6MH - 6M	*P-DP*	0.04	0.02	0.15	2.99	0.65	0.29	0.00	0.36	0.00	3.57	2.13	29.59
ALLRED UNIT B 08-05 6SH - 6S	*P-DP*	0.04	0.07	0.40	2.98	1.80	0.79	0.00	0.60	0.00	4.96	2.63	45.89
ALLRED UNIT B 08-05 7AH - 7A	*P-DP*	0.05	0.05	0.30	4.07	1.33	0.58	0.00	0.58	0.00	5.40	2.94	42.65
ALLRED UNIT B 08-05 7BH - 7B	*P-DP*	0.03	0.05	0.29	2.17	1.30	0.57	0.00	0.44	0.00	3.60	2.01	35.20
ALLRED UNIT B 08-05 8AH - 8A	*P-DP*	0.10	0.00	0.03	7.59	0.12	0.05	0.00	0.57	0.00	7.19	3.94	41.87
ALLRED UNIT B 08-05 8SH - 8S	*P-DP*	0.03	0.01	0.04	2.33	0.18	0.08	0.00	0.20	0.00	2.38	1.36	29.99
ALPHA 210488 1A - 1A	*P-DP*	0.00	0.00	0.28	0.00	0.00	0.58	0.00	0.05	0.00	0.53	0.35	19.14
ALPHA 210488 2B - 2B	*P-DP*	0.00	0.00	0.36	0.00	0.00	0.74	0.00	0.06	0.00	0.68	0.41	24.41
ALPHA 210488 3C - 3C	*P-DP*	0.00	0.00	0.66	0.00	0.00	1.36	0.00	0.12	0.00	1.24	0.68	32.53
AMAZON 3304-02H - 3304-02H	*P-DP*	0.02	0.00	0.06	1.65	0.01	0.27	0.00	0.16	0.00	1.77	1.09	34.28
AMAZON 3304-03H - 3304-03H	*P-DP*	0.05	0.00	0.09	3.80	0.02	0.38	0.00	0.33	0.00	3.87	2.18	45.62
AMAZON 3304-05H - 3304-05H	*P-DP*	0.03	0.00	0.69	2.51	0.12	3.04	0.00	0.65	0.00	5.01	2.79	41.84
AMAZON 3304-4H - 3304-4H	*P-DP*	0.02	0.00	0.58	1.82	0.10	2.56	0.00	0.53	0.00	3.96	2.10	41.02
AMBER NE WEL JF 3H - 3H	*P-DP*	0.00	0.00	6.58	0.00	0.00	13.03	0.00	8.12	0.00	4.92	2.38	50.00
AMBER NW WEL JF 1H - 1H	*P-DP*	0.00	0.00	7.24	0.00	0.00	14.34	0.00	8.93	0.00	5.41	2.67	50.00
AMPHITHEATER A1 4LA - 4LA	*P-DP*	0.01	0.01	0.01	0.60	0.15	0.00	0.00	0.16	0.00	0.59	0.52	4.33
AMPHITHEATER A2 3LA - 3LA	*P-DP*	0.02	0.01	0.01	1.16	0.14	0.00	0.00	0.41	0.00	0.89	0.67	16.01
AMPHITHEATER A3 15UA - 15U	*P-DP*	0.21	0.05	0.05	15.85	1.01	0.03	0.00	2.46	0.00	14.43	8.07	50.00
AMPHITHEATER A4 2LA - 2LA	*P-DP*	0.03	0.01	0.01	1.88	0.31	0.01	0.00	0.60	0.00	1.60	1.12	22.98
AMPHITHEATER A5 14UA - 14U	*P-DP*	0.14	0.02	0.02	10.24	0.43	0.01	0.00	1.30	0.00	9.39	6.24	18.02

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
AMPHITHEATER A6 16UA - 16U	P-DP	0.03	0.00	0.00	2.10	0.09	0.00	0.00	0.52	0.00	1.68	1.26	18.10
ANN COLE TRUST 1 - 1	P-DP	0.41	0.15	0.71	30.77	3.21	0.96	0.00	3.45	0.00	31.49	15.05	40.49
ANNABEL 1 - 1	P-DP	0.21	0.00	0.00	15.99	0.00	0.00	0.00	1.14	0.00	14.84	7.54	22.75
ARCH BENGE B10 1504MH - 15	P-DP	0.09	0.03	0.10	7.11	0.53	0.11	0.00	0.83	0.00	6.92	3.72	50.00
ARCH BENGE B9 1502MH - 150	P-DP	0.09	0.03	0.10	7.11	0.53	0.11	0.00	0.83	0.00	6.92	3.72	50.00
ARCHIE E WYN JF 6H - 6H	P-DP	0.00	0.00	88.72	0.00	0.00	175.75	0.00	109.46	0.00	66.30	40.16	32.68
ARCHIE E WYN JF 8H - 8H	P-DP	0.00	0.00	61.50	0.00	0.00	121.83	0.00	75.87	0.00	45.96	29.38	27.28
ARENA A1 1LA - 1LA	P-DP	0.00	0.00	0.00	0.37	0.03	0.00	0.00	0.08	0.00	0.32	0.22	31.91
ARENA A2 9UA - 9UA	P-DP	0.01	0.00	0.00	0.45	0.02	0.00	0.00	0.05	0.00	0.43	0.24	37.91
ARENA A3 2LA - 2LA	P-DP	0.00	0.00	0.00	0.16	0.02	0.00	0.00	0.02	0.00	0.16	0.11	19.08
ARENA A4 3LA - 3LA	P-DP	0.01	0.00	0.00	1.07	0.04	0.00	0.00	0.10	0.00	1.00	0.50	50.00
ARENA A5 10UA - 10UA	P-DP	0.01	0.00	0.00	0.49	0.02	0.00	0.00	0.05	0.00	0.46	0.25	38.95
ARLINGTON 33-40 C UNIT 4H -	P-DP	0.02	0.00	0.02	1.78	0.11	0.05	0.00	0.15	0.00	1.79	0.90	43.10
ARLINGTON 33-40 D UNIT 5H -	P-DP	0.04	0.01	0.06	2.80	0.27	0.12	0.00	0.26	0.00	2.94	1.47	50.00
ARON 41-32 1AH - 1AH	P-DP	0.35	0.05	0.27	26.60	1.21	0.53	0.00	2.16	0.00	26.17	16.49	27.15
ARON 41-32 2SH - 2SH	P-DP	0.29	0.20	1.17	22.16	5.25	2.30	0.00	2.72	0.00	26.99	14.96	31.40
ARON 41-32 3AH - 3AH	P-DP	0.45	0.13	0.78	34.56	3.49	1.53	0.00	3.23	0.00	36.35	20.31	34.14
ARON 41-32 3SH - 3SH	P-DP	0.15	0.01	0.07	11.11	0.32	0.14	0.00	0.86	0.00	10.70	6.83	19.20
ATHENA N SMF JF 3H - 3H	P-DP	0.00	0.00	222.47	0.00	0.00	440.69	0.00	274.45	0.00	166.24	89.63	43.81
ATHENA NE SMF JF 5H - 5H	P-DP	0.00	0.00	336.51	0.00	0.00	666.60	0.00	415.15	0.00	251.46	134.57	44.32
ATHENA NE SMF JF 7H - 7H	P-DP	0.00	0.00	417.94	0.00	0.00	827.89	0.00	515.59	0.00	312.30	171.06	46.25
ATHENA NW SMF JF 1H - 1H	P-DP	0.00	0.00	260.95	0.00	0.00	516.92	0.00	321.93	0.00	194.99	104.91	49.08
AUSTIN 5H - 5H	P-DP	0.00	0.00	26.56	0.00	0.00	49.77	0.00	17.53	0.00	32.25	17.54	39.99
AUSTIN 6H - 6H	P-DP	0.00	0.00	29.84	0.00	0.00	55.93	0.00	19.69	0.00	36.24	19.00	42.09
AUSTIN 7H - 7H	P-DP	0.00	0.00	30.12	0.00	0.00	56.45	0.00	19.88	0.00	36.58	19.98	41.02
AUSTIN 8H - 8H	P-DP	0.00	0.00	33.88	0.00	0.00	63.50	0.00	22.36	0.00	41.14	21.42	43.55
B AND B 1H - 1H	P-DP	0.07	0.08	0.23	5.65	1.92	-0.06	0.00	0.06	0.00	7.46	3.79	41.61
B AND B 2H - 2H	P-DP	0.08	0.13	0.37	6.36	3.16	-0.07	0.00	-0.18	0.00	9.62	4.90	49.17
B AND B 6H - 6H	P-DP	0.04	0.05	0.14	3.06	1.20	-0.06	0.00	-0.01	0.00	4.20	2.46	34.56
B AND B STATE 4H - 4H	P-DP	0.05	0.05	0.13	3.98	1.11	-0.05	0.00	0.10	0.00	4.94	2.64	44.70
B AND B STATE A 5H - 5H	P-DP	0.08	0.15	0.42	5.78	3.52	-0.13	0.00	-0.32	0.00	9.48	5.08	50.00
B AND B STATE B 7H - 7H	P-DP	0.04	0.23	0.66	2.85	5.55	-0.23	0.00	-1.09	0.00	9.26	5.01	39.87
BADFISH 31-43 A 1JM - 1JM	P-DP	0.22	0.05	0.25	16.54	1.13	0.34	0.00	1.63	0.00	16.38	9.77	50.00
BADFISH 31-43 A 4LS - 4LS	P-DP	0.01	0.03	0.17	0.78	0.76	0.23	0.00	0.35	0.00	1.43	0.88	23.81
BADFISH 31-43 B 9LS - 9LS	P-DP	0.18	0.08	0.37	13.29	1.66	0.49	0.00	1.59	0.00	13.85	7.90	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
BADFISH 31-43 E 5WA - 5WA	P-DP	0.10	0.03	0.16	7.26	0.70	0.21	0.00	0.79	0.00	7.38	4.54	43.92
BADFISH 31-43 E 7WB - 7WB	P-DP	0.11	0.05	0.23	8.02	1.06	0.32	0.00	0.98	0.00	8.41	5.26	43.48
BADFISH 31-43 F 6WA - 6WA	P-DP	0.07	0.02	0.09	5.67	0.40	0.12	0.00	0.56	0.00	5.63	3.21	43.05
BADFISH 31-43 F 8WB - 8WB	P-DP	0.13	0.10	0.46	10.07	2.08	0.62	0.00	1.52	0.00	11.25	6.24	50.00
BADFISH 31-43 J 10WA - 10WA	P-DP	0.08	0.06	0.28	5.70	1.24	0.37	0.00	0.88	0.00	6.42	3.67	44.89
BADFISH 31-43 J 11WB - 11WB	P-DP	0.12	0.13	0.65	9.15	2.92	0.87	0.00	1.77	0.00	11.16	6.33	50.00
BADFISH 31-43 L 12MS - 12MS	P-DP	0.10	0.04	0.21	7.73	0.94	0.28	0.00	0.92	0.00	8.03	4.77	46.17
BADFISH 31-43 M 13JM - 13JM	P-DP	0.01	0.00	0.01	0.64	0.07	0.02	0.00	0.07	0.00	0.65	0.44	17.72
BADFISH 31-43 M 3LS - 3LS	P-DP	0.26	0.08	0.41	19.51	1.84	0.55	0.00	2.11	0.00	19.78	11.31	50.00
BARNES, D. E. ESTATE 2 - 2	P-DP	0.00	0.00	0.00	0.36	0.02	0.00	0.00	0.04	0.00	0.35	0.17	38.65
BARNES, D. E. ESTATE 3H - 3H	P-DP	0.02	0.01	0.01	1.37	0.17	0.01	0.00	0.16	0.00	1.38	0.75	33.64
BARNES, D. E. ESTATE 4H - 4H	P-DP	0.06	0.01	0.01	4.66	0.12	0.00	0.00	0.44	0.00	4.34	2.27	46.71
BARR 10-8 B UNIT A 5H - A 5H	P-DP	0.06	0.00	0.02	4.78	0.11	0.05	0.00	0.37	0.00	4.58	2.39	50.00
BARR 10-8 B UNIT L 5H - L 5H	P-DP	0.05	0.00	0.01	3.82	0.03	0.01	0.00	0.28	0.00	3.59	1.97	49.15
BARSTOW -14- 10 - 10	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.34
BARSTOW -18- 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.77
BARSTOW -18- 2 - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.14
BARSTOW -18- 3 - 3	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.59
BARSTOW -18- 4 - 4	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.24
BARSTOW -18- 5 - 5	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.71
BARSTOW -18- 6 - 6	P-DP	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.04	0.02	50.00
BARSTOW -19- 8 - 8	P-DP	0.00	0.00	0.00	0.06	0.01	0.00	0.00	0.01	0.00	0.06	0.04	50.00
BARSTOW -19- 9 - 9	P-DP	0.00	0.00	0.00	0.17	0.01	0.00	0.00	0.02	0.00	0.17	0.09	50.00
BARSTOW -23- 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.30
BARSTOW -23- 10 - 10	P-DP	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.03	0.02	49.42
BARSTOW -23- 2 - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.02
BARSTOW -23- 3 - 3	P-DP	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.02	0.01	46.16
BARSTOW -23- 4 - 4	P-DP	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	36.93
BARSTOW -23- 5 - 5	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.27
BARSTOW -23- 6A - 6A	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.32
BARSTOW -23- 7 - 7	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.79
BARSTOW -23- 8 - 8	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.06
BARSTOW -23- 9 - 9	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.51
BARSTOW 155 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.68
BARSTOW 155 2 - 2	P-DP	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.01	0.00	0.06	0.03	47.58

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
BARSTOW 155 3 - 3	P-DP	0.01	0.00	0.00	0.65	0.05	0.00	0.00	0.07	0.00	0.64	0.35	50.00
BARSTOW 155 4 - 4	P-DP	0.00	0.00	0.00	0.17	0.01	0.00	0.00	0.02	0.00	0.17	0.09	50.00
BARSTOW 18 7 - 7	P-DP	0.00	0.00	0.00	0.17	0.01	0.00	0.00	0.02	0.00	0.17	0.09	50.00
BARSTOW 27 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.84
BARSTOW 27 2 - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.68
BARSTOW 27 3 - 3	P-DP	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.02	0.01	40.32
BARSTOW 27 4 - 4	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.51
BARSTOW 27 5 - 5	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.66
BARSTOW 27 6 - 6	P-DP	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	39.47
BARSTOW 27 7 - 7	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.41
BARSTOW 27 8 - 8	P-DP	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.03	0.02	44.87
BARSTOW 33 UA 1BS - 1BS	P-DP	0.00	0.00	0.00	0.06	0.02	0.00	0.00	0.01	0.00	0.06	0.05	18.92
BARSTOW 33 UB 2H - 2H	P-DP	0.00	0.00	0.00	0.19	0.05	0.00	0.00	0.03	0.00	0.21	0.14	36.23
BARSTOW 33-34 1H - 1H	P-DP	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.02	0.01	35.61
BARSTOW 33-35 1H - 1H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.50
BARSTOW 33-35 2H - 2H	P-DP	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	34.08
BARSTOW 33-35 3H - 3H	P-DP	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.02	0.01	41.64
BARSTOW A 3652H - 3652H	P-DP	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.03	0.02	50.00
BATES S CRC JF 5H - 5H	P-DP	0.00	0.00	287.58	0.00	0.00	569.66	0.00	354.77	0.00	214.89	107.90	39.87
BAYES 16 1 - 1	P-DP	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.04	0.03	6.15
BAYES 16A 1 - 1	P-DP	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.01	0.00	0.07	0.04	12.80
BAYES 4 1 - 1	P-DP	0.00	0.00	0.02	0.37	0.07	0.02	0.00	0.06	0.00	0.41	0.24	26.16
BAYES 4 3 - 3	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BAYES 4A 2 - 2	P-DP	0.00	0.00	0.02	0.14	0.07	0.02	0.00	0.04	0.00	0.19	0.14	16.44
BAYES 4A 3 - 3	P-DP	0.00	0.00	0.00	0.08	0.01	0.00	0.00	0.01	0.00	0.09	0.07	9.99
BAYES 4A 4 - 4	P-DP	0.00	0.01	0.03	0.35	0.14	0.04	0.00	0.08	0.00	0.46	0.28	28.34
BBC 4-20C5 - 4-20C5	P-DP	0.02	0.00	0.09	0.96	0.00	0.15	0.00	0.05	0.00	1.06	0.57	35.64
BELL 1A - 1A	P-DP	0.00	0.00	0.21	0.00	0.00	0.29	0.00	0.03	0.00	0.27	0.18	50.00
BIG EL 45-04 1AH - 1AH	P-DP	0.45	0.03	0.20	33.99	0.92	0.40	0.00	2.63	0.00	32.68	18.99	41.65
BIG EL 45-04 1SH - 1SH	P-DP	0.21	0.18	1.07	15.70	4.78	2.09	0.00	2.16	0.00	20.42	12.52	35.01
BIG EL 45-04 B 2MS - 2MS	P-DP	0.70	0.23	1.38	53.14	6.19	2.71	0.00	5.14	0.00	56.90	31.79	50.00
BIG EL 45-04 C 3SA - 3SA	P-DP	0.55	0.17	1.02	41.58	4.58	2.01	0.00	3.97	0.00	44.20	23.57	50.00
BIG EL 45-04 C 3SS - 3SS	P-DP	0.67	0.21	1.26	51.09	5.63	2.47	0.00	4.87	0.00	54.31	28.79	50.00
BIG EL 45-04 D 4MS - 4MS	P-DP	0.60	0.21	1.25	45.63	5.60	2.45	0.00	4.48	0.00	49.20	27.82	50.00
BIG EL 45-04 D 4SA - 4SA	P-DP	0.46	0.27	1.62	35.32	7.25	3.17	0.00	4.10	0.00	41.64	22.12	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
BIG EL 45-04 D 4SS - 4SS	P-DP	0.71	0.30	1.78	54.19	7.95	3.48	0.00	5.60	0.00	60.02	33.56	50.00
BIG JAY 10-15 A 1JD - 1JD	P-DP	0.04	0.01	0.03	3.34	0.11	0.03	0.00	0.28	0.00	3.20	2.09	36.11
BIG JAY 10-15 A 1LS - 1LS	P-DP	0.06	0.01	0.07	4.88	0.32	0.10	0.00	0.48	0.00	4.83	2.88	43.34
BIG JAY 10-15 A 1MS - 1MS	P-DP	0.04	0.02	0.08	3.15	0.38	0.11	0.00	0.37	0.00	3.27	2.22	34.84
BIG JAY 10-15 A 1WA - 1WA	P-DP	0.05	0.13	0.62	3.69	2.80	0.84	0.00	1.34	0.00	5.99	3.72	41.17
BIG JAY 10-15 B 2DN - 2DN	P-DP	0.02	0.03	0.16	1.45	0.72	0.22	0.00	0.38	0.00	2.00	1.20	31.67
BIG JAY 10-15 B 2LS - 2LS	P-DP	0.02	0.04	0.22	1.31	0.97	0.29	0.00	0.46	0.00	2.10	1.26	30.55
BIG JAY 10-15 B 2WB - 2WB	P-DP	0.01	0.04	0.21	1.12	0.96	0.29	0.00	0.45	0.00	1.92	1.15	28.90
BIG JAY 10-15 B 3JC - 3JC	P-DP	0.02	0.03	0.15	1.71	0.65	0.19	0.00	0.37	0.00	2.18	1.29	33.71
BIG JAY 10-15 C 4LS - 4LS	P-DP	0.02	0.14	0.66	1.71	2.97	0.89	0.00	1.26	0.00	4.31	2.33	35.40
BIG JAY 10-15 C 4WA - 4WA	P-DP	0.01	0.13	0.65	0.51	2.94	0.88	0.00	1.16	0.00	3.17	1.94	20.82
BIG JAY 10-15 D 5JC - 5JC	P-DP	0.01	0.03	0.13	0.68	0.57	0.17	0.00	0.27	0.00	1.15	0.68	25.08
BIG JAY 10-15 D 6DN - 6DN	P-DP	0.01	0.04	0.19	1.09	0.88	0.26	0.00	0.41	0.00	1.81	1.17	26.36
BIG JAY 10-15 D 6LS - 6LS	P-DP	0.03	0.07	0.32	2.01	1.44	0.43	0.00	0.70	0.00	3.19	1.70	37.99
BIG JAY 10-15 D 6WB - 6WB	P-DP	0.02	0.09	0.43	1.56	1.93	0.58	0.00	0.85	0.00	3.22	1.74	35.06
BIG JAY 10-15 E 7JD - 7JD	P-DP	0.03	0.05	0.26	2.48	1.17	0.35	0.00	0.63	0.00	3.37	1.78	40.40
BIG JAY 10-15 E 7LS - 7LS	P-DP	0.04	0.06	0.30	2.79	1.34	0.40	0.00	0.71	0.00	3.82	2.02	41.76
BIG JAY 10-15 E 7MS - 7MS	P-DP	0.00	0.02	0.11	0.25	0.49	0.15	0.00	0.21	0.00	0.68	0.48	12.28
BIG JAY 10-15 E 7WA - 7WA	P-DP	0.02	0.05	0.23	1.57	1.05	0.31	0.00	0.51	0.00	2.42	1.37	33.98
BIG JAY 10-15 F 4MS - 4MS	P-DP	0.01	0.03	0.15	0.72	0.69	0.20	0.00	0.31	0.00	1.30	0.80	24.29
BIGHORN 33E 2HJ - 2HJ	P-DP	0.08	0.02	0.13	6.37	0.56	0.25	0.00	0.58	0.00	6.60	3.46	49.98
BIGHORN 33G 3HJ - 3HJ	P-DP	0.06	0.03	0.19	4.34	0.86	0.37	0.00	0.50	0.00	5.07	2.82	44.61
BIGHORN HORIZONTAL UNIT 1	P-DP	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.01	0.00	0.07	0.06	2.39
BILLINGSLEY 12 1 - 1	P-DP	0.01	0.00	0.01	0.65	0.00	0.02	0.00	0.05	0.00	0.62	0.41	25.58
BIZZELL -B- 1 - 1	P-DP	0.01	0.00	0.00	0.50	0.01	0.00	0.00	0.05	0.00	0.47	0.19	35.29
BIZZELL -B- 2 - 2	P-DP	0.01	0.00	0.00	0.40	0.02	0.00	0.00	0.04	0.00	0.38	0.19	25.39
BIZZELL-IRVIN 15L UNIT 116H -	P-DP	0.17	0.05	0.21	12.70	1.06	0.21	0.00	1.53	0.00	12.43	8.02	33.50
BIZZELL-IRVIN 15L UNIT 13H -	P-DP	0.23	0.70	2.71	17.48	13.74	2.71	0.00	7.91	0.00	26.02	14.36	42.78
BIZZELL-IRVIN 15L UNIT 18H -	P-DP	0.16	0.31	1.21	12.47	6.12	1.21	0.00	3.91	0.00	15.90	9.03	36.61
BIZZELL-IRVIN 15U UNIT 113H	P-DP	0.19	0.14	0.55	14.77	2.78	0.55	0.00	2.51	0.00	15.58	8.35	41.81
BIZZELL-IRVIN 15U UNIT 114H	P-DP	0.38	0.30	1.14	28.87	5.81	1.15	0.00	5.09	0.00	30.74	16.03	50.00
BIZZELL-IRVIN 15U UNIT 115H	P-DP	0.28	0.12	0.47	21.73	2.39	0.47	0.00	2.90	0.00	21.70	11.93	43.42
BIZZELL-IRVIN 15U UNIT 117H	P-DP	0.24	0.19	0.73	18.15	3.71	0.73	0.00	3.23	0.00	19.37	10.20	50.00
BIZZELL-IRVIN 15U UNIT 118H	P-DP	0.36	0.27	1.03	27.27	5.24	1.03	0.00	4.69	0.00	28.85	15.16	49.91
BIZZELL-IRVIN 15U UNIT 14H -	P-DP	0.34	0.16	0.62	26.03	3.15	0.62	0.00	3.60	0.00	26.20	13.86	46.44

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
BIZZELL-IRVIN 15U UNIT 15H -	P-DP	0.28	0.22	0.85	21.24	4.34	0.86	0.00	3.77	0.00	22.66	11.84	47.19
BIZZELL-IRVIN 15U UNIT 16H -	P-DP	0.29	0.24	0.93	21.94	4.71	0.93	0.00	4.01	0.00	23.57	12.81	46.82
BIZZELL-IRVIN 15U UNIT 17H -	P-DP	0.51	0.16	0.60	39.44	3.06	0.60	0.00	4.65	0.00	38.46	20.33	50.00
BLUEBELL 16-24-23-C5-9H - 16-	P-DP	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.03	0.03	2.91
BLUEBELL 24/23-25/26-C5-1H -	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BOBCAT 55-1-16-21 E 12H - 12H	P-DP	0.02	0.01	0.02	1.37	0.17	-0.01	0.00	0.09	0.00	1.44	0.85	50.00
BOBCAT 55-1-16-21 F 13H - 13H	P-DP	0.02	0.01	0.03	1.28	0.29	-0.01	0.00	0.05	0.00	1.51	0.89	50.00
BOBCAT 55-1-16-21 G 14H - 14H	P-DP	0.02	0.01	0.03	1.80	0.28	-0.01	0.00	0.10	0.00	1.97	1.11	50.00
BOBCAT 55-1-16-21 H 15H - 15H	P-DP	0.02	0.01	0.03	1.89	0.29	-0.01	0.00	0.10	0.00	2.07	1.16	50.00
BOBCAT 55-1-16-21 I 21H - 21H	P-DP	0.01	0.01	0.03	0.73	0.29	-0.01	0.00	0.00	0.00	1.01	0.59	50.00
BOBCAT 55-1-16-21 J 22H - 22H	P-DP	0.01	0.02	0.04	1.02	0.38	-0.02	0.00	0.00	0.00	1.37	0.77	50.00
BOBCAT 55-1-28 UNIT 1H - 1H	P-DP	0.02	0.01	0.03	1.55	0.25	-0.01	0.00	0.08	0.00	1.71	0.85	48.90
BOENING UNIT 1H - 1H	P-DP	0.07	0.02	0.11	5.27	0.41	0.22	0.00	0.50	0.00	5.41	2.88	28.15
BOENING UNIT 2H - 2H	P-DP	0.17	0.48	2.40	12.53	8.76	4.65	0.00	2.38	0.00	23.57	11.72	50.00
BOENING UNIT 3H - 3H	P-DP	0.78	0.86	4.25	57.80	15.52	8.24	0.00	7.17	0.00	74.39	43.19	30.07
BOENING UNIT 4H - 4H	P-DP	0.43	0.57	2.83	32.23	10.34	5.49	0.00	4.25	0.00	43.80	24.71	50.00
BOENING UNIT 6L - 6L	P-DP	0.41	0.47	2.34	30.19	8.54	4.54	0.00	3.81	0.00	39.46	22.59	26.63
BOENING UNIT 6U - 6U	P-DP	1.01	1.27	6.31	75.20	23.04	12.24	0.00	9.76	0.00	100.72	56.91	34.27
BOLT 15-33H - 15-33H	P-DP	0.04	0.00	0.07	2.88	0.01	0.30	0.00	0.25	0.00	2.94	1.53	36.44
BOLT 406-0904H - 406-0904H	P-DP	0.30	0.01	1.21	22.23	0.21	5.35	0.00	2.42	0.00	25.38	14.89	29.96
BOLT 407-0904H - 407-0904H	P-DP	0.36	0.00	0.46	26.65	0.08	2.01	0.00	2.22	0.00	26.52	15.18	29.62
BONACCI 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BONACCI 2 - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BOND 223A - 223A	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.09
BOREAS 79 1H - 1H	P-DP	0.02	0.00	0.00	1.23	0.00	0.00	0.00	0.09	0.00	1.15	0.65	29.97
BORUM E SMF JF 4H - 4H	P-DP	0.00	0.00	49.22	0.00	0.00	97.50	0.00	60.72	0.00	36.78	25.06	25.26
BORUM E SMF JF 6H - 6H	P-DP	0.00	0.00	59.08	0.00	0.00	117.02	0.00	72.88	0.00	44.14	26.54	33.11
BORUM W SMF JF 2H - 2H	P-DP	0.00	0.00	4.62	0.00	0.00	9.16	0.00	5.70	0.00	3.45	1.99	36.71
BOW TIE 41-44 1AH - 1AH	P-DP	0.03	0.01	0.08	2.10	0.37	0.16	0.00	0.23	0.00	2.41	1.31	40.30
BOW TIE 41-44 1BH - 1BH	P-DP	0.02	0.00	0.00	1.54	0.01	0.00	0.00	0.11	0.00	1.44	0.86	30.63
BOW TIE 41-44 2AH - 2AH	P-DP	0.02	0.00	0.01	1.27	0.06	0.03	0.00	0.11	0.00	1.26	0.72	30.50
BOW TIE 41-44 2SH - 2SH	P-DP	0.02	0.01	0.04	1.27	0.17	0.08	0.00	0.13	0.00	1.39	0.79	31.92
BOW TIE 41-44 3AH - 3AH	P-DP	0.03	0.01	0.05	2.43	0.24	0.11	0.00	0.23	0.00	2.55	1.40	40.78
BOW TIE 41-44 3SH - 3SH	P-DP	0.02	0.01	0.06	1.80	0.28	0.12	0.00	0.19	0.00	2.01	1.11	37.45
BOX 42-55 UNIT 1AH - 1AH	P-DP	0.03	0.01	0.04	2.63	0.17	0.07	0.00	0.22	0.00	2.64	1.56	43.04

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

		Net Sales Volumes			Net Revenue						Cash Flow		
				Residue			Residue		Expense				
Lease Name	Reserve Category	Oil (Mbbl)	NGL (Mbbl)	Gas (MMcf)	Oil (M$)	NGL (M$)	Gas (M$)	Other (M$)	& Tax (M$)	Invest. (M$)	Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
BOX 42-55 UNIT 1SH - 1SH	*P-DP*	0.04	0.01	0.04	2.88	0.16	0.07	0.00	0.24	0.00	2.87	1.58	50.00
BOX 42-55 UNIT 2AH - 2AH	*P-DP*	0.04	0.01	0.03	3.38	0.13	0.06	0.00	0.27	0.00	3.30	1.81	50.00
BOX 42-55 UNIT 2SH - 2SH	*P-DP*	0.02	0.00	0.01	1.24	0.06	0.03	0.00	0.10	0.00	1.23	0.74	37.43
BOX 42-55 UNIT 3LS - 3LS	*P-DP*	0.08	0.01	0.04	5.84	0.17	0.07	0.00	0.45	0.00	5.63	3.23	50.00
BOX 42-55 UNIT 4WA - 4WA	*P-DP*	0.03	0.01	0.04	2.16	0.19	0.08	0.00	0.20	0.00	2.24	1.13	50.00
BOX NAIL 2LM - 2LM	*P-DP*	0.00	0.00	0.02	0.31	0.07	0.02	0.00	0.05	0.00	0.36	0.20	29.23
BOX NAIL 3LL - 3LL	*P-DP*	0.00	0.00	0.02	0.36	0.08	0.02	0.00	0.06	0.00	0.41	0.23	30.69
BOX NAIL E 1LM - 1LM	*P-DP*	0.01	0.00	0.02	0.40	0.09	0.03	0.00	0.06	0.00	0.45	0.25	32.67
BOYD, FANNIE 4 - 4	*P-DP*	0.02	0.02	0.00	1.59	0.36	0.01	0.00	0.17	0.00	1.77	1.08	14.50
BOYD, FANNIE 5 - 5	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BOYD, FANNIE 8 - 8	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BRACERO 226-34 UNIT 1H - 1H	*P-DP*	0.10	0.15	0.15	7.51	3.24	0.10	0.00	1.43	0.00	9.42	5.56	38.82
BRAMBLETT 34-216 1H - 1H	*P-DP*	0.06	0.04	0.03	4.43	0.77	0.02	0.00	0.58	0.00	4.65	2.31	42.93
BRAUN B S1 2008LH - 2008LH	*P-DP*	0.02	0.01	0.03	1.35	0.17	0.03	0.00	0.19	0.00	1.37	0.76	50.00
BRAUN B S10 2014JH - 2014JH	*P-DP*	0.01	0.01	0.06	0.95	0.28	0.06	0.00	0.21	0.00	1.08	0.62	48.65
BRAUN B S11 2004LH - 2004LH	*P-DP*	0.03	0.01	0.06	2.01	0.28	0.06	0.00	0.30	0.00	2.05	1.19	45.00
BRAUN B S12 2004MH - 2004M	*P-DP*	0.03	0.02	0.08	2.09	0.40	0.08	0.00	0.36	0.00	2.20	1.31	45.29
BRAUN B S13 2003LH - 2003LH	*P-DP*	0.05	0.02	0.07	3.72	0.35	0.07	0.00	0.47	0.00	3.67	2.11	50.00
BRAUN B S14 2003MH - 2003M	*P-DP*	0.02	0.02	0.06	1.49	0.31	0.06	0.00	0.27	0.00	1.60	0.97	41.00
BRAUN B S2 2008MH - 2008MH	*P-DP*	0.02	0.01	0.03	1.46	0.14	0.03	0.00	0.18	0.00	1.44	0.83	50.00
BRAUN B S3 2007LH - 2007LH	*P-DP*	0.01	0.00	0.02	0.67	0.09	0.02	0.00	0.10	0.00	0.68	0.41	44.98
BRAUN B S4 2007MH - 2007MH	*P-DP*	0.01	0.01	0.03	0.69	0.16	0.03	0.00	0.13	0.00	0.75	0.44	46.68
BRAUN B S5 2016JH - 2016JH	*P-DP*	0.01	0.01	0.04	1.05	0.20	0.04	0.00	0.18	0.00	1.12	0.63	50.00
BRAUN B S6 2006LH - 2006LH	*P-DP*	0.01	0.01	0.03	0.66	0.16	0.03	0.00	0.13	0.00	0.72	0.41	47.85
BRAUN B S7 2006MH - 2006MH	*P-DP*	0.01	0.01	0.04	0.84	0.22	0.04	0.00	0.17	0.00	0.94	0.54	50.00
BRAUN B S8 2005LH - 2005LH	*P-DP*	0.01	0.01	0.03	0.59	0.14	0.03	0.00	0.12	0.00	0.65	0.36	47.04
BRAUN B S9 2005MH - 2005MH	*P-DP*	0.03	0.03	0.11	2.21	0.55	0.11	0.00	0.44	0.00	2.43	1.38	50.00
BRAUN B W1 2001MH - 2001MH	*P-DP*	0.08	0.03	0.13	6.51	0.68	0.13	0.00	0.85	0.00	6.48	3.45	50.00
BRAUN B W3 2001LH - 2001LH	*P-DP*	0.05	0.03	0.10	4.15	0.51	0.10	0.00	0.58	0.00	4.19	2.27	47.56
BRAUN C W10 2106LH - 2106LH	*P-DP*	0.04	0.03	0.11	3.35	0.54	0.11	0.00	0.53	0.00	3.47	1.72	42.17
BRAUN C W11 2106BH - 2106BH	*P-DP*	0.01	0.04	0.14	0.99	0.71	0.14	0.00	0.41	0.00	1.42	0.72	50.00
BRAUN C W5 2108LH - 2108LH	*P-DP*	0.08	0.02	0.08	6.12	0.39	0.08	0.00	0.68	0.00	5.90	3.00	49.20
BRAUN C W6 2108BH - 2108BH	*P-DP*	0.01	0.03	0.11	0.90	0.54	0.11	0.00	0.33	0.00	1.22	0.62	36.00
BRAUN C W7 2107MH - 2107MH	*P-DP*	0.02	0.01	0.03	1.73	0.16	0.03	0.00	0.22	0.00	1.71	0.85	36.00
BRAUN C W8 2107LH - 2107LH	*P-DP*	0.03	0.02	0.07	2.35	0.37	0.07	0.00	0.36	0.00	2.43	1.34	36.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
BRAUN C W9 2106MH - 2106MH	P-DP	0.02	0.01	0.05	1.40	0.25	0.05	0.00	0.23	0.00	1.46	0.81	36.25
BROKEN ARROW 55-54-1-12 H	P-DP	0.10	0.02	0.14	7.64	0.62	0.27	0.00	0.68	0.00	7.85	3.42	47.87
BROKEN ARROW 55-54-1-12 H	P-DP	0.13	0.04	0.22	9.57	1.00	0.44	0.00	0.90	0.00	10.11	4.24	50.00
BROOKE 184-185 UNIT 132H - 1	P-DP	0.10	0.12	0.12	7.26	2.64	0.08	0.00	1.27	0.00	8.71	4.94	50.00
BROOKE 184-185 UNIT 221H - 2	P-DP	0.16	0.14	0.14	12.26	3.10	0.09	0.00	1.82	0.00	13.64	7.51	50.00
BROOKE 184-185 UNIT 232H - 2	P-DP	0.13	0.16	0.16	9.72	3.60	0.11	0.00	1.72	0.00	11.72	6.32	50.00
BROOKE 184-185 UNIT 233H - 2	P-DP	0.07	0.09	0.09	4.99	1.96	0.06	0.00	0.91	0.00	6.10	3.57	45.42
BROOKE 184-185 UNIT 2H - 2H	P-DP	0.10	0.20	0.19	7.58	4.35	0.13	0.00	1.70	0.00	10.35	5.37	50.00
BROOKE 184-185 UNIT 331H - 3	P-DP	0.10	0.20	0.20	7.47	4.37	0.13	0.00	1.70	0.00	10.27	5.70	50.00
BROOKS 1 - 1	P-DP	0.25	0.07	0.32	18.85	1.43	0.43	0.00	1.90	0.00	18.79	9.15	35.84
BRUT 40-33 1AH - 1AH	P-DP	1.47	0.37	2.15	111.83	9.64	4.22	0.00	10.09	0.00	115.61	66.87	35.03
BRUT A 1MS - 1MS	P-DP	1.48	0.07	0.40	112.61	1.79	0.78	0.00	8.44	0.00	106.74	63.48	43.51
BRUT B 2LS - 2LS	P-DP	0.83	0.07	0.41	63.37	1.84	0.81	0.00	4.93	0.00	61.09	38.41	33.97
BRUT C 3A - 3A	P-DP	1.90	0.33	1.93	144.43	8.64	3.78	0.00	12.20	0.00	144.66	80.47	50.00
BRUT D 5A - 5A	P-DP	0.05	0.00	0.03	3.90	0.12	0.05	0.00	0.31	0.00	3.77	2.25	45.59
BRUT E 6LS - 6LS	P-DP	1.48	0.36	2.14	112.44	9.58	4.19	0.00	10.12	0.00	116.10	67.85	43.85
BUCHANAN 3111 2 - 2	P-DP	0.04	0.00	0.00	3.10	0.00	0.00	0.00	0.22	0.00	2.88	1.30	45.94
BUCKEYE 55-1-28 UNIT 1H - 1H	P-DP	0.02	0.01	0.03	1.38	0.22	0.00	0.00	0.07	0.00	1.52	0.73	47.79
BUELL 10-11-5 10H - 10H	P-DP	0.00	28.82	328.22	0.00	587.32	678.13	0.00	1,099.18	0.00	166.26	87.98	45.69
BUELL 10-11-5 1H - 1H	P-DP	0.02	2.57	29.31	1.70	52.44	60.55	0.00	94.73	0.00	19.96	10.17	36.90
BUELL 10-11-5 206H - 206H	P-DP	0.00	26.91	306.46	0.24	548.38	633.17	0.00	1,026.35	0.00	155.44	81.01	47.83
BUELL 10-11-5 210H - 210H	P-DP	0.01	29.13	331.72	0.87	593.59	685.37	0.00	1,111.05	0.00	168.79	89.13	45.90
BUELL 10-11-5 2H - 2H	P-DP	0.01	1.72	19.55	0.91	34.98	40.39	0.00	63.16	0.00	13.12	7.59	24.30
BUELL 10-11-5 3H - 3H	P-DP	0.01	1.87	21.24	0.42	38.01	43.89	0.00	68.55	0.00	13.77	7.70	30.38
BUELL 10-11-5 4H - 4H	P-DP	0.03	2.88	32.78	1.87	58.66	67.73	0.00	105.96	0.00	22.30	11.98	32.99
BUELL 10-11-5 6H - 6H	P-DP	0.00	11.22	127.78	0.00	228.66	264.01	0.00	427.94	0.00	64.73	36.14	41.86
BURKHOLDER A UNIT 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.00	4.64
BUSH-NUNN 13A 1H - 1H	P-DP	0.30	0.22	0.77	22.24	3.71	1.55	0.00	2.82	0.00	24.68	15.15	50.00
BUSH-NUNN 13B 2H - 2H	P-DP	0.30	0.22	0.77	22.24	3.71	1.55	0.00	2.82	0.00	24.68	15.15	50.00
BUSH-NUNN 13C 3H - 3H	P-DP	0.38	0.28	0.98	28.25	4.72	1.97	0.00	3.59	0.00	31.35	19.25	50.00
BUSH-NUNN 13D 4H - 4H	P-DP	0.38	0.28	0.98	28.25	4.72	1.97	0.00	3.59	0.00	31.35	19.25	50.00
BUSH-NUNN 13E 5H - 5H	P-DP	0.38	0.28	0.98	28.25	4.72	1.97	0.00	3.59	0.00	31.35	19.25	50.00
BUTCHEE 21 1 - 1	P-DP	0.34	0.02	0.11	26.12	0.50	0.15	0.00	2.08	0.00	24.69	10.45	46.03
BUTCHEE 21 2 - 2	P-DP	0.11	0.01	0.03	8.54	0.12	0.04	0.00	0.66	0.00	8.04	3.85	29.34
BUTCHEE 21 3 - 3	P-DP	0.45	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.60

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
BUTCHEE 21 4 - 4	P-DP	0.14	0.01	0.02	10.77	0.11	0.03	0.00	0.82	0.00	10.09	5.05	31.01
BUTCHEE 21 5 - 5	P-DP	0.05	0.00	0.00	3.87	0.02	0.01	0.00	0.29	0.00	3.61	2.64	12.11
BUTCHEE 21 6 - 6	P-DP	0.29	0.01	0.04	21.90	0.18	0.05	0.00	1.65	0.00	20.48	9.52	41.58
BUTCHEE 21 7 - 7	P-DP	0.18	0.00	0.02	13.96	0.11	0.03	0.00	1.05	0.00	13.05	5.89	36.23
BUTCHEE 21 8 - 8	P-DP	0.36	0.02	0.08	27.17	0.36	0.11	0.00	2.10	0.00	25.55	10.97	46.28
BUTCHER BUTTE 27-144EWH-2	P-DP	0.06	0.00	0.05	3.56	0.00	0.09	0.00	0.07	0.00	3.57	2.07	29.25
BUTTERBUMPS 39-46 A 2DN - 2	P-DP	0.00	0.00	0.00	0.12	0.01	0.00	0.00	0.01	0.00	0.11	0.07	50.00
BUZZARD NORTH 6972 A 1H - A	P-DP	0.11	0.03	0.18	8.21	0.60	0.25	0.00	0.77	0.00	8.29	5.00	34.30
BUZZARD NORTH 6972 B 2H - B	P-DP	0.14	0.15	0.91	10.61	2.98	1.22	0.00	1.65	0.00	13.16	7.02	49.43
BUZZARD NORTH 6972 S 3H - S	P-DP	0.19	0.16	0.97	14.77	3.19	1.30	0.00	2.01	0.00	17.26	9.05	50.00
BUZZARD SOUTH 6972 A 3H - A	P-DP	0.24	0.16	1.00	18.43	3.28	1.34	0.00	2.30	0.00	20.74	11.00	45.23
BUZZARD SOUTH 6972 A 4H - A	P-DP	0.24	0.15	0.91	17.85	2.99	1.22	0.00	2.17	0.00	19.87	10.75	50.00
BUZZARD SOUTH 6972 B 1H - B	P-DP	0.14	0.08	0.49	10.53	1.60	0.66	0.00	1.24	0.00	11.55	6.59	36.56
BYRD 34-170 UNIT 3H - 3H	P-DP	0.02	0.01	0.01	1.72	0.12	0.00	0.00	0.18	0.00	1.67	0.83	39.30
BYRD 34-170 UNIT 4H - 4H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CALIFORNIA CHROME UNIT 2H	P-DP	0.16	0.25	0.24	12.11	5.38	0.16	0.00	2.35	0.00	15.31	8.19	50.00
CALIFORNIA CHROME UNIT 50	P-DP	0.16	0.20	0.19	12.24	4.29	0.13	0.00	2.10	0.00	14.56	7.31	50.00
CALVERLEY-LANE 30G 7H - 7H	P-DP	0.83	0.93	0.23	62.96	17.46	0.27	0.00	7.28	0.00	73.41	42.63	50.00
CALVERLEY-LANE 30H 8H - 8H	P-DP	0.50	1.21	0.30	38.30	22.86	0.36	0.00	5.88	0.00	55.64	31.56	46.64
CALVERLEY-LANE 30I 9H - 9H	P-DP	1.06	0.63	0.16	80.80	11.96	0.19	0.00	8.11	0.00	84.84	47.69	50.00
CALVERLEY-LANE 30J 10H - 10	P-DP	0.58	1.10	0.27	43.84	20.70	0.32	0.00	6.08	0.00	58.78	32.39	49.51
CALVERLEY-LANE 30K 11H - 1	P-DP	0.74	0.35	0.09	56.28	6.53	0.10	0.00	5.43	0.00	57.47	32.44	47.70
CALVERLEY-LANE 30L 12H - 12	P-DP	0.72	1.37	0.34	54.82	25.78	0.40	0.00	7.60	0.00	73.41	40.99	50.00
CARALYNE 24 1 - 1	P-DP	0.00	0.06	0.23	0.15	1.17	0.23	0.00	0.56	0.00	0.98	0.55	25.17
CARELESS WHISPER I 19-15 5S	P-DP	0.02	0.00	0.01	1.15	0.03	0.01	0.00	0.09	0.00	1.10	0.61	50.00
CARELESS WHISPER J 19-15 5A	P-DP	0.28	0.02	0.12	21.11	0.54	0.23	0.00	1.63	0.00	20.26	11.28	50.00
CARELESS WHISPER K 19-15 6S	P-DP	0.26	0.02	0.12	19.67	0.54	0.23	0.00	1.52	0.00	18.92	10.53	50.00
CARELESS WHISPER L 19-15 6A	P-DP	0.02	0.00	0.01	1.15	0.03	0.01	0.00	0.09	0.00	1.10	0.61	50.00
CASPER A1 8LA - 8LA	P-DP	0.02	0.00	0.00	1.57	0.06	0.00	0.00	0.25	0.00	1.39	0.74	44.27
CASPER A2 15UA - 15UA	P-DP	0.02	0.00	0.00	1.39	0.06	0.00	0.00	0.14	0.00	1.32	0.76	36.35
CASPER A3 7LA - 7LA	P-DP	0.02	0.00	0.00	1.71	0.07	0.00	0.00	0.17	0.00	1.61	0.87	39.98
CASSIDY UNIT 26-23 1H - 1H	P-DP	0.06	0.00	0.61	4.71	0.03	2.05	0.00	0.67	0.00	6.13	3.42	23.29
CASSIDY UNIT 26-23 5AH - 5AH	P-DP	1.45	0.00	1.47	106.60	0.08	4.91	0.00	8.38	0.00	103.21	51.18	50.00
CASSIDY UNIT 26-23 7AH - 7AH	P-DP	6.66	0.02	8.07	490.87	0.41	27.00	0.00	39.31	0.00	478.98	266.27	50.00
CATES 24 1 - 1	P-DP	0.08	0.00	0.00	6.01	0.00	0.00	0.00	0.43	0.00	5.58	2.89	26.82

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
CENA WYN JF 2H - 2H	*P-DP*	0.00	0.00	368.53	0.00	0.00	730.01	0.00	454.64	0.00	275.38	165.38	39.26
CENA WYN JF 4H - 4H	*P-DP*	0.00	0.00	172.93	0.00	0.00	342.55	0.00	213.33	0.00	129.22	82.25	29.39
CHALUPA 34-153 UNIT 1H - 1H	*P-DP*	0.38	0.18	0.17	28.63	3.86	0.12	0.00	3.44	0.00	29.16	16.36	37.89
CHALUPA 34-153 UNIT 2H - 2H	*P-DP*	0.74	0.16	0.16	55.31	3.55	0.11	0.00	5.72	0.00	53.25	30.19	44.88
CHAMBERS FED W-39138 1-25 -	*P-DP*	0.00	0.00	0.24	0.01	0.04	1.04	0.00	0.16	0.00	0.94	0.47	20.97
CHAPARRAL UNIT A1 15SH - 15	*P-DP*	0.18	0.03	0.16	14.04	0.73	0.32	0.00	1.16	0.00	13.92	8.31	44.79
CHAPARRAL UNIT A1 21H - 21H	*P-DP*	0.10	0.02	0.09	8.00	0.42	0.18	0.00	0.66	0.00	7.94	4.87	38.29
CHAPARRAL UNIT A1 8AH - 8A	*P-DP*	0.19	0.03	0.18	14.75	0.83	0.36	0.00	1.23	0.00	14.71	8.11	48.34
CHAPARRAL UNIT A2 7AH - 7A	*P-DP*	0.03	0.00	0.13	2.33	0.01	0.44	0.00	0.24	0.00	2.54	1.53	26.27
CHAPARRAL UNIT A3 14SH - 14	*P-DP*	0.16	0.00	0.66	11.51	0.03	2.21	0.00	1.17	0.00	12.57	7.38	43.37
CHAPARRAL UNIT A3 20H - 20H	*P-DP*	0.20	0.00	0.93	14.72	0.05	3.10	0.00	1.55	0.00	16.33	9.21	47.23
CHAPARRAL UNIT A4 6AH - 6A	*P-DP*	0.21	0.00	0.91	15.20	0.05	3.03	0.00	1.57	0.00	16.71	9.04	48.74
CHAPARRAL UNIT A5 13SH - 13	*P-DP*	0.10	0.05	0.21	7.43	1.18	0.21	0.00	1.19	0.00	7.64	4.51	38.51
CHAPARRAL UNIT A5 19H - 19H	*P-DP*	0.03	0.03	0.15	2.51	0.84	0.15	0.00	0.61	0.00	2.90	1.76	28.37
CHAPARRAL UNIT A5 5AH - 5A	*P-DP*	0.16	0.07	0.33	12.58	1.86	0.34	0.00	1.94	0.00	12.84	7.71	43.89
CHARLIE 210468 7A - 7A	*P-DP*	0.00	0.00	7.53	0.00	0.00	15.40	0.00	1.34	0.00	14.06	7.72	40.11
CHARLIE 210468 8B - 8B	*P-DP*	0.00	0.00	5.66	0.00	0.00	11.58	0.00	1.01	0.00	10.57	5.91	36.61
CHARLIE 210469 10B - 10B	*P-DP*	0.00	0.00	68.51	0.00	0.00	140.09	0.00	12.20	0.00	127.89	70.78	39.46
CHARLIE 210469 9A - 9A	*P-DP*	0.00	0.00	71.44	0.00	0.00	146.08	0.00	12.73	0.00	133.35	73.58	39.98
CHARLIE 210472 4A - 4A	*P-DP*	0.00	0.00	33.42	0.00	0.00	68.34	0.00	5.95	0.00	62.38	37.50	22.31
CHARLIE 210472 5B - 5B	*P-DP*	0.00	0.00	45.94	0.00	0.00	93.94	0.00	8.18	0.00	85.76	49.93	25.80
CHARLIE 210472 6C - 6C	*P-DP*	0.00	0.00	21.81	0.00	0.00	44.59	0.00	3.88	0.00	40.71	28.19	14.88
CHAROLAIS 28 21 B2NC STATE	*P-DP*	0.11	0.00	0.09	8.03	0.04	0.10	0.00	1.10	0.00	7.07	4.05	34.57
CHAROLAIS 28 21 W1MD STAT	*P-DP*	0.05	0.00	0.04	4.11	0.02	0.05	0.00	0.56	0.00	3.61	1.98	35.70
CHAROLAIS 33 21 B1GB STATE	*P-DP*	1.40	0.05	2.08	106.60	1.02	2.35	0.00	15.08	0.00	94.88	55.83	48.99
CHAROLAIS 33 21 B1HA STATE	*P-DP*	1.93	0.08	3.36	147.32	1.65	3.80	0.00	21.10	0.00	131.67	78.26	50.00
CHEST THUMPER 1-5 UNIT 1 11	*P-DP*	0.11	0.06	0.27	8.69	1.22	0.37	0.00	1.13	0.00	9.14	5.47	50.00
CHEST THUMPER 1-5 UNIT 1 12	*P-DP*	0.12	0.08	0.38	9.41	1.72	0.51	0.00	1.40	0.00	10.24	6.04	50.00
CHEST THUMPER 1-5 UNIT 1 12	*P-DP*	0.13	0.08	0.40	9.67	1.79	0.53	0.00	1.45	0.00	10.54	6.23	50.00
CHEST THUMPER 1-5 UNIT 1 12	*P-DP*	0.15	0.10	0.50	11.76	2.24	0.67	0.00	1.78	0.00	12.89	7.65	50.00
CHEST THUMPER 1-5 UNIT 1 12	*P-DP*	0.17	0.10	0.47	13.28	2.11	0.63	0.00	1.84	0.00	14.18	8.42	50.00
CHEST THUMPER 1-5 UNIT 1 13	*P-DP*	0.12	0.08	0.38	8.75	1.72	0.51	0.00	1.35	0.00	9.63	5.67	50.00
CHEST THUMPER 1-5 UNIT 1 13	*P-DP*	0.06	0.04	0.20	4.74	0.89	0.27	0.00	0.72	0.00	5.18	3.08	50.00
CHEST THUMPER 1-5 UNIT 1 13	*P-DP*	0.14	0.09	0.44	10.64	1.96	0.58	0.00	1.58	0.00	11.60	6.86	50.00
CHEST THUMPER 1-5 UNIT 1 13	*P-DP*	0.13	0.09	0.42	10.12	1.88	0.56	0.00	1.52	0.00	11.04	6.55	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
CHEST THUMPER 1-5 UNIT 1 14	P-DP	0.15	0.09	0.46	11.76	2.05	0.61	0.00	1.71	0.00	12.72	7.54	50.00
CHEST THUMPER 1-5 UNIT 1 14	P-DP	0.08	0.05	0.22	6.14	1.00	0.30	0.00	0.86	0.00	6.58	3.92	50.00
CHEST THUMPER 1-5 UNIT 1A	P-DP	0.06	0.01	0.07	4.29	0.32	0.10	0.00	0.44	0.00	4.27	2.62	50.00
CHEST THUMPER 1-5 UNIT 1A	P-DP	0.04	0.01	0.06	3.26	0.25	0.07	0.00	0.34	0.00	3.25	2.00	47.87
CHEST THUMPER 1-5 UNIT 1A	P-DP	0.06	0.02	0.08	4.38	0.35	0.11	0.00	0.46	0.00	4.38	2.69	50.00
CHEST THUMPER 1-5 UNIT 1B	P-DP	0.07	0.04	0.21	4.97	0.94	0.28	0.00	0.75	0.00	5.44	3.26	50.00
CHEST THUMPER 1-5 UNIT 1B	P-DP	0.09	0.07	0.34	6.79	1.54	0.46	0.00	1.13	0.00	7.66	4.58	50.00
CHEST THUMPER 1-5 UNIT 1B	P-DP	0.10	0.06	0.29	7.44	1.29	0.39	0.00	1.07	0.00	8.05	4.83	50.00
CHEVRON UNIT 03-38 1H - 1H	P-DP	0.06	0.06	0.32	4.27	1.45	0.64	0.00	0.62	0.00	5.74	2.92	50.00
CHEVRON UNIT 03-38 2AH - 2A	P-DP	0.05	0.01	0.04	3.86	0.16	0.07	0.00	0.31	0.00	3.78	2.17	46.67
CHEVRON UNIT 03-38 2SH - 2S	P-DP	0.12	0.00	0.02	8.84	0.09	0.04	0.00	0.65	0.00	8.32	4.38	50.00
CHINOOK 55-1-7 UNIT 1H - 1H	P-DP	0.02	0.01	0.04	1.83	0.35	-0.01	0.00	0.08	0.00	2.09	1.03	38.94
CHRIESMAN 2 - 2	P-DP	0.01	0.00	0.01	0.56	0.07	0.03	0.00	0.06	0.00	0.60	0.32	22.26
CHRIESMAN 3 - 3	P-DP	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.00	0.00	0.04	0.03	2.62
CHUMCHAL UNIT 1H - 1H	P-DP	0.01	0.01	0.02	0.44	0.09	0.05	0.00	0.05	0.00	0.52	0.29	30.27
CHUMCHAL UNIT 4H - 4H	P-DP	0.02	0.01	0.05	1.15	0.17	0.09	0.00	0.12	0.00	1.29	0.95	11.80
CHUMCHAL UNIT 6L - 6L	P-DP	0.55	0.47	2.32	40.91	8.48	4.50	0.00	4.69	0.00	49.21	26.78	35.38
CHUMCHAL UNIT 7L - 7L	P-DP	0.57	0.44	2.18	42.12	7.97	4.23	0.00	4.71	0.00	49.61	26.94	50.00
CHUMCHAL UNIT B 2H - 2H	P-DP	1.54	1.27	6.29	114.61	22.95	12.19	0.00	13.02	0.00	136.73	108.70	33.35
CHURRO 34-157/158 UNIT 1H -	P-DP	0.05	0.01	0.01	3.70	0.25	0.01	0.00	0.38	0.00	3.57	1.95	50.00
CLARICE STARLING SUNDOW	P-DP	1.36	0.35	2.04	103.67	9.13	4.00	0.00	9.39	0.00	107.41	59.31	50.00
CLARICE STARLING SUNDOW	P-DP	0.89	0.30	1.78	68.11	7.95	3.48	0.00	6.59	0.00	72.95	39.98	50.00
CLAWSON 3 - 3	P-DP	0.00	0.00	2.70	0.00	0.00	3.79	0.00	0.36	0.00	3.44	1.97	50.00
CLEMENTS ALLOCATION A 26-	P-DP	0.03	0.00	0.06	1.97	0.00	0.19	0.00	0.17	0.00	1.99	1.05	50.00
COLE 36-37 A UNIT A 2H - A 2H	P-DP	0.00	0.00	0.00	0.31	0.00	0.00	0.00	0.02	0.00	0.29	0.17	24.64
COLLE UNIT 1H - 1H	P-DP	0.82	0.65	3.24	61.24	11.82	6.28	0.00	6.89	0.00	72.45	35.15	50.00
COLLINS WYN JF 2H - 2H	P-DP	0.00	0.00	193.63	0.00	0.00	383.56	0.00	238.87	0.00	144.69	85.53	29.56
COLLINS WYN JF 4H - 4H	P-DP	0.00	0.00	185.00	0.00	0.00	366.46	0.00	228.22	0.00	138.24	82.76	28.76
COLLINS WYN JF 6H - 6H	P-DP	0.00	0.00	244.51	0.00	0.00	484.35	0.00	301.64	0.00	182.71	106.56	32.26
COLUMBINE 34-167 1H - 1H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.92
COLUMBINE 34-167 2H - 2H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	45.13
COLUMBINE 34-167 3H - 3H	P-DP	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.02	0.02	6.38
COLUMBINE 34-167 4H - 4H	P-DP	0.00	0.00	0.00	0.26	0.01	0.00	0.00	0.03	0.00	0.25	0.15	25.47
CONNER 15 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CONNER 15 1504N - 1504N	P-DP	0.07	0.07	0.40	5.61	1.79	0.79	0.00	0.79	0.00	7.40	5.55	8.38

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
CONNER 15 2 - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CONNER 15 3 - 3	P-DP	0.05	0.05	0.31	3.84	1.38	0.60	0.00	0.57	0.00	5.24	3.93	7.52
CONNER 15-10 (ALLOC-A) 1NA	P-DP	2.50	1.04	6.16	190.27	27.56	12.06	0.00	19.58	0.00	210.31	119.48	50.00
CONNER 15-10 (ALLOC-B) 2NB	P-DP	1.05	0.31	1.82	80.15	8.14	3.56	0.00	7.50	0.00	84.36	46.82	42.20
CONNER 15-10 (ALLOC-B) 2NS	P-DP	1.36	0.46	2.73	103.25	12.23	5.35	0.00	10.03	0.00	110.80	60.61	46.39
CONNER 15-10 (ALLOC-C) 3NA	P-DP	2.05	0.85	5.02	156.44	22.49	9.84	0.00	16.06	0.00	172.71	90.31	50.00
CONNER 15-10 (ALLOC-D) 4NB	P-DP	3.54	1.36	8.03	269.86	35.95	15.74	0.00	27.09	0.00	294.46	151.80	50.00
CONNER 15-10 (ALLOC-D) 4NS	P-DP	0.45	1.16	6.85	34.19	30.67	13.42	0.00	9.09	0.00	69.19	34.53	42.92
CONNER 15-3 (ALLOC-E) 5NA -	P-DP	1.87	0.47	2.77	142.27	12.41	5.43	0.00	12.86	0.00	147.25	77.80	50.00
CONNER 15-3 (ALLOC-F) 6NB -	P-DP	1.70	1.01	5.95	129.60	26.63	11.66	0.00	15.04	0.00	152.86	78.04	50.00
CONNER 15-3 (ALLOC-F) 6NS -	P-DP	0.71	0.40	2.37	53.82	10.59	4.64	0.00	6.14	0.00	62.91	32.18	50.00
CONNER 15-3 (ALLOC-G) 7NA -	P-DP	1.31	0.45	2.67	99.83	11.97	5.24	0.00	9.73	0.00	107.30	58.81	50.00
CONNER 15-3 (ALLOC-H) 8NB -	P-DP	2.38	0.77	4.56	181.04	20.40	8.93	0.00	17.37	0.00	193.00	101.10	50.00
CONNER 15-3 (ALLOC-H) 8NS -	P-DP	1.52	0.64	3.77	115.77	16.88	7.39	0.00	11.94	0.00	128.10	66.23	50.00
CONSTANTAN 34-174 (N) 1H - 1	P-DP	0.00	0.00	0.00	0.06	0.01	0.00	0.00	0.01	0.00	0.06	0.03	33.62
COOK 21 1 - 1	P-DP	0.10	0.00	0.00	7.35	0.01	0.00	0.00	0.53	0.00	6.83	3.49	26.38
COOK 21 2 - 2	P-DP	0.08	0.00	0.00	6.30	0.01	0.00	0.00	0.46	0.00	5.86	3.35	22.44
COOK 21 3 - 3	P-DP	0.12	0.00	0.02	9.33	0.10	0.03	0.00	0.71	0.00	8.74	4.70	27.84
COOK 21 4 - 4	P-DP	0.13	0.00	0.02	9.95	0.11	0.03	0.00	0.76	0.00	9.33	5.10	28.14
COOK 21 5 - 5	P-DP	0.05	0.01	0.03	4.12	0.12	0.03	0.00	0.34	0.00	3.93	2.42	17.41
COOK 21 6 - 6	P-DP	0.09	0.01	0.03	6.62	0.16	0.05	0.00	0.54	0.00	6.28	3.61	23.00
COOK 21 7 - 7	P-DP	0.10	0.00	0.02	7.92	0.10	0.03	0.00	0.61	0.00	7.44	4.22	24.85
COOK 21 8 - 8	P-DP	0.05	0.01	0.03	3.51	0.13	0.04	0.00	0.30	0.00	3.37	2.18	15.34
COOKIE 55-2728-23S - 55-2728-2	P-DP	0.47	0.00	0.25	28.14	0.00	0.43	0.00	0.51	0.00	28.06	15.65	50.00
COOKIE 57-2728-23K - 57-2728-	P-DP	0.39	0.00	0.10	23.51	0.00	0.18	0.00	0.39	0.00	23.31	11.50	50.00
COOKIE 58-2728-23R - 58-2728-2	P-DP	0.65	0.00	0.83	39.55	0.00	1.42	0.00	0.90	0.00	40.07	20.66	50.00
COOKIE 78-2728-23G - 78-2728-	P-DP	0.36	0.00	0.41	21.66	0.00	0.70	0.00	0.47	0.00	21.88	11.58	50.00
COPPER CREEK A8 44H - 44H	P-DP	0.09	0.05	0.23	6.95	1.33	0.24	0.00	1.22	0.00	7.31	3.73	50.00
COPPER CREEK A9 12SH - 12SH	P-DP	0.10	0.05	0.22	7.55	1.26	0.23	0.00	1.23	0.00	7.80	4.00	50.00
CORNELL 226-34 1H - 1H	P-DP	0.16	0.25	0.25	12.39	5.54	0.17	0.00	2.41	0.00	15.69	7.94	50.00
COURAGE 53-2827-23P - 53-282	P-DP	0.36	0.00	0.14	21.70	0.00	0.25	0.00	0.37	0.00	21.57	11.77	50.00
COURAGE 63-2827-23K - 63-282	P-DP	0.40	0.00	0.43	24.08	0.00	0.74	0.00	0.52	0.00	24.30	13.20	50.00
COURAGE 67-2827-23M - 67-282	P-DP	0.58	0.00	0.70	35.24	0.00	1.19	0.00	0.78	0.00	35.64	18.75	50.00
COURAGE 75-2827-23O - 75-282	P-DP	0.41	0.00	0.23	25.08	0.00	0.40	0.00	0.46	0.00	25.02	13.80	50.00
COWDEN F 2402 - 2402	P-DP	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.01	0.00	0.08	0.06	7.71

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
COWDEN F 2403 - 2403	*P-DP*	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.01	0.00	0.04	0.03	4.68
COWDEN F 2404 - 2404	*P-DP*	0.01	0.00	0.00	0.78	0.02	0.00	0.00	0.07	0.00	0.73	0.45	20.41
COWDEN F 2405 - 2405	*P-DP*	0.01	0.00	0.00	0.58	0.01	0.00	0.00	0.05	0.00	0.54	0.33	21.23
CRAZY CAMEL 1 - 1	*P-DP*	0.02	0.00	0.00	1.66	0.02	0.00	0.00	0.15	0.00	1.53	0.88	24.27
CRAZY CAMEL 2 - 2	*P-DP*	0.06	0.00	0.00	4.67	0.06	0.00	0.00	0.43	0.00	4.30	2.40	34.87
CRAZY CAMEL 5 - 5	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CRAZY CAMEL 6 - 6	*P-DP*	0.01	0.00	0.00	0.44	0.06	0.00	0.00	0.05	0.00	0.44	0.31	11.48
CRAZY CAMEL 7 - 7	*P-DP*	0.02	0.01	0.01	1.31	0.29	0.01	0.00	0.18	0.00	1.42	0.85	23.16
CRAZY CAT 41-32 1SH - 1SH	*P-DP*	0.26	0.01	0.04	19.95	0.17	0.07	0.00	1.46	0.00	18.73	10.23	27.37
CRAZY CAT 41-32 2AH - 2AH	*P-DP*	0.38	0.11	0.68	28.98	3.02	1.32	0.00	2.73	0.00	30.60	16.01	33.60
CRAZY CAT 41-32 3SH - 3SH	*P-DP*	0.21	0.09	0.53	16.08	2.37	1.04	0.00	1.66	0.00	17.82	9.71	27.41
CRAZY CAT 41-32 4AH - 4AH	*P-DP*	0.19	0.01	0.05	14.23	0.23	0.10	0.00	1.07	0.00	13.49	7.11	25.00
CROSS CREEK A 5H-20 - 5H-20	*P-DP*	0.00	0.00	285.27	0.00	0.00	565.10	0.00	351.93	0.00	213.17	116.03	33.89
CROSS V RANCH 34-170 UNIT 1	*P-DP*	0.08	0.00	0.00	6.38	0.07	0.00	0.00	0.58	0.00	5.88	2.93	46.22
CROWIE E RCH BL 3H - 3H	*P-DP*	0.00	0.00	12.87	0.00	0.00	26.31	0.00	2.29	0.00	24.02	12.41	46.88
CROWIE RCH BL 1H - 1H	*P-DP*	0.00	0.00	7.81	0.00	0.00	15.98	0.00	1.39	0.00	14.59	7.61	41.06
CUATRO HIJOS FEE 003H - 003H	*P-DP*	0.07	0.00	0.03	5.21	0.01	0.03	0.00	0.70	0.00	4.55	2.30	32.37
CUATRO HIJOS FEE 004H - 004H	*P-DP*	0.14	0.00	0.06	11.03	0.03	0.07	0.00	1.48	0.00	9.65	4.76	42.64
CUATRO HIJOS FEE 008H - 008H	*P-DP*	0.02	0.00	0.04	1.24	0.02	0.04	0.00	0.18	0.00	1.12	0.78	12.30
CV RB SU58;SJ MONDELLO ET	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CV RB SUV;SHELBY INTEREST	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CV RB SUW;LESHE 36 001 - 001	*P-DP*	0.00	0.00	7.81	0.00	0.00	15.97	0.00	9.05	0.00	6.92	5.18	8.44
CV RB SUW;NAC 36 001-ALT - 0	*P-DP*	0.00	0.00	2.57	0.00	0.00	5.26	0.00	2.98	0.00	2.28	2.01	3.29
DANIEL D & EDNA MILLER 1 -	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DANIELLE 183 UNIT 1H - 1H	*P-DP*	0.02	0.02	0.02	1.39	0.34	0.01	0.00	0.20	0.00	1.53	0.85	39.17
DANIELLE 183 UNIT 2H - 2H	*P-DP*	0.03	0.03	0.03	2.37	0.72	0.02	0.00	0.38	0.00	2.73	1.37	50.00
DARWIN 22 1 - 1	*P-DP*	0.06	0.02	0.09	4.51	0.41	0.12	0.00	0.48	0.00	4.56	2.32	30.50
DARWIN 22 2 - 2	*P-DP*	0.05	0.00	0.00	3.54	0.00	0.00	0.00	0.26	0.00	3.28	1.79	26.01
DAVID 1 - 1	*P-DP*	0.11	0.00	0.01	8.12	0.05	0.01	0.00	0.70	0.00	7.48	2.65	50.00
DAVID L BONACCI 0031 - 0031	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DAVIS 1_1 - 1	*P-DP*	0.75	0.21	1.27	57.11	5.67	2.48	0.00	5.31	0.00	59.95	22.47	50.00
DAVIS 2 - 2	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DAVIS 36-5 (ALLOC-E) 5SA - 5S	*P-DP*	0.03	0.01	0.08	2.51	0.37	0.16	0.00	0.26	0.00	2.79	1.39	50.00
DAVIS 36-5 (ALLOC-F) 6SB - 6S	*P-DP*	0.09	0.02	0.13	6.49	0.60	0.26	0.00	0.59	0.00	6.76	3.36	50.00
DAVIS 36-5 (ALLOC-F) 6SS - 6SS	*P-DP*	0.04	0.02	0.09	2.83	0.41	0.18	0.00	0.29	0.00	3.13	1.72	48.18

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
DAVIS 36-5 (ALLOC-G) 7SA - 7S	P-DP	0.04	0.01	0.06	3.31	0.28	0.12	0.00	0.30	0.00	3.41	1.88	50.00
DAVIS 36-5 (ALLOC-H) 8SB - 8S	P-DP	0.06	0.03	0.20	4.92	0.91	0.40	0.00	0.55	0.00	5.67	2.94	50.00
DAVIS 36-5 (ALLOC-H) 8SS - 8S	P-DP	0.03	0.01	0.08	1.98	0.34	0.15	0.00	0.21	0.00	2.25	1.25	44.49
DEMANGONE 1 - 1	P-DP	0.00	0.00	1.10	0.00	0.00	1.54	0.00	0.15	0.00	1.39	0.94	50.00
DICKSON CRC JF 1H - 1H	P-DP	0.00	0.00	217.90	0.00	0.00	431.64	0.00	268.82	0.00	162.82	102.98	26.88
DICKSON CRC JF 3H - 3H	P-DP	0.00	0.00	184.29	0.00	0.00	365.07	0.00	227.36	0.00	137.71	86.21	25.69
DILLES BOTTOM 210744 3B - 3	P-DP	0.00	0.00	0.04	0.00	0.00	0.07	0.00	0.01	0.00	0.07	0.04	34.12
DIRE WOLF 30 3BS A 1H - 1H	P-DP	0.04	0.01	0.01	2.69	0.22	0.01	0.00	0.29	0.00	2.62	1.58	44.30
DIRE WOLF 50 WA A 1H - 1H	P-DP	0.09	0.02	0.02	6.57	0.35	0.01	0.00	0.66	0.00	6.27	3.56	50.00
DIRE WOLF 60 WB A 1H - 1H	P-DP	0.04	0.01	0.01	2.98	0.29	0.01	0.00	0.33	0.00	2.94	1.81	44.69
DIRE WOLF 70 WC A 1H - 1H	P-DP	0.04	0.01	0.01	3.05	0.31	0.01	0.00	0.34	0.00	3.03	1.78	44.28
DIRE WOLF UNIT 1 0402BH - 04	P-DP	0.69	1.02	4.95	52.60	22.26	6.64	0.00	12.30	0.00	69.20	40.93	45.45
DIRE WOLF UNIT 1 0404BH - 04	P-DP	0.15	1.03	5.00	11.37	22.46	6.71	0.00	9.40	0.00	31.13	18.94	30.34
DIRE WOLF UNIT 1 0411AH - 04	P-DP	0.00	0.13	0.64	0.07	2.87	0.86	0.00	1.10	0.00	2.70	2.00	9.91
DIRE WOLF UNIT 1 0413AH - 04	P-DP	0.00	0.08	0.38	0.07	1.73	0.52	0.00	0.66	0.00	1.65	1.24	8.37
DIRE WOLF UNIT 1 0414AH - 04	P-DP	0.56	0.04	0.20	42.45	0.91	0.27	0.00	3.41	0.00	40.21	23.58	43.45
DIRE WOLF UNIT 1 0422SH - 04	P-DP	0.00	0.16	0.79	0.07	3.53	1.05	0.00	1.35	0.00	3.30	1.91	21.13
DIRE WOLF UNIT 1 0424SH - 04	P-DP	0.53	0.33	1.62	40.59	7.27	2.17	0.00	5.71	0.00	44.32	25.07	46.00
DIRE WOLF UNIT 1 0433SH - 04	P-DP	0.54	0.01	0.04	40.83	0.16	0.05	0.00	3.01	0.00	38.03	22.82	42.40
DIRE WOLF UNIT 1 0471JH - 047	P-DP	0.55	0.05	0.22	41.74	1.00	0.30	0.00	3.39	0.00	39.64	23.97	42.24
DIRE WOLF UNIT 1 0474JH - 047	P-DP	0.61	0.02	0.11	46.42	0.49	0.15	0.00	3.54	0.00	43.52	26.51	43.36
DIRE WOLF UNIT 2 0406BH - 04	P-DP	0.53	0.52	2.55	40.33	11.46	3.42	0.00	7.29	0.00	47.92	26.50	50.00
DIRE WOLF UNIT 2 0407BH - 04	P-DP	0.54	0.47	2.30	41.34	10.34	3.09	0.00	6.93	0.00	47.83	26.57	50.00
DIRE WOLF UNIT 2 0415AH - 04	P-DP	0.31	0.31	1.50	23.40	6.76	2.02	0.00	4.27	0.00	27.91	16.21	50.00
DIRE WOLF UNIT 2 0416AH - 04	P-DP	0.35	0.03	0.16	26.55	0.73	0.22	0.00	2.19	0.00	25.30	14.64	49.13
DIRE WOLF UNIT 2 0417AH - 04	P-DP	0.30	0.24	1.17	22.60	5.24	1.56	0.00	3.63	0.00	25.77	14.42	50.00
DIRE WOLF UNIT 2 0426SH - 04	P-DP	0.18	0.16	0.79	13.36	3.57	1.07	0.00	2.33	0.00	15.67	8.57	45.96
DIRE WOLF UNIT 2 0427SH - 04	P-DP	0.12	0.47	2.27	9.23	10.19	3.04	0.00	4.56	0.00	17.90	10.28	42.23
DIRE WOLF UNIT 2 0428SH - 04	P-DP	0.12	0.07	0.36	9.09	1.62	0.48	0.00	1.27	0.00	9.92	6.06	38.21
DIRE WOLF UNIT 2 0435SH - 04	P-DP	0.01	0.00	0.00	0.58	0.00	0.00	0.00	0.04	0.00	0.54	0.42	8.67
DIRE WOLF UNIT 2 0437SH - 04	P-DP	0.03	0.04	0.18	2.34	0.81	0.24	0.00	0.48	0.00	2.91	1.72	26.52
DOBBY 43D 1HF - 1HF	P-DP	0.08	0.03	0.15	6.03	0.67	0.29	0.00	0.58	0.00	6.42	3.46	50.00
DONALDSON 4-54 1H - 1H	P-DP	0.00	0.02	0.11	0.19	0.37	0.15	0.00	0.12	0.00	0.59	0.32	38.87
DONALDSON 4-54 U 34H - U 34	P-DP	0.01	0.02	0.14	0.82	0.47	0.19	0.00	0.20	0.00	1.28	0.66	38.41
DOYEN NE WEL JF 3H - 3H	P-DP	0.00	0.00	49.44	0.00	0.00	97.93	0.00	60.99	0.00	36.94	21.68	40.33

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
DOYEN NW WEL JF 1H - 1H	P-DP	0.00	0.00	1.97	0.00	0.00	3.90	0.00	2.43	0.00	1.47	0.76	49.13
DRAINAGE 34-136 1H - 1H	P-DP	0.00	0.00	0.00	0.11	0.02	0.00	0.00	0.01	0.00	0.11	0.07	16.79
DRAINAGE 34-136 2H - 2H	P-DP	0.01	0.00	0.00	0.83	0.09	0.00	0.00	0.09	0.00	0.82	0.49	21.69
DRAINAGE 34-136 3H - 3H	P-DP	0.02	0.00	0.00	1.60	0.02	0.00	0.00	0.15	0.00	1.48	0.80	30.41
DRAINAGE 34-136 4H - 4H	P-DP	0.04	0.00	0.00	2.86	0.04	0.00	0.00	0.26	0.00	2.64	1.53	34.16
DRAINAGE A3 6LA - 6LA	P-DP	0.04	0.01	0.01	2.73	0.16	0.00	0.00	0.28	0.00	2.61	1.57	47.18
DRIVER-LANE 30A 1H - 1H	P-DP	0.67	0.50	0.12	51.21	9.37	0.15	0.00	5.35	0.00	55.38	31.99	50.00
DRIVER-LANE 30B 2H - 2H	P-DP	0.50	0.46	0.11	38.33	8.63	0.14	0.00	4.20	0.00	42.90	24.81	47.44
DRIVER-LANE 30C 3H - 3H	P-DP	0.74	0.63	0.16	56.47	11.96	0.19	0.00	6.09	0.00	62.53	34.88	50.00
DRIVER-LANE 30D 4H - 4H	P-DP	0.52	0.43	0.11	39.30	8.03	0.13	0.00	4.21	0.00	43.25	24.22	48.32
DRIVER-LANE 30E 5H - 5H	P-DP	0.77	0.66	0.16	58.20	12.43	0.19	0.00	6.29	0.00	64.53	36.54	50.00
DRIVER-LANE 30F 6H - 6H	P-DP	0.60	1.22	0.30	45.95	22.97	0.36	0.00	6.53	0.00	62.76	33.60	50.00
DUCHESNE LAND 4-10C5 - 4-10	P-DP	0.05	0.00	0.16	3.32	0.00	0.27	0.00	0.11	0.00	3.48	1.44	50.00
DYER 33 A - 33 A	P-DP	0.06	0.00	0.00	4.48	0.00	0.00	0.00	0.32	0.00	4.16	2.52	15.45
DYER 3301 - 3301	P-DP	0.20	0.00	0.01	14.88	0.07	0.02	0.00	1.10	0.00	13.87	7.77	24.97
DYER 3303 - 3303	P-DP	0.11	0.00	0.02	8.36	0.10	0.03	0.00	0.64	0.00	7.85	4.69	19.15
DYER 33B - 33B	P-DP	0.01	0.00	0.01	0.79	0.03	0.01	0.00	0.07	0.00	0.75	0.64	3.84
DYER 33D - 33D	P-DP	0.21	0.00	0.02	16.02	0.07	0.02	0.00	1.18	0.00	14.93	8.62	24.97
DYER 33F - 33F	P-DP	0.04	0.00	0.01	3.31	0.04	0.01	0.00	0.26	0.00	3.11	2.17	10.83
DYER 33H - 33H	P-DP	0.02	0.00	0.01	1.88	0.04	0.01	0.00	0.15	0.00	1.78	1.36	7.37
EASON UNIT 1 - 1	P-DP	0.43	0.09	0.52	32.78	2.31	1.01	0.00	2.84	0.00	33.25	11.45	50.00
EAST ACKERLY DEAN UNIT 99	P-DP	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.02	0.02	8.70
EILAND 1806A-33 1H - 1H	P-DP	0.03	0.01	0.01	2.38	0.14	0.00	0.00	0.24	0.00	2.28	1.27	35.79
EILAND 1806B-33 1H - 1H	P-DP	0.05	0.01	0.01	3.84	0.14	0.00	0.00	0.37	0.00	3.61	1.96	42.59
EILAND 1806B-33 62H - 62H	P-DP	0.03	0.01	0.01	2.08	0.25	0.01	0.00	0.24	0.00	2.10	1.32	32.25
EILAND 1806C-33 1H - 1H	P-DP	0.03	0.01	0.01	1.93	0.28	0.01	0.00	0.24	0.00	1.98	1.17	32.95
EILAND 1806C-33 81H - 81H	P-DP	0.02	0.01	0.01	1.45	0.12	0.00	0.00	0.16	0.00	1.42	0.77	36.18
EILAND 1806C-33 82H - 82H	P-DP	0.09	0.01	0.01	6.64	0.20	0.01	0.00	0.63	0.00	6.21	3.43	50.00
EILAND 1806C-33 83H - 83H	P-DP	0.03	0.01	0.01	2.10	0.22	0.01	0.00	0.24	0.00	2.09	1.21	34.47
EILAND 6047A-34 41H - 41H	P-DP	0.12	0.04	0.04	9.06	0.93	0.03	0.00	1.02	0.00	9.00	5.06	40.22
EL KABONG UNIT 48-17-8 301H	P-DP	0.03	0.00	0.01	2.19	0.08	0.01	0.00	0.18	0.00	2.10	1.16	36.74
EL KABONG UNIT 48-17-8 302H	P-DP	0.05	0.01	0.02	3.58	0.20	0.02	0.00	0.30	0.00	3.49	1.87	46.72
EL KABONG UNIT 48-17-8 303H	P-DP	0.02	0.00	0.01	1.89	0.06	0.00	0.00	0.15	0.00	1.80	1.10	40.68
EL KABONG UNIT 48-17-8 701H	P-DP	0.03	0.01	0.02	2.36	0.15	0.01	0.00	0.20	0.00	2.31	1.24	38.37
EL KABONG UNIT 48-17-8 702H	P-DP	0.06	0.03	0.07	4.34	0.63	0.05	0.00	0.43	0.00	4.59	2.31	46.44

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
EL KABONG UNIT 48-17-8 703H	P-DP	0.05	0.01	0.02	3.64	0.14	0.01	0.00	0.30	0.00	3.49	1.88	43.05
EL KABONG UNIT 48-17-8 704H	P-DP	0.04	0.01	0.02	2.97	0.13	0.01	0.00	0.25	0.00	2.86	1.54	44.29
EL KABONG UNIT 48-17-8 705H	P-DP	0.04	0.00	0.00	3.30	0.03	0.00	0.00	0.26	0.00	3.08	1.75	44.23
EL KABONG UNIT 48-17-8 801H	P-DP	0.00	0.01	0.02	0.23	0.21	0.02	0.00	0.05	0.00	0.41	0.25	20.25
EL PASO 4-29B5 - 4-29B5	P-DP	0.03	0.00	0.04	2.00	0.00	0.07	0.00	0.04	0.00	2.02	0.87	43.29
ELIAS 16-9 D 143 - 143	P-DP	0.06	0.02	0.12	4.77	0.52	0.16	0.00	0.54	0.00	4.90	3.27	50.00
ELIAS 16-9 UNIT 1 111 - 111	P-DP	0.61	0.29	1.39	46.20	6.24	1.86	0.00	5.72	0.00	48.59	33.02	50.00
ELIAS 16-9 UNIT 1 122 - 122	P-DP	0.05	0.03	0.14	3.76	0.62	0.19	0.00	0.51	0.00	4.06	2.53	50.00
ELIAS 16-9 UNIT 1 124 - 124	P-DP	0.05	0.03	0.14	3.77	0.62	0.19	0.00	0.51	0.00	4.07	2.54	50.00
ELIAS 16-9 UNIT 1 132 - 132	P-DP	0.05	0.03	0.16	3.73	0.71	0.21	0.00	0.54	0.00	4.12	2.71	47.79
ELIAS 16-9 UNIT 1 141 - 141	P-DP	0.05	0.04	0.21	3.51	0.94	0.28	0.00	0.61	0.00	4.12	2.90	42.82
ELIAS 16-9 UNIT 1 221 - 221	P-DP	0.03	0.02	0.10	2.57	0.44	0.13	0.00	0.36	0.00	2.79	1.87	44.25
ELIAS 16-9 UNIT 1 231 - 231	P-DP	0.07	0.04	0.19	5.01	0.87	0.26	0.00	0.70	0.00	5.45	3.63	50.00
ELIAS 16-9 UNIT 1 233 - 233	P-DP	0.59	0.28	1.36	45.00	6.12	1.83	0.00	5.59	0.00	47.37	31.94	50.00
ELIAS 16-9 UNIT 1 242 - 242	P-DP	0.07	0.04	0.19	4.99	0.87	0.26	0.00	0.69	0.00	5.43	3.62	50.00
ELIAS 16-9 UNIT 2 151 - 151	P-DP	0.05	0.04	0.20	3.43	0.92	0.27	0.00	0.60	0.00	4.02	2.83	42.57
ELIAS 16-9 UNIT 2 161 - 161	P-DP	0.05	0.03	0.16	3.69	0.70	0.21	0.00	0.53	0.00	4.07	2.68	47.18
ELIAS 16-9 UNIT 2 163 - 163	P-DP	0.05	0.04	0.21	3.48	0.93	0.28	0.00	0.61	0.00	4.08	2.87	42.64
ELIAS 16-9 UNIT 2 172 - 172	P-DP	0.46	0.25	1.19	35.23	5.37	1.60	0.00	4.59	0.00	37.61	25.53	50.00
ELKHEAD 4144 A 2H - A 2H	P-DP	0.12	0.12	0.76	8.88	2.50	1.02	0.00	1.38	0.00	11.02	5.53	50.00
ELKHEAD 4144 A 5H - A 5H	P-DP	0.08	0.09	0.59	5.97	1.93	0.79	0.00	1.00	0.00	7.69	3.86	48.40
ELKHEAD 4144 A 7H - A 7H	P-DP	0.08	0.10	0.64	6.44	2.09	0.85	0.00	1.08	0.00	8.31	4.39	44.68
ELKHEAD 4144 B 1H - B 1H	P-DP	0.08	0.05	0.29	6.28	0.96	0.39	0.00	0.74	0.00	6.89	3.59	43.54
ELKHEAD 4144 B 6H - B 6H	P-DP	0.05	0.06	0.40	3.49	1.32	0.54	0.00	0.64	0.00	4.71	2.47	36.11
ELKHEAD 4144 B 8H - B 8H	P-DP	0.05	0.05	0.33	3.51	1.09	0.45	0.00	0.58	0.00	4.47	2.49	42.55
ELKHEAD 4144 C 4H - C 4H	P-DP	0.06	0.06	0.37	4.58	1.22	0.50	0.00	0.69	0.00	5.61	2.96	38.86
ELKHEAD 4144 S 3H - S 3H	P-DP	0.06	0.03	0.22	4.58	0.71	0.29	0.00	0.54	0.00	5.03	2.64	45.15
ELUSIVE JAZZ 167-168 2HA - 2H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
ELY GAS UNIT NO. 2 1 - 1	P-DP	0.00	0.00	1.77	0.00	0.00	3.10	0.00	1.50	0.00	1.60	0.88	20.17
EMMA 218-219 UNIT 1H - 1H	P-DP	0.03	0.05	0.04	2.19	1.00	0.03	0.00	0.43	0.00	2.79	1.46	50.00
EP ENERGY 8-13-14-C5-1H - 8-1	P-DP	0.13	0.00	0.27	8.05	0.00	0.46	0.00	0.22	0.00	8.29	4.95	31.79
EP ENERGY 8-13-14-C5-2H - 8-1	P-DP	0.08	0.00	0.72	4.79	0.00	1.22	0.00	0.34	0.00	5.67	3.80	22.01
EP ENERGY 8-24-23-C5-2H - 8-2	P-DP	0.01	0.00	0.30	0.73	0.00	0.51	0.00	0.12	0.00	1.11	0.62	29.68
EP ENERGY 8-24-23-C5-3H - 8-2	P-DP	0.01	0.00	0.11	0.35	0.00	0.19	0.00	0.05	0.00	0.49	0.29	25.83
EPLEY, J. C. 9 - 9	P-DP	0.03	0.00	0.00	2.36	0.00	0.00	0.00	0.17	0.00	2.19	1.10	31.66

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
EUGENE L CONDOR NT243 - N	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EXTREME 210716 3A - 210716 3	P-DP	0.00	0.00	5.35	0.00	0.00	10.59	0.00	6.60	0.00	4.00	2.05	50.00
EXTREME 210716 4B - 210716 4	P-DP	0.00	0.00	4.35	0.00	0.00	8.62	0.00	5.37	0.00	3.25	2.32	11.78
FAIREY UNIT 1H - 1H	P-DP	0.31	0.00	0.00	23.05	0.00	0.00	0.00	1.92	0.00	21.13	12.33	18.59
FEARLESS 136-137 A 8WB - 8W	P-DP	0.92	0.19	0.94	69.80	4.21	1.26	0.00	6.64	0.00	68.62	33.25	50.00
FED W-18346 2-11 - 2-11	P-DP	0.01	0.01	0.96	0.68	0.17	4.24	0.00	0.71	0.00	4.39	1.37	50.00
FED W-18346 3-33 - 3-33	P-DP	0.00	0.00	0.10	0.19	0.02	0.42	0.00	0.08	0.00	0.55	0.37	11.27
FEDERAL W-7037 30-11 - 30-11	P-DP	0.00	0.00	0.78	0.26	0.14	3.44	0.00	0.55	0.00	3.29	1.96	16.34
FERGUSON 6 - 6	P-DP	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.01	0.00	50.00
FIELDS UNIT 1H - 1H	P-DP	0.35	0.39	1.95	26.02	7.13	3.79	0.00	3.25	0.00	33.69	16.60	50.00
FIELDS UNIT 2H - 2H	P-DP	0.24	0.26	1.27	17.53	4.64	2.46	0.00	2.16	0.00	22.46	10.94	44.86
FIELDS UNIT 3H - 3H	P-DP	0.12	0.11	0.55	8.59	2.01	1.07	0.00	1.02	0.00	10.65	6.21	32.12
FIELDS UNIT 4H - 4H	P-DP	0.15	0.45	2.25	10.99	8.20	4.36	0.00	2.16	0.00	21.38	10.49	47.78
FINLEY 1-11 WRD 1H - 1H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.58
FINLEY 1-11 WRD 2H - 2H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.54
FIRE EYES 47-38 1NA - 1NA	P-DP	0.30	0.07	0.43	22.56	1.93	0.84	0.00	2.03	0.00	23.30	13.02	50.00
FIRE EYES 47-38 1NS - 1NS	P-DP	0.21	0.04	0.22	15.66	1.00	0.44	0.00	1.34	0.00	15.76	8.87	50.00
FIRE EYES 47-38 3NA - 3NA	P-DP	0.21	0.06	0.33	16.08	1.46	0.64	0.00	1.47	0.00	16.71	9.41	50.00
FIRE EYES 47-38 3NS - 3NS	P-DP	0.11	0.03	0.19	8.33	0.85	0.37	0.00	0.78	0.00	8.78	4.97	49.18
FIRE EYES 47-38 4AH - 4AH	P-DP	0.24	0.02	0.11	18.02	0.51	0.22	0.00	1.40	0.00	17.36	7.69	50.00
FIRE EYES 47-38 4NS - 4NS	P-DP	0.11	0.02	0.12	8.01	0.53	0.23	0.00	0.69	0.00	8.09	4.67	47.30
FIRE FROG 57-32 A 1WA - 1WA	P-DP	0.11	0.04	0.04	8.27	0.89	0.03	0.00	0.94	0.00	8.24	4.56	48.60
FIRE FROG 57-32 B 2BS - 2BS	P-DP	0.23	0.00	0.10	16.96	0.05	0.07	0.00	1.80	0.00	15.28	7.96	50.00
FIRE FROG 57-32 C 3WA - 3WA	P-DP	0.15	0.00	0.05	11.49	0.03	0.04	0.00	1.18	0.00	10.37	5.58	50.00
FIRE FROG 57-32 D 4BS - 4BS	P-DP	0.21	0.00	0.11	16.09	0.06	0.07	0.00	1.76	0.00	14.46	7.84	50.00
FIRESTORM 54-1-12-13-24 AL1	P-DP	0.04	0.00	0.03	2.75	0.13	0.06	0.00	0.22	0.00	2.71	1.49	49.29
FIRESTORM 54-1-12-13-24 AL2	P-DP	0.04	0.01	0.04	2.93	0.16	0.07	0.00	0.24	0.00	2.91	1.61	50.00
FIRESTORM 54-1-12-13-24 AL3	P-DP	0.04	0.01	0.06	2.72	0.29	0.13	0.00	0.26	0.00	2.88	1.59	50.00
FIRESTORM 54-1-12-13-24 AL4	P-DP	0.03	0.01	0.04	2.43	0.20	0.09	0.00	0.22	0.00	2.49	1.43	46.84
FIRESTORM 54-1-12-13-24 AL5	P-DP	0.04	0.01	0.04	3.03	0.16	0.07	0.00	0.25	0.00	3.01	1.72	49.68
FIRESTORM 54-1-12-13-24 AL6	P-DP	0.04	0.01	0.06	3.32	0.27	0.12	0.00	0.30	0.00	3.41	1.95	48.08
FISHERMAN -A- 2 - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.62
FISHERMAN-BRISTOW 23A 1H	P-DP	0.80	0.21	1.02	60.59	4.60	1.37	0.00	6.13	0.00	60.43	36.16	42.29
FISHERMAN-BRISTOW 23B 2H	P-DP	0.70	0.16	0.79	53.17	3.54	1.06	0.00	5.19	0.00	52.57	30.83	41.51
FISHERMAN-BRISTOW 23C 3H	P-DP	0.88	0.23	1.12	66.83	5.06	1.51	0.00	6.75	0.00	66.64	37.61	45.07

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
FISHERMAN-BRISTOW 23D 4H	P-DP	1.16	0.38	1.87	87.70	8.42	2.51	0.00	9.54	0.00	89.08	49.45	50.00
FLAMING STAR 02-11 1SA - 1SA	P-DP	0.55	0.15	0.87	42.03	3.90	1.71	0.00	3.85	0.00	43.80	22.29	50.00
FLAMING STAR 02-11 1SS - 1SS	P-DP	0.39	0.06	0.34	29.81	1.51	0.66	0.00	2.46	0.00	29.53	15.24	50.00
FLAMING STAR 02-11 2SS - 2SS	P-DP	0.61	0.05	0.27	46.18	1.20	0.52	0.00	3.56	0.00	44.34	24.68	50.00
FLAMING STAR 02-11 3SA - 3SA	P-DP	0.60	0.09	0.51	45.63	2.28	1.00	0.00	3.76	0.00	45.16	24.97	50.00
FLAMING STAR 02-11 4AH - 4A	P-DP	0.03	0.16	0.95	1.99	4.24	1.85	0.00	1.06	0.00	7.02	3.51	36.00
FLAMING STAR 02-11 4SH - 4SH	P-DP	0.02	0.15	0.88	1.16	3.93	1.72	0.00	0.94	0.00	5.88	2.81	34.70
FLEMING 13 10H - 10H	P-DP	0.13	0.68	4.24	9.77	13.93	5.69	0.00	4.80	0.00	24.58	12.28	40.19
FLYING DUTCHMAN 1-13C5 - 1	P-DP	0.00	0.00	0.00	0.21	0.00	0.01	0.00	0.00	0.00	0.21	0.12	20.73
FORT KNOX 11-2 H 1LS - H 1LS	P-DP	0.03	0.03	0.19	2.20	0.84	0.37	0.00	0.34	0.00	3.07	1.62	38.06
FORT KNOX 11-2 H 1WA - H 1W	P-DP	0.09	0.02	0.09	6.69	0.40	0.18	0.00	0.57	0.00	6.70	3.42	50.00
FORT KNOX 11-2 H 1WB - H 1W	P-DP	0.06	0.03	0.17	4.72	0.77	0.34	0.00	0.50	0.00	5.32	2.71	46.32
FORT KNOX 11-2 H 2WA - H 2W	P-DP	0.06	0.06	0.35	4.87	1.55	0.68	0.00	0.68	0.00	6.42	3.61	46.59
FORT KNOX 11-2 H 2WB - H 2W	P-DP	0.05	0.07	0.42	3.62	1.87	0.82	0.00	0.66	0.00	5.65	2.75	48.61
FORT KNOX 11-2 R 2LS - R 2LS	P-DP	0.03	0.02	0.12	1.95	0.56	0.24	0.00	0.26	0.00	2.49	1.34	34.81
FORT KNOX 11-2-58EX H 3WA -	P-DP	0.11	0.04	0.25	8.18	1.13	0.49	0.00	0.83	0.00	8.97	4.71	50.00
FORT KNOX 11-2-58X H 3WB -	P-DP	0.05	0.03	0.16	4.01	0.73	0.32	0.00	0.45	0.00	4.61	2.51	43.03
FRED HALL UNIT 1 - 1	P-DP	0.03	0.01	0.03	2.26	0.14	0.03	0.00	0.25	0.00	2.18	1.21	25.25
FRED HALL UNIT 2 - 2	P-DP	0.03	0.03	0.11	2.32	0.54	0.11	0.00	0.44	0.00	2.52	1.54	24.48
FRED HALL UNIT 3 - 3	P-DP	0.05	0.04	0.16	3.52	0.84	0.16	0.00	0.68	0.00	3.84	2.10	31.79
FRYAR 18 2 - 2	P-DP	0.18	0.03	0.21	14.09	0.92	0.40	0.00	1.21	0.00	14.21	6.25	36.97
FRYING PAN A 22202 175-176 01	P-DP	0.00	0.00	0.00	0.34	0.03	0.00	0.00	0.05	0.00	0.33	0.20	50.00
FRYING PAN B 22202 175-176 02	P-DP	0.00	0.00	0.00	0.27	0.02	0.00	0.00	0.04	0.00	0.25	0.16	48.75
FULLER 1 - 1	P-DP	0.19	0.00	0.00	14.14	0.00	0.00	0.00	1.02	0.00	13.12	6.39	35.62
FUNKY BOSS B 8251H - 8251H	P-DP	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.02	0.01	49.27
FUNKY BOSS C 8270H - 8270H	P-DP	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.02	0.01	50.00
GADDIE 1-31 UNIT 1H - 1H	P-DP	0.08	0.02	0.02	5.85	0.53	0.02	0.00	0.64	0.00	5.75	3.10	36.12
GADDIE 1-31 UNIT 2H - 2H	P-DP	0.05	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.31
GADDIE 1-31 UNIT 3H - 3H	P-DP	0.02	0.00	0.00	1.24	0.00	0.00	0.00	0.11	0.00	1.13	0.62	21.43
GASTON 1 - 1	P-DP	0.00	0.00	0.39	0.00	0.00	0.55	0.00	0.05	0.00	0.50	0.30	50.00
GASTON 4 - 4	P-DP	0.00	0.00	3.33	0.00	0.00	4.68	0.00	0.44	0.00	4.24	2.17	50.00
GELETKA 1 - 1	P-DP	0.00	0.00	2.85	0.00	0.00	4.01	0.00	0.38	0.00	3.63	1.97	50.00
GENFIVE ENERGY LLC UNIT	P-DP	0.00	0.00	36.28	0.00	0.00	51.00	0.00	4.96	0.00	46.04	24.15	50.00
GEORGE T STAGG 5-2 UNIT 1H	P-DP	0.02	0.09	0.55	1.22	1.81	0.74	0.00	0.62	0.00	3.15	2.12	16.66
GEORGIA 39 1 - 1	P-DP	0.15	0.06	0.27	11.22	1.22	0.36	0.00	1.28	0.00	11.53	5.98	46.72

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
GERDES UNIT 1H - 1H	P-DP	0.04	0.03	0.15	3.28	0.55	0.29	0.00	0.36	0.00	3.77	1.94	50.00
GERDES UNIT 2H - 2H	P-DP	0.02	0.12	0.62	1.69	2.25	1.20	0.00	0.48	0.00	4.65	2.08	46.42
GERDES UNIT 3H - 3H	P-DP	0.08	0.26	1.29	6.05	4.72	2.51	0.00	1.22	0.00	12.05	5.89	37.10
GERDES UNIT 4H - 4H	P-DP	0.08	0.16	0.82	6.30	2.98	1.58	0.00	0.98	0.00	9.89	5.19	23.52
GERDES UNIT 5H - 5H	P-DP	0.53	0.20	0.99	39.54	3.60	1.91	0.00	3.83	0.00	41.22	22.36	22.84
GERDES UNIT 6H - 6H	P-DP	0.81	0.62	3.10	60.53	11.32	6.01	0.00	6.75	0.00	71.10	39.59	26.61
GERDES-LANGHOFF 1L - 1L	P-DP	0.19	0.05	0.27	14.34	0.99	0.52	0.00	1.34	0.00	14.51	7.67	50.00
GERDES-RATHKAMP 1L - 1L	P-DP	1.21	0.92	4.55	89.68	16.61	8.82	0.00	9.98	0.00	105.13	55.41	50.00
GILLESPIE UNIT 1H - 1H	P-DP	0.42	0.00	0.00	31.12	0.00	0.00	0.00	2.59	0.00	28.53	15.80	27.70
GINGER 22-27 1AH - 1AH	P-DP	0.18	0.04	0.26	14.04	1.16	0.51	0.00	1.26	0.00	14.46	6.89	50.00
GINGER 22-27 1MS - 1MS	P-DP	0.09	0.01	0.04	6.51	0.17	0.07	0.00	0.50	0.00	6.25	3.12	45.88
GINGER 22-27 2AH - 2AH	P-DP	0.18	0.06	0.37	13.51	1.64	0.72	0.00	1.32	0.00	14.54	6.96	50.00
GINGER 22-27 2SH - 2SH	P-DP	0.18	0.06	0.36	13.67	1.63	0.71	0.00	1.33	0.00	14.69	7.04	50.00
GIST '4' 1 - 1	P-DP	0.03	0.02	0.00	2.56	0.34	0.01	0.00	0.25	0.00	2.65	1.51	21.14
GIST '4' 4 - 4	P-DP	0.06	0.04	0.01	4.78	0.68	0.01	0.00	0.48	0.00	5.00	2.58	29.83
GLASS -Y- 1 - 1	P-DP	0.00	0.00	0.00	0.31	0.00	0.00	0.00	0.02	0.00	0.29	0.13	50.00
GLASS RANCH 19 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.90
GLASS RANCH 19 2HA - 2HA	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.39
GOERGEN 9-13-14-C5-3H - 9-13-	P-DP	0.12	0.00	0.94	7.23	0.00	1.60	0.00	0.46	0.00	8.37	4.69	32.70
GOERGEN 9-13-14-C5-4H - 9-13-	P-DP	0.08	0.00	1.39	5.00	0.00	2.38	0.00	0.60	0.00	6.78	4.23	27.21
GOLD LION 39-46 A 2DN - 2DN	P-DP	0.00	0.00	0.00	0.32	0.01	0.00	0.00	0.03	0.00	0.30	0.17	50.00
GOLD LION 39-46 B 6DN - 6DN	P-DP	0.00	0.00	0.00	0.11	0.01	0.00	0.00	0.01	0.00	0.10	0.06	50.00
GOLINSKI 4-24B5 - 4-24B5	P-DP	0.08	0.00	0.05	4.82	0.00	0.09	0.00	0.09	0.00	4.81	2.22	32.02
GORDON SE CRC JF 4H - 4H	P-DP	0.00	0.00	183.93	0.00	0.00	364.34	0.00	226.90	0.00	137.44	90.37	28.33
GORDON SE CRC JF 6H - 6H	P-DP	0.00	0.00	218.85	0.00	0.00	433.52	0.00	269.99	0.00	163.53	102.04	31.96
GORDON SW CRC JF 2H - 2H	P-DP	0.00	0.00	156.10	0.00	0.00	309.22	0.00	192.58	0.00	116.64	79.13	24.21
GRAFF 1 - 1	P-DP	0.00	0.00	0.96	0.00	0.00	1.35	0.00	0.13	0.00	1.22	0.85	50.00
GRANT 18A 4HK - 4HK	P-DP	0.07	0.02	0.09	5.30	0.40	0.18	0.00	0.47	0.00	5.41	3.13	31.41
GRANT 18B 5HJ - 5HJ	P-DP	0.13	0.04	0.26	9.80	1.15	0.51	0.00	0.95	0.00	10.51	6.07	37.91
GRANT 18B 6HK - 6HK	P-DP	0.15	0.06	0.33	11.70	1.47	0.65	0.00	1.16	0.00	12.67	7.23	40.13
GRANTHAM WEST 50-48 UNIT	P-DP	0.48	0.12	0.57	36.60	2.57	0.77	0.00	3.62	0.00	36.31	23.64	38.81
GRANTHAM WEST 50-48 UNIT	P-DP	0.01	0.01	0.05	0.89	0.25	0.07	0.00	0.16	0.00	1.05	0.90	5.12
GRANTHAM WEST 50-48 UNIT	P-DP	0.80	0.58	2.85	60.93	12.80	3.82	0.00	9.29	0.00	68.27	43.85	50.00
GRANTHAM WEST 50-48 UNIT	P-DP	0.63	0.95	4.61	48.09	20.73	6.19	0.00	11.39	0.00	63.62	39.76	50.00
GRANTHAM WEST 50-48 UNIT	P-DP	0.56	0.14	0.69	42.40	3.10	0.92	0.00	4.24	0.00	42.17	27.88	40.87

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
GRANTHAM WEST 50-48 UNIT	P-DP	0.37	0.11	0.55	27.74	2.46	0.73	0.00	2.94	0.00	27.99	18.33	36.45
GRANTHAM WEST 50-48 UNIT	P-DP	0.71	0.17	0.83	53.78	3.75	1.12	0.00	5.31	0.00	53.33	34.38	44.32
GRANTHAM WEST 50-48 UNIT	P-DP	0.24	0.24	1.15	17.89	5.15	1.54	0.00	3.26	0.00	21.32	14.36	30.17
GRANTHAM WEST 50-48 UNIT	P-DP	0.15	0.02	0.08	11.61	0.37	0.11	0.00	0.98	0.00	11.12	7.53	26.49
GRANTHAM WEST 50-48 UNIT	P-DP	0.45	0.33	1.61	34.05	7.23	2.16	0.00	5.22	0.00	38.23	24.04	47.45
GRANTHAM WEST 50-48 UNIT	P-DP	0.10	0.15	0.72	7.63	3.25	0.97	0.00	1.79	0.00	10.05	7.32	20.24
GRANTHAM WEST 50-48 UNIT	P-DP	0.25	0.19	0.93	19.16	4.17	1.24	0.00	2.97	0.00	21.60	14.78	30.84
GREER SIKES 42-41 E 251 - 251	P-DP	0.06	0.09	0.31	4.27	1.50	0.63	0.00	0.75	0.00	5.66	3.23	45.49
GREER SIKES 42-41 F 261 - 261	P-DP	0.07	0.41	1.43	5.58	6.85	2.86	0.00	2.27	0.00	13.02	6.34	50.00
GREER SIKES 42-41 F 262 - 262	P-DP	0.14	0.15	0.50	10.30	2.41	1.01	0.00	1.49	0.00	12.24	6.67	50.00
GREER SIKES 42-41 G 271 - 271	P-DP	0.12	0.17	0.58	9.11	2.76	1.15	0.00	1.48	0.00	11.54	6.10	50.00
GREER SIKES 42-41 G 272 - 272	P-DP	0.05	0.13	0.45	3.47	2.17	0.91	0.00	0.86	0.00	5.69	3.00	48.19
GREER SIKES 42-41 H 281 - 281	P-DP	0.04	0.07	0.23	2.73	1.12	0.47	0.00	0.52	0.00	3.79	2.32	37.37
GRIFFIN RANCH UNIT 23-31 1A	P-DP	0.22	0.02	0.13	16.53	0.59	0.26	0.00	1.31	0.00	16.06	8.67	50.00
GRIFFIN RANCH UNIT 23-31 1S	P-DP	0.15	0.03	0.18	11.57	0.79	0.34	0.00	1.00	0.00	11.70	6.05	50.00
GRIFFIN RANCH UNIT 23-31 2A	P-DP	0.10	0.02	0.13	7.81	0.60	0.26	0.00	0.69	0.00	7.98	4.30	50.00
GRIFFIN RANCH UNIT 23-31 2S	P-DP	0.11	0.04	0.24	8.16	1.09	0.48	0.00	0.82	0.00	8.90	4.64	50.00
GRIFFIN RANCH UNIT 23-31 3A	P-DP	0.15	0.03	0.16	11.34	0.72	0.32	0.00	0.97	0.00	11.41	5.93	50.00
GRIFFIN RANCH UNIT 23-31 3S	P-DP	0.05	0.07	0.41	3.78	1.84	0.81	0.00	0.67	0.00	5.76	3.07	47.60
GRISWOLD S WYN JF 4H - 4H	P-DP	0.00	0.00	69.02	0.00	0.00	136.73	0.00	85.15	0.00	51.58	33.50	26.35
GRISWOLD SW WYN JF 2H - 2H	P-DP	0.00	0.00	19.80	0.00	0.00	39.23	0.00	24.43	0.00	14.80	9.39	28.40
GRISWOLD WYN JF 6H - 6H	P-DP	0.00	0.00	124.72	0.00	0.00	247.06	0.00	153.86	0.00	93.20	58.62	26.40
GRISWOLD WYN JF 8H - 8H	P-DP	0.00	0.00	117.88	0.00	0.00	233.51	0.00	145.43	0.00	88.09	56.25	25.38
GRIZZLY BEAR 7780 2U A 2H -	P-DP	0.03	0.02	0.10	2.02	0.34	0.14	0.00	0.25	0.00	2.25	1.25	26.87
GRIZZLY BEAR 7780 3U A 3H -	P-DP	0.02	0.03	0.16	1.46	0.54	0.22	0.00	0.26	0.00	1.95	1.13	23.43
GRIZZLY BEAR 7780 4U A 4H -	P-DP	0.06	0.08	0.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.53
GRIZZLY BEAR 7780 5U A 5H -	P-DP	0.02	0.02	0.13	1.68	0.42	0.17	0.00	0.25	0.00	2.03	1.25	22.62
GRIZZLY BEAR 7780 6U A 6H -	P-DP	0.06	0.05	0.30	4.44	0.98	0.40	0.00	0.61	0.00	5.21	2.73	35.43
GRIZZLY SOUTH 7673 A 1H - A	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GRIZZLY SOUTH 7673 A 3H - A	P-DP	0.18	0.06	0.37	13.81	1.20	0.49	0.00	1.36	0.00	14.15	7.70	39.48
GRIZZLY SOUTH 7673 A 5H - A	P-DP	0.21	0.08	0.47	15.79	1.55	0.63	0.00	1.60	0.00	16.37	8.83	41.19
GRIZZLY SOUTH 7673 A 8H - A	P-DP	0.30	0.15	0.92	22.68	3.03	1.24	0.00	2.54	0.00	24.42	12.49	46.95
GRIZZLY SOUTH 7673 B 2H - B	P-DP	0.18	0.02	0.13	13.44	0.44	0.18	0.00	1.11	0.00	12.95	7.21	34.53
GRIZZLY SOUTH 7673 B 4H - B	P-DP	0.09	0.07	0.41	6.97	1.34	0.55	0.00	0.90	0.00	7.96	4.41	33.07
GRIZZLY SOUTH 7673 B 6H - B	P-DP	0.22	0.19	1.19	16.56	3.91	1.60	0.00	2.35	0.00	19.72	11.20	42.41

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
GRIZZLY WEST 77 1H - 1H	P-DP	0.07	0.06	0.38	5.47	1.25	0.51	0.00	0.76	0.00	6.47	3.54	31.95
GRIZZLY WEST 77 A 3H - A 3H	P-DP	0.04	0.01	0.06	2.69	0.19	0.08	0.00	0.25	0.00	2.71	1.62	24.13
GRIZZLY WEST 77 C 2H - C 2H	P-DP	0.03	0.02	0.12	2.34	0.38	0.16	0.00	0.28	0.00	2.59	1.44	24.15
GUARDIAN A 12-22 6SH - 6SH	P-DP	0.06	0.03	0.15	4.79	0.67	0.29	0.00	0.49	0.00	5.27	2.86	50.00
GUARDIAN UNIT 12-21 5AH - 5	P-DP	0.35	0.04	0.21	26.51	0.95	0.42	0.00	2.10	0.00	25.78	13.52	50.00
GUARDIAN UNIT 12-21 5SH - 5S	P-DP	0.11	0.04	0.23	8.69	1.04	0.46	0.00	0.85	0.00	9.34	5.16	49.77
GUARDIAN UNIT 12-21 6AH - 6	P-DP	0.19	0.03	0.19	14.62	0.83	0.36	0.00	1.23	0.00	14.59	7.93	50.00
GUARDIAN UNIT 12-22 4AH - 4	P-DP	0.30	0.09	0.52	22.51	2.33	1.02	0.00	2.11	0.00	23.74	12.89	50.00
GUARDIAN UNIT 12-22 4SH - 4S	P-DP	0.19	0.08	0.46	14.25	2.05	0.90	0.00	1.46	0.00	15.73	9.15	48.78
GUITAR 11 1 - 1	P-DP	0.00	0.00	0.02	0.36	0.08	0.03	0.00	0.04	0.00	0.42	0.33	6.95
GUITAR 13 1 - 1	P-DP	0.01	0.00	0.01	0.49	0.06	0.02	0.00	0.05	0.00	0.53	0.42	6.72
GUNNER C 3LS - 3LS	P-DP	0.01	0.00	0.01	0.40	0.04	0.02	0.00	0.04	0.00	0.42	0.24	43.29
GUNNER C 4A - 4A	P-DP	0.01	0.00	0.01	0.57	0.03	0.01	0.00	0.05	0.00	0.58	0.32	50.00
GUNNER D 5MS - 5MS	P-DP	0.01	0.00	0.02	0.48	0.09	0.04	0.00	0.05	0.00	0.55	0.30	47.44
GUNNER D 6LS - 6LS	P-DP	0.01	0.00	0.01	0.65	0.05	0.02	0.00	0.06	0.00	0.66	0.36	50.00
GUNSLINGER UNIT L 4H - L 4H	P-DP	0.06	0.01	0.03	4.22	0.15	0.07	0.00	0.33	0.00	4.10	2.47	40.58
GUNSMOKE 1-40 A 1JM - 1JM	P-DP	0.52	0.36	1.74	39.55	7.82	2.33	0.00	5.84	0.00	43.87	23.65	50.00
GUNSMOKE 1-40 B 2LS - 2LS	P-DP	0.31	0.17	0.84	23.27	3.78	1.13	0.00	3.12	0.00	25.05	12.96	50.00
GUNSMOKE 1-40 C 3WA - 3WA	P-DP	0.36	0.25	1.21	27.68	5.42	1.62	0.00	4.07	0.00	30.66	16.22	50.00
GUNSMOKE 1-40 D 4LB - 4LB	P-DP	0.27	0.35	1.68	20.30	7.57	2.26	0.00	4.36	0.00	25.77	13.80	50.00
GUNSMOKE 40-1 F 6LS - 6LS	P-DP	0.32	0.19	0.93	24.12	4.19	1.25	0.00	3.34	0.00	26.21	14.31	50.00
GUNSMOKE 40-1 G 7WA - 7WA	P-DP	0.24	0.27	1.32	18.21	5.92	1.77	0.00	3.57	0.00	22.32	12.81	46.84
GUNSMOKE 40-1 H 8WB - 8WB	P-DP	0.26	0.14	0.67	19.53	3.02	0.90	0.00	2.56	0.00	20.89	10.98	48.68
GUNSMOKE 40-1 I 9LS - 9LS	P-DP	0.36	0.06	0.30	27.22	1.36	0.40	0.00	2.48	0.00	26.50	14.37	49.08
GUNSMOKE 40-1 J 10WA - 10WA	P-DP	0.17	0.39	1.89	13.24	8.51	2.54	0.00	4.20	0.00	20.08	12.37	39.48
GUNSMOKE 40-1 K 11WB - 11W	P-DP	0.22	0.27	1.34	16.82	6.01	1.79	0.00	3.51	0.00	21.11	10.99	48.13
GUNSMOKE 40-1 L R009LS - R0	P-DP	0.29	0.19	0.94	22.21	4.23	1.26	0.00	3.22	0.00	24.49	13.80	49.51
GUY COWDEN UNIT 1 2502BH -	P-DP	0.12	0.12	0.47	9.10	2.38	0.47	0.00	1.86	0.00	10.09	5.96	50.00
GUY COWDEN UNIT 1 2504BH -	P-DP	0.12	0.12	0.46	8.90	2.32	0.46	0.00	1.82	0.00	9.85	5.85	50.00
GUY COWDEN UNIT 1 2514AH -	P-DP	0.16	0.12	0.47	11.97	2.36	0.47	0.00	2.09	0.00	12.71	7.20	50.00
GUY COWDEN UNIT 1 2571JH -	P-DP	0.13	0.05	0.21	9.99	1.07	0.21	0.00	1.32	0.00	9.96	5.80	50.00
GUY COWDEN UNIT 1 2573JH -	P-DP	0.06	0.01	0.05	4.74	0.28	0.05	0.00	0.52	0.00	4.55	2.60	50.00
GUY COWDEN UNIT 1 2575JH -	P-DP	0.12	0.04	0.14	9.47	0.71	0.14	0.00	1.11	0.00	9.22	5.39	50.00
GUY COWDEN UNIT 2 2505BH -	P-DP	0.03	0.01	0.04	2.08	0.19	0.04	0.00	0.26	0.00	2.05	1.08	30.13
GUY COWDEN UNIT 2 2506BH -	P-DP	0.03	0.14	0.52	2.23	2.66	0.52	0.00	1.44	0.00	3.97	2.31	27.62

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	Net Sales Volumes NGL (Mbbl)	Net Sales Volumes Residue Gas (MMcf)	Net Revenue Oil (M$)	Net Revenue NGL (M$)	Net Revenue Residue Gas (M$)	Net Revenue Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Cash Flow Disc. 10% (M$)	Life (years)
GUY COWDEN UNIT 2 2507BH -	*P-DP*	0.02	0.02	0.08	1.28	0.40	0.08	0.00	0.29	0.00	1.47	0.84	24.20
GUY COWDEN UNIT 2 2508BH -	*P-DP*	0.08	0.17	0.67	5.78	3.40	0.67	0.00	2.08	0.00	7.78	4.21	39.64
GUY COWDEN UNIT 2 2515AH -	*P-DP*	0.01	0.00	0.01	0.77	0.07	0.01	0.00	0.10	0.00	0.76	0.46	19.21
GUY COWDEN UNIT 2 2516AH -	*P-DP*	0.03	0.03	0.13	2.62	0.68	0.13	0.00	0.53	0.00	2.90	1.70	29.94
GUY COWDEN UNIT 2 2517AH -	*P-DP*	0.02	0.04	0.15	1.70	0.75	0.15	0.00	0.49	0.00	2.11	1.26	25.40
GUY COWDEN UNIT 2 2518AH -	*P-DP*	0.17	0.05	0.18	13.08	0.93	0.18	0.00	1.50	0.00	12.69	6.84	49.90
HA RA SU77;LEE 25-36 HC 001-	*P-DP*	0.00	0.00	9.40	0.00	0.00	19.22	0.00	10.89	0.00	8.33	5.43	21.21
HA RA SU98;ONEAL 8&17-14-16	*P-DP*	0.00	0.00	3.21	0.00	0.00	6.83	0.00	2.31	0.00	4.53	2.95	35.59
HA RA SU98;ONEAL 8&17-14-16	*P-DP*	0.00	0.00	4.03	0.00	0.00	8.58	0.00	2.90	0.00	5.69	3.67	38.42
HA RA SU98;PACE 8-14-16 H 001	*P-DP*	0.00	0.00	0.72	0.00	0.00	1.54	0.00	0.52	0.00	1.02	0.68	15.79
HA RA SUA;GOLSON 36-25 HC	*P-DP*	0.00	0.00	186.82	0.00	0.00	437.72	0.00	57.73	0.00	379.99	240.24	30.06
HA RA SUA;GOLSON 36-25 HC	*P-DP*	0.00	0.00	198.96	0.00	0.00	466.15	0.00	61.48	0.00	404.68	244.83	31.98
HA RA SUA;WIGGINS 36-25 HC	*P-DP*	0.00	0.00	24.21	0.00	0.00	56.72	0.00	7.48	0.00	49.24	35.01	14.18
HA RA SUB;LAWSON 31-30 HC	*P-DP*	0.00	0.00	11.70	0.00	0.00	27.41	0.00	3.61	0.00	23.79	16.18	22.31
HA RA SUB;LAWSON 31-30-19 H	*P-DP*	0.00	0.00	15.17	0.00	0.00	35.54	0.00	4.69	0.00	30.85	20.01	29.10
HA RA SUB;LAWSON 31-30-19 H	*P-DP*	0.00	0.00	17.59	0.00	0.00	41.22	0.00	5.44	0.00	35.78	24.10	28.51
HA RA SUL;L & L INV 18-19 HC	*P-DP*	0.00	0.00	1.09	0.00	0.00	2.56	0.00	0.34	0.00	2.22	1.73	12.69
HA RA SUL;L & L INV 18-19 HC	*P-DP*	0.00	0.00	2.00	0.00	0.00	4.69	0.00	0.62	0.00	4.07	2.76	21.37
HA RA SUL;SCHION 18-19 HC 0	*P-DP*	0.00	0.00	17.72	0.00	0.00	41.51	0.00	5.47	0.00	36.04	24.52	28.35
HA RA SUL;TALBERT 9-14-16 H	*P-DP*	0.00	0.00	0.54	0.00	0.00	1.15	0.00	0.39	0.00	0.76	0.46	18.07
HA RA SUS;MJR FAMLLC 21-39	*P-DP*	0.00	0.00	476.68	0.00	0.00	1,116.86	0.00	147.29	0.00	969.56	799.85	19.33
HA RA SUS;MJR FAMLLC21-28-	*P-DP*	0.00	0.00	583.07	0.00	0.00	1,366.14	0.00	180.17	0.00	1,185.97	937.16	27.43
HA RA SUS;MJR FAMLLC21-28-	*P-DP*	0.00	0.00	1,059.74	0.00	0.00	2,482.97	0.00	327.46	0.00	2,155.51	1,595.30	38.89
HA RA SUS;POOLE-DRAKE 21 H	*P-DP*	0.00	0.00	169.75	0.00	0.00	397.73	0.00	52.45	0.00	345.28	224.86	25.00
HA RA SUSS;JORDAN 16-21 HC	*P-DP*	0.00	0.00	0.05	0.00	0.00	0.10	0.00	0.03	0.00	0.07	0.06	4.52
HA RA SUTT;BSMC LA 21 HZ 00	*P-DP*	0.00	0.00	0.40	0.00	0.00	0.85	0.00	0.22	0.00	0.63	0.47	13.35
HA RA SUZ;GLOVER 20 001 - 00	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HA RA SUZ;GLOVER 20 002-AL	*P-DP*	0.00	0.00	8.13	0.00	0.00	19.06	0.00	2.51	0.00	16.54	9.32	26.01
HA RA SUZ;GLOVER 20 003-AL	*P-DP*	0.00	0.00	7.57	0.00	0.00	17.73	0.00	2.34	0.00	15.39	8.94	24.50
HA RA SUZ;JUNCACEAE 20 001	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HA RA SUZ;JUNCACEAE 20 002	*P-DP*	0.00	0.00	1.52	0.00	0.00	3.57	0.00	0.47	0.00	3.10	2.18	10.35
HA RA SUZ;JUNCACEAE 20 003	*P-DP*	0.00	0.00	0.93	0.00	0.00	2.18	0.00	0.29	0.00	1.90	1.51	6.49
HA RB SU69;NAC ROYALTY 33	*P-DP*	0.00	0.00	44.21	0.00	0.00	103.58	0.00	13.66	0.00	89.92	49.24	21.54
HA RB SU77;NAC ROYALTY 27-	*P-DP*	0.00	0.00	148.89	0.00	0.00	348.86	0.00	46.01	0.00	302.85	247.27	19.26
HA RB SU77;WAHL 27 H 001 - 0	*P-DP*	0.00	0.00	219.25	0.00	0.00	513.69	0.00	67.75	0.00	445.95	357.93	26.93

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
HA RB SU90;BYU PIERRE29-12-	P-DP	0.00	0.00	25.04	0.00	0.00	58.66	0.00	7.74	0.00	50.92	39.37	12.95
HA RB SU90;BYU PIERRE29-12-	P-DP	0.00	0.00	30.28	0.00	0.00	70.95	0.00	9.36	0.00	61.59	44.61	17.05
HA RB SU90;NRG 29-12-10 H 00	P-DP	0.00	0.00	23.37	0.00	0.00	54.74	0.00	7.22	0.00	47.53	31.76	18.43
HA RB SU90;NRG 29-12-10 H 00	P-DP	0.00	0.00	27.51	0.00	0.00	64.45	0.00	8.50	0.00	55.95	44.53	12.33
HA RB SU90;NRG 29-12-10 H 00	P-DP	0.00	0.00	31.18	0.00	0.00	73.06	0.00	9.64	0.00	63.42	48.64	14.40
HA RB SU92;NAC ROYALTY 34	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HA RB SU92;NAC ROYALTY 34	P-DP	0.00	0.00	897.43	0.00	0.00	2,102.67	0.00	277.31	0.00	1,825.37	1,463.01	24.43
HA RB SU92;NAC ROYALTY 34	P-DP	0.00	0.00	994.88	0.00	0.00	2,331.00	0.00	307.42	0.00	2,023.58	1,611.43	25.97
HA RB SUZZ;BIER 15&10-11-10	P-DP	0.00	0.00	2.38	0.00	0.00	5.12	0.00	1.33	0.00	3.79	2.85	25.14
HALL 18 1 - 1	P-DP	0.01	0.00	0.00	0.84	0.00	0.00	0.00	0.06	0.00	0.78	0.41	24.72
HALL 18 2 - 2	P-DP	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.06	0.05	5.26
HALL 18 3 - 3	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.41
HALL 18 4 - 4	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HALL TRUST 38 1 - 1	P-DP	0.13	0.05	0.27	9.99	1.20	0.36	0.00	1.18	0.00	10.37	6.04	24.27
HALL TRUST 38 2 - 2	P-DP	0.04	0.03	0.15	3.37	0.68	0.20	0.00	0.50	0.00	3.75	2.51	23.07
HALL-PORTER 621-596 UNIT 1 1	P-DP	0.02	0.02	0.08	1.61	0.41	0.08	0.00	0.32	0.00	1.78	1.18	14.73
HALL-PORTER 621-596 UNIT 1 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.75
HALL-PORTER 621-596 UNIT 1 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.16
HALL-PORTER 621-596 UNIT 1 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
HALL-PORTER 621-596 UNIT 1 2	P-DP	0.05	0.04	0.17	3.67	0.87	0.17	0.00	0.71	0.00	4.00	2.19	31.10
HALL-PORTER 621-596 UNIT 1 2	P-DP	0.04	0.03	0.13	3.38	0.68	0.13	0.00	0.59	0.00	3.60	2.04	29.13
HALL-PORTER 621-596 UNIT 1 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.25
HALL-PORTER 621-596 UNIT 1 2	P-DP	0.03	0.04	0.16	2.62	0.80	0.16	0.00	0.59	0.00	2.99	1.82	25.98
HALL-PORTER 621-596 UNIT 1 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.08
HALL-PORTER 621-596 UNIT 1 2	P-DP	0.05	0.04	0.15	3.56	0.75	0.15	0.00	0.65	0.00	3.82	2.25	23.43
HARA SUS;MJR FAMLLC 21-39	P-DP	0.00	0.00	380.68	0.00	0.00	891.93	0.00	117.63	0.00	774.30	584.89	26.12
HARGROVE, BETTY 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HARPER-BAYES 16 1 - 1	P-DP	0.02	0.00	0.01	1.45	0.03	0.01	0.00	0.12	0.00	1.38	0.71	42.97
HAWKS 55-1-28 UNIT 1H - 1H	P-DP	0.02	0.01	0.02	1.20	0.15	0.00	0.00	0.07	0.00	1.28	0.64	50.00
HEMLOCK 0409-03H - 0409-03H	P-DP	0.01	0.00	0.30	0.42	0.05	1.34	0.00	0.24	0.00	1.58	0.95	45.56
HEMLOCK 0409-04H - 0409-04H	P-DP	0.01	0.00	0.48	0.90	0.09	2.13	0.00	0.39	0.00	2.72	1.47	50.00
HEMLOCK 0409-14H - 0409-14H	P-DP	0.01	0.00	0.34	1.00	0.06	1.48	0.00	0.30	0.00	2.24	1.32	46.55
HEMLOCK 0409-15H - 0409-15H	P-DP	0.01	0.00	0.32	0.94	0.06	1.42	0.00	0.29	0.00	2.13	1.24	47.20
HEMLOCK 0409-16H - 0409-16H	P-DP	0.03	0.00	0.65	2.53	0.11	2.86	0.00	0.62	0.00	4.88	2.67	50.00
HENDERSHOT 210471 1A - 1A	P-DP	0.00	0.00	1.46	0.00	0.00	2.98	0.00	0.26	0.00	2.72	1.61	39.67

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
HENDERSHOT 210471 2B - 2B	P-DP	0.00	0.00	1.78	0.00	0.00	3.65	0.00	0.32	0.00	3.33	1.86	43.67
HENDERSHOT 210501 6A-M - 6	P-DP	2.02	0.00	107.77	135.21	0.00	220.37	0.00	30.66	0.00	324.92	199.96	50.00
HENDERSHOT 211824 5A-M - 5	P-DP	4.03	0.00	31.85	270.57	0.00	65.13	0.00	28.61	0.00	307.08	208.75	46.51
HEREFORD 29 20 W1NC STATE	P-DP	1.21	0.02	0.98	92.05	0.48	1.11	0.00	12.62	0.00	81.02	41.44	50.00
HIGGINBOTHAM UNIT A 30-18	P-DP	0.16	0.00	0.98	11.59	0.05	3.27	0.00	1.35	0.00	13.56	7.16	47.52
HIGGINBOTHAM UNIT A 30-18	P-DP	0.11	0.00	0.11	7.90	0.01	0.35	0.00	0.62	0.00	7.64	3.90	40.18
HIGGINBOTHAM UNIT A 30-18	P-DP	0.09	0.00	0.10	6.68	0.01	0.34	0.00	0.53	0.00	6.49	3.48	37.50
HIGGINBOTHAM UNIT B 30-19	P-DP	0.21	0.00	0.13	15.68	0.01	0.45	0.00	1.19	0.00	14.95	7.38	50.00
HIGGINBOTHAM UNIT B 30-19	P-DP	0.07	0.00	0.77	5.17	0.04	2.57	0.00	0.78	0.00	7.00	3.54	37.74
HIGGINBOTHAM UNIT C 30-18	P-DP	0.10	0.00	0.59	7.49	0.03	1.98	0.00	0.85	0.00	8.65	4.68	41.34
HIGGINBOTHAM UNIT C 30-18	P-DP	0.12	0.00	0.48	8.76	0.02	1.61	0.00	0.88	0.00	9.51	4.89	43.51
HOCHSTETLER 7-11-5 5H - 5H	P-DP	0.01	5.46	62.16	0.84	111.24	128.43	0.00	208.30	0.00	32.21	17.02	50.00
HOERMANN UNIT 1H - 1H	P-DP	0.01	0.00	0.01	0.45	0.05	0.03	0.00	0.04	0.00	0.48	0.28	19.64
HOERMANN UNIT 2H - 2H	P-DP	0.14	0.09	0.45	10.25	1.65	0.88	0.00	1.10	0.00	11.67	6.69	36.42
HOERMANN UNIT 3H - 3H	P-DP	0.91	0.53	2.63	67.64	9.60	5.10	0.00	7.08	0.00	75.27	38.17	50.00
HOERMANN UNIT 4H - 4H	P-DP	0.73	0.29	1.42	54.66	5.18	2.75	0.00	5.33	0.00	57.26	28.15	35.13
HOERMANN-KOLM 1H - 1H	P-DP	0.39	0.16	0.82	28.81	2.98	1.58	0.00	2.85	0.00	30.52	17.26	50.00
HOERMANN-KOLM 201H - 201	P-DP	0.30	0.16	0.80	22.47	2.92	1.55	0.00	2.31	0.00	24.63	13.97	46.86
HOERMANN-KOLM A 2H - 2H	P-DP	2.01	1.66	8.22	149.47	29.98	15.93	0.00	16.99	0.00	178.39	141.31	36.61
HOERMANN-KOLM B 3H - 3H	P-DP	3.34	2.75	13.67	248.50	49.87	26.49	0.00	28.25	0.00	296.61	233.96	42.65
HOERMANN-LANGHOFF B 1H -	P-DP	0.64	0.62	3.05	47.96	11.14	5.92	0.00	5.68	0.00	59.34	35.27	50.00
HOERMANN-LANGHOFF B 201	P-DP	1.00	1.37	6.83	74.28	24.90	13.23	0.00	9.97	0.00	102.44	57.84	50.00
HOERMANN-LANGHOFF B A 2	P-DP	0.26	0.33	1.64	19.47	5.98	3.18	0.00	2.53	0.00	26.10	15.54	41.40
HOFFERKAMP 1 - 1	P-DP	0.01	0.00	0.00	0.40	0.02	0.00	0.00	0.04	0.00	0.39	0.17	40.29
HONEY BEE A 20-29 4201H - 420	P-DP	0.04	0.01	0.04	3.38	0.21	0.09	0.00	0.34	0.00	3.34	2.23	32.75
HONEY BEE C 20-29 4303H - 43	P-DP	0.07	0.14	0.49	5.53	2.35	0.98	0.00	1.08	0.00	7.79	4.57	48.35
HONEY BEE E 20-29 4205H - 42	P-DP	0.04	0.03	0.12	3.37	0.56	0.23	0.00	0.43	0.00	3.73	2.47	32.47
HONEY BEE E 20-29 4405H - 44	P-DP	0.05	0.15	0.53	4.06	2.53	1.06	0.00	1.00	0.00	6.65	3.83	49.94
HONEY BEE G 20-29 4307H - 43	P-DP	0.08	0.09	0.33	5.90	1.57	0.66	0.00	0.90	0.00	7.22	4.38	40.97
HONOR 41-2728-23R - 41-2728-2	P-DP	0.10	0.00	0.15	6.07	0.00	0.26	0.00	0.15	0.00	6.18	4.63	21.69
HONOR 51-2728-23O - 51-2728-2	P-DP	0.53	0.00	0.29	31.92	0.00	0.50	0.00	0.58	0.00	31.83	17.19	50.00
HONOR 71-2728-23G - 71-2728-2	P-DP	0.45	0.00	0.25	27.02	0.00	0.42	0.00	0.49	0.00	26.95	14.63	50.00
HORNSILVER 1H - 1H	P-DP	0.02	0.03	0.03	1.48	0.65	0.02	0.00	0.29	0.00	1.87	0.96	42.76
HOUSE 47 1 - 1	P-DP	0.35	0.07	0.27	26.83	1.38	0.27	0.00	2.83	0.00	25.65	13.53	34.26
HUBBARD 18-B 2 - 2	P-DP	0.04	0.00	0.00	3.36	0.00	0.00	0.00	0.28	0.00	3.08	1.20	44.21

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
HULING 'A' 18-7 ESL (ALLOC) 1	P-DP	0.03	0.01	0.00	2.23	0.27	0.00	0.00	0.22	0.00	2.29	1.46	27.29
HULING 'D' 18-7 ESL (ALLOC) 4	P-DP	0.01	0.00	0.00	0.62	0.08	0.00	0.00	0.06	0.00	0.64	0.44	15.24
HULING 7-19 B 221 - 221	P-DP	0.16	0.11	0.03	11.90	2.05	0.03	0.00	1.23	0.00	12.76	7.77	42.41
HULING 7-19 D 241 - 241	P-DP	0.12	0.03	0.01	8.82	0.63	0.01	0.00	0.81	0.00	8.66	5.39	39.23
HUTCHINS CHIODO 13-21-22-C	P-DP	0.04	0.00	0.71	2.32	0.00	1.21	0.00	0.30	0.00	3.23	1.74	32.26
HUTCHINS-CHIODO 12-21-22-C	P-DP	0.05	0.00	0.32	3.00	0.00	0.54	0.00	0.16	0.00	3.38	1.61	33.22
HYDEN UNIT 47-35 1H - 1H	P-DP	0.08	0.04	0.22	6.33	0.99	0.43	0.00	0.67	0.00	7.09	3.44	46.18
HYDEN UNIT 47-35 1SH - 1SH	P-DP	0.08	0.01	0.03	6.13	0.16	0.07	0.00	0.47	0.00	5.88	3.21	42.78
HYDEN UNIT 47-35 2AH - 2AH	P-DP	0.17	0.02	0.14	12.94	0.63	0.28	0.00	1.06	0.00	12.78	7.22	50.00
HYDEN UNIT 47-35 2SH - 2SH	P-DP	0.17	0.01	0.07	13.17	0.31	0.13	0.00	1.01	0.00	12.60	6.99	50.00
HYDEN UNIT 47-35 3AH - 3AH	P-DP	0.24	0.02	0.10	18.32	0.47	0.21	0.00	1.41	0.00	17.59	9.93	50.00
HYDRA 45-4 UNIT 1 112 - 112	P-DP	0.09	0.09	0.43	6.78	1.91	0.57	0.00	1.22	0.00	8.05	4.44	44.26
HYDRA 45-4 UNIT 1 122 - 122	P-DP	0.08	0.08	0.37	5.85	1.69	0.50	0.00	1.07	0.00	6.97	3.81	42.87
HYDRA 45-4 UNIT 1 124 - 124	P-DP	0.13	0.13	0.61	9.61	2.76	0.82	0.00	1.75	0.00	11.45	6.15	50.00
HYDRA 45-4 UNIT 1 132 - 132	P-DP	0.14	0.17	0.84	10.27	3.77	1.13	0.00	2.18	0.00	12.98	6.93	50.00
HYDRA 45-4 UNIT 1 142 - 142	P-DP	0.08	0.07	0.36	6.30	1.61	0.48	0.00	1.07	0.00	7.32	4.01	43.33
HYDRA 45-4 UNIT 1 211 - 211	P-DP	0.11	0.11	0.52	7.99	2.33	0.69	0.00	1.46	0.00	9.54	5.20	46.49
HYDRA 45-4 UNIT 1 221 - 221	P-DP	0.20	0.04	0.22	14.99	0.98	0.29	0.00	1.46	0.00	14.81	8.01	50.00
HYDRA 45-4 UNIT 1 223 - 223	P-DP	0.12	0.14	0.68	9.16	3.08	0.92	0.00	1.84	0.00	11.32	6.01	50.00
HYDRA 45-4 UNIT 1 231 - 231	P-DP	0.08	0.07	0.36	6.28	1.60	0.48	0.00	1.07	0.00	7.30	4.00	43.26
HYDRA 45-4 UNIT 1 241 - 241	P-DP	0.15	0.15	0.72	11.59	3.26	0.97	0.00	2.08	0.00	13.74	7.36	50.00
HYDRA 45-4 UNIT 2 151 - 151	P-DP	0.12	0.07	0.34	9.30	1.53	0.46	0.00	1.25	0.00	10.03	5.79	45.58
HYDRA 45-4 UNIT 2 161 - 161	P-DP	0.08	0.10	0.50	5.75	2.25	0.67	0.00	1.27	0.00	7.40	4.16	42.04
HYDRA 45-4 UNIT 2 164 - 164	P-DP	0.15	0.11	0.55	11.61	2.47	0.74	0.00	1.78	0.00	13.04	7.39	49.19
HYDRA 45-4 UNIT 2 171 - 171	P-DP	0.06	0.07	0.36	4.67	1.61	0.48	0.00	0.95	0.00	5.81	3.32	37.99
HYDRA 45-4 UNIT 2 173 - 173	P-DP	0.18	0.09	0.45	13.42	2.01	0.60	0.00	1.74	0.00	14.29	8.10	50.00
HYDRA 45-4 UNIT 2 181 - 181	P-DP	0.07	0.10	0.51	5.06	2.29	0.68	0.00	1.24	0.00	6.79	3.82	41.08
HYDRA 45-4 UNIT 2 262 - 262	P-DP	0.20	0.11	0.52	14.83	2.33	0.70	0.00	1.96	0.00	15.90	8.75	50.00
HYDRA 45-4 UNIT 2 263 - 263	P-DP	0.03	0.11	0.55	2.52	2.46	0.73	0.00	1.12	0.00	4.60	2.69	33.31
HYDRA 45-4 UNIT 2 272 - 272	P-DP	0.14	0.11	0.54	10.34	2.42	0.72	0.00	1.67	0.00	11.81	6.69	48.13
HYDRA 45-4 UNIT 2 274 - 274	P-DP	0.04	0.14	0.69	3.12	3.12	0.93	0.00	1.42	0.00	5.76	3.30	35.72
HYDRA 45-4 UNIT 2 282 - 282	P-DP	0.15	0.10	0.47	11.43	2.09	0.62	0.00	1.62	0.00	12.53	7.14	48.54
IORG 4-12B3 - 4-12B3	P-DP	0.20	0.00	0.24	12.03	0.00	0.40	0.00	0.27	0.00	12.17	5.09	50.00
JACKSON A 34-166-175 5201H -	P-DP	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	50.00
JANAK UNIT 3H - 3H	P-DP	0.28	0.13	0.66	20.81	2.40	1.27	0.00	2.09	0.00	22.38	11.71	27.12

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
JANAK UNIT 4H - 4H	P-DP	0.42	0.40	2.01	31.32	7.32	3.89	0.00	3.72	0.00	38.81	22.30	18.73
JANAK UNIT 5H - 5H	P-DP	0.33	0.42	2.10	24.24	7.65	4.06	0.00	3.18	0.00	32.77	16.62	50.00
JANAK UNIT 7L - 7L	P-DP	0.31	0.34	1.67	22.71	6.11	3.24	0.00	2.82	0.00	29.24	17.35	33.39
JANAK-LOOS 6L - 6L	P-DP	0.44	0.49	2.43	32.78	8.86	4.70	0.00	4.07	0.00	42.26	23.93	46.52
JENKINS 2-12B3 - 2-12B3	P-DP	0.08	0.00	0.02	5.11	0.00	0.03	0.00	0.08	0.00	5.06	3.67	10.69
JERSEY 35-23-A 4401H - 4401H	P-DP	0.05	0.02	0.00	4.17	0.37	0.01	0.00	0.39	0.00	4.15	2.05	50.00
JERSEY 35-23-B 4203H - 4203H	P-DP	0.03	0.01	0.00	1.92	0.15	0.00	0.00	0.18	0.00	1.90	0.89	50.00
JERSEY 35-23-C 4305H - 4305H	P-DP	0.02	0.01	0.00	1.31	0.25	0.00	0.00	0.14	0.00	1.43	0.74	50.00
JERSEY 35-23-H 4215H - 4215H	P-DP	0.01	0.00	0.00	1.08	0.09	0.00	0.00	0.10	0.00	1.07	0.57	49.18
JERSEY 35-23-H 4315H - 4315H	P-DP	0.01	0.00	0.00	0.93	0.07	0.00	0.00	0.09	0.00	0.91	0.47	50.00
JH SELMAN ALLOCATION A 26-	P-DP	0.02	0.00	0.03	1.81	0.00	0.11	0.00	0.15	0.00	1.77	1.01	46.88
JH SELMAN ALLOCATION B 26-	P-DP	0.03	0.00	0.05	2.33	0.00	0.18	0.00	0.19	0.00	2.32	1.25	50.00
JMW NAIL 10 1 - 1	P-DP	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.01	0.00	0.04	0.03	13.52
JMW NAIL 10 2 - 2	P-DP	0.00	0.00	0.00	0.06	0.02	0.00	0.00	0.01	0.00	0.07	0.04	16.90
JMW NAIL 10A 3 - 3	P-DP	0.00	0.00	0.00	0.08	0.02	0.01	0.00	0.01	0.00	0.10	0.06	18.95
JMW NAIL 10A 4 - 4	P-DP	0.00	0.00	0.01	0.20	0.02	0.01	0.00	0.02	0.00	0.21	0.11	29.16
JOHN F FERGUSON 1 - 1	P-DP	0.00	0.00	0.10	0.00	0.00	0.14	0.00	0.01	0.00	0.13	0.11	50.00
JOHN F FERGUSON 2 - 2	P-DP	0.00	0.00	0.25	0.00	0.00	0.36	0.00	0.03	0.00	0.32	0.14	50.00
JOHN F. FERGUSON 4 - 4	P-DP	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.01	0.01	50.00
JOTUNN UNIT A 25-24 3AH - 3A	P-DP	0.12	0.00	1.30	8.57	0.07	4.35	0.00	1.31	0.00	11.68	5.79	41.53
JOTUNN UNIT A 25-24 4AH - 4A	P-DP	0.17	0.00	0.90	12.84	0.05	3.00	0.00	1.40	0.00	14.49	7.62	45.02
JOTUNN UNIT A 25-24 5AH - 5A	P-DP	0.10	0.00	1.04	7.14	0.05	3.48	0.00	1.07	0.00	9.61	5.24	37.83
JOTUNN UNIT B 25-13 6AH - 6A	P-DP	0.21	0.00	0.91	15.16	0.05	3.03	0.00	1.57	0.00	16.67	8.40	49.81
JOTUNN UNIT B 25-13 7AH - 7A	P-DP	0.15	0.00	1.06	11.07	0.05	3.53	0.00	1.36	0.00	13.31	6.72	46.38
JOYCE 1 - 1	P-DP	0.00	0.00	0.48	0.00	0.00	0.68	0.00	0.06	0.00	0.62	0.41	50.00
JUDY '16' 1 - 1	P-DP	0.01	0.00	0.00	0.42	0.00	0.00	0.00	0.03	0.00	0.39	0.24	22.08
JUR RA SUG;OLYMPIA MIN 30	P-DP	0.00	0.00	0.34	0.00	0.00	0.69	0.00	0.39	0.00	0.30	0.23	6.96
KAISER UNIT 1H - 1H	P-DP	0.12	0.18	0.90	8.69	3.29	1.75	0.00	1.22	0.00	12.50	7.06	28.41
KAISER UNIT 4H - 4H	P-DP	0.23	0.50	2.50	16.91	9.11	4.84	0.00	2.79	0.00	28.07	14.25	45.22
KAISER UNIT 5H - 5H	P-DP	0.37	0.20	1.02	27.62	3.71	1.97	0.00	2.86	0.00	30.43	14.48	50.00
KEELINE 2-13 - 2-13	P-DP	0.22	0.01	1.36	16.31	0.24	5.99	0.00	2.10	0.00	20.44	8.02	42.99
KEMPER 16 1 - 1	P-DP	0.00	0.00	0.00	0.32	0.00	0.00	0.00	0.02	0.00	0.30	0.16	27.82
KEMPER 16 2 - 2	P-DP	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.01	0.00	0.09	0.06	13.46
KEMPER 16A 1 - 1	P-DP	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.01	0.00	0.02	0.02	5.40
KEMPER 16A 3 - 3	P-DP	0.00	0.00	0.02	0.15	0.08	0.02	0.00	0.04	0.00	0.22	0.15	11.92

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
KENOSHA 4441 1H - 1H	P-DP	0.07	0.07	0.45	5.22	1.46	0.60	0.00	0.81	0.00	6.48	3.42	42.00
KENOSHA 4441 B 2H - B 2H	P-DP	0.07	0.09	0.56	5.35	1.84	0.75	0.00	0.93	0.00	7.01	3.59	50.00
KENOSHA-KEYHOLE 4341 1U A	P-DP	0.13	0.10	0.59	9.80	1.95	0.80	0.00	1.29	0.00	11.26	6.40	50.00
KENOSHA-KEYHOLE 4341 2U B	P-DP	0.07	0.09	0.57	5.18	1.86	0.76	0.00	0.92	0.00	6.88	4.13	44.11
KENTEX-HARRISON 35A 1H - 1	P-DP	1.11	0.28	1.36	84.17	6.12	1.83	0.00	8.41	0.00	83.70	44.40	50.00
KENTEX-HARRISON 35B 2H - 2	P-DP	0.99	0.37	1.80	74.90	8.10	2.42	0.00	8.50	0.00	76.92	40.63	46.34
KENTEX-HARRISON 35C 3H - 3	P-DP	1.11	0.27	1.34	83.99	6.02	1.80	0.00	8.36	0.00	83.44	42.87	48.56
KENTEX-HARRISON 35D 4H - 4	P-DP	0.55	0.29	1.42	42.05	6.38	1.90	0.00	5.47	0.00	44.86	24.74	45.56
KEYHOLE 43 1H - 1H	P-DP	0.07	0.01	0.04	5.17	0.13	0.05	0.00	0.41	0.00	4.93	2.35	48.09
KILLER BEE I 8-44 4209H - 4209	P-DP	0.14	0.10	0.33	10.70	1.58	0.66	0.00	1.31	0.00	11.64	7.02	50.00
KILLER BEE J 8-44 4310H - 4310	P-DP	0.15	0.07	0.24	11.06	1.13	0.47	0.00	1.21	0.00	11.44	7.01	50.00
KILLER BEE K 8-44 4411HR - 44	P-DP	0.12	0.12	0.40	9.23	1.92	0.80	0.00	1.27	0.00	10.69	6.34	50.00
KILLER BEE M 8-44 4213H - 421	P-DP	0.13	0.09	0.33	9.54	1.57	0.66	0.00	1.21	0.00	10.56	6.33	50.00
KILLER BEE N 8-44 4314H - 431	P-DP	0.15	0.14	0.49	11.17	2.35	0.98	0.00	1.55	0.00	12.96	7.70	50.00
KINGSLEY 10HK - 10HK	P-DP	0.22	0.05	0.32	16.53	1.42	0.62	0.00	1.49	0.00	17.08	9.21	50.00
KINGSLEY 1HJ - 1HJ	P-DP	0.21	0.06	0.36	16.21	1.60	0.70	0.00	1.50	0.00	17.00	9.21	45.30
KINGSLEY 2HF - 2HF	P-DP	0.26	0.05	0.32	20.04	1.42	0.62	0.00	1.74	0.00	20.35	11.38	46.59
KINGSLEY 3HK - 3HK	P-DP	0.17	0.07	0.44	12.72	1.95	0.86	0.00	1.33	0.00	14.20	8.17	43.49
KINGSLEY 4HJ - 4HJ	P-DP	0.67	0.19	1.14	51.36	5.10	2.23	0.00	4.78	0.00	53.91	29.99	46.51
KINGSLEY 5HK - 5HK	P-DP	0.64	0.22	1.31	48.60	5.87	2.57	0.00	4.75	0.00	52.29	27.21	49.28
KINGSLEY 6HF - 6HF	P-DP	0.56	0.28	1.63	43.01	7.30	3.20	0.00	4.66	0.00	48.85	26.78	47.42
KINGSLEY 7HJ - 7HJ	P-DP	0.21	0.05	0.31	15.84	1.40	0.61	0.00	1.44	0.00	16.42	8.82	49.41
KINGSLEY 8HK - 8HK	P-DP	0.18	0.05	0.27	13.82	1.22	0.53	0.00	1.25	0.00	14.32	7.74	46.74
KINGSLEY 9HJ - 9HJ	P-DP	0.19	0.04	0.22	14.67	0.99	0.43	0.00	1.26	0.00	14.83	7.92	48.10
KODIAK 7677 1U B 1H - B 1H	P-DP	0.07	0.02	0.13	5.01	0.43	0.17	0.00	0.49	0.00	5.12	2.82	41.75
KODIAK 7677 2U B 2H - B 2H	P-DP	0.04	0.03	0.19	3.16	0.62	0.25	0.00	0.41	0.00	3.62	1.98	38.33
KODIAK 7677 3U A 3H - A 3H	P-DP	0.11	0.04	0.23	8.25	0.76	0.31	0.00	0.82	0.00	8.49	4.43	48.70
KODIAK 7677 4U A 4H - A 4H	P-DP	0.06	0.01	0.07	4.49	0.24	0.10	0.00	0.40	0.00	4.43	2.50	39.66
KOFFORD 2-36B5 - 2-36B5	P-DP	0.00	0.00	0.01	0.11	0.00	0.01	0.00	0.00	0.00	0.12	0.09	5.51
KOOS 1 - 1	P-DP	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.01	0.01	50.00
KOOS 2 - 2	P-DP	0.00	0.00	1.35	0.00	0.00	1.89	0.00	0.18	0.00	1.72	1.02	50.00
KRAKEN 10-3 E1 251 - 251	P-DP	0.02	0.07	0.41	1.68	1.84	0.80	0.00	0.52	0.00	3.80	2.31	23.33
KRAKEN 10-3 UNIT 2 153 - 153	P-DP	0.13	0.06	0.37	9.57	1.65	0.72	0.00	1.04	0.00	10.90	5.66	44.41
KRAKEN 10-3 UNIT 2 162 - 162	P-DP	0.18	0.08	0.44	13.40	1.99	0.87	0.00	1.39	0.00	14.87	7.81	47.75
KRAKEN 10-3 UNIT 2 171 - 171	P-DP	0.17	0.07	0.44	13.22	1.95	0.85	0.00	1.37	0.00	14.66	7.69	47.62

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
KRAKEN 10-3 UNIT 2 181 - 181	P-DP	0.18	0.12	0.57	13.99	2.55	0.76	0.00	1.98	0.00	15.32	7.98	48.62
KRAKEN 10-3 UNIT 2 183 - 183	P-DP	0.09	0.13	0.63	6.85	2.85	0.85	0.00	1.58	0.00	8.97	4.87	42.01
KRAKEN 10-3 UNIT 2 252 - 252	P-DP	0.08	0.02	0.13	6.29	0.56	0.25	0.00	0.57	0.00	6.53	3.67	32.59
KRAKEN 10-3 UNIT 2 261 - 261	P-DP	0.11	0.07	0.40	8.56	1.80	0.79	0.00	1.00	0.00	10.15	5.49	42.83
KRAKEN 10-3 UNIT 2 272 - 272	P-DP	0.16	0.11	0.64	12.24	2.86	1.25	0.00	1.50	0.00	14.86	7.71	48.04
KRAKEN 10-3 UNIT 2 273 - 273	P-DP	0.06	0.08	0.38	4.41	1.73	0.52	0.00	0.98	0.00	5.68	3.08	37.13
KRAKEN 10-3 UNIT 2 282 - 282	P-DP	0.21	0.12	0.57	15.80	2.58	0.77	0.00	2.12	0.00	17.02	8.95	49.62
KRONOS 61-7 E1 151 - 151	P-DP	0.97	0.20	0.96	73.71	4.31	1.29	0.00	6.97	0.00	72.34	42.43	50.00
KRONOS 61-7 E1 252 - 252	P-DP	0.46	0.40	1.97	35.10	8.83	2.64	0.00	5.91	0.00	40.66	21.62	50.00
KRONOS 61-7 UNIT 2 153 - 153	P-DP	1.56	0.92	4.48	118.21	20.13	6.01	0.00	16.22	0.00	128.13	73.14	50.00
KRONOS 61-7 UNIT 2 154 - 154	P-DP	0.07	0.07	0.34	5.21	1.53	0.46	0.00	0.96	0.00	6.24	4.17	18.30
KRONOS 61-7 UNIT 2 161 - 161	P-DP	1.82	1.22	5.94	138.37	26.70	7.97	0.00	20.18	0.00	152.86	87.11	50.00
KRONOS 61-7 UNIT 2 163 - 163	P-DP	1.50	0.76	3.68	113.80	16.54	4.94	0.00	14.53	0.00	120.74	69.44	50.00
KRONOS 61-7 UNIT 2 171 - 171	P-DP	0.17	0.12	0.58	12.84	2.62	0.78	0.00	1.93	0.00	14.32	8.78	29.68
KRONOS 61-7 UNIT 2 173 - 173	P-DP	1.67	1.19	5.79	127.06	26.04	7.77	0.00	19.12	0.00	141.76	80.56	50.00
KRONOS 61-7 UNIT 2 181 - 181	P-DP	1.86	1.07	5.22	140.86	23.48	7.01	0.00	19.13	0.00	152.22	87.02	50.00
KRONOS 61-7 UNIT 2 182 - 182	P-DP	0.28	0.16	0.80	21.61	3.61	1.08	0.00	2.94	0.00	23.36	13.80	33.02
KRONOS 61-7 UNIT 2 255 - 255	P-DP	1.21	2.35	11.45	91.71	51.49	15.37	0.00	26.28	0.00	132.28	76.41	50.00
KRONOS 61-7 UNIT 2 262 - 262	P-DP	1.21	1.59	7.72	91.53	34.70	10.36	0.00	19.86	0.00	116.73	65.72	50.00
KRONOS 61-7 UNIT 2 272 - 272	P-DP	2.36	1.17	5.71	179.44	25.66	7.66	0.00	22.75	0.00	190.00	108.52	50.00
KRONOS 61-7 UNIT 2 274 - 274	P-DP	0.81	1.92	9.34	61.49	41.96	12.53	0.00	20.47	0.00	95.51	52.03	50.00
KRONOS 61-7 UNIT 2 283 - 283	P-DP	1.84	1.07	5.22	139.55	23.45	7.00	0.00	19.03	0.00	150.98	89.41	50.00
KRUPA 210483 3A - 3A	P-DP	0.00	0.00	123.67	0.00	0.00	252.89	0.00	22.03	0.00	230.86	121.05	37.20
KRUPA 211259 2A - 2A	P-DP	0.00	0.00	51.12	0.00	0.00	104.52	0.00	9.11	0.00	95.42	49.44	40.68
KUBENKA UNIT 1H - 1H	P-DP	0.35	0.00	0.01	25.65	0.01	0.02	0.00	2.14	0.00	23.54	14.41	15.82
L E STARTZELL 2 - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
L E STARTZELL UNIT BR 19 4 -	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
L E STARTZELL UNIT BR 19 5 -	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LAITALA UNIT B 21-24 4AH - 4A	P-DP	0.02	0.00	0.03	1.19	0.12	0.05	0.00	0.11	0.00	1.26	0.78	34.89
LAITALA UNIT B 21-24 4SH - 4S	P-DP	0.01	0.01	0.07	1.14	0.30	0.13	0.00	0.15	0.00	1.42	0.85	40.43
LAITALA UNIT B 21-24 5AH - 5A	P-DP	0.03	0.00	0.01	2.58	0.06	0.03	0.00	0.20	0.00	2.47	1.31	42.56
LAITALA UNIT B 21-24 5SH - 5S	P-DP	0.03	0.00	0.01	2.06	0.04	0.02	0.00	0.16	0.00	1.97	1.03	50.00
LAITALA UNIT B 21-24 6AH - 6A	P-DP	0.04	0.02	0.14	2.94	0.60	0.26	0.00	0.34	0.00	3.46	1.82	50.00
LAITALA UNIT B 21-24 6SH - 6S	P-DP	0.03	0.00	0.00	2.62	0.01	0.01	0.00	0.19	0.00	2.45	1.28	50.00
LAMAR 13-1-A 03LS - 03LS	P-DP	0.33	0.05	0.24	25.35	1.09	0.32	0.00	2.24	0.00	24.52	13.30	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
LAMAR 13-1-B 03WA - 03WA	P-DP	0.22	0.03	0.14	16.70	0.62	0.18	0.00	1.44	0.00	16.06	8.94	50.00
LAMAR 13-1-C 08WB - 08WB	P-DP	0.25	0.09	0.44	19.11	1.98	0.59	0.00	2.14	0.00	19.55	10.73	50.00
LAMAR 13-1-D 10JM - 10JM	P-DP	0.20	0.04	0.19	15.46	0.86	0.26	0.00	1.44	0.00	15.13	7.91	50.00
LAMAR 13-1-E 13WA - 13WA	P-DP	0.18	0.06	0.30	13.40	1.37	0.41	0.00	1.49	0.00	13.69	7.18	50.00
LAMAR 13-1-F 17LS - 17LS	P-DP	0.14	0.04	0.19	10.63	0.84	0.25	0.00	1.09	0.00	10.64	6.51	42.73
LAMAR 13-1-G 18WB - 18WB	P-DP	0.20	0.10	0.47	14.86	2.13	0.64	0.00	1.89	0.00	15.74	8.89	50.00
LAMAR 13-1-H 22JM - 22JM	P-DP	0.22	0.06	0.31	16.51	1.37	0.41	0.00	1.72	0.00	16.57	9.52	50.00
LAMAR 13-1-I 22WA - 22WA	P-DP	0.13	0.08	0.37	9.62	1.66	0.49	0.00	1.33	0.00	10.45	6.27	48.34
LANDRY 23 1 - 1	P-DP	0.01	0.01	0.00	0.51	0.21	0.00	0.00	0.07	0.00	0.65	0.33	36.35
LANDRY 23 2 - 2	P-DP	0.00	0.00	0.00	0.02	0.04	0.00	0.00	0.01	0.00	0.05	0.04	6.95
LANDRY 23 3 - 3	P-DP	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	2.50
LANDRY UNIT 23 4 - 4	P-DP	0.00	0.02	0.00	0.36	0.30	0.00	0.00	0.07	0.00	0.60	0.31	31.09
LANGHOFF UNIT A 1H - 1H	P-DP	0.00	0.50	2.47	0.26	9.03	4.80	0.00	1.40	0.00	12.69	6.28	50.00
LANGHOFF UNIT A 2H - 2H	P-DP	0.02	0.01	0.04	1.82	0.16	0.08	0.00	0.18	0.00	1.89	1.36	11.98
LANGHOFF UNIT A 3H - 3H	P-DP	0.02	0.04	0.22	1.36	0.81	0.43	0.00	0.24	0.00	2.36	1.39	31.71
LANGHOFF UNIT A 4H - 4H	P-DP	0.01	0.06	0.29	0.78	1.06	0.56	0.00	0.23	0.00	2.18	1.32	25.80
LANGHOFF UNIT A 8L - 8L	P-DP	0.40	0.71	3.53	29.48	12.87	6.84	0.00	4.41	0.00	44.78	24.47	50.00
LANGHOFF UNIT A 9L - 9L	P-DP	0.32	0.60	2.98	23.85	10.89	5.79	0.00	3.64	0.00	36.88	20.01	48.72
LANGHOFF UNIT B 701 - 701	P-DP	0.03	0.04	0.22	2.06	0.81	0.43	0.00	0.30	0.00	3.01	1.69	50.00
LAURA WILDER 72-69 UNIT A 3	P-DP	0.03	0.02	0.12	2.40	0.39	0.16	0.00	0.29	0.00	2.66	1.55	44.22
LAURA WILDER 72-69 UNIT B 4	P-DP	0.02	0.01	0.04	1.51	0.15	0.06	0.00	0.15	0.00	1.56	0.86	43.84
LEAVITT FED 1-9-4NH - 1-9-4NH	P-DP	0.69	0.03	4.29	50.84	0.76	18.92	0.00	6.57	0.00	63.94	37.11	45.63
LEAVITT FED 1-9-4PH - 1-9-4PH	P-DP	1.25	0.02	2.87	92.44	0.51	12.68	0.00	8.58	0.00	97.04	50.21	47.53
LEAVITT FED 1-9-4TH - 1-9-4TH	P-DP	0.58	0.05	8.71	43.21	1.54	38.38	0.00	9.04	0.00	74.09	34.70	48.99
LEAVITT FED 2-9-4NH - 2-9-4NH	P-DP	1.26	0.05	8.11	93.40	1.43	35.76	0.00	12.23	0.00	118.36	63.26	50.00
LEAVITT FED 2-9-4PH - 2-9-4PH	P-DP	2.10	0.03	5.13	155.16	0.91	22.60	0.00	14.61	0.00	164.05	78.56	50.00
LEAVITT FED 2-9-4TH - 2-9-4TH	P-DP	1.30	0.08	12.95	96.06	2.29	57.09	0.00	15.73	0.00	139.72	75.67	50.00
LEE 34-154 1H - 1H	P-DP	0.17	0.04	0.04	13.13	0.91	0.03	0.00	1.37	0.00	12.70	6.67	30.53
LEECH 32-41 UNIT A 1LS - 1LS	P-DP	0.13	0.00	0.01	9.83	0.04	0.02	0.00	0.71	0.00	9.17	3.83	50.00
LEECH EAST 5SA - 5SA	P-DP	0.08	0.00	0.01	6.03	0.06	0.03	0.00	0.44	0.00	5.67	3.36	30.50
LEECH EAST 7SB - 7SB	P-DP	0.02	0.00	0.01	1.86	0.05	0.02	0.00	0.14	0.00	1.79	1.25	14.91
LEECH EAST 8SA - 8SA	P-DP	0.19	0.02	0.10	14.76	0.45	0.20	0.00	1.15	0.00	14.26	7.43	46.58
LEECH WEST 2SB - 2SB	P-DP	2.11	0.04	0.22	161.03	1.00	0.44	0.00	11.73	0.00	150.73	72.23	50.00
LEECH WEST 3SA - 3SA	P-DP	2.26	0.14	0.81	172.37	3.63	1.59	0.00	13.11	0.00	164.48	84.20	50.00
LEECH WEST 4SB - 4SB	P-DP	2.19	0.11	0.62	167.02	2.78	1.22	0.00	12.55	0.00	158.48	81.86	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
LEEDE UNIT 7 1 - 1	*P-DP*	0.06	0.01	0.01	4.68	0.20	0.01	0.00	0.46	0.00	4.43	2.34	41.52
LEEDE UNIT 7 2H - 2H	*P-DP*	0.04	0.01	0.01	3.09	0.20	0.01	0.00	0.32	0.00	2.97	1.60	36.77
LEVIATHAN UNIT A 29-17 4AH -	*P-DP*	0.12	0.00	1.14	8.96	0.06	3.83	0.00	1.25	0.00	11.59	5.85	45.23
LEVIATHAN UNIT A 29-17 5AH -	*P-DP*	0.18	0.00	0.08	13.15	0.00	0.28	0.00	0.98	0.00	12.45	6.47	45.17
LEVIATHAN UNIT A 29-17 6AH -	*P-DP*	0.16	0.00	0.80	11.79	0.04	2.66	0.00	1.27	0.00	13.23	6.54	48.60
LEVIATHAN UNIT B 29-20 7AH	*P-DP*	0.08	0.00	1.34	5.82	0.07	4.47	0.00	1.13	0.00	9.23	4.71	35.28
LEVIATHAN UNIT B 29-20 8SH -	*P-DP*	0.04	0.00	0.32	2.79	0.02	1.07	0.00	0.37	0.00	3.51	1.91	27.12
LEVIATHAN UNIT B 29-20 9AH	*P-DP*	0.05	0.00	0.49	3.94	0.03	1.64	0.00	0.54	0.00	5.07	2.75	30.77
LGM A 1H - 1H	*P-DP*	0.12	0.11	0.55	8.72	2.00	1.06	0.00	1.03	0.00	10.75	7.74	35.64
LGM B 2H - 2H	*P-DP*	1.15	0.97	4.82	85.25	17.60	9.35	0.00	9.77	0.00	102.43	73.65	35.77
LGM C 201H - 201H	*P-DP*	1.27	1.29	6.42	94.74	23.41	12.43	0.00	11.44	0.00	119.14	80.90	39.33
LIMBER PINE A1 1LA - 1LA	*P-DP*	0.02	0.00	0.00	1.16	0.03	0.00	0.00	0.17	0.00	1.02	0.50	50.00
LIMBER PINE A1 28SB - 28SB	*P-DP*	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.01	0.00	0.06	0.04	37.26
LIMBER PINE A2 5LA - 5LA	*P-DP*	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.01	0.00	0.05	0.03	34.09
LIMBER PINE A3 16H - 16H	*P-DP*	0.00	0.00	0.00	0.07	0.01	0.00	0.00	0.01	0.00	0.07	0.04	39.35
LIMBER PINE A3 9UA - 9UA	*P-DP*	0.19	0.03	0.03	14.03	0.56	0.02	0.00	1.93	0.00	12.67	6.31	50.00
LIMBER PINE A4 2LA - 2LA	*P-DP*	0.02	0.00	0.00	1.77	0.07	0.00	0.00	0.24	0.00	1.60	0.83	50.00
LIMBER PINE A5 3LA - 3LA	*P-DP*	0.01	0.00	0.00	0.71	0.03	0.00	0.00	0.13	0.00	0.61	0.29	50.00
LIMBER PINE A6 10UA - 10UA	*P-DP*	0.00	0.00	0.00	0.37	0.02	0.00	0.00	0.08	0.00	0.32	0.19	40.36
LIMBER PINE A7 11UA - 11UA	*P-DP*	0.02	0.00	0.00	1.29	0.08	0.00	0.00	0.19	0.00	1.19	0.57	50.00
LION 1H - 1H	*P-DP*	0.01	0.01	0.00	0.92	0.44	0.00	0.00	0.26	0.00	1.10	0.81	10.41
LION 3H - 3H	*P-DP*	0.03	0.03	0.00	1.92	1.27	0.00	0.00	0.68	0.00	2.50	1.65	29.30
LISA MARIE 34-27 4AH - 4AH	*P-DP*	0.00	0.00	0.00	0.33	0.02	0.01	0.00	0.03	0.00	0.33	0.18	28.30
LOBLOLLY A1 12UA - 12UA	*P-DP*	0.01	0.00	0.00	0.64	0.03	0.00	0.00	0.06	0.00	0.61	0.38	37.80
LOBLOLLY A2 13UA - 13UA	*P-DP*	0.01	0.00	0.00	0.52	0.02	0.00	0.00	0.05	0.00	0.49	0.31	40.98
LOBO 34-147 1H - 1H	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
LOBO 34-147 2H - 2H	*P-DP*	0.01	0.00	0.00	0.42	0.05	0.00	0.00	0.05	0.00	0.42	0.20	29.46
LONE WOLF 12 1HB - 1HB	*P-DP*	0.18	0.14	0.49	13.33	2.33	0.97	0.00	1.72	0.00	14.91	6.55	50.00
LONG 18 1 - 1	*P-DP*	0.01	0.00	0.00	0.63	0.00	0.00	0.00	0.05	0.00	0.59	0.43	8.38
LONGLEAF A2 2LA - 2LA	*P-DP*	0.03	0.01	0.01	1.98	0.14	0.00	0.00	0.21	0.00	1.92	1.16	50.00
LOOS UNIT 10H - 10H	*P-DP*	0.05	0.05	0.24	3.58	0.86	0.46	0.00	0.43	0.00	4.47	3.27	10.02
LOOS UNIT 11L - 11L	*P-DP*	0.85	0.70	3.47	63.02	12.66	6.73	0.00	7.17	0.00	75.24	39.76	50.00
LOOS UNIT 12L - 12L	*P-DP*	0.63	0.80	3.95	46.86	14.42	7.66	0.00	6.09	0.00	62.85	32.92	50.00
LOOS UNIT 1H - 1H	*P-DP*	0.01	0.01	0.03	0.91	0.09	0.05	0.00	0.09	0.00	0.97	0.70	9.02
LOOS UNIT 2H - 2H	*P-DP*	0.00	0.00	0.01	0.00	0.04	0.02	0.00	0.01	0.00	0.06	0.04	18.59

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
LOOS UNIT 3H - 3H	P-DP	0.00	0.01	0.05	0.00	0.17	0.09	0.00	0.03	0.00	0.23	0.11	36.67
LOOS UNIT 8H - 8H	P-DP	0.06	0.06	0.31	4.31	1.14	0.61	0.00	0.53	0.00	5.52	3.03	26.33
LOOS UNIT 9H - 9H	P-DP	0.85	0.53	2.63	63.21	9.60	5.10	0.00	6.72	0.00	71.20	36.78	48.96
LOST KEYS 4345 1U B 1H - B 1H	P-DP	0.02	0.02	0.09	1.21	0.31	0.13	0.00	0.18	0.00	1.47	0.92	42.33
LOST KEYS 4345 2U A 2H - A 2H	P-DP	0.03	0.02	0.15	2.52	0.51	0.21	0.00	0.33	0.00	2.90	1.64	50.00
LOST KEYS 4345 3U A 3H - A 3H	P-DP	0.02	0.01	0.09	1.86	0.28	0.12	0.00	0.22	0.00	2.04	1.26	42.21
LOST KEYS 4345 4U A 4H - A 4H	P-DP	0.01	0.01	0.08	1.03	0.27	0.11	0.00	0.15	0.00	1.25	0.72	45.24
LOST KEYS 4345 5U B 5H - B 5H	P-DP	0.01	0.02	0.11	0.83	0.36	0.15	0.00	0.17	0.00	1.17	0.67	43.24
LOST KEYS 4345 6U A 6H - A 6H	P-DP	0.01	0.01	0.05	0.70	0.17	0.07	0.00	0.10	0.00	0.84	0.47	50.00
LRT UNIT 2 ALLOCATION 2318	P-DP	0.04	0.00	0.02	2.90	0.09	0.02	0.00	0.28	0.00	2.73	1.29	44.27
LUKCIK 4 - 4	P-DP	0.00	0.00	0.36	0.00	0.00	0.50	0.00	0.05	0.00	0.45	0.24	50.00
LUKCIK 5 - 5	P-DP	0.00	0.00	2.18	0.00	0.00	3.07	0.00	0.29	0.00	2.78	1.57	50.00
LULO 2531LP 4H - 4H	P-DP	0.31	0.02	0.10	23.29	0.45	0.20	0.00	1.76	0.00	22.17	13.49	49.26
LULO 2533LP 8H - 8H	P-DP	0.14	0.02	0.10	10.47	0.43	0.19	0.00	0.84	0.00	10.25	6.02	45.63
LULO 2543DP 6H - 6H	P-DP	0.30	0.07	0.43	22.61	1.91	0.83	0.00	2.03	0.00	23.32	13.69	50.00
LULO 2551AP 5H - 5H	P-DP	0.40	0.02	0.15	30.70	0.65	0.29	0.00	2.34	0.00	29.30	16.93	50.00
LULO 2553AP 9H - 9H	P-DP	0.26	0.03	0.18	19.88	0.79	0.35	0.00	1.59	0.00	19.43	11.09	49.75
LULO 3641DP 2H - 2H	P-DP	0.50	0.04	0.22	38.23	0.96	0.42	0.00	2.94	0.00	36.68	21.27	50.00
MABEE 22A 1H - 1H	P-DP	0.00	0.00	0.01	0.14	0.03	0.01	0.00	0.03	0.00	0.15	0.08	45.37
MABEE-ELKIN W16B 2H - 2H	P-DP	0.00	0.00	0.00	0.07	0.01	0.00	0.00	0.01	0.00	0.08	0.04	46.39
MABEE-STIMSON 22B 2H - 2H	P-DP	0.01	0.01	0.02	0.58	0.10	0.02	0.00	0.09	0.00	0.61	0.33	39.95
MABEE-TREDAWAY W16A 1H -	P-DP	0.72	0.51	1.97	54.89	10.01	1.98	0.00	9.19	0.00	57.69	31.35	43.75
MARY GRACE 201-202 UNIT 1H	P-DP	0.04	0.04	0.04	2.64	0.93	0.03	0.00	0.46	0.00	3.15	1.62	43.27
MARY GRACE 201-202 UNIT 3H	P-DP	0.03	0.03	0.03	2.45	0.70	0.02	0.00	0.38	0.00	2.79	1.46	40.71
MARYRUTH-ANDERSON 47C 1	P-DP	0.07	0.01	0.07	4.95	0.30	0.09	0.00	0.47	0.00	4.87	2.67	45.55
MARYRUTH-ANDERSON 47D 1	P-DP	0.05	0.01	0.06	4.17	0.26	0.08	0.00	0.40	0.00	4.11	2.16	44.60
MARYRUTH-ANDERSON 47E 1	P-DP	0.05	0.01	0.06	3.61	0.28	0.08	0.00	0.37	0.00	3.61	2.05	41.17
MARYRUTH-ANDERSON 47F 1	P-DP	0.07	0.01	0.04	5.01	0.16	0.05	0.00	0.42	0.00	4.80	2.53	46.66
MATTIE 18-11-5 6H - 6H	P-DP	0.09	4.77	54.37	6.14	97.30	112.34	0.00	182.97	0.00	32.81	18.25	33.53
MATTIE 18-11-5 7H - 7H	P-DP	0.06	5.25	59.83	4.10	107.07	123.62	0.00	200.96	0.00	33.83	17.69	36.57
MATTIE 18-11-5 8H - 8H	P-DP	0.09	5.92	67.41	6.36	120.62	139.27	0.00	226.64	0.00	39.60	21.24	37.59
MCCALL, JACK O. ET AL 2 - 2	P-DP	0.02	0.00	0.01	1.48	0.02	0.01	0.00	0.11	0.00	1.40	0.80	18.49
MCCALL, JACK O. ET AL 3 - 3	P-DP	0.01	0.00	0.02	1.05	0.07	0.03	0.00	0.10	0.00	1.05	0.68	13.88
MCCALL, JACK O. ET AL 4 - 4	P-DP	0.01	0.00	0.01	1.03	0.03	0.01	0.00	0.08	0.00	0.98	0.63	13.73
MCCLANE 2 - 2	P-DP	0.05	0.01	0.04	3.50	0.17	0.05	0.00	0.32	0.00	3.40	1.85	25.49

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	Net Sales Volumes NGL (Mbbl)	Net Sales Volumes Residue Gas (MMcf)	Net Revenue Oil (M$)	Net Revenue NGL (M$)	Net Revenue Residue Gas (M$)	Net Revenue Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Cash Flow Disc. 10% (M$)	Life (years)
MCCLANE 3 - 3	P-DP	0.08	0.00	0.02	6.21	0.09	0.03	0.00	0.48	0.00	5.85	3.38	25.04
MCCONNELL 4 - 4	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MCDANIEL A 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.55
MCDANIEL A 2 - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MCDANIEL, LOIS 2 - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
MCINTIRE 1 - 1	P-DP	0.00	0.00	0.12	0.00	0.00	0.17	0.00	0.02	0.00	0.15	0.09	50.00
MEDUSA UNIT A 28-21 1AH - 1A	P-DP	0.11	0.00	0.83	8.04	0.04	2.78	0.00	1.02	0.00	9.84	5.08	37.41
MEDUSA UNIT A 28-21 2AH - 2A	P-DP	0.13	0.00	1.29	9.67	0.07	4.33	0.00	1.38	0.00	12.68	6.42	39.66
MEDUSA UNIT B 28-21 7AH - 7A	P-DP	0.12	0.00	0.65	8.81	0.03	2.18	0.00	0.98	0.00	10.04	5.35	37.16
MEDUSA UNIT B 28-21 8AH - 8A	P-DP	0.16	0.00	0.97	11.55	0.05	3.24	0.00	1.34	0.00	13.50	7.21	40.70
MEDUSA UNIT C 28-09 3AH - 3A	P-DP	0.19	0.00	0.33	13.72	0.02	1.12	0.00	1.16	0.00	13.70	7.40	46.03
MEDUSA UNIT C 28-09 6AH - 6A	P-DP	0.11	0.00	0.39	8.08	0.02	1.29	0.00	0.78	0.00	8.61	4.56	41.43
MEHAFFEY - BURNEM 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MELISSA 2 - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.96
MELISSA A 1 - 1	P-DP	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.01	0.00	0.05	0.04	9.22
MEMPHIS FLASH 39-27 1LS - 1L	P-DP	0.00	0.00	0.01	0.24	0.03	0.01	0.00	0.02	0.00	0.25	0.14	40.21
MEMPHIS FLASH 39-27 2A - 2A	P-DP	0.01	0.00	0.01	0.41	0.05	0.02	0.00	0.04	0.00	0.44	0.24	48.74
MEMPHIS FLASH 39-27 4AH - 4	P-DP	0.01	0.00	0.01	0.73	0.03	0.01	0.00	0.06	0.00	0.71	0.43	50.00
MIDDLETON 21 1 - 1	P-DP	0.03	0.01	0.07	1.96	0.31	0.14	0.00	0.21	0.00	2.20	1.22	22.17
MIKE SCOTT 19-30-H 4315H - 43	P-DP	0.08	0.05	0.18	6.22	0.87	0.36	0.00	0.74	0.00	6.71	3.38	50.00
MIKE SCOTT 19-30-H 4415H - 44	P-DP	0.05	0.03	0.11	3.74	0.54	0.22	0.00	0.45	0.00	4.05	2.15	50.00
MILES 3-12B5 - 3-12B5	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MILLETT 2-14C5 - 2-14C5	P-DP	0.47	0.00	0.69	28.18	0.00	1.18	0.00	0.68	0.00	28.68	12.07	50.00
MIMS 32H 3306BH - 3306BH	P-DP	0.36	0.19	0.90	27.03	4.06	1.21	0.00	3.50	0.00	28.80	15.44	40.12
MIMS 32H 3307BH - 3307BH	P-DP	0.23	0.13	0.66	17.59	2.95	0.88	0.00	2.40	0.00	19.02	10.52	33.29
MIMS 32H 3315AH - 3315AH	P-DP	0.33	0.26	1.27	25.30	5.71	1.70	0.00	4.01	0.00	28.70	15.43	40.22
MIMS 32H 3317AH - 3317AH	P-DP	0.19	0.31	1.52	14.48	6.85	2.05	0.00	3.66	0.00	19.72	11.26	26.00
MIMS 32H 3318AH - 3318AH	P-DP	0.17	0.11	0.56	13.09	2.50	0.75	0.00	1.90	0.00	14.44	8.10	31.93
MIMS 32H 3326SH - 3326SH	P-DP	0.10	0.07	0.32	7.48	1.43	0.43	0.00	1.09	0.00	8.26	5.27	18.33
MIMS 32H 3327SH - 3327SH	P-DP	0.13	0.08	0.37	10.03	1.67	0.50	0.00	1.36	0.00	10.83	6.51	22.08
MIMS 32H 3345SH - 3345SH	P-DP	0.18	0.06	0.31	13.75	1.38	0.41	0.00	1.52	0.00	14.02	7.95	31.23
MIMS 32H 3347SH - 3347SH	P-DP	0.11	0.13	0.64	7.98	2.88	0.86	0.00	1.68	0.00	10.04	5.46	29.15
MIMS 32H 3348SH - 3348SH	P-DP	0.11	0.14	0.66	8.05	2.98	0.89	0.00	1.72	0.00	10.21	5.92	21.30
MINGO S CRC JF 4H - 4H	P-DP	0.00	0.00	48.06	0.00	0.00	95.21	0.00	59.29	0.00	35.91	21.73	30.57
MINGO SE CRC JF 6H - 6H	P-DP	0.00	0.00	117.03	0.00	0.00	231.82	0.00	144.37	0.00	87.45	50.57	34.15

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
MINGO SW CRC JF 2H - 2H	P-DP	0.00	0.00	26.63	0.00	0.00	52.75	0.00	32.85	0.00	19.90	11.46	34.06
MINGO W CRC JF 8H - 8H	P-DP	0.00	0.00	70.55	0.00	0.00	139.76	0.00	87.04	0.00	52.72	31.73	27.92
MIPA NO SLEEP 8201 4H - 4H	P-DP	0.02	0.01	0.01	1.23	0.17	0.01	0.00	0.15	0.00	1.26	0.76	43.58
MIPA NO SLEEP 8202 2H - 2H	P-DP	0.02	0.01	0.01	1.84	0.31	0.01	0.00	0.24	0.00	1.92	1.14	48.75
MIPA NO SLEEP 8252 3H - 3H	P-DP	0.05	0.02	0.02	3.51	0.37	0.01	0.00	0.40	0.00	3.49	2.09	50.00
MITCHELL 47-31 A UNIT A 2H -	P-DP	0.26	0.01	0.09	20.03	0.38	0.17	0.00	1.51	0.00	19.07	10.28	50.00
MITCHELL 47-31 A UNIT L 2H -	P-DP	0.19	0.01	0.07	14.23	0.30	0.13	0.00	1.08	0.00	13.57	7.32	50.00
MITCHELL 47-31 B UNIT A 7H -	P-DP	1.99	0.12	0.73	151.81	3.27	1.43	0.00	11.56	0.00	144.94	77.83	50.00
MITCHELL 47-31 B UNIT L 6H -	P-DP	0.04	0.00	0.00	3.42	0.00	0.00	0.00	0.25	0.00	3.18	1.21	50.00
MOLNOSKEY UNIT 1H - 1H	P-DP	0.06	0.00	0.02	4.59	0.03	0.04	0.00	0.40	0.00	4.26	3.47	5.17
MOLNOSKEY UNIT 2H - 2H	P-DP	0.77	0.00	0.00	56.36	0.00	0.00	0.00	4.69	0.00	51.67	29.55	30.60
MONROE 34-158 UNIT 1H - 1H	P-DP	0.00	0.00	0.00	0.03	0.05	0.00	0.00	0.02	0.00	0.07	0.05	7.17
MONROE 34-158 UNIT 2H - 2H	P-DP	0.00	0.00	0.00	0.16	0.01	0.00	0.00	0.02	0.00	0.15	0.11	10.40
MONROE 34-158 UNIT 3H - 3H	P-DP	0.02	0.00	0.00	1.43	0.07	0.00	0.00	0.14	0.00	1.36	0.73	35.77
MONROE 34-158 UNIT 4H - 4H	P-DP	0.01	0.00	0.00	0.41	0.03	0.00	0.00	0.04	0.00	0.40	0.25	20.05
MONSEN 1-21A3 - 1-21A3	P-DP	0.08	0.00	0.29	5.01	0.00	0.49	0.00	0.18	0.00	5.31	2.99	25.85
MOOSE HOLLOW 16-24-23-C5-8	P-DP	0.00	0.00	0.01	0.25	0.00	0.02	0.00	0.01	0.00	0.26	0.21	9.45
MOOSE HOLLOW 9-24-23-C5-6H	P-DP	0.01	0.00	0.05	0.63	0.00	0.09	0.00	0.03	0.00	0.69	0.39	30.41
MOOSE HOLLOW 9-24-23-C5-7H	P-DP	0.04	0.00	0.19	2.30	0.00	0.32	0.00	0.10	0.00	2.51	1.31	37.92
MORAN 28SB - 28SB	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.15
MORAN 8LA - 8LA	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.41
MORAN A1 16H - 16H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.85
MORAN A1 1LA - 1LA	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.86
MORAN A1 9UA - 9UA	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	47.29
MORGAN-NEAL 39-26 2LS - 2LS	P-DP	0.01	0.00	0.02	0.83	0.09	0.04	0.00	0.08	0.00	0.88	0.42	49.60
MORGAN-NEAL 39-26 3WA - 3W	P-DP	0.02	0.01	0.03	1.16	0.13	0.06	0.00	0.11	0.00	1.24	0.60	50.00
MORGAN-NEAL UNIT NO.2 39-	P-DP	0.01	0.00	0.02	0.55	0.08	0.04	0.00	0.06	0.00	0.61	0.32	44.11
MORGAN-NEAL UNIT NO.2 39-	P-DP	0.01	0.00	0.01	0.66	0.06	0.02	0.00	0.06	0.00	0.68	0.32	47.72
MORGAN-NEAL UNIT NO.2 39-	P-DP	0.01	0.00	0.02	0.44	0.09	0.04	0.00	0.05	0.00	0.51	0.25	42.83
MORTAL STORM 12-13-24 H 1W	P-DP	0.05	0.01	0.08	4.02	0.36	0.16	0.00	0.37	0.00	4.17	2.28	43.94
MOTHMAN UNIT A 45-04 2AH -	P-DP	0.39	0.00	0.65	28.67	0.03	2.17	0.00	2.39	0.00	28.48	13.48	50.00
MR. HOBBS 11-14 H 1W - H 1W	P-DP	0.08	0.01	0.04	6.02	0.17	0.07	0.00	0.47	0.00	5.79	2.72	50.00
MR. HOBBS 11-14-23 H 1LS - H	P-DP	0.04	0.01	0.09	2.77	0.39	0.17	0.00	0.28	0.00	3.04	1.76	44.86
MR. HOBBS 11-14-23A H 2W - H	P-DP	0.03	0.01	0.07	2.46	0.30	0.13	0.00	0.24	0.00	2.65	1.36	47.90
MR. PHILLIPS 11-02 A 1NA - 1N	P-DP	0.51	0.29	1.74	39.03	7.77	3.40	0.00	4.48	0.00	45.73	23.73	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
MR. PHILLIPS 11-02 A 1NS - 1NS	P-DP	0.55	0.11	0.67	42.19	3.00	1.31	0.00	3.67	0.00	42.84	22.88	50.00
MR. PHILLIPS 11-02 B 2AH - 2A	P-DP	0.34	0.08	0.47	25.78	2.12	0.93	0.00	2.30	0.00	26.53	13.37	50.00
MR. PHILLIPS 11-02 B 2SH - 2SH	P-DP	0.34	0.06	0.34	25.68	1.51	0.66	0.00	2.16	0.00	25.68	12.90	50.00
MR. PHILLIPS 11-02 D 4SA - 4SA	P-DP	0.42	0.17	0.98	32.08	4.39	1.92	0.00	3.24	0.00	35.15	19.51	50.00
MR. PHILLIPS 11-2 1SH - 1SH	P-DP	0.08	0.04	0.21	6.22	0.94	0.41	0.00	0.65	0.00	6.93	3.89	32.67
MUD HEN 57-31 A 1WA - 1WA	P-DP	0.03	0.00	0.03	2.50	0.02	0.02	0.00	0.32	0.00	2.22	1.31	39.23
MUD HEN 57-31 B 2BS - 2BS	P-DP	0.10	0.00	0.04	7.24	0.02	0.03	0.00	0.77	0.00	6.52	3.61	47.43
MUD HEN 57-31 C 3WA - 3WA	P-DP	0.07	0.00	0.05	5.26	0.02	0.03	0.00	0.61	0.00	4.71	2.61	46.23
MUD HEN 57-31 D 4BS - 4BS	P-DP	0.14	0.00	0.05	10.22	0.03	0.04	0.00	1.07	0.00	9.22	5.13	50.00
MULLINS 1-24-23-C5-6H - 1-24-2	P-DP	0.04	0.00	0.18	2.16	0.00	0.30	0.00	0.10	0.00	2.36	1.20	49.84
MULSEN 24/23-13-14-C5-2H - 24	P-DP	0.21	0.00	1.31	12.63	0.00	2.23	0.00	0.68	0.00	14.18	7.47	50.00
MURDOCK 2-34B5 - 2-34B5	P-DP	0.00	0.00	0.00	0.10	0.00	0.01	0.00	0.00	0.00	0.10	0.07	14.26
MURPH 69-2221-23R - 69-2221-2	P-DP	1.69	0.00	0.92	102.02	0.00	1.57	0.00	1.85	0.00	101.74	61.99	38.49
MUSGROVE MILLER 0904 2HM	P-DP	0.11	0.02	0.09	8.45	0.40	0.18	0.00	0.69	0.00	8.34	4.25	46.02
MUSSER 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N A C R C 1-15 ACRES 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N A C R C 5-132 - 5-132	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NAC 3H-20 - 3H-20	P-DP	0.00	0.00	108.18	0.00	0.00	214.29	0.00	133.46	0.00	80.84	52.61	20.13
NAC 4H-20 - 4H-20	P-DP	0.00	0.00	167.86	0.00	0.00	332.52	0.00	207.08	0.00	125.43	73.69	26.12
NAC B WYN JF 1H - 1H	P-DP	0.00	0.00	211.34	0.00	0.00	418.65	0.00	260.72	0.00	157.92	96.36	27.39
NAC B WYN JF 3H - 3H	P-DP	0.00	0.00	218.70	0.00	0.00	433.22	0.00	269.80	0.00	163.42	96.58	28.65
NAC B WYN JF 5H - 5H	P-DP	0.00	0.00	300.54	0.00	0.00	595.34	0.00	370.76	0.00	224.57	125.95	33.20
NAC ROYALTY 27-41 HC 001 - 0	P-DP	0.00	0.00	137.40	0.00	0.00	321.92	0.00	42.46	0.00	279.47	225.93	19.36
NAIL -A- 1 - 1	P-DP	0.00	0.00	0.01	0.28	0.02	0.01	0.00	0.03	0.00	0.28	0.09	50.00
NAIL -C- 1 - 1	P-DP	0.00	0.00	0.00	0.04	0.01	0.00	0.00	0.01	0.00	0.04	0.03	19.33
NAIL -E- 2 - 2	P-DP	0.00	0.00	0.00	0.12	0.00	0.00	0.00	0.01	0.00	0.12	0.07	20.53
NAIL -E- 3 - 3	P-DP	0.00	0.00	0.00	0.12	0.01	0.00	0.00	0.01	0.00	0.12	0.07	22.49
NAIL -K- 1 - 1	P-DP	0.00	0.00	0.00	0.18	0.01	0.00	0.00	0.02	0.00	0.17	0.06	50.00
NAIL -P- 1 - 1	P-DP	0.00	0.00	0.00	0.06	0.01	0.00	0.00	0.01	0.00	0.06	0.04	20.01
NAIL J 1 - 1	P-DP	0.00	0.00	0.00	0.15	0.01	0.00	0.00	0.01	0.00	0.14	0.04	50.00
NAIL O 1 - 1	P-DP	0.00	0.00	0.00	0.18	0.01	0.00	0.00	0.02	0.00	0.17	0.09	27.09
NAIL RANCH 10 1 - 1	P-DP	0.00	0.00	0.00	0.15	0.02	0.01	0.00	0.02	0.00	0.16	0.09	24.72
NAIL RANCH 10 2 - 2	P-DP	0.00	0.00	0.00	0.14	0.01	0.00	0.00	0.02	0.00	0.14	0.08	23.62
NAIL RANCH 10 3 - 3	P-DP	0.00	0.00	0.00	0.12	0.00	0.00	0.00	0.01	0.00	0.12	0.07	21.05
NAIL RANCH 10 4 - 4	P-DP	0.00	0.00	0.01	0.13	0.03	0.01	0.00	0.02	0.00	0.15	0.09	22.49

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
NANCY 1H - 1H	*P-DP*	0.12	0.00	0.02	8.98	0.03	0.04	0.00	0.76	0.00	8.28	4.24	35.68
NE AXIS 2H - 2H	*P-DP*	0.07	0.10	0.00	4.91	3.52	0.00	0.00	1.87	0.00	6.57	3.79	35.41
NE NAIL 10 1 - 1	*P-DP*	0.00	0.00	0.01	0.27	0.03	0.01	0.00	0.03	0.00	0.28	0.15	31.53
NE NAIL 10 2 - 2	*P-DP*	0.00	0.00	0.01	0.33	0.06	0.02	0.00	0.05	0.00	0.36	0.20	34.70
NE NAIL 10 3 - 3	*P-DP*	0.00	0.00	0.01	0.09	0.02	0.01	0.00	0.02	0.00	0.10	0.06	20.22
NE NAIL 10 4 - 4	*P-DP*	0.00	0.00	0.00	0.07	0.02	0.00	0.00	0.01	0.00	0.08	0.05	18.44
NE NAIL 10 5 - 5	*P-DP*	0.00	0.00	0.00	0.07	0.01	0.00	0.00	0.01	0.00	0.08	0.05	18.72
NEIHART 2-2C5 - 2-2C5	*P-DP*	0.03	0.00	0.04	1.55	0.00	0.07	0.00	0.04	0.00	1.58	0.72	50.00
NESSIE UNIT A 34-46 1AH - 1AH	*P-DP*	8.32	0.01	4.96	612.59	0.25	16.59	0.00	46.31	0.00	583.13	261.23	50.00
NESSIE UNIT A 34-46 2AH - 2AH	*P-DP*	5.51	0.04	18.63	406.07	0.96	62.29	0.00	38.93	0.00	430.38	200.09	50.00
NESSIE UNIT A 34-46 3AH - 3AH	*P-DP*	3.08	0.46	2.69	234.82	12.06	5.28	0.00	19.40	0.00	232.75	106.21	50.00
NESSIE UNIT A 34-46 3SH - 3SH	*P-DP*	3.92	0.09	43.44	288.97	2.23	145.28	0.00	43.92	0.00	392.56	195.20	50.00
NESSIE UNIT B 34-46 7AH - 7AH	*P-DP*	6.38	0.04	19.46	469.85	1.00	65.07	0.00	43.92	0.00	492.00	233.50	50.00
NESSIE UNIT B 34-46 8AH - 8AH	*P-DP*	1.71	0.05	23.95	126.03	1.23	80.10	0.00	21.84	0.00	185.52	83.98	50.00
NEWTON 43A 1HE - 1HE	*P-DP*	0.18	0.06	0.37	13.85	1.67	0.73	0.00	1.35	0.00	14.91	7.48	42.14
NEWTON 43A 2HK - 2HK	*P-DP*	0.13	0.05	0.27	9.92	1.19	0.52	0.00	0.97	0.00	10.67	5.47	38.08
NEWTON 43B 3HJ - 3HJ	*P-DP*	0.01	0.02	0.09	1.03	0.40	0.17	0.00	0.16	0.00	1.44	0.92	19.91
NEWTON 43BK 4HE - 4HE	*P-DP*	0.07	0.02	0.10	5.25	0.47	0.20	0.00	0.48	0.00	5.45	2.94	46.48
NEWTON 43BK 5HK - 5HK	*P-DP*	0.11	0.04	0.24	8.47	1.08	0.47	0.00	0.84	0.00	9.18	5.31	40.65
NM HARRISON 16-11-5 10H - 10	*P-DP*	0.01	1.02	11.57	0.42	20.71	23.91	0.00	37.37	0.00	7.66	4.30	28.33
NM HARRISON 16-11-5 6H - 6H	*P-DP*	0.02	1.05	11.93	1.10	21.35	24.65	0.00	38.62	0.00	8.48	4.86	27.93
NM HARRISON 16-11-5 8H - 8H	*P-DP*	0.01	1.07	12.18	0.43	21.79	25.16	0.00	39.32	0.00	8.05	4.69	28.29
NOELLE SW CRC JF 4H - 4H	*P-DP*	0.00	0.00	201.12	0.00	0.00	398.41	0.00	248.12	0.00	150.29	95.38	50.00
NOELLE SW CRC JF 6H - 6H	*P-DP*	0.00	0.00	201.58	0.00	0.00	399.31	0.00	248.68	0.00	150.63	96.10	50.00
NOELLE W CRC JF 2H - 2H	*P-DP*	0.00	0.00	225.68	0.00	0.00	447.06	0.00	278.42	0.00	168.64	108.58	50.00
NOLAN NE CRC JF 3H - 3H	*P-DP*	0.00	0.00	53.32	0.00	0.00	105.63	0.00	65.78	0.00	39.85	28.69	13.99
NOLAN NW CRC JF 1H - 1H	*P-DP*	0.00	0.00	377.54	0.00	0.00	747.86	0.00	465.75	0.00	282.11	166.10	36.85
NOLAN S CRC JF 2H - 2H	*P-DP*	0.00	0.00	167.80	0.00	0.00	332.39	0.00	207.01	0.00	125.38	75.99	27.20
NOLAN S CRC JF 4H - 4H	*P-DP*	0.00	0.00	178.47	0.00	0.00	353.53	0.00	220.17	0.00	133.36	80.14	28.02
NOLAN S CRC JF 6H - 6H	*P-DP*	0.00	0.00	187.60	0.00	0.00	371.61	0.00	231.43	0.00	140.18	84.87	28.27
NORRIS UNIT 32-H 3301BH - 33	*P-DP*	0.20	0.25	1.22	15.27	5.50	1.64	0.00	3.20	0.00	19.20	10.37	36.03
NORRIS UNIT 32-H 3303BH - 33	*P-DP*	0.22	0.29	1.42	16.52	6.37	1.90	0.00	3.62	0.00	21.16	11.72	36.56
NORRIS UNIT 32-H 3304BH - 33	*P-DP*	0.23	0.06	0.28	17.79	1.24	0.37	0.00	1.76	0.00	17.63	9.94	33.61
NORRIS UNIT 32-H 3312AH - 33	*P-DP*	0.16	0.28	1.35	11.80	6.07	1.81	0.00	3.17	0.00	16.51	8.97	33.49
NORRIS UNIT 32-H 3313AH - 33	*P-DP*	0.19	0.39	1.90	14.42	8.55	2.55	0.00	4.31	0.00	21.22	11.72	36.89

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
NORRIS UNIT 32-H 3322SH - 332	P-DP	0.37	0.40	1.95	28.14	8.76	2.61	0.00	5.38	0.00	34.13	17.95	42.76
NORRIS UNIT 32-H 3323SH - 332	P-DP	0.63	1.14	5.55	47.86	24.97	7.45	0.00	12.99	0.00	67.29	36.65	48.79
NORRIS UNIT 32-H 3361DH - 33	P-DP	0.42	0.59	2.86	32.00	12.85	3.84	0.00	7.22	0.00	41.47	21.84	45.09
NORRIS UNIT 32-H 3363DH - 33	P-DP	0.38	0.55	2.66	28.76	11.95	3.57	0.00	6.64	0.00	37.63	20.05	43.52
NORRIS UNIT 32-H 3364DH - 33	P-DP	0.37	0.44	2.12	27.71	9.54	2.85	0.00	5.64	0.00	34.46	18.35	42.67
NORRIS UNIT 32-H 3371JH - 337	P-DP	0.20	0.25	1.20	15.47	5.38	1.61	0.00	3.17	0.00	19.28	10.78	35.28
NORRIS UNIT 32-H 3373JH - 337	P-DP	0.19	0.24	1.18	14.48	5.32	1.59	0.00	3.08	0.00	18.31	10.26	34.74
NORRIS UNIT 32-H 3374JH - 337	P-DP	0.25	0.26	1.25	19.01	5.63	1.68	0.00	3.52	0.00	22.79	12.25	37.85
NORRIS-MIMS ALLOCATION 33	P-DP	0.17	0.18	0.88	12.69	3.98	1.19	0.00	2.44	0.00	15.42	8.63	32.81
NORRIS-MIMS ALLOCATION 33	P-DP	0.11	0.31	1.53	8.60	6.89	2.06	0.00	3.25	0.00	14.30	8.79	27.61
NORTH AMERICAN COAL 1S - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL 2S - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL 3A -	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL CO 4	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL COR	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL COR	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL COR	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL COR	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL COR	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL COR	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL ROY	P-DP	0.04	8.21	93.51	2.60	167.32	193.19	0.00	313.52	0.00	49.60	26.73	31.83
NORTH AMERICAN COAL ROY	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL ROY	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NUNN '5-44' 4303H - 4303H	P-DP	0.09	0.20	0.69	6.94	3.29	1.38	0.00	1.44	0.00	10.17	4.65	50.00
NUNN '5-44' 4403H - 4403H	P-DP	0.07	0.08	0.26	4.95	1.26	0.52	0.00	0.74	0.00	5.99	2.81	46.96
NUNN '5-44' 4803H - 4803H	P-DP	0.05	0.10	0.35	4.03	1.70	0.71	0.00	0.78	0.00	5.65	2.60	46.82
NUNN 1 - 1	P-DP	0.01	0.00	0.00	0.38	0.02	0.01	0.00	0.04	0.00	0.37	0.18	25.89
NUNN 2 - 2	P-DP	0.01	0.00	0.01	0.38	0.03	0.01	0.00	0.04	0.00	0.38	0.18	26.35
NUNN 5-44 1HB - 1HB	P-DP	0.08	0.23	0.80	6.28	3.82	1.60	0.00	1.53	0.00	10.17	4.63	50.00
NUNN A 2 - 2	P-DP	0.01	0.00	0.01	0.48	0.03	0.01	0.00	0.05	0.00	0.47	0.22	29.29
NUNN A 3 - 3	P-DP	0.02	0.00	0.00	1.61	0.00	0.00	0.00	0.13	0.00	1.48	0.59	39.53
NUNN B 3 - 3	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NUNN, J. F. B 3 - 3	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
O'NEAL 1 - 1	P-DP	0.11	0.05	0.18	8.76	0.90	0.18	0.00	1.14	0.00	8.70	4.60	24.08
OAK VALLEY 2 1 - 1	P-DP	0.09	0.01	0.05	6.67	0.27	0.05	0.00	0.68	0.00	6.30	3.08	36.15

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
OLDHAM 38-27 B UNIT A 7H - A	P-DP	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	2.58
OLDHAM 38-27 B UNIT A 8H - A	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.71
OLDHAM 38-27 B UNIT L 7H - L	P-DP	0.04	0.00	0.01	3.17	0.05	0.02	0.00	0.24	0.00	3.01	1.42	50.00
OLDHAM 38-27 B UNIT L 8H - L	P-DP	0.00	0.01	0.04	0.05	0.16	0.07	0.00	0.04	0.00	0.24	0.17	10.46
OLDHAM TRUST EAST 1SH - 1S	P-DP	0.02	0.00	0.02	1.86	0.10	0.04	0.00	0.15	0.00	1.84	1.11	49.65
OLDHAM TRUST EAST 2AH - 2	P-DP	0.05	0.01	0.07	4.11	0.31	0.14	0.00	0.36	0.00	4.20	2.57	46.59
OLDHAM TRUST EAST 3871WA	P-DP	0.03	0.00	0.02	2.29	0.11	0.05	0.00	0.19	0.00	2.26	1.03	50.00
OLDHAM TRUST EAST 3875LS	P-DP	0.03	0.00	0.02	2.48	0.08	0.03	0.00	0.19	0.00	2.39	1.02	50.00
OLDHAM TRUST EAST 3876WA	P-DP	0.04	0.00	0.01	2.99	0.04	0.02	0.00	0.22	0.00	2.82	1.36	50.00
OLDHAM TRUST EAST 3AH - 3	P-DP	0.04	0.00	0.02	2.95	0.09	0.04	0.00	0.23	0.00	2.85	1.72	50.00
OLDHAM TRUST EAST 3SH - 3S	P-DP	0.04	0.00	0.01	3.20	0.06	0.03	0.00	0.24	0.00	3.04	1.80	50.00
OLDHAM TRUST EAST 4AH - 4	P-DP	0.02	0.00	0.01	1.86	0.06	0.02	0.00	0.15	0.00	1.79	1.09	49.00
OLDHAM TRUST WEST 1SH - 1	P-DP	0.06	0.00	0.02	4.64	0.09	0.04	0.00	0.35	0.00	4.42	2.22	50.00
OLDHAM TRUST WEST 2AH - 2	P-DP	0.03	0.01	0.08	2.65	0.35	0.15	0.00	0.26	0.00	2.89	1.50	50.00
OLDHAM TRUST WEST 4051WA	P-DP	0.04	0.00	0.03	2.91	0.12	0.05	0.00	0.23	0.00	2.84	1.33	50.00
OLDHAM TRUST WEST 4058LS	P-DP	0.03	0.00	0.01	2.44	0.06	0.03	0.00	0.19	0.00	2.34	1.16	50.00
OLDHAM TRUST WEST 4AH - 4	P-DP	0.04	0.01	0.07	2.69	0.32	0.14	0.00	0.26	0.00	2.88	1.81	35.01
OLDHAM TRUST WEST 4SH - 4	P-DP	0.04	0.02	0.10	2.93	0.43	0.19	0.00	0.30	0.00	3.24	1.98	36.34
OLDHAM TRUST WEST 5AH - 5	P-DP	0.02	0.02	0.13	1.76	0.58	0.25	0.00	0.25	0.00	2.34	1.48	32.27
OLDHAM TRUST WEST 5MH - 5	P-DP	0.02	0.01	0.06	1.90	0.28	0.12	0.00	0.20	0.00	2.11	1.35	30.30
OLDHAM TRUST WEST 5SH - 5	P-DP	0.02	0.02	0.14	1.89	0.65	0.28	0.00	0.28	0.00	2.55	1.60	33.40
OLDHAM TRUST WEST 6AH - 6	P-DP	0.04	0.02	0.10	3.01	0.46	0.20	0.00	0.31	0.00	3.35	2.02	37.07
OLDHAM TRUST WEST LONG 2	P-DP	0.03	0.02	0.09	2.46	0.42	0.19	0.00	0.27	0.00	2.80	1.62	50.00
OLDHAM TRUST WEST UNIT 2	P-DP	0.05	0.01	0.08	3.53	0.34	0.15	0.00	0.33	0.00	3.70	2.07	50.00
OLDHAM TRUST WEST UNIT 2	P-DP	0.03	0.01	0.08	2.50	0.36	0.16	0.00	0.26	0.00	2.77	1.60	50.00
OLDHAM-GRAHAM 35A 1H - 1H	P-DP	0.12	0.20	0.79	9.54	4.02	0.79	0.00	2.67	0.00	11.68	6.73	34.17
OLDHAM-GRAHAM 35B 2H - 2	P-DP	0.18	0.31	1.19	14.07	6.04	1.19	0.00	3.99	0.00	17.31	9.42	41.20
OLDHAM-GRAHAM 35C 3H - 3	P-DP	0.14	0.38	1.47	10.83	7.45	1.47	0.00	4.40	0.00	15.36	8.49	36.09
OLDHAM-GRAHAM 35D 4H - 4	P-DP	0.17	0.32	1.24	13.13	6.30	1.24	0.00	4.04	0.00	16.62	9.27	39.44
OLDHAM-GRAHAM 35E 5H - 5H	P-DP	0.25	0.22	0.85	19.16	4.32	0.85	0.00	3.60	0.00	20.74	11.62	42.07
OLDHAM-GRAHAM 35F 6H - 6H	P-DP	0.33	0.26	1.02	25.33	5.15	1.02	0.00	4.49	0.00	27.01	13.97	48.19
OLSEN 13/14-24/23-C5-1H - 13/1	P-DP	0.09	0.00	0.08	5.20	0.00	0.14	0.00	0.11	0.00	5.23	2.78	36.61
OLSEN 16-13-14-C5-5H - 16-13-1	P-DP	0.41	0.00	3.01	24.86	0.00	5.12	0.00	1.50	0.00	28.48	14.73	50.00
ONEAL-ANNIE 15G 7H - 7H	P-DP	0.61	0.28	1.10	46.71	5.58	1.10	0.00	6.43	0.00	46.96	29.65	46.97
ONEAL-ANNIE 15H 8H - 8H	P-DP	1.03	0.67	2.61	79.19	13.22	2.61	0.00	12.68	0.00	82.34	49.38	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
ONEAL-ANNIE 15H 9H - 9H	P-DP	1.39	1.44	5.57	106.56	28.25	5.58	0.00	22.00	0.00	118.39	72.79	50.00
ONEAL-ANNIE 15J 10H - 10H	P-DP	1.15	1.20	4.66	88.26	23.62	4.66	0.00	18.33	0.00	98.22	57.71	50.00
ONEAL-ANNIE 15K 11H - 11H	P-DP	1.56	0.76	2.94	119.79	14.89	2.94	0.00	16.77	0.00	120.85	73.77	50.00
ONEAL-ANNIE 15K 12H - 12H	P-DP	0.75	0.58	2.25	57.87	11.41	2.25	0.00	10.09	0.00	61.44	38.20	50.00
ONEAL-ANNIE 15M 13H - 13H	P-DP	0.84	1.23	4.75	64.10	24.12	4.76	0.00	16.60	0.00	76.38	43.89	50.00
ONEAL-ANNIE 15M 14H - 14H	P-DP	1.83	0.22	0.86	140.55	4.37	0.86	0.00	13.49	0.00	132.29	77.79	50.00
ONEAL-ANNIE 15O 15H - 15H	P-DP	0.83	0.42	1.64	63.68	8.30	1.64	0.00	9.10	0.00	64.52	39.69	50.00
ONEAL-ANNIE 15P 16H - 16H	P-DP	0.66	0.37	1.45	50.33	7.34	1.45	0.00	7.56	0.00	51.56	31.14	50.00
ONEAL-ANNIE 15P 17H - 17H	P-DP	1.33	1.16	4.48	102.29	22.71	4.48	0.00	19.04	0.00	110.44	66.29	50.00
ONEAL-ANNIE 15R 18H - 18H	P-DP	0.30	0.18	0.70	23.03	3.57	0.70	0.00	3.56	0.00	23.75	16.32	37.80
ORSON-BILLY 139A 1H - 1H	P-DP	0.60	0.10	0.51	45.48	2.28	0.68	0.00	4.15	0.00	44.29	23.28	50.00
ORSON-BILLY 139B 2H - 2H	P-DP	0.57	0.12	0.59	43.47	2.66	0.79	0.00	4.15	0.00	42.77	24.46	50.00
ORSON-BILLY 139C 3H - 3H	P-DP	0.64	0.19	0.94	48.45	4.23	1.26	0.00	5.11	0.00	48.83	27.69	50.00
ORSON-BILLY 139D 4H - 4H	P-DP	0.38	0.07	0.35	28.99	1.55	0.46	0.00	2.69	0.00	28.32	15.19	50.00
ORSON-BILLY 139E 5H - 5H	P-DP	0.32	0.06	0.29	23.96	1.29	0.39	0.00	2.22	0.00	23.42	12.64	48.00
ORSON-BILLY 139F 6H - 6H	P-DP	0.79	0.26	1.27	60.05	5.73	1.71	0.00	6.52	0.00	60.96	32.93	50.00
ORSON-BILLY 139G 7H - 7H	P-DP	0.52	0.18	0.89	39.30	3.98	1.19	0.00	4.36	0.00	40.11	21.54	50.00
ORTHRUS UNIT A 34-22 1AH - 1	P-DP	2.46	0.02	7.57	181.57	0.39	25.33	0.00	17.00	0.00	190.28	90.46	50.00
ORTHRUS UNIT A 34-22 2AH - 2	P-DP	2.32	0.02	8.20	170.95	0.42	27.44	0.00	16.59	0.00	182.22	86.25	50.00
ORTHRUS UNIT A 34-22 3AH - 3	P-DP	1.88	0.01	5.32	138.34	0.27	17.79	0.00	12.71	0.00	143.69	72.92	50.00
ORTHRUS UNIT B 34-22 7AH - 7	P-DP	0.87	0.02	7.94	64.25	0.41	26.55	0.00	8.84	0.00	82.37	43.63	43.96
ORTHRUS UNIT B 34-22 8AH - 8	P-DP	1.81	0.01	4.10	133.60	0.21	13.72	0.00	11.72	0.00	135.81	70.52	50.00
OV UNIT 1 - 1	P-DP	0.03	0.00	0.01	2.61	0.07	0.01	0.00	0.25	0.00	2.44	1.28	25.91
OVMLC 1 - 1	P-DP	0.07	0.01	0.03	5.74	0.16	0.03	0.00	0.55	0.00	5.37	2.75	28.35
OVMLC 2 - 2	P-DP	0.06	0.00	0.00	4.50	0.02	0.00	0.00	0.39	0.00	4.14	2.09	30.96
OWL & HAWK 2-21C5 - 2-21C5	P-DP	0.08	0.00	0.15	4.79	0.00	0.26	0.00	0.13	0.00	4.93	2.45	49.52
OWL & HAWK 3-16C5 - 3-16C5	P-DP	0.01	0.00	0.01	0.66	0.00	0.02	0.00	0.01	0.00	0.67	0.32	30.56
OWL & HAWK 3-21C5 - 3-21C5	P-DP	0.02	0.00	0.07	0.95	0.00	0.12	0.00	0.04	0.00	1.03	0.71	17.96
OWL AND HAWK 2-31B5 - 2-31B	P-DP	0.08	0.00	0.08	4.84	0.00	0.13	0.00	0.10	0.00	4.87	2.18	43.40
OWL AND HAWK 3-10C5 - 3-10C	P-DP	0.07	0.00	0.20	4.05	0.00	0.33	0.00	0.13	0.00	4.25	1.92	50.00
OYSTER 001 - 001	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.33
P LAMANTIA 1 - 1	P-DP	0.00	0.00	0.18	0.00	0.00	0.25	0.00	0.02	0.00	0.23	0.13	50.00
P LONG 1 - 1	P-DP	0.00	0.00	0.27	0.00	0.00	0.38	0.00	0.04	0.00	0.34	0.22	50.00
P LONG 4 - 4	P-DP	0.00	0.00	0.10	0.00	0.00	0.14	0.00	0.01	0.00	0.12	0.08	50.00
PALMER 52 UNIT 222H - 222H	P-DP	0.32	0.43	0.42	23.68	9.43	0.29	0.00	4.33	0.00	29.06	15.56	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
PALMER 52 UNIT 332H - 332H	P-DP	0.15	0.32	0.31	11.40	6.98	0.21	0.00	2.67	0.00	15.93	8.75	50.00
PALOS 01-12-241	P-DP	0.00	0.00	2.07	0.00	0.00	5.34	0.00	0.62	0.00	4.71	4.08	3.26
PALOS 02-10-239	P-DP	0.00	0.00	2.03	0.00	0.00	5.23	0.00	0.61	0.00	4.62	3.63	5.78
PALOS 02-16-240	P-DP	0.00	0.00	11.47	0.00	0.00	29.57	0.00	3.44	0.00	26.13	17.56	11.33
PALOS 03-06-245	P-DP	0.00	0.00	4.70	0.00	0.00	12.12	0.00	1.41	0.00	10.71	8.19	6.44
PALOS 03-10-232	P-DP	0.00	0.00	3.79	0.00	0.00	9.76	0.00	1.14	0.00	8.62	6.92	5.21
PALOS 03-14-233	P-DP	0.00	0.00	2.29	0.00	0.00	5.90	0.00	0.69	0.00	5.22	4.53	3.24
PALOS 03-16-231	P-DP	0.00	0.00	3.22	0.00	0.00	8.29	0.00	0.97	0.00	7.33	6.14	4.23
PAMOLA UNIT A 35-23 1AH - 1A	P-DP	0.86	0.00	0.90	63.65	0.05	3.02	0.00	5.02	0.00	61.70	33.16	40.00
PAMOLA UNIT A 35-23 2AH - 2A	P-DP	0.54	0.01	2.49	39.78	0.13	8.32	0.00	4.17	0.00	44.06	23.52	35.85
PAMOLA UNIT A 35-23 3AH - 3A	P-DP	1.68	0.01	6.38	124.13	0.33	21.34	0.00	12.27	0.00	133.52	71.48	50.00
PAMOLA UNIT A 35-23 4AH - 4A	P-DP	2.08	0.03	12.69	153.37	0.65	42.43	0.00	17.74	0.00	178.72	89.40	50.00
PAPER RINGS 136-137 A 1WB - 1	P-DP	0.42	0.06	0.31	31.50	1.41	0.42	0.00	2.81	0.00	30.53	17.33	50.00
PARKS 1 - 1	P-DP	0.03	0.00	0.00	2.44	0.00	0.00	0.00	0.20	0.00	2.25	1.14	30.47
PARKS 6 2 - 2	P-DP	0.02	0.00	0.01	1.33	0.04	0.01	0.00	0.13	0.00	1.25	0.55	41.11
PARKS FIELD UNIT #2 2314 - 23	P-DP	0.00	0.00	0.00	0.10	0.01	0.00	0.00	0.01	0.00	0.09	0.07	8.02
PARKS FIELD UNIT 2 1450BH -	P-DP	0.06	0.10	0.37	4.30	1.88	0.37	0.00	1.24	0.00	5.31	2.82	32.47
PARKS FIELD UNIT 2 1450LH - 1	P-DP	0.06	0.10	0.40	4.94	2.04	0.40	0.00	1.37	0.00	6.02	3.21	43.13
PARKS FIELD UNIT 2 1451LH - 1	P-DP	0.11	0.07	0.25	8.53	1.29	0.25	0.00	1.30	0.00	8.78	4.54	40.51
PARKS FIELD UNIT 2 1454H - 14	P-DP	0.02	0.02	0.08	1.51	0.39	0.08	0.00	0.31	0.00	1.67	1.01	20.14
PARKS FIELD UNIT 2 1454LH - 1	P-DP	0.15	0.08	0.31	11.80	1.59	0.31	0.00	1.71	0.00	11.99	6.17	44.24
PARKS FIELD UNIT 2 1455LH - 1	P-DP	0.05	0.04	0.16	4.21	0.82	0.16	0.00	0.73	0.00	4.46	2.39	32.22
PARKS FIELD UNIT 2 1458CH -	P-DP	0.14	0.39	1.50	10.35	7.62	1.50	0.00	4.44	0.00	15.04	8.12	41.42
PARKS FIELD UNIT 2 1458LH - 1	P-DP	0.15	0.48	1.85	11.51	9.36	1.85	0.00	5.36	0.00	17.37	9.05	43.19
PARKS FIELD UNIT 2 1863BH -	P-DP	0.02	0.08	0.31	1.59	1.59	0.31	0.00	0.88	0.00	2.61	1.61	19.87
PARKS FIELD UNIT 2 1863LH - 1	P-DP	0.04	0.08	0.32	3.43	1.63	0.32	0.00	1.05	0.00	4.33	2.43	28.92
PARKS FIELD UNIT 2 1904BH -	P-DP	0.07	0.03	0.12	5.08	0.62	0.12	0.00	0.71	0.00	5.11	2.60	41.42
PARKS FIELD UNIT 2 1921H - 19	P-DP	0.03	0.04	0.16	2.64	0.82	0.16	0.00	0.60	0.00	3.02	1.62	27.69
PARKS FIELD UNIT 2 2001BH -	P-DP	0.07	0.23	0.88	5.56	4.46	0.88	0.00	2.56	0.00	8.34	4.54	47.10
PARKS FIELD UNIT 2 2101 - 210	P-DP	0.00	0.00	0.00	0.04	0.01	0.00	0.00	0.01	0.00	0.04	0.03	4.56
PARKS FIELD UNIT 2 2210 - 221	P-DP	0.00	0.00	0.00	0.33	0.02	0.00	0.00	0.03	0.00	0.32	0.19	19.72
PARKS FIELD UNIT 2 2307LH - 2	P-DP	0.06	0.01	0.06	4.90	0.28	0.06	0.00	0.53	0.00	4.71	2.60	43.55
PARKS FIELD UNIT 2 2307MH -	P-DP	0.22	0.02	0.08	16.77	0.39	0.08	0.00	1.55	0.00	15.69	8.62	50.00
PARKS FIELD UNIT 2 2308BH -	P-DP	0.06	0.07	0.26	4.25	1.30	0.26	0.00	0.96	0.00	4.85	2.79	38.60
PARKS FIELD UNIT 2 2308LH - 2	P-DP	0.22	0.19	0.72	16.74	3.64	0.72	0.00	3.08	0.00	18.02	8.88	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
PARKS FIELD UNIT 2 2308MH -	P-DP	0.16	0.16	0.62	12.59	3.12	0.62	0.00	2.50	0.00	13.83	7.21	50.00
PARKS FIELD UNIT 2 2329LH - 2	P-DP	0.00	0.03	0.11	0.32	0.56	0.11	0.00	0.29	0.00	0.70	0.54	7.01
PARKS FIELD UNIT 2 2336BH -	P-DP	0.00	0.03	0.11	0.14	0.54	0.11	0.00	0.26	0.00	0.52	0.43	4.58
PARKS FIELD UNIT 2 2346CH -	P-DP	0.00	0.01	0.02	0.03	0.10	0.02	0.00	0.05	0.00	0.10	0.08	4.90
PARKS FIELD UNIT 2 2348H - 23	P-DP	0.09	0.02	0.09	6.81	0.46	0.09	0.00	0.77	0.00	6.59	3.38	38.41
PARKS FIELD UNIT 2 2606 - 260	P-DP	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	1.53
PARKS FIELD UNIT 2 2630H - 26	P-DP	0.03	0.07	0.29	2.11	1.46	0.29	0.00	0.86	0.00	3.00	2.05	11.94
PARKS FIELD UNIT 2 2709H - 27	P-DP	0.03	0.07	0.28	2.10	1.45	0.29	0.00	0.85	0.00	2.98	1.82	21.77
PARKS FIELD UNIT 2 911 - 911	P-DP	0.00	0.00	0.01	0.13	0.03	0.01	0.00	0.03	0.00	0.14	0.10	11.70
PARKS FIELD UNIT NO. 2 1320H	P-DP	0.01	0.05	0.21	0.89	1.08	0.21	0.00	0.58	0.00	1.60	0.68	45.73
PARKS FIELD UNIT NO. 2 1421H	P-DP	0.01	0.12	0.48	0.64	2.44	0.48	0.00	1.20	0.00	2.35	1.09	39.32
PARKS FIELD UNIT NO. 2 1422H	P-DP	0.01	0.16	0.62	1.06	3.15	0.62	0.00	1.58	0.00	3.26	1.44	45.30
PARKS FIELD UNIT NO. 2 1423H	P-DP	0.00	0.01	0.04	0.22	0.20	0.04	0.00	0.11	0.00	0.35	0.21	15.35
PARKS FIELD UNIT NO. 2 1829H	P-DP	0.00	0.00	0.01	0.18	0.06	0.01	0.00	0.04	0.00	0.21	0.14	10.20
PARKS FIELD UNIT NO. 2 1831H	P-DP	0.00	0.00	0.01	0.00	0.07	0.01	0.00	0.03	0.00	0.05	0.04	7.21
PARKS FIELD UNIT NO. 2 1917H	P-DP	0.00	0.04	0.14	0.20	0.70	0.14	0.00	0.35	0.00	0.70	0.42	30.40
PARKS FIELD UNIT NO. 2 2324H	P-DP	0.01	0.05	0.21	0.62	1.07	0.21	0.00	0.56	0.00	1.35	0.69	29.44
PARKS FIELD UNIT NO. 2 2401 -	P-DP	0.00	0.00	0.01	0.00	0.03	0.01	0.00	0.01	0.00	0.02	0.02	1.52
PARKS FIELD UNIT NO. 2 2417H	P-DP	0.00	0.01	0.03	0.02	0.14	0.03	0.00	0.07	0.00	0.12	0.09	8.44
PARKS, ROY 10 - 10	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.69
PARKS, ROY 301MH - 301MH	P-DP	0.09	0.05	0.20	6.56	1.01	0.20	0.00	1.01	0.00	6.76	4.63	48.38
PARKS, ROY 302LH - 302LH	P-DP	0.10	0.11	0.43	7.99	2.20	0.43	0.00	1.69	0.00	8.94	5.68	50.00
PARKS, ROY 302MH - 302MH	P-DP	0.09	0.07	0.27	6.88	1.38	0.27	0.00	1.21	0.00	7.33	4.60	50.00
PARKS, ROY 303BH - 303BH	P-DP	0.09	0.07	0.27	6.88	1.38	0.27	0.00	1.21	0.00	7.33	4.60	50.00
PARKS, ROY 303LH - 303LH	P-DP	0.09	0.11	0.42	6.99	2.14	0.42	0.00	1.58	0.00	7.97	4.84	50.00
PARKS, ROY 303MH - 303MH	P-DP	0.07	0.06	0.22	5.51	1.11	0.22	0.00	0.97	0.00	5.86	3.68	50.00
PARKS, ROY 306BH - 306BH	P-DP	0.03	0.03	0.11	2.05	0.55	0.11	0.00	0.42	0.00	2.28	1.40	32.53
PARKS, ROY 306LH - 306LH	P-DP	0.05	0.02	0.06	3.53	0.30	0.06	0.00	0.43	0.00	3.46	1.98	40.83
PARKS, ROY 307BH - 307BH	P-DP	0.03	0.02	0.08	1.92	0.39	0.08	0.00	0.34	0.00	2.05	1.22	33.85
PARKS, ROY 307LH - 307LH	P-DP	0.00	0.02	0.09	0.00	0.43	0.09	0.00	0.20	0.00	0.31	0.17	28.55
PARKS, ROY 308BH - 308BH	P-DP	0.03	0.01	0.04	2.19	0.19	0.04	0.00	0.27	0.00	2.15	1.26	35.04
PARKS, ROY 308LH - 308LH	P-DP	0.00	0.01	0.04	0.00	0.22	0.04	0.00	0.10	0.00	0.16	0.10	19.28
PARKS, ROY 308MH - 308MH	P-DP	0.09	0.02	0.06	6.57	0.30	0.06	0.00	0.68	0.00	6.26	3.62	50.00
PARKS, ROY 31 - 31	P-DP	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.01	0.00	0.02	0.01	7.92
PARKS, ROY 311JH - 311JH	P-DP	0.10	0.13	0.49	7.93	2.47	0.49	0.00	1.81	0.00	9.08	5.53	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
PARKS, ROY 316CH - 316CH	P-DP	0.01	0.01	0.03	0.51	0.14	0.03	0.00	0.11	0.00	0.57	0.36	20.05
PARKS, ROY 316LH - 316LH	P-DP	0.05	0.01	0.04	3.92	0.22	0.04	0.00	0.42	0.00	3.76	2.08	48.33
PARKS, ROY 34 - 34	P-DP	0.00	0.00	0.01	0.00	0.03	0.01	0.00	0.02	0.00	0.02	0.02	11.06
PARKS, ROY 4 - 4	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PARKS, ROY 53 - 53	P-DP	0.00	0.00	0.01	0.11	0.04	0.01	0.00	0.03	0.00	0.13	0.06	26.62
PARKS, ROY 99H - 99H	P-DP	0.00	0.03	0.11	0.06	0.54	0.11	0.00	0.26	0.00	0.45	0.29	20.47
PARKS-COYOTE 1506 A 15HJ - 1	P-DP	0.36	0.09	0.36	27.90	1.85	0.37	0.00	3.14	0.00	26.97	15.41	46.54
PARKS-COYOTE 1506 A 1HM - 1	P-DP	0.35	0.17	0.64	26.62	3.25	0.64	0.00	3.70	0.00	26.81	15.93	39.94
PARKS-COYOTE 1506 A 8HS - 8	P-DP	0.56	0.18	0.71	42.82	3.58	0.71	0.00	5.17	0.00	41.93	23.83	50.00
PARKS-COYOTE 1506 B 2HM - 2	P-DP	0.15	0.09	0.36	11.41	1.84	0.36	0.00	1.80	0.00	11.81	7.29	29.96
PARKS-COYOTE 1506 B 9HS - 9	P-DP	0.28	0.15	0.57	21.18	2.87	0.57	0.00	3.08	0.00	21.54	12.94	42.72
PARKS-COYOTE 1506 C 10HS -	P-DP	0.52	0.18	0.68	40.03	3.46	0.68	0.00	4.89	0.00	39.28	21.76	50.00
PARKS-COYOTE 1506 C 16HJ - 1	P-DP	0.48	0.17	0.66	37.18	3.32	0.66	0.00	4.59	0.00	36.57	20.32	50.00
PARKS-COYOTE 1506 C 3HM - 3	P-DP	0.21	0.22	0.86	16.17	4.34	0.86	0.00	3.36	0.00	18.00	11.00	33.35
PARKS-COYOTE 1506 D 11HS -	P-DP	0.26	0.14	0.53	20.25	2.70	0.53	0.00	2.92	0.00	20.56	12.23	42.80
PARKS-COYOTE 1506 D 17HS -	P-DP	0.20	0.09	0.34	15.61	1.72	0.34	0.00	2.08	0.00	15.59	9.31	39.23
PARKS-COYOTE 1506 D 4HM - 4	P-DP	0.57	0.34	1.31	43.78	6.67	1.32	0.00	6.71	0.00	45.05	26.06	46.15
PARKS-COYOTE 1506 E 12HS -	P-DP	0.39	0.31	1.18	29.83	6.01	1.19	0.00	5.26	0.00	31.77	18.66	48.99
PARKS-COYOTE 1506 E 18HJ - 1	P-DP	0.35	0.20	0.78	27.01	3.97	0.78	0.00	4.07	0.00	27.69	16.34	46.79
PARKS-COYOTE 1506 E 5HM - 5	P-DP	0.26	0.21	0.80	19.93	4.04	0.80	0.00	3.53	0.00	21.24	12.46	37.05
PARKS-COYOTE 1506 F 13HS - 1	P-DP	0.52	0.42	1.64	39.96	8.32	1.64	0.00	7.18	0.00	42.74	24.05	50.00
PARKS-COYOTE 1506 F 6HM - 6	P-DP	0.36	0.10	0.39	27.80	1.97	0.39	0.00	3.19	0.00	26.96	15.76	40.92
PARKS-COYOTE 1506 G 14HS -	P-DP	0.82	0.15	0.60	63.24	3.03	0.60	0.00	6.57	0.00	60.30	35.06	50.00
PARKS-COYOTE 1506 G 19HS -	P-DP	0.28	0.05	0.19	21.59	0.98	0.19	0.00	2.22	0.00	20.55	12.03	42.49
PARKS-COYOTE 1506 G 7HM - 7	P-DP	0.47	0.12	0.48	35.81	2.43	0.48	0.00	4.06	0.00	34.66	20.67	43.18
PATRICIA-NORRIS ALLOCATIO	P-DP	0.04	0.14	0.70	3.15	3.17	0.95	0.00	1.44	0.00	5.82	3.71	24.67
PATRICIA-NORRIS ALLOCATIO	P-DP	0.06	0.18	0.89	4.54	3.99	1.19	0.00	1.85	0.00	7.87	5.72	12.68
PATTERSON 3 - 3	P-DP	0.00	0.00	0.29	0.00	0.00	0.41	0.00	0.04	0.00	0.37	0.20	50.00
PAULSEN 2-15C5 - 2-15C5	P-DP	0.17	0.00	0.64	10.25	0.00	1.10	0.00	0.39	0.00	10.95	4.79	42.86
PERCY 39 1R - 1R	P-DP	0.05	0.03	0.14	3.91	0.62	0.19	0.00	0.52	0.00	4.20	2.02	37.54
PERRY 48 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.44
PHILLIPS 1 - 1	P-DP	0.00	0.00	1.97	0.00	0.00	2.77	0.00	0.26	0.00	2.51	1.20	50.00
PHILLIPS 2 - 2	P-DP	0.00	0.00	0.70	0.00	0.00	0.98	0.00	0.09	0.00	0.89	0.55	50.00
PHILLIPS 3 - 3	P-DP	0.00	0.00	0.65	0.00	0.00	0.92	0.00	0.09	0.00	0.83	0.52	50.00
PHILLIPS-GUTHRIE 1 - 1	P-DP	0.00	0.00	0.00	0.18	0.01	0.00	0.00	0.02	0.00	0.18	0.15	4.24

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
PHILLIPS-GUTHRIE 2 - 2	*P-DP*	0.00	0.00	0.00	0.14	0.01	0.00	0.00	0.01	0.00	0.14	0.13	1.75
PHOENIX UNIT 35-38 8AH - 8AH	*P-DP*	1.60	0.01	4.95	117.76	0.25	16.55	0.00	11.05	0.00	123.52	71.82	26.66
PIXIE UNIT A 35-47 1AH - 1AH	*P-DP*	3.35	0.00	1.04	246.75	0.05	3.46	0.00	18.14	0.00	232.13	116.95	50.00
PIXIE UNIT A 35-47 2AH - 2AH	*P-DP*	0.90	0.01	6.53	66.29	0.34	21.83	0.00	8.23	0.00	80.23	44.61	33.51
PIXIE UNIT A 35-47 3AH - 3AH	*P-DP*	7.07	0.04	17.09	520.88	0.88	57.15	0.00	46.29	0.00	532.62	315.73	50.00
PIXIE UNIT A 35-47 3SH - 3SH	*P-DP*	4.47	0.03	11.83	329.15	0.61	39.56	0.00	29.80	0.00	339.52	203.63	49.18
PIXIE UNIT B 35-47 5AH - 5AH	*P-DP*	6.89	0.03	14.29	507.36	0.73	47.77	0.00	43.82	0.00	512.05	236.33	50.00
PIXIE UNIT B 35-47 6AH - 6AH	*P-DP*	7.56	0.03	11.95	556.74	0.61	39.97	0.00	46.08	0.00	551.24	311.12	50.00
POCONO WEST A2 1LA - 1LA	*P-DP*	0.25	0.58	3.59	19.11	11.80	4.82	0.00	4.86	0.00	30.88	18.64	42.77
POCONO WEST A2 5H - 5H	*P-DP*	0.01	0.13	0.79	1.08	2.60	1.06	0.00	0.84	0.00	3.90	2.92	12.45
POCONO WEST A3 7CH - 7CH	*P-DP*	0.04	0.08	0.53	2.93	1.73	0.71	0.00	0.72	0.00	4.65	2.71	34.32
POCONO WEST A3 9UA - 9UA	*P-DP*	0.22	0.35	2.18	16.95	7.16	2.92	0.00	3.34	0.00	23.70	13.00	50.00
POCONO WEST A4 2LA - 2LA	*P-DP*	0.05	0.24	1.50	3.66	4.92	2.01	0.00	1.71	0.00	8.88	4.97	45.85
POCONO WEST A4 6H - 6H	*P-DP*	0.15	0.34	2.12	11.56	6.97	2.84	0.00	2.89	0.00	18.49	9.94	50.00
POCONO WEST A5 10UA - 10UA	*P-DP*	0.20	0.17	1.05	14.88	3.44	1.41	0.00	2.09	0.00	17.64	10.38	30.73
POCONO WEST A6 3LA - 3LA	*P-DP*	0.16	0.25	1.56	12.16	5.13	2.09	0.00	2.39	0.00	17.00	9.09	50.00
POINTER N CRC JF 7H - 7H	*P-DP*	0.00	0.00	83.73	0.00	0.00	165.85	0.00	103.29	0.00	62.56	32.86	50.00
POINTER N CRC JF 9H - 9H	*P-DP*	0.00	0.00	124.61	0.00	0.00	246.84	0.00	153.73	0.00	93.11	48.53	50.00
POINTER W CRC JF 5H - 5H	*P-DP*	0.00	0.00	7.11	0.00	0.00	14.08	0.00	8.77	0.00	5.31	2.89	50.00
POLTERGEIST GUARDIAN A 12-	*P-DP*	0.02	0.00	0.03	1.27	0.12	0.05	0.00	0.12	0.00	1.33	0.74	50.00
POLTERGEIST GUARDIAN B 12	*P-DP*	0.08	0.02	0.11	5.94	0.48	0.21	0.00	0.53	0.00	6.10	3.36	50.00
POLTERGEIST GUARDIAN C 12	*P-DP*	0.05	0.01	0.09	4.03	0.39	0.17	0.00	0.37	0.00	4.22	2.30	50.00
POLTERGEIST UNIT B 11-02 5SH	*P-DP*	0.13	0.01	0.05	9.80	0.20	0.09	0.00	0.75	0.00	9.35	5.57	50.00
POLTERGEIST-PIXIE A 11-38 6S	*P-DP*	2.16	0.37	2.19	164.32	9.82	4.30	0.00	13.88	0.00	164.56	98.10	50.00
POLTERGEIST-PIXIE B 11-38 6A	*P-DP*	3.04	0.51	3.00	231.53	13.44	5.88	0.00	19.47	0.00	231.38	138.04	50.00
POTH UNIT 1H - 1H	*P-DP*	0.20	0.17	0.82	14.60	3.01	1.60	0.00	1.67	0.00	17.53	8.89	37.83
POWELL 43 1 - 1	*P-DP*	0.04	0.01	0.03	3.05	0.13	0.04	0.00	0.27	0.00	2.95	1.49	30.31
POWELL A 2 - 2	*P-DP*	0.14	0.03	0.16	10.44	0.72	0.22	0.00	1.03	0.00	10.34	6.01	26.36
POWELL A 3 - 3	*P-DP*	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.01	0.00	0.03	0.03	1.14
POWELL B 1 - 1	*P-DP*	0.07	0.02	0.07	5.54	0.34	0.10	0.00	0.53	0.00	5.45	3.24	31.89
POWELL C 1 - 1	*P-DP*	0.10	0.02	0.10	7.37	0.46	0.14	0.00	0.71	0.00	7.27	4.17	35.70
PRIMA 1H - 1H	*P-DP*	0.06	0.09	0.09	4.73	1.96	0.06	0.00	0.88	0.00	5.86	2.95	43.43
PRIMERO 42 1 - 1	*P-DP*	1.71	0.15	0.89	130.66	3.96	1.74	0.00	10.20	0.00	126.16	52.42	50.00
PRIMERO 42 A 2 - 2	*P-DP*	0.07	0.00	0.00	5.51	0.00	0.00	0.00	0.39	0.00	5.12	3.33	12.57
PRIMERO 42 B3 3 - 3	*P-DP*	0.82	0.03	0.18	62.35	0.80	0.35	0.00	4.63	0.00	58.87	24.66	45.22

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
PRIMERO 42 C 5 - 5	P-DP	0.21	0.00	0.00	16.06	0.00	0.00	0.00	1.15	0.00	14.91	7.53	25.12
PRIMERO 42 D 6 - 6	P-DP	0.06	0.00	0.00	4.62	0.00	0.00	0.00	0.33	0.00	4.29	3.15	8.66
PRISCILLA 23-14 1LS - 1LS	P-DP	0.07	0.03	0.15	5.09	0.68	0.30	0.00	0.51	0.00	5.55	2.99	50.00
PRISCILLA 23-14 2MS - 2MS	P-DP	0.03	0.02	0.11	2.66	0.50	0.22	0.00	0.30	0.00	3.08	1.75	49.56
PRISCILLA 23-14 3A - 3A	P-DP	0.09	0.02	0.09	7.06	0.41	0.18	0.00	0.59	0.00	7.06	3.80	50.00
PRISCILLA 23-14 4AH - 4AH	P-DP	0.02	0.01	0.03	1.60	0.15	0.07	0.00	0.15	0.00	1.67	0.86	43.67
PRISCILLA 23-14 4LS - 4LS	P-DP	0.08	0.01	0.07	6.04	0.33	0.14	0.00	0.50	0.00	6.01	3.27	50.00
PRISCILLA 23-14 4SH - 4SH	P-DP	0.03	0.01	0.03	2.17	0.14	0.06	0.00	0.19	0.00	2.19	1.08	48.62
PRISCILLA 23-14 5A - 5A	P-DP	0.05	0.02	0.15	3.98	0.66	0.29	0.00	0.43	0.00	4.50	2.63	45.55
PRISCILLA 23-14 6LS - 6LS	P-DP	0.08	0.04	0.22	6.06	1.00	0.44	0.00	0.65	0.00	6.85	3.68	50.00
PRISCILLA 23-14 7MS - 7MS	P-DP	0.03	0.00	0.00	2.13	0.01	0.01	0.00	0.16	0.00	2.00	1.24	40.56
PRONGHORN B 34-166-165 WA	P-DP	0.00	0.00	0.00	0.32	0.03	0.00	0.00	0.04	0.00	0.31	0.16	50.00
PRONGHORN C 34-166-165 WB	P-DP	0.00	0.00	0.00	0.20	0.02	0.00	0.00	0.03	0.00	0.19	0.10	50.00
PRONTO 1H - 1H	P-DP	0.05	0.06	0.06	3.56	1.42	0.04	0.00	0.65	0.00	4.38	2.19	40.51
PRUETT 20 2 - 2	P-DP	0.00	0.00	0.00	0.14	0.01	0.00	0.00	0.01	0.00	0.14	0.07	43.07
PRUETT 20 4 - 4	P-DP	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.01	0.00	0.10	0.06	28.21
PRUETT 20 5H - 5H	P-DP	0.00	0.00	0.00	0.07	0.01	0.00	0.00	0.01	0.00	0.07	0.04	22.66
PRUETT 20 6H - 6H	P-DP	0.00	0.00	0.00	0.31	0.02	0.00	0.00	0.03	0.00	0.30	0.15	42.08
PRUETT 23 1 - 1	P-DP	0.00	0.00	0.00	0.17	0.06	0.00	0.00	0.03	0.00	0.21	0.07	50.00
PRUETT 23 2H - 2H	P-DP	0.00	0.00	0.00	0.18	0.00	0.00	0.00	0.02	0.00	0.16	0.09	28.18
PRUETT 23A 1 - 1	P-DP	0.01	0.00	0.00	0.42	0.02	0.00	0.00	0.04	0.00	0.40	0.20	39.42
PRUETT 23A 2H - 2H	P-DP	0.01	0.00	0.00	0.46	0.02	0.00	0.00	0.05	0.00	0.44	0.23	39.37
PUGGLE E WYN JF 4H - 4H	P-DP	0.00	0.00	396.51	0.00	0.00	785.45	0.00	489.16	0.00	296.29	182.34	34.58
PUGGLE E WYN JF 6H - 6H	P-DP	0.00	0.00	456.19	0.00	0.00	903.67	0.00	562.78	0.00	340.88	200.40	37.85
PUGGLE W WYN JF 2H - 2H	P-DP	0.00	0.00	50.03	0.00	0.00	99.11	0.00	61.72	0.00	37.39	31.11	8.33
QUESO 34-153 UNIT 1H - 1H	P-DP	0.47	0.25	0.24	35.43	5.40	0.17	0.00	4.41	0.00	36.59	21.45	42.38
QUESO 34-153 UNIT 2H - 2H	P-DP	0.51	0.23	0.22	38.49	5.01	0.15	0.00	4.59	0.00	39.07	21.74	41.43
QUICK SILVER 55-1-18-19 A 12H	P-DP	0.02	0.01	0.04	1.60	0.34	-0.02	0.00	0.07	0.00	1.86	1.08	50.00
QUICK SILVER 55-1-18-19 B 21H	P-DP	0.02	0.01	0.04	1.36	0.32	-0.01	0.00	0.05	0.00	1.61	0.94	50.00
QUICK SILVER 55-1-18-19 C 13H	P-DP	0.04	0.03	0.09	2.74	0.76	-0.03	0.00	0.07	0.00	3.39	1.96	50.00
QUICK SILVER 55-1-7 UNIT 1H -	P-DP	0.03	0.02	0.05	2.42	0.45	-0.02	0.00	0.11	0.00	2.74	1.37	46.86
QUITO, S. W. (DELAWARE) UNI	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAGLAND 2 6 - 6	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.46
RAGLAND-ANDERSON 47A 1H	P-DP	0.75	0.19	0.95	56.65	4.26	1.27	0.00	5.71	0.00	56.46	31.13	39.94
RAGLAND-ANDERSON 47B 2H	P-DP	0.87	0.37	1.78	66.03	8.01	2.39	0.00	7.82	0.00	68.61	36.82	42.35

TABLE 7

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As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
RAGLAND-ANDERSON 47C 3H	P-DP	0.63	0.23	1.13	47.59	5.07	1.51	0.00	5.37	0.00	48.80	27.11	37.61
RAINIER 55-1-28 UNIT 1H - 1H	P-DP	0.02	0.01	0.02	1.19	0.20	-0.01	0.00	0.06	0.00	1.32	0.71	48.33
RAMBO E2 08 17 STATE COM 0	P-DP	0.05	0.00	0.03	4.11	0.02	0.04	0.00	0.56	0.00	3.61	2.10	38.93
RAMBO E2 08 17 STATE COM 0	P-DP	0.07	0.00	0.06	5.36	0.03	0.07	0.00	0.74	0.00	4.72	2.77	41.58
RATHKAMP UNIT 1H - 1H	P-DP	0.04	0.04	0.19	2.72	0.70	0.37	0.00	0.33	0.00	3.45	1.87	26.13
RATHKAMP UNIT 2H - 2H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RATHKAMP UNIT 3H - 3H	P-DP	0.07	0.07	0.35	4.99	1.29	0.68	0.00	0.61	0.00	6.35	3.49	36.34
RATHKAMP UNIT 4H - 4H	P-DP	0.00	0.32	1.58	0.00	5.76	3.06	0.00	0.88	0.00	7.94	4.16	50.00
REBEL 3-35B5 - 3-35B5	P-DP	0.00	0.00	0.01	0.02	0.00	0.02	0.00	0.01	0.00	0.04	0.03	5.71
REED 24 UNIT 2H - 2H	P-DP	0.02	0.00	0.00	1.83	0.00	0.00	0.00	0.17	0.00	1.66	1.04	30.42
REED 24 UNIT 4H - 4H	P-DP	0.01	0.00	0.01	0.79	0.06	0.00	0.00	0.06	0.00	0.78	0.52	20.65
REED 24 UNIT 5H - 5H	P-DP	0.04	0.02	0.05	3.14	0.40	-0.02	0.00	0.19	0.00	3.32	2.04	36.24
REED 24 UNIT 7H - 7H	P-DP	0.04	0.01	0.04	3.13	0.33	-0.02	0.00	0.21	0.00	3.24	1.99	36.37
REED 24 UNIT 8H - 8H	P-DP	0.03	0.00	0.00	2.61	0.03	0.00	0.00	0.23	0.00	2.40	1.45	35.02
REITZ UNIT 3H - 3H	P-DP	0.00	0.00	24.65	0.00	0.00	50.41	0.00	4.39	0.00	46.02	30.45	38.78
REITZ UNIT 5H - 5H	P-DP	0.00	0.00	5.98	0.00	0.00	12.23	0.00	1.07	0.00	11.16	7.33	24.08
RENDEZVOUS NORTH POOLED	P-DP	0.08	0.01	0.01	5.73	0.18	0.01	0.00	0.55	0.00	5.37	2.79	48.43
RENDEZVOUS NORTH POOLED	P-DP	0.06	0.01	0.01	4.35	0.27	0.01	0.00	0.45	0.00	4.18	2.05	46.42
RICHARD E LEHMAN SWITZ9B	P-DP	0.00	0.00	2.28	0.00	0.00	4.13	0.00	0.44	0.00	3.69	1.95	40.41
RICHARD E LEHMAN SWITZ9D	P-DP	0.00	0.00	1.33	0.00	0.00	2.41	0.00	0.26	0.00	2.15	1.20	33.46
RICHMOND 39 2H - 2H	P-DP	0.01	0.01	0.05	0.81	0.16	0.07	0.00	0.11	0.00	0.93	0.56	37.94
RICHMOND 39 3H - 3H	P-DP	0.02	0.02	0.13	1.40	0.41	0.17	0.00	0.22	0.00	1.76	0.88	50.00
RICHMOND W STATE 4239 A-A	P-DP	0.01	0.00	0.03	0.46	0.09	0.04	0.00	0.06	0.00	0.53	0.29	45.57
RICHMOND W STATE 4239 A-B	P-DP	0.01	0.01	0.04	0.40	0.12	0.05	0.00	0.07	0.00	0.51	0.30	33.77
RICHMOND W STATE 4239 A-C	P-DP	0.00	0.00	0.02	0.21	0.07	0.03	0.00	0.04	0.00	0.27	0.15	39.07
RICHMOND W STATE 4239 A-D	P-DP	0.00	0.00	0.02	0.25	0.08	0.03	0.00	0.04	0.00	0.32	0.17	40.81
RICHMOND W. STATE 4239 A5	P-DP	0.01	0.01	0.06	0.39	0.20	0.08	0.00	0.09	0.00	0.59	0.31	50.00
RICHMOND W. STATE 4239 A6	P-DP	0.01	0.01	0.04	0.47	0.14	0.06	0.00	0.08	0.00	0.59	0.32	50.00
RICHMOND W. STATE 4239 A7	P-DP	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.03	0.02	45.56
RIO GRANDE 12-24-C 36WB - 36	P-DP	0.17	0.08	0.39	12.78	1.74	0.52	0.00	1.59	0.00	13.45	8.29	50.00
RIO GRANDE 12-24-D 42LS - 42	P-DP	0.20	0.03	0.13	14.85	0.59	0.17	0.00	1.30	0.00	14.32	8.68	50.00
RIO GRANDE 12-24-E 42WA - 42	P-DP	0.19	0.06	0.30	14.12	1.34	0.40	0.00	1.53	0.00	14.32	9.25	50.00
RIO GRANDE 12-24-F 48WB - 48	P-DP	0.11	0.06	0.29	8.16	1.28	0.38	0.00	1.08	0.00	8.75	5.56	49.67
RIO GRANDE 12-24-G 52WA - 52	P-DP	0.19	0.07	0.36	14.05	1.63	0.49	0.00	1.64	0.00	14.53	9.21	50.00
RIO GRANDE 12-24-H 52LS - 52	P-DP	0.14	0.05	0.24	10.92	1.08	0.32	0.00	1.20	0.00	11.13	7.23	48.94

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes: Oil (Mbbl)	Net Sales Volumes: NGL (Mbbl)	Net Sales Volumes: Residue Gas (MMcf)	Net Revenue: Oil (M$)	Net Revenue: NGL (M$)	Net Revenue: Residue Gas (M$)	Net Revenue: Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow: Non-Disc. (M$)	Cash Flow: Disc. 10% (M$)	Life (years)
RISING SUN 40-33 1AH - 1AH	P-DP	1.68	0.47	2.79	128.16	12.51	5.48	0.00	11.87	0.00	134.27	82.46	40.24
RISING SUN B 1LS - 1LS	P-DP	1.85	0.45	2.63	140.61	11.76	5.15	0.00	12.60	0.00	144.92	86.69	50.00
RISING SUN C 2A - 2A	P-DP	1.20	0.17	0.98	91.19	4.40	1.93	0.00	7.47	0.00	90.05	56.95	42.48
RISING SUN C 3LS - 3LS	P-DP	0.73	0.07	0.42	55.68	1.88	0.82	0.00	4.39	0.00	54.00	33.73	36.49
RISING SUN D 4A - 4A	P-DP	1.47	0.34	2.01	112.21	8.99	3.94	0.00	9.97	0.00	115.16	71.70	45.72
RIVER CAT 57-33 A 1WA - 1WA	P-DP	0.22	0.00	0.09	16.31	0.05	0.06	0.00	1.72	0.00	14.70	8.05	50.00
RIVER CAT 57-33 B 2BS - 2BS	P-DP	0.11	0.00	0.05	8.30	0.02	0.03	0.00	0.88	0.00	7.48	4.48	42.08
RIVER CAT 57-33 C 3TS - 3TS	P-DP	0.28	0.00	0.12	21.08	0.06	0.08	0.00	2.25	0.00	18.98	11.09	45.57
ROADRUNNER 1 - 1	P-DP	0.02	0.01	0.01	1.49	0.19	0.01	0.00	0.18	0.00	1.51	0.86	20.34
ROADRUNNER 2 - 2	P-DP	0.03	0.01	0.01	2.28	0.18	0.01	0.00	0.24	0.00	2.22	1.19	24.62
ROBYN LEE C 3H - 3H	P-DP	0.02	0.01	0.03	1.60	0.17	0.03	0.00	0.24	0.00	1.57	0.98	49.57
ROBYN LEE D 4H - 4H	P-DP	0.03	0.01	0.03	2.07	0.15	0.03	0.00	0.26	0.00	1.98	1.23	50.00
ROBYN LEE I 9H - 9H	P-DP	0.10	0.02	0.07	7.75	0.41	0.07	0.00	0.84	0.00	7.39	4.56	50.00
ROBYN LEE J 10H - 10H	P-DP	0.07	0.01	0.05	5.43	0.29	0.05	0.00	0.59	0.00	5.18	3.19	50.00
ROCA UNIT 7 1 - 1	P-DP	0.06	0.01	0.01	4.20	0.12	0.00	0.00	0.40	0.00	3.92	1.90	39.73
ROCA UNIT 7 2H - 2H	P-DP	0.03	0.00	0.00	2.57	0.07	0.00	0.00	0.24	0.00	2.40	1.22	33.62
ROI TAN A 1A - 1A	P-DP	0.48	0.11	0.63	36.21	2.84	1.24	0.00	3.20	0.00	37.09	23.69	38.09
ROI TAN B 2A - 2A	P-DP	0.82	0.09	0.50	62.38	2.25	0.99	0.00	4.95	0.00	60.67	38.17	43.99
ROI TAN B 3LS - 3LS	P-DP	0.44	0.12	0.73	33.26	3.25	1.42	0.00	3.08	0.00	34.86	22.20	37.12
ROI TAN C 4A - 4A	P-DP	0.62	0.13	0.76	47.48	3.41	1.49	0.00	4.13	0.00	48.24	30.70	41.21
ROI TAN D 5A - 5A	P-DP	0.76	0.10	0.59	57.55	2.65	1.16	0.00	4.69	0.00	56.67	35.56	43.83
ROI TAN E 6A - 6A	P-DP	0.21	0.03	0.18	15.75	0.82	0.36	0.00	1.30	0.00	15.62	10.09	29.33
ROI TAN F 7LS - 7LS	P-DP	0.62	0.04	0.21	47.29	0.94	0.41	0.00	3.58	0.00	45.05	27.64	42.44
ROI TAN F 8A - 8A	P-DP	0.23	0.03	0.20	17.27	0.88	0.39	0.00	1.43	0.00	17.11	10.80	30.81
ROSS NW WHL BL 1H - 1H	P-DP	0.00	0.00	574.18	0.00	0.00	1,174.08	0.00	102.28	0.00	1,071.79	610.44	50.00
ROUGAROU UNIT 36-48 5AH - 5	P-DP	7.52	0.01	5.07	553.73	0.26	16.96	0.00	42.17	0.00	528.78	239.48	50.00
ROUGAROU UNIT 36-48 6AH - 6	P-DP	3.38	0.01	3.01	249.06	0.15	10.07	0.00	19.36	0.00	239.92	155.56	36.57
ROXY CRC JF 1H - 1H	P-DP	0.00	0.00	64.19	0.00	0.00	127.15	0.00	79.19	0.00	47.97	30.37	25.83
ROXY N CRC JF 3H - 3H	P-DP	0.00	0.00	17.15	0.00	0.00	33.96	0.00	21.15	0.00	12.81	8.20	25.99
ROXY NE CRC JF 5H - 5H	P-DP	0.00	0.00	5.70	0.00	0.00	11.30	0.00	7.04	0.00	4.26	2.75	25.43
RUSTLER A UNIT 3H - 3H	P-DP	0.08	0.03	0.10	6.45	0.83	-0.02	0.00	0.40	0.00	6.87	3.35	50.00
RUSTLER A UNIT 4H - 4H	P-DP	0.19	0.00	0.00	14.69	0.02	0.00	0.00	1.36	0.00	13.35	6.48	50.00
RUSTLER B UNIT 1H - 1H	P-DP	0.09	0.03	0.08	7.16	0.67	-0.02	0.00	0.50	0.00	7.31	4.02	49.37
RUSTLER B UNIT 3H - 3H	P-DP	0.12	0.02	0.07	9.08	0.59	-0.02	0.00	0.70	0.00	8.95	5.05	50.00
RUSTLER C UNIT 1H - 1H	P-DP	0.07	0.05	0.14	5.08	1.15	-0.05	0.00	0.19	0.00	6.00	3.42	46.04

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
RUSTLER C UNIT 2H - 2H	P-DP	0.09	0.00	0.00	6.94	0.00	0.00	0.00	0.64	0.00	6.30	3.46	46.38
RUSTLER D UNIT 1H - 1H	P-DP	0.01	0.00	0.00	0.62	0.03	0.00	0.00	0.05	0.00	0.59	0.41	17.20
RUSTLER D UNIT 2H - 2H	P-DP	0.03	0.04	0.12	2.34	0.98	-0.05	0.00	-0.02	0.00	3.29	1.92	39.16
RUSTLER D UNIT 4H - 4H	P-DP	0.04	0.00	0.00	3.23	0.03	0.00	0.00	0.29	0.00	2.97	1.89	34.31
RUSTLER D UNIT 5H - 5H	P-DP	0.04	0.00	0.00	2.86	0.02	0.00	0.00	0.26	0.00	2.62	1.65	43.02
SABINE 39 1 - 1	P-DP	0.09	0.05	0.22	7.03	0.99	0.29	0.00	0.88	0.00	7.42	4.12	41.17
SABINE 39 2 - 2	P-DP	0.01	0.01	0.04	0.55	0.18	0.05	0.00	0.11	0.00	0.68	0.44	14.90
SADIE 33-10-4 1H - 1H	P-DP	0.00	13.48	153.53	0.00	274.74	317.21	0.00	514.18	0.00	77.77	41.42	40.27
SADIE 33-10-4 201H - 201H	P-DP	0.00	17.36	197.73	0.00	353.82	408.52	0.00	662.18	0.00	100.16	52.16	43.57
SADIE 33-10-4 205H - 205H	P-DP	0.00	2.57	29.28	0.00	52.39	60.49	0.00	98.05	0.00	14.83	7.71	46.22
SADIE 33-10-4 3H - 3H	P-DP	0.00	7.15	81.42	0.00	145.70	168.23	0.00	272.68	0.00	41.25	22.18	42.15
SADIE 33-10-4 5H - 5H	P-DP	0.00	6.62	75.39	0.00	134.90	155.76	0.00	252.47	0.00	38.19	20.67	41.03
SAND DOLLAR UNIT 1 - 1	P-DP	0.01	0.00	0.00	1.00	0.00	0.00	0.00	0.07	0.00	0.93	0.58	14.88
SANTANA 29 2H - 2H	P-DP	0.17	0.30	1.89	13.24	6.20	2.53	0.00	2.79	0.00	19.20	10.84	30.20
SASQUATCH UNIT 36-24 1AH -	P-DP	3.18	0.01	2.44	234.47	0.13	8.17	0.00	18.02	0.00	224.75	105.48	50.00
SASQUATCH UNIT 36-24 2AH -	P-DP	1.92	0.01	7.03	141.27	0.36	23.51	0.00	13.84	0.00	151.30	74.26	50.00
SASQUATCH UNIT 36-24 3AH -	P-DP	1.87	0.01	4.29	137.49	0.22	14.34	0.00	12.10	0.00	139.96	68.18	50.00
SAU 25 1B - 1B	P-DP	0.01	0.01	0.02	0.49	0.11	0.05	0.00	0.07	0.00	0.58	0.31	21.65
SAU 25 1C - 1C	P-DP	0.00	0.00	0.00	0.10	0.02	0.01	0.00	0.01	0.00	0.12	0.09	6.57
SAU 25-2 2C - 2C	P-DP	0.00	0.00	0.00	0.13	0.01	0.01	0.00	0.01	0.00	0.13	0.10	7.05
SAU MARINER 25-2A 2A - 2A	P-DP	0.00	0.00	0.00	0.33	0.02	0.01	0.00	0.03	0.00	0.33	0.21	14.42
SAU MARINER 29-3 3 - 3	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAU MARINER 29-3B 3B - 3B	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAU MARINER 29-3B 3C - 3C	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SCATTER 15-10 1AH - 1AH	P-DP	0.07	0.01	0.05	5.64	0.20	0.09	0.00	0.45	0.00	5.48	2.91	48.63
SCATTER 15-10 2AH - 2AH	P-DP	0.05	0.02	0.14	4.12	0.60	0.26	0.00	0.43	0.00	4.57	2.51	45.05
SCATTER 15-10 2SH - 2SH	P-DP	0.09	0.02	0.15	6.65	0.66	0.29	0.00	0.62	0.00	6.97	3.60	50.00
SCATTER GINGER 15-27 (ALLO	P-DP	0.15	0.05	0.32	11.78	1.44	0.63	0.00	1.16	0.00	12.70	7.08	50.00
SCATTER GINGER 15-27 (ALLO	P-DP	0.15	0.06	0.37	11.63	1.67	0.73	0.00	1.19	0.00	12.83	7.14	50.00
SCATTER TISH 10-46 (ALLOC-D	P-DP	4.52	1.69	10.00	344.45	44.76	19.59	0.00	34.33	0.00	374.47	212.95	50.00
SCATTER TISH 10-46 (ALLOC-D	P-DP	3.79	1.28	7.56	289.11	33.86	14.82	0.00	28.01	0.00	309.78	176.74	48.45
SCHWALBE-SONOMA STATE 12	P-DP	0.00	0.00	0.03	0.20	0.09	0.03	0.00	0.04	0.00	0.28	0.14	40.36
SHADRACH 68 UNIT 134H - 134	P-DP	0.05	0.19	1.20	3.81	3.94	1.61	0.00	1.44	0.00	7.93	4.67	40.26
SHADRACH 68 UNIT 1H - 1H	P-DP	0.17	0.15	0.95	12.54	3.13	1.28	0.00	1.83	0.00	15.12	8.60	40.96
SHADRACH 68 UNIT 223H - 223	P-DP	0.14	0.15	0.93	10.83	3.05	1.24	0.00	1.68	0.00	13.44	7.57	46.58

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes: Oil (Mbbl)	Net Sales Volumes: NGL (Mbbl)	Net Sales Volumes: Residue Gas (MMcf)	Net Revenue: Oil (M$)	Net Revenue: NGL (M$)	Net Revenue: Residue Gas (M$)	Net Revenue: Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow: Non-Disc. (M$)	Cash Flow: Disc. 10% (M$)	Life (years)
SHADRACH 68 UNIT 2H - 2H	*P-DP*	0.19	0.09	0.53	14.60	1.76	0.72	0.00	1.58	0.00	15.50	8.87	42.39
SHADRACH 68 UNIT 324H - 324	*P-DP*	0.09	0.15	0.91	7.09	2.98	1.22	0.00	1.39	0.00	9.90	5.69	32.89
SHADRACH 68 UNIT 332H - 332	*P-DP*	0.14	0.14	0.88	10.35	2.89	1.18	0.00	1.60	0.00	12.81	7.28	44.62
SHADRACH MOSES CANTALO	*P-DP*	0.03	0.12	0.73	2.15	2.41	0.98	0.00	0.86	0.00	4.68	2.59	37.71
SHANNON 210470 3C - 3C	*P-DP*	0.00	0.00	0.06	0.00	0.00	0.11	0.00	0.01	0.00	0.10	0.06	39.39
SHANNON 210470 4B - 4B	*P-DP*	0.00	0.00	0.07	0.00	0.00	0.14	0.00	0.01	0.00	0.13	0.07	41.94
SHANNON 211271 1B - 1B	*P-DP*	0.00	0.00	47.19	0.00	0.00	96.50	0.00	8.41	0.00	88.09	52.06	35.58
SHANNON 211271 2A - 2A	*P-DP*	0.00	0.00	60.11	0.00	0.00	122.91	0.00	10.71	0.00	112.20	65.11	38.66
SHENANDOAH 11-2-58 H 1W - H	*P-DP*	0.03	0.00	0.02	2.40	0.10	0.04	0.00	0.19	0.00	2.36	1.24	44.47
SHENANDOAH 11-2-58 H 2WA -	*P-DP*	0.03	0.01	0.06	2.30	0.27	0.12	0.00	0.22	0.00	2.46	1.32	44.55
SHEPARD 5-2C5 - 5-2C5	*P-DP*	0.02	0.00	0.03	1.02	0.00	0.05	0.00	0.03	0.00	1.04	0.48	44.93
SHERROD UNIT 3903 - 3903	*P-DP*	0.01	0.00	0.00	0.46	0.00	0.00	0.00	0.04	0.00	0.42	0.28	13.57
SHERROD UNIT 903 - 903	*P-DP*	0.00	0.00	0.00	0.37	0.00	0.00	0.00	0.03	0.00	0.34	0.24	11.15
SHINABERRY MILDRED K 1 - 1	*P-DP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SHIRLEY -B- 3815R - 3815R	*P-DP*	0.31	0.12	0.47	23.50	2.41	0.48	0.00	3.05	0.00	23.34	12.80	33.31
SHIRLEY 3806 - 3806	*P-DP*	0.18	0.03	0.12	13.50	0.61	0.12	0.00	1.39	0.00	12.84	7.13	27.01
SHIRLEY 3807 - 3807	*P-DP*	0.08	0.02	0.09	6.21	0.43	0.09	0.00	0.71	0.00	6.02	3.33	20.80
SHIRLEY 3808 - 3808	*P-DP*	0.15	0.03	0.12	11.28	0.63	0.12	0.00	1.21	0.00	10.82	5.63	26.80
SHOSHONE A 34-166-165 5201H	*P-DP*	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	43.57
SHOSHONE B 34-166-165 TB 2H	*P-DP*	0.01	0.00	0.00	0.53	0.04	0.00	0.00	0.07	0.00	0.50	0.28	50.00
SHOSHONE C 34-166-165 WA 3H	*P-DP*	0.01	0.01	0.01	0.85	0.13	0.00	0.00	0.12	0.00	0.86	0.48	50.00
SHRINERS 2-10C5 - 2-10C5	*P-DP*	0.02	0.00	0.10	1.06	0.00	0.17	0.00	0.05	0.00	1.18	0.58	38.16
SIDWELL SE WHL BL 10H - 10H	*P-DP*	0.00	0.00	55.28	0.00	0.00	113.04	0.00	9.85	0.00	103.19	70.94	23.08
SIDWELL SE WHL BL 8H - 8H	*P-DP*	0.00	0.00	81.88	0.00	0.00	167.43	0.00	14.59	0.00	152.85	88.76	32.81
SIDWELL SW WHL BL 2H - 2H	*P-DP*	0.00	0.00	30.06	0.00	0.00	61.47	0.00	5.36	0.00	56.12	27.95	49.88
SIDWELL SW WHL BL 4H - 4H	*P-DP*	0.00	0.00	3.48	0.00	0.00	7.12	0.00	0.62	0.00	6.50	4.54	14.68
SILVERADO 40-1 A 1JM - 1JM	*P-DP*	0.52	0.28	1.39	39.63	6.23	1.86	0.00	5.24	0.00	42.48	24.17	50.00
SILVERADO 40-1 B 2LS - 2LS	*P-DP*	0.23	0.09	0.46	17.30	2.06	0.61	0.00	2.03	0.00	17.94	12.33	18.16
SILVERADO 40-1 C 3WA - 3WA	*P-DP*	0.28	0.09	0.46	21.02	2.06	0.61	0.00	2.30	0.00	21.39	12.03	46.95
SILVERADO 40-1 E 5JM - 5JM	*P-DP*	0.35	0.16	0.76	26.43	3.41	1.02	0.00	3.21	0.00	27.65	15.81	49.69
SILVERADO 40-1 F 6LS - 6LS	*P-DP*	0.22	0.12	0.61	16.84	2.73	0.81	0.00	2.26	0.00	18.12	10.28	43.87
SILVERADO 40-1 G 7LS - 7LS	*P-DP*	0.22	0.21	1.04	16.39	4.69	1.40	0.00	2.98	0.00	19.51	12.11	43.46
SILVERADO 40-1 H 8WA - 8WA	*P-DP*	0.27	0.22	1.05	20.87	4.71	1.41	0.00	3.30	0.00	23.68	13.81	47.68
SILVERADO 40-1 I 9WB - 9WB	*P-DP*	0.24	0.19	0.92	18.49	4.11	1.23	0.00	2.91	0.00	20.93	11.96	46.87
SILVERADO 40-1 J 10WB - 10W	*P-DP*	0.20	0.31	1.49	15.44	6.69	2.00	0.00	3.67	0.00	20.46	11.24	45.80

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
SILVERADO 40-1 K 11WA - 11W	P-DP	0.30	0.35	1.68	22.44	7.56	2.26	0.00	4.51	0.00	27.75	15.21	50.00
SIMPSON SMITH 0844 A 1WH -	P-DP	2.01	0.41	2.42	153.39	10.81	4.73	0.00	13.31	0.00	155.63	90.48	50.00
SIMPSON SMITH A 08-44 1SH - 1	P-DP	0.73	0.17	1.03	55.78	4.60	2.01	0.00	4.99	0.00	57.41	32.32	50.00
SIMPSON SMITH B 08-44 2AH -	P-DP	1.38	0.36	2.14	105.33	9.56	4.19	0.00	9.60	0.00	109.47	64.13	50.00
SIMPSON SMITH C 08-44 2SH -	P-DP	1.85	0.54	3.18	140.67	14.26	6.24	0.00	13.15	0.00	148.01	87.34	49.63
SIMPSON SMITH D 08-44 3AH -	P-DP	1.92	0.46	2.73	146.46	12.21	5.35	0.00	13.12	0.00	150.90	85.12	50.00
SIMPSON SMITH E 08-44 3SH -	P-DP	0.71	0.24	1.41	53.84	6.33	2.77	0.00	5.22	0.00	57.72	33.46	50.00
SIREN UNIT 36-48 1AH - 1AH	P-DP	7.75	0.04	18.82	571.13	0.97	62.94	0.00	50.80	0.00	584.25	264.05	50.00
SIXTEEN PENNY NAIL 310 1LL	P-DP	0.00	0.00	0.00	0.14	0.02	0.01	0.00	0.02	0.00	0.15	0.10	14.05
SIXTEEN PENNY NAIL 310 2LM	P-DP	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.01	0.00	0.05	0.04	6.96
SIXTEEN PENNY NAIL 310 8JM	P-DP	0.03	0.02	0.11	2.13	0.47	0.14	0.00	0.33	0.00	2.41	1.32	41.11
SIXTEEN PENNY NAIL 310A 3L	P-DP	0.01	0.00	0.01	0.56	0.05	0.01	0.00	0.06	0.00	0.57	0.31	28.80
SIXTEEN PENNY NAIL 310A 9J	P-DP	0.01	0.02	0.07	0.48	0.33	0.10	0.00	0.16	0.00	0.75	0.43	33.79
SIXTEEN PENNY NAIL 310B 10J	P-DP	0.01	0.00	0.00	0.70	0.01	0.00	0.00	0.05	0.00	0.66	0.37	35.32
SIXTEEN PENNY NAIL 310B 4L	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.48
SIXTEEN PENNY NAIL 310B 5L	P-DP	0.00	0.00	0.02	0.04	0.10	0.03	0.00	0.04	0.00	0.13	0.11	4.68
SIXTEEN PENNY NAIL 310C 11J	P-DP	0.02	0.01	0.05	1.26	0.22	0.06	0.00	0.17	0.00	1.37	0.75	44.06
SIXTEEN PENNY NAIL 310C 6L	P-DP	0.00	0.01	0.03	0.33	0.13	0.04	0.00	0.07	0.00	0.43	0.25	23.91
SIXTEEN PENNY NAIL 310C 7L	P-DP	0.00	0.00	0.01	0.13	0.06	0.02	0.00	0.03	0.00	0.18	0.12	13.92
SMASHOSAURUS 3 - 3	P-DP	0.00	0.00	0.34	0.00	0.00	0.69	0.00	0.06	0.00	0.63	0.35	39.47
SMASHOSAURUS 5 - 5	P-DP	0.00	0.00	32.21	0.00	0.00	65.86	0.00	5.74	0.00	60.12	37.38	31.36
SON 136 1 - 1	P-DP	0.10	0.04	0.20	7.36	0.88	0.26	0.00	0.87	0.00	7.64	4.05	32.36
SON 136 2 - 2	P-DP	0.11	0.05	0.23	8.69	1.02	0.30	0.00	1.02	0.00	9.00	4.72	34.40
SPARROW 22 001 - 001	P-DP	0.07	0.00	0.08	5.06	0.04	0.08	0.00	0.70	0.00	4.47	2.49	17.86
SPIRE 226-34 UNIT 1H - 1H	P-DP	0.10	0.30	0.30	7.47	6.66	0.20	0.00	2.25	0.00	12.09	6.29	49.43
SPITFIRE 1H - 1H	P-DP	0.00	0.00	0.10	0.00	0.00	0.21	0.00	0.02	0.00	0.19	0.13	16.15
SPITFIRE 3H - 3H	P-DP	0.00	0.00	0.07	0.00	0.00	0.14	0.00	0.01	0.00	0.13	0.08	17.92
SPORT E WYN JF 3H - 3H	P-DP	0.00	0.00	514.92	0.00	0.00	1,020.00	0.00	635.24	0.00	384.77	217.73	44.87
SPORT W WYN JF 1H - 1H	P-DP	0.00	0.00	578.66	0.00	0.00	1,146.27	0.00	713.87	0.00	432.40	238.92	44.65
SPRABERRY DRIVER UNIT 132	P-DP	0.13	0.03	0.01	10.02	0.64	0.01	0.00	0.91	0.00	9.76	4.61	29.19
SPRABERRY DRIVER UNIT 134	P-DP	0.11	0.03	0.01	8.61	0.53	0.01	0.00	0.78	0.00	8.38	4.01	27.29
SPRABERRY DRIVER UNIT 135	P-DP	0.04	0.02	0.01	2.97	0.43	0.01	0.00	0.30	0.00	3.11	2.14	12.13
SPRABERRY DRIVER UNIT 136	P-DP	0.11	0.04	0.01	8.58	0.77	0.01	0.00	0.80	0.00	8.56	4.23	27.02
STATE EILAND 3-33 11H - 11H	P-DP	0.05	0.04	0.04	3.85	0.83	0.03	0.00	0.54	0.00	4.16	2.78	30.25
STATE EILAND 6047B-34 51H - 5	P-DP	0.03	0.01	0.01	2.55	0.25	0.01	0.00	0.28	0.00	2.52	1.61	28.20

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
STATE MUDDY WATERS UNIT 2	P-DP	0.08	0.16	0.98	5.81	3.21	1.31	0.00	1.37	0.00	8.97	4.52	50.00
STATE MUDDY WATERS UNIT 7	P-DP	0.09	0.07	0.42	6.51	1.37	0.56	0.00	0.88	0.00	7.56	4.55	33.92
STATE MUDDY WATERS UNIT 7	P-DP	0.03	0.12	0.74	2.34	2.44	1.00	0.00	0.89	0.00	4.89	3.15	24.00
STATE MUDDY WATERS UNIT 7	P-DP	0.27	1.05	6.53	20.69	21.47	8.76	0.00	7.81	0.00	43.10	23.85	50.00
STATE MUDDY WATERS UNIT 7	P-DP	0.09	0.10	0.63	6.51	2.07	0.84	0.00	1.08	0.00	8.34	5.10	34.40
STATE MUDDY WATERS UNIT 7	P-DP	0.06	0.52	3.20	4.52	10.53	4.30	0.00	3.42	0.00	15.93	9.39	37.88
STELLA STATE 34-208 WRD UN	P-DP	0.02	0.02	0.02	1.79	0.40	0.01	0.00	0.25	0.00	1.94	0.94	39.51
STICKLINE 1H - 1H	P-DP	0.01	0.01	0.01	0.61	0.26	0.01	0.00	0.12	0.00	0.76	0.38	49.68
STIMSON BURLEY -B- 1 - 1	P-DP	0.00	0.00	0.00	0.07	0.01	0.00	0.00	0.01	0.00	0.07	0.05	16.67
STIMSON BURLEY -B- 4 - 4	P-DP	0.00	0.00	0.00	0.08	0.01	0.00	0.00	0.01	0.00	0.08	0.05	16.82
STIMSON BURLEY -D- 1 - 1	P-DP	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.01	0.00	0.15	0.10	17.12
STIMSON BURLEY -E- 3DW - 3D	P-DP	0.00	0.00	0.01	0.27	0.03	0.01	0.00	0.03	0.00	0.28	0.18	26.67
STIMSON BURLEY -M- 1 - 1	P-DP	0.00	0.00	0.00	0.06	0.01	0.00	0.00	0.01	0.00	0.06	0.04	16.97
STIMSON-BURLEY -C- 1 - 1	P-DP	0.00	0.00	0.00	0.05	0.01	0.00	0.00	0.01	0.00	0.05	0.03	19.12
STIMSON-BURLEY -C- 3 - 3	P-DP	0.00	0.00	0.00	0.22	0.01	0.00	0.00	0.02	0.00	0.22	0.10	39.34
STIMSON-BURLEY 18 1 - 1	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.76
STIMSON-BURLEY 4 - 4	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.36
STIMSON-BURLEY 6 - 6	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STIMSON-BURLEY K 1 - 1	P-DP	0.00	0.00	0.00	0.16	0.01	0.00	0.00	0.02	0.00	0.16	0.08	26.96
STIMSON-NAIL E17K 111H - 111	P-DP	0.07	0.06	0.24	5.74	1.24	0.25	0.00	0.59	0.00	6.63	4.32	50.00
STIMSON-NAIL E17L 112H - 112	P-DP	0.07	0.06	0.24	5.46	1.23	0.24	0.00	0.58	0.00	6.35	4.06	50.00
STIMSON-NAIL E17M 113H - 11	P-DP	0.07	0.06	0.25	5.75	1.24	0.25	0.00	0.59	0.00	6.65	4.33	50.00
STIMSON-NAIL E17N 114H - 114	P-DP	0.09	0.06	0.24	6.85	1.23	0.24	0.00	1.14	0.00	7.19	4.72	50.00
STIMSON-NAIL E17O 115H - 115	P-DP	0.09	0.06	0.24	6.73	1.21	0.24	0.00	1.12	0.00	7.06	4.64	50.00
STIMSON-NAIL E17P 116H - 116	P-DP	0.09	0.06	0.24	6.72	1.21	0.24	0.00	1.12	0.00	7.06	4.64	50.00
STIMSON-NAIL E17Q 117H - 117	P-DP	0.07	0.04	0.15	5.64	0.74	0.15	0.00	0.81	0.00	5.72	3.87	50.00
STIMSON-NAIL E17R 118H - 118	P-DP	0.09	0.06	0.24	6.84	1.23	0.24	0.00	1.14	0.00	7.18	4.72	50.00
STIMSON-NAIL E17S 119H - 119	P-DP	0.08	0.04	0.15	5.80	0.76	0.15	0.00	0.83	0.00	5.88	3.98	50.00
STIMSON-NAIL E17T 120H - 120	P-DP	0.07	0.04	0.15	5.73	0.75	0.15	0.00	0.82	0.00	5.81	3.94	50.00
STIMSON-NAIL W17K 11H - 11H	P-DP	0.00	0.00	0.00	0.22	0.02	0.00	0.00	0.03	0.00	0.21	0.13	47.62
STIMSON-NAIL W17L 12H - 12H	P-DP	0.01	0.00	0.01	0.45	0.03	0.01	0.00	0.05	0.00	0.44	0.25	50.00
STIMSON-NAIL W17M 13H - 13	P-DP	0.01	0.00	0.02	0.50	0.08	0.02	0.00	0.08	0.00	0.52	0.31	50.00
STIMSON-NAIL W17N 14H - 14H	P-DP	0.00	0.00	0.00	0.28	0.02	0.00	0.00	0.03	0.00	0.27	0.16	44.49
STIMSON-NAIL W17O 15H - 15H	P-DP	0.01	0.00	0.01	0.52	0.07	0.01	0.00	0.08	0.00	0.53	0.33	50.00
STIMSON-NAIL W17P 16H - 16H	P-DP	0.00	0.00	0.01	0.23	0.05	0.01	0.00	0.04	0.00	0.25	0.15	49.48

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
STIMSON-NAIL W17Q 17H - 17H	P-DP	0.00	0.00	0.00	0.22	0.03	0.00	0.00	0.03	0.00	0.22	0.13	47.64
STIMSON-NAIL W17R 18H - 18H	P-DP	0.00	0.00	0.00	0.23	0.02	0.00	0.00	0.03	0.00	0.23	0.13	48.39
STIMSON-NAIL W17S 19H - 19H	P-DP	0.01	0.01	0.02	0.50	0.12	0.02	0.00	0.10	0.00	0.54	0.32	50.00
STIMSON-NAIL W17T 20H - 20H	P-DP	0.00	0.00	0.00	0.18	0.01	0.00	0.00	0.02	0.00	0.17	0.10	44.62
STONE-GIST W45A 1H - 1H	P-DP	0.47	0.15	0.04	35.42	2.92	0.05	0.00	3.28	0.00	35.11	19.51	43.24
STONE-GIST W45B 2H - 2H	P-DP	0.36	0.03	0.01	27.58	0.60	0.01	0.00	2.36	0.00	25.84	14.15	42.17
STONE-GIST W45C 3H - 3H	P-DP	0.39	0.10	0.03	29.31	1.97	0.03	0.00	2.66	0.00	28.65	17.27	40.28
STONE-GIST W45I 9H - 9H	P-DP	0.16	0.05	0.01	12.37	0.88	0.01	0.00	1.13	0.00	12.13	6.69	34.17
STONE-GIST W45J 10H - 10H	P-DP	0.19	0.06	0.01	14.19	1.07	0.02	0.00	1.30	0.00	13.98	8.43	28.49
SUCCUBUS UNIT B 25-24 5AH -	P-DP	1.48	0.00	1.35	109.29	0.07	4.53	0.00	8.51	0.00	105.37	65.36	36.85
SUCCUBUS UNIT B 25-24 8AH -	P-DP	0.86	0.01	2.70	63.64	0.14	9.02	0.00	5.98	0.00	66.81	34.19	44.76
SUCCUBUS-ROUGAROU 24-37	P-DP	2.60	0.01	3.06	191.46	0.16	10.24	0.00	15.28	0.00	186.57	114.12	43.42
SUGARLOAF 74 1H - 1H	P-DP	0.22	0.01	0.04	16.98	0.13	0.05	0.00	1.27	0.00	15.88	8.08	37.78
SUGARLOAF 7475 10U C 10H -	P-DP	0.20	0.14	0.86	15.44	2.82	1.15	0.00	1.95	0.00	17.46	10.12	48.02
SUGARLOAF 7475 1U B 1H - B 1	P-DP	0.25	0.19	1.20	19.15	3.94	1.61	0.00	2.55	0.00	22.16	10.75	42.08
SUGARLOAF 7475 2U B 2H - B 2	P-DP	0.11	0.06	0.36	8.52	1.19	0.48	0.00	0.97	0.00	9.22	4.93	47.79
SUGARLOAF 7475 3U A 3H - A 3	P-DP	0.23	0.12	0.72	17.54	2.38	0.97	0.00	1.97	0.00	18.92	10.35	39.78
SUGARLOAF 7475 4U A 4H - A 4	P-DP	0.44	0.21	1.33	33.35	4.36	1.78	0.00	3.70	0.00	35.78	21.29	50.00
SUGARLOAF 7475 5U B 5H - B 5	P-DP	0.34	0.25	1.57	26.14	5.15	2.10	0.00	3.41	0.00	29.99	17.24	50.00
SUGARLOAF 7475 6U A 6H - A 6	P-DP	0.46	0.25	1.57	35.17	5.15	2.10	0.00	4.07	0.00	38.35	22.72	50.00
SUGARLOAF 7475 7U A 7H - A 7	P-DP	0.33	0.22	1.39	24.71	4.57	1.87	0.00	3.14	0.00	28.01	16.76	49.63
SUGARLOAF 7475 8U A 8H - A 8	P-DP	0.42	0.15	0.94	31.92	3.08	1.26	0.00	3.22	0.00	33.02	19.88	50.00
SUGARLOAF 7475 9U B 9H - B 9	P-DP	0.38	0.29	1.77	28.58	5.83	2.38	0.00	3.79	0.00	33.00	19.48	50.00
SUGG A 141-140 (ALLOC-A) 1SM	P-DP	0.57	2.47	8.55	42.71	40.97	17.12	0.00	14.34	0.00	86.45	47.98	33.01
SUGG A 141-140 (ALLOC-B) 2SU	P-DP	0.38	1.54	5.33	28.32	25.55	10.67	0.00	9.08	0.00	55.46	31.79	34.84
SUGG A 141-140 (ALLOC-C) 3SM	P-DP	0.57	3.11	10.79	42.90	51.71	21.61	0.00	17.19	0.00	99.03	52.25	43.33
SUGG A 141-140 (ALLOC-D) 4SU	P-DP	0.33	2.01	6.98	24.66	33.44	13.97	0.00	10.86	0.00	61.22	30.81	39.14
SUGG A 141-140 (ALLOC-E) 5RM	P-DP	0.31	2.78	9.63	23.34	46.15	19.28	0.00	14.10	0.00	74.68	41.24	26.92
SUGG A 141-140 (ALLOC-F) 6SM	P-DP	0.05	0.75	2.58	3.50	12.39	5.18	0.00	3.55	0.00	17.50	10.81	21.47
SUGG A 141-140 (ALLOC-F) 6SU	P-DP	0.10	1.22	4.23	7.74	20.25	8.46	0.00	5.98	0.00	30.48	17.13	32.19
SUGG A 141-140 (ALLOC-G) 7SM	P-DP	0.16	2.38	8.25	11.83	39.54	16.52	0.00	11.40	0.00	56.49	29.11	37.99
SUGG A 141-140 (ALLOC-G) 7SU	P-DP	0.15	2.65	9.19	11.16	44.04	18.40	0.00	12.53	0.00	61.07	30.64	39.25
SUGG A 141-140 (ALLOC-H) 8SM	P-DP	0.16	4.51	15.65	12.11	74.97	31.32	0.00	20.76	0.00	97.64	49.73	44.40
SUGG A 141-140 (ALLOC-H) 8SU	P-DP	0.16	1.19	4.13	12.29	19.80	8.27	0.00	6.24	0.00	34.12	19.73	30.00
SUNDOG A1 1LA - 1LA	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
SUNDOG A2 2LA - 2LA	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.03
SUNDOWN 4524LS - 4524LS	P-DP	0.65	0.21	1.25	49.35	5.60	2.45	0.00	4.74	0.00	52.66	28.91	39.39
SUNDOWN 4541WA - 4541WA	P-DP	2.46	0.43	2.52	187.45	11.26	4.93	0.00	15.84	0.00	187.80	102.27	50.00
SUNDOWN 4566WB - 4566WB	P-DP	0.78	0.29	1.68	59.55	7.54	3.30	0.00	5.89	0.00	64.50	35.91	41.56
SUSTR UNIT 1H - 1H	P-DP	0.25	0.02	0.16	18.56	0.22	0.27	0.00	1.66	0.00	17.40	9.98	21.34
TAMSULA 015-2 - 015-2	P-DP	0.00	0.00	0.06	0.00	0.00	0.08	0.00	0.01	0.00	0.07	0.04	50.00
TAMSULA 016-3 - 016-3	P-DP	0.00	0.00	0.07	0.00	0.00	0.10	0.00	0.01	0.00	0.09	0.06	50.00
TAMSULA 017-4 - 017-4	P-DP	0.00	0.00	0.58	0.00	0.00	0.82	0.00	0.08	0.00	0.74	0.39	50.00
TAMSULA 5 - 5	P-DP	0.00	0.00	0.04	0.00	0.00	0.06	0.00	0.01	0.00	0.05	0.03	50.00
TANNER WYN JF 2H - 2H	P-DP	0.00	0.00	216.84	0.00	0.00	429.54	0.00	267.51	0.00	162.03	101.70	27.41
TANNER WYN JF 4H - 4H	P-DP	0.00	0.00	425.57	0.00	0.00	843.01	0.00	525.01	0.00	318.00	186.12	36.40
TARGAC UNIT 1H - 1H	P-DP	0.32	0.01	0.06	23.60	0.08	0.11	0.00	2.01	0.00	21.78	15.44	12.70
TCB 39-34 1AH - 1AH	P-DP	0.00	0.00	0.00	0.16	0.01	0.01	0.00	0.01	0.00	0.16	0.09	32.97
TCB 39-34 4AH - 4AH	P-DP	0.01	0.00	0.00	0.69	0.02	0.01	0.00	0.05	0.00	0.67	0.38	50.00
TCB 39-34 4SH - 4SH	P-DP	0.00	0.00	0.00	0.30	0.01	0.01	0.00	0.02	0.00	0.29	0.17	39.90
TCB A 1LS - 1LS	P-DP	0.02	0.01	0.04	1.37	0.17	0.07	0.00	0.13	0.00	1.48	0.83	50.00
TCB B 2A - 2A	P-DP	0.02	0.00	0.03	1.84	0.12	0.05	0.00	0.16	0.00	1.86	1.04	50.00
TCM 3 - 3	P-DP	0.08	0.01	0.04	6.13	0.19	0.06	0.00	0.51	0.00	5.86	2.86	31.25
TCM 48L - 48L	P-DP	0.21	0.07	0.33	16.18	1.49	0.44	0.00	1.74	0.00	16.38	6.93	47.72
TEEWINOT A1 3LA - 3LA	P-DP	0.04	0.01	0.01	2.65	0.19	0.01	0.00	0.28	0.00	2.57	1.50	47.33
TEEWINOT NORTH UNIT 4LA -	P-DP	0.02	0.00	0.00	1.59	0.08	0.00	0.00	0.16	0.00	1.52	0.82	27.93
TEEWINOT SOUTH UNIT 5LA -	P-DP	0.06	0.01	0.01	4.40	0.12	0.00	0.00	0.42	0.00	4.10	1.98	40.28
TESTA 5 - 5	P-DP	0.00	0.00	0.02	0.00	0.00	0.03	0.00	0.00	0.00	0.03	0.02	50.00
THE KING 45-04 1AH - 1AH	P-DP	0.04	0.00	0.01	3.17	0.03	0.01	0.00	0.23	0.00	2.97	1.66	25.87
THE KING 45-04 1MS - 1MS	P-DP	0.64	0.22	1.27	49.07	5.69	2.49	0.00	4.74	0.00	52.51	29.74	50.00
THE KING 45-04 1SH - 1SH	P-DP	0.02	0.00	0.01	1.15	0.06	0.03	0.00	0.10	0.00	1.14	0.71	14.11
THE KING 45-04 C 3SA - 3SA	P-DP	0.36	0.15	0.89	27.73	3.97	1.74	0.00	2.84	0.00	30.59	16.93	50.00
THE KING 45-04 C 3SS - 3SS	P-DP	0.33	0.15	0.89	24.81	3.97	1.74	0.00	2.63	0.00	27.88	16.22	50.00
THE KING 45-04 D 4MS - 4MS	P-DP	0.34	0.22	1.30	25.70	5.82	2.55	0.00	3.10	0.00	30.97	17.07	50.00
THE KING 45-04 D 4SA - 4SA	P-DP	0.33	0.09	0.51	25.10	2.27	0.99	0.00	2.29	0.00	26.07	15.52	49.22
THE KING 45-04 D 4SS - 4SS	P-DP	0.33	0.22	1.29	24.84	5.77	2.53	0.00	3.03	0.00	30.11	16.61	50.00
THOMPSON E SMF JF 5H - 5H	P-DP	0.00	0.00	5.38	0.00	0.00	10.67	0.00	6.64	0.00	4.02	2.46	35.24
THOMPSON W SMF JF 1H - 1H	P-DP	0.00	0.00	19.69	0.00	0.00	39.01	0.00	24.29	0.00	14.71	9.77	28.56
THOMPSON W SMF JF 3H - 3H	P-DP	0.00	0.00	19.01	0.00	0.00	37.65	0.00	23.45	0.00	14.20	9.47	28.03
THORPE 1-74 LOV 2H - 2H	P-DP	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.03	0.02	12.57

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

		Net Sales Volumes			Net Revenue						Cash Flow		
				Residue			Residue		Expense				
Lease Name	Reserve Category	Oil (Mbbl)	NGL (Mbbl)	Gas (MMcf)	Oil (M$)	NGL (M$)	Gas (M$)	Other (M$)	& Tax (M$)	Invest. (M$)	Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
THORPE 1-74 LOV 3H - 3H	*P-DP*	0.01	0.00	0.01	0.65	0.06	0.00	0.00	0.04	0.00	0.67	0.32	38.93
THORPE 1-74 LOV 4H - 4H	*P-DP*	0.00	0.00	0.00	0.31	0.02	0.00	0.00	0.02	0.00	0.31	0.18	21.31
THUNDERBIRD UNIT 07-10 1AH	*P-DP*	0.19	0.00	0.25	13.69	0.01	0.84	0.00	1.11	0.00	13.43	8.09	32.64
THURMOND A137 ALLOC. A 10	*P-DP*	0.12	0.15	0.96	9.42	3.15	1.29	0.00	1.61	0.00	12.24	6.53	34.83
TIGER 210187 2A - 2A	*P-DP*	0.00	0.00	5.36	0.00	0.00	10.97	0.00	0.96	0.00	10.01	5.78	30.15
TIGER 210187 3C - 3C	*P-DP*	0.00	0.00	3.86	0.00	0.00	7.90	0.00	0.69	0.00	7.21	4.27	26.42
TIGER 210187 5B - 5B	*P-DP*	0.00	0.00	2.72	0.00	0.00	5.57	0.00	0.49	0.00	5.09	3.24	20.89
TIGER 210475 4C - 4C	*P-DP*	0.00	0.00	0.01	0.00	0.00	0.02	0.00	0.00	0.00	0.02	0.01	24.13
TIGER 210476 1A - 1A	*P-DP*	0.00	0.00	4.53	0.00	0.00	9.25	0.00	0.81	0.00	8.45	4.93	28.37
TIGIWON 2627-C23 E 433H - 433	*P-DP*	0.12	0.03	0.00	9.28	1.10	0.00	0.00	1.17	0.00	9.21	5.06	50.00
TIMMERMAN 14 1 - 1	*P-DP*	0.00	0.00	0.01	0.09	0.03	0.01	0.00	0.02	0.00	0.11	0.06	48.68
TIMMERMAN A1 403BH - 403B	*P-DP*	0.30	0.18	0.69	22.74	3.50	0.69	0.00	3.50	0.00	23.43	13.40	50.00
TIMMERMAN A10 411JH - 411JH	*P-DP*	0.30	0.18	0.69	22.74	3.50	0.69	0.00	3.50	0.00	23.43	13.40	50.00
TIMMERMAN A2 413JH - 413JH	*P-DP*	0.23	0.14	0.53	17.38	2.71	0.54	0.00	2.69	0.00	17.93	12.15	50.00
TIMMERMAN A3 402MH - 402M	*P-DP*	0.22	0.13	0.51	16.94	2.60	0.51	0.00	2.60	0.00	17.44	11.94	48.93
TIMMERMAN A4 402LH - 402LH	*P-DP*	0.21	0.15	0.57	15.97	2.87	0.57	0.00	2.65	0.00	16.75	10.80	50.00
TIMMERMAN A5 402BH - 402B	*P-DP*	0.30	0.18	0.69	22.74	3.50	0.69	0.00	3.50	0.00	23.43	13.40	50.00
TIMMERMAN A6 412JH - 412JH	*P-DP*	0.22	0.14	0.53	17.09	2.67	0.53	0.00	2.65	0.00	17.64	11.94	50.00
TIMMERMAN A7 401MH - 401M	*P-DP*	0.30	0.18	0.69	22.74	3.50	0.69	0.00	3.50	0.00	23.43	13.40	50.00
TIMMERMAN A8 401LH - 401LH	*P-DP*	0.40	0.18	0.69	30.43	3.50	0.69	0.00	4.12	0.00	30.49	16.19	50.00
TIMMERMAN A9 401BH - 401B	*P-DP*	0.25	0.19	0.72	19.12	3.66	0.72	0.00	3.28	0.00	20.22	12.82	50.00
TIMMERMAN J1 2208MH - 2208	*P-DP*	0.01	0.01	0.05	1.05	0.25	0.05	0.00	0.20	0.00	1.15	0.67	35.76
TIMMERMAN J10 2206LH - 2206	*P-DP*	0.03	0.01	0.05	1.98	0.25	0.05	0.00	0.28	0.00	1.99	1.13	42.44
TIMMERMAN J11 2206BH - 220	*P-DP*	0.02	0.02	0.06	1.16	0.30	0.06	0.00	0.24	0.00	1.28	0.72	36.95
TIMMERMAN J2 2208LH - 2208	*P-DP*	0.02	0.02	0.07	1.64	0.37	0.07	0.00	0.31	0.00	1.78	0.98	42.21
TIMMERMAN J3 2208BH - 2208	*P-DP*	0.01	0.02	0.08	0.77	0.42	0.08	0.00	0.26	0.00	1.01	0.57	33.93
TIMMERMAN J4 2207MH - 2207	*P-DP*	0.01	0.00	0.01	0.72	0.04	0.01	0.00	0.08	0.00	0.69	0.38	32.08
TIMMERMAN J5 2207LH - 2207	*P-DP*	0.01	0.01	0.02	0.84	0.13	0.02	0.00	0.13	0.00	0.86	0.43	35.59
TIMMERMAN J6 2207BH - 2207	*P-DP*	0.01	0.03	0.12	0.75	0.63	0.12	0.00	0.36	0.00	1.15	0.66	31.93
TIMMERMAN J7 2217LH - 2217	*P-DP*	0.01	0.01	0.05	1.09	0.24	0.05	0.00	0.20	0.00	1.18	0.67	36.06
TIMMERMAN J8 2207CH - 2207	*P-DP*	0.00	0.00	0.00	0.05	0.01	0.00	0.00	0.01	0.00	0.06	0.04	9.35
TIMMERMAN J9 2206MH - 2206	*P-DP*	0.03	0.02	0.07	2.68	0.36	0.07	0.00	0.39	0.00	2.73	1.50	46.84
TIN STAR A L 33H - L 33H	*P-DP*	0.18	0.16	1.01	13.55	3.31	1.35	0.00	1.96	0.00	16.25	7.69	50.00
TIN STAR B L 42H - L 42H	*P-DP*	0.05	0.05	0.28	3.86	0.92	0.38	0.00	0.55	0.00	4.61	2.54	32.99
TIN STAR D U 46H - U 46H	*P-DP*	0.12	0.14	0.86	8.82	2.83	1.16	0.00	1.47	0.00	11.33	6.19	47.51

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
TIPI CHAPMAN 34-163 1H - 1H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.57
TIPI CHAPMAN 34-163 2H - 2H	P-DP	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	28.90
TIPI CHAPMAN 34-163 3H - 3H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.96
TIPI CHAPMAN 34-163 4H - 4H	P-DP	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	16.66
TISH 46-03 1AH - 1AH	P-DP	1.74	0.15	0.87	132.94	3.91	1.71	0.00	10.35	0.00	128.20	66.66	36.82
TISH 46-03 1SS - 1SS	P-DP	1.59	1.11	6.57	121.38	29.41	12.87	0.00	15.05	0.00	148.60	89.62	32.88
TISH 46-03 3SA - 3SA	P-DP	4.30	1.93	11.37	327.34	50.89	22.28	0.00	34.44	0.00	366.07	218.94	35.21
TISH 46-03 3SS - 3SS	P-DP	3.98	1.08	6.34	302.93	28.40	12.43	0.00	27.82	0.00	315.95	191.07	34.90
TITO'S 31-42 1LS - 1LS	P-DP	0.05	0.00	0.02	3.91	0.10	0.03	0.00	0.32	0.00	3.71	2.27	28.59
TITO'S 31-42 1WA - 1WA	P-DP	0.06	0.01	0.02	4.41	0.11	0.03	0.00	0.36	0.00	4.19	2.52	30.35
TITO'S 31-42 1WB - 1WB	P-DP	0.05	0.00	0.02	3.65	0.09	0.03	0.00	0.30	0.00	3.47	2.10	28.14
TITO'S 31-42 2LS - 2LS	P-DP	0.11	0.03	0.14	8.05	0.63	0.19	0.00	0.82	0.00	8.04	4.45	33.14
TITO'S 31-42 2WA - 2WA	P-DP	0.03	0.12	0.57	2.42	2.57	0.77	0.00	1.15	0.00	4.60	2.81	21.14
TITO'S 31-42 2WB - 2WB	P-DP	0.04	0.04	0.20	2.92	0.88	0.26	0.00	0.55	0.00	3.51	2.24	21.17
TITO'S 31-42 3WA - 3WA	P-DP	0.03	0.01	0.05	2.50	0.21	0.06	0.00	0.26	0.00	2.52	1.51	29.13
TODD 2-21A3 - 2-21A3	P-DP	0.14	0.00	0.78	8.64	0.00	1.33	0.00	0.42	0.00	9.55	4.15	50.00
TOMCAT 23-24 A 1LS - 1LS	P-DP	0.29	0.08	0.39	22.09	1.76	0.53	0.00	2.27	0.00	22.12	14.08	41.92
TOMCAT 23-24 B 2LS - 2LS	P-DP	0.24	0.05	0.22	18.30	1.01	0.30	0.00	1.71	0.00	17.90	11.61	38.73
TOMCAT 23-24 C 1DN - 1DN	P-DP	1.12	0.58	2.85	84.86	12.79	3.82	0.00	11.01	0.00	90.46	55.94	50.00
TOMCAT 23-24 D 2DN - 2DN	P-DP	0.69	0.27	1.33	52.49	5.98	1.78	0.00	6.07	0.00	54.18	34.23	50.00
TOMCAT 23-24 E 1AB - 1AB	P-DP	0.15	0.04	0.20	11.70	0.89	0.27	0.00	1.18	0.00	11.67	8.05	31.93
TOMCAT 23-24 F 2AB - 2AB	P-DP	0.16	0.07	0.34	12.20	1.52	0.45	0.00	1.46	0.00	12.71	8.68	33.76
TOMCAT 23-24 G 3AB - 3AB	P-DP	0.36	0.15	0.75	27.34	3.39	1.01	0.00	3.27	0.00	28.47	17.56	46.62
TOMCAT 4448WA - 4448WA	P-DP	1.48	0.30	1.78	112.57	7.97	3.49	0.00	9.78	0.00	114.25	63.18	44.20
TORO 22 001 - 001	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.95
TOWNSEN 24265 ALLOC. A 10H	P-DP	0.17	0.31	1.95	13.25	6.41	2.62	0.00	2.85	0.00	19.44	9.53	45.84
TRAUBE 1-11 WRD 1H - 1H	P-DP	0.02	0.00	0.00	1.23	0.01	0.00	0.00	0.11	0.00	1.13	0.66	30.82
TRAUBE 1-11 WRD 2H - 2H	P-DP	0.02	0.01	0.01	1.32	0.14	0.00	0.00	0.15	0.00	1.32	0.73	33.29
TREBLE STATE COM 601H - 601	P-DP	0.15	0.00	0.13	11.27	0.06	0.15	0.00	1.55	0.00	9.93	6.24	29.68
TREBLE STATE COM 701H - 701	P-DP	0.11	0.00	0.12	8.68	0.06	0.14	0.00	1.20	0.00	7.67	5.03	29.51
TREBLE STATE COM 801H - 801	P-DP	0.19	0.00	0.14	14.61	0.07	0.16	0.00	2.00	0.00	12.85	8.15	29.51
TREE FROG 47 EAST A 1LS - 1L	P-DP	0.05	0.03	0.16	4.18	0.71	0.31	0.00	0.45	0.00	4.75	2.69	29.16
TREE FROG 47 EAST A 1WA - 1	P-DP	0.09	0.03	0.18	6.91	0.81	0.35	0.00	0.67	0.00	7.40	4.16	34.15
TREE FROG 47 EAST C 3LS - 3L	P-DP	0.08	0.06	0.35	6.47	1.57	0.69	0.00	0.80	0.00	7.93	4.31	34.45
TREE FROG 47 EAST C 3WA - 3	P-DP	0.09	0.16	0.94	6.86	4.20	1.84	0.00	1.40	0.00	11.49	5.96	36.05

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	Net Sales Volumes NGL (Mbbl)	Net Sales Volumes Residue Gas (MMcf)	Net Revenue Oil (M$)	Net Revenue NGL (M$)	Net Revenue Residue Gas (M$)	Net Revenue Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Cash Flow Disc. 10% (M$)	Life (years)
TREE FROG 47 EAST C 3WB - 3	P-DP	0.07	0.09	0.53	5.40	2.35	1.03	0.00	0.90	0.00	7.89	4.24	32.74
TREE FROG 47 WEST UNIT 5LS	P-DP	0.05	0.03	0.16	3.71	0.73	0.32	0.00	0.42	0.00	4.33	2.59	26.12
TREE FROG 47 WEST UNIT 5WA	P-DP	0.13	0.06	0.36	10.28	1.61	0.71	0.00	1.08	0.00	11.51	6.15	39.25
TREE FROG 47 WEST UNIT 5WB	P-DP	0.10	0.05	0.27	7.70	1.21	0.53	0.00	0.81	0.00	8.63	4.63	36.00
TREE FROG 47 WEST UNIT 7LS	P-DP	0.10	0.06	0.36	7.52	1.60	0.70	0.00	0.89	0.00	8.94	4.76	43.45
TREE FROG 47 WEST UNIT 7WA	P-DP	0.11	0.11	0.64	8.63	2.86	1.25	0.00	1.24	0.00	11.50	6.19	45.10
TRENTINO 1 - 1	P-DP	0.30	0.03	0.19	23.14	0.83	0.36	0.00	1.83	0.00	22.50	9.90	50.00
TRENTINO 2 - 2	P-DP	0.09	0.00	0.00	6.93	0.01	0.01	0.00	0.50	0.00	6.45	2.72	46.66
TRENTINO 36 3 - 3	P-DP	0.02	0.00	0.01	1.41	0.06	0.03	0.00	0.11	0.00	1.38	0.76	19.54
TRENTINO 36-37 (ALLOC-C) 3S	P-DP	0.07	0.03	0.16	4.95	0.71	0.31	0.00	0.51	0.00	5.47	3.34	40.04
TRENTINO 36-37 (ALLOC-C) 3S	P-DP	0.18	0.17	1.02	13.39	4.57	2.00	0.00	1.95	0.00	18.01	10.31	50.00
TRENTINO 36-37 (ALLOC-C) 3S	P-DP	0.05	0.01	0.08	3.78	0.37	0.16	0.00	0.35	0.00	3.96	2.33	36.25
TRENTINO 36-37 (ALLOC-D) 4S	P-DP	0.16	0.04	0.23	12.25	1.03	0.45	0.00	1.10	0.00	12.63	6.67	48.66
TRENTINO 36-37 (ALLOC-D) 4S	P-DP	0.08	0.08	0.49	6.30	2.21	0.97	0.00	0.93	0.00	8.54	4.30	44.98
TRENTINO 36-37 (ALLOC-DA) 4	P-DP	0.05	0.04	0.25	4.03	1.13	0.50	0.00	0.53	0.00	5.12	3.31	30.04
TRIANGLE 75 2H - 2H	P-DP	0.02	0.01	0.06	1.30	0.19	0.08	0.00	0.15	0.00	1.42	0.84	19.02
TRIDACNA 34-208 WRD UNIT 1	P-DP	0.01	0.01	0.01	0.50	0.16	0.00	0.00	0.08	0.00	0.58	0.34	29.86
TRIDACNA 34-208 WRD UNIT 2	P-DP	0.01	0.01	0.01	0.54	0.20	0.01	0.00	0.09	0.00	0.65	0.38	29.48
TRIDACNA 34-208 WRD UNIT 3	P-DP	0.01	0.01	0.01	0.63	0.14	0.00	0.00	0.09	0.00	0.69	0.40	31.54
TROTT 34-183 1H - 1H	P-DP	0.00	0.00	0.00	0.18	0.07	0.00	0.00	0.03	0.00	0.23	0.15	20.76
UNFORGIVEN 34 113-114 A 605	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
UNFORGIVEN 34 113-114 B 706	P-DP	0.00	0.00	0.00	0.08	0.01	0.00	0.00	0.01	0.00	0.08	0.04	49.23
UNFORGIVEN 34 113-114 C 606	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.92
UNFORGIVEN 34 113-114 D 604	P-DP	0.00	0.00	0.00	0.18	0.01	0.00	0.00	0.02	0.00	0.17	0.09	50.00
UNICORN UNIT A 04-37 1AH - 1	P-DP	0.01	0.00	0.01	0.75	0.00	0.05	0.00	0.06	0.00	0.73	0.42	30.47
UNICORN UNIT B 37-04 7AH - 7	P-DP	0.01	0.00	0.02	0.53	0.00	0.07	0.00	0.05	0.00	0.55	0.31	32.65
UNICORN UNIT B 37-04 8MH - 8	P-DP	0.01	0.00	0.00	0.75	0.00	0.02	0.00	0.06	0.00	0.71	0.40	31.39
URSULA 0848WA - 0848WA	P-DP	0.42	0.00	0.00	31.98	0.01	0.00	0.00	2.29	0.00	29.71	19.32	32.74
URSULA 1546WA - 1546WA	P-DP	0.30	0.23	1.37	22.84	6.14	2.69	0.00	2.96	0.00	28.71	18.73	29.11
URSULA BIG DADDY B 1527LS	P-DP	0.20	0.04	0.23	15.48	1.01	0.44	0.00	1.33	0.00	15.61	10.64	36.48
URSULA BIG DADDY B 1547WA	P-DP	0.19	0.04	0.21	14.70	0.95	0.42	0.00	1.26	0.00	14.81	9.72	37.78
URSULA BIG DADDY C 1528LS	P-DP	0.21	0.09	0.53	16.37	2.39	1.05	0.00	1.69	0.00	18.13	11.21	40.10
URSULA TOMCAT A 4446WA - 4	P-DP	1.31	0.21	1.22	99.68	5.48	2.40	0.00	8.32	0.00	99.25	65.77	41.45
URSULA TOMCAT B 4421LS - 44	P-DP	0.93	0.16	0.92	70.70	4.11	1.80	0.00	5.95	0.00	70.66	39.11	42.40
URSULA TOMCAT C 4447WA - 4	P-DP	1.68	0.30	1.79	127.62	8.01	3.50	0.00	10.86	0.00	128.27	75.59	45.88

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
UTE 3-12B3 - 3-12B3	P-DP	0.02	0.00	0.04	1.45	0.00	0.06	0.00	0.04	0.00	1.48	0.86	20.53
VALENCIA 10-8 A UNIT A 2H - A	P-DP	0.03	0.01	0.09	2.45	0.39	0.17	0.00	0.26	0.00	2.75	1.72	33.97
VALENCIA 10-8 A UNIT A 3H - A	P-DP	0.06	0.00	0.02	4.58	0.08	0.03	0.00	0.34	0.00	4.35	2.38	50.00
VALENCIA 10-8 A UNIT L 2H - L	P-DP	0.03	0.01	0.03	1.97	0.14	0.06	0.00	0.17	0.00	2.00	1.28	31.53
VALENCIA 10-8 A UNIT L 3H - L	P-DP	0.05	0.00	0.01	3.46	0.05	0.02	0.00	0.26	0.00	3.27	1.87	50.00
VALERIE 210473 1A - 1A	P-DP	0.00	0.00	8.14	0.00	0.00	16.65	0.00	1.45	0.00	15.20	9.50	21.80
VALERIE 210473 2B - 2B	P-DP	0.00	0.00	7.15	0.00	0.00	14.61	0.00	1.27	0.00	13.34	8.22	21.28
VALERIE 210473 4C - 4C	P-DP	0.00	0.00	10.49	0.00	0.00	21.46	0.00	1.87	0.00	19.59	11.16	26.68
VANNELLE SW WHL BL 2H - 2H	P-DP	0.00	0.00	96.29	0.00	0.00	196.90	0.00	17.15	0.00	179.75	97.01	50.00
VICKERS '34-127' 1H - 1H	P-DP	0.00	0.00	0.00	0.37	0.06	0.00	0.00	0.05	0.00	0.39	0.29	9.62
VICKERS '34-127' 2H - 2H	P-DP	0.01	0.00	0.00	0.85	0.05	0.00	0.00	0.09	0.00	0.81	0.50	20.32
VINTAGE A U 06H - U 06H	P-DP	0.03	0.04	0.23	2.55	0.75	0.31	0.00	0.41	0.00	3.20	1.72	42.56
VINTAGE B T 13H - T 13H	P-DP	0.06	0.10	0.60	4.51	1.97	0.81	0.00	0.91	0.00	6.39	3.56	50.00
VINTAGE C C 03H - C 03H	P-DP	0.10	0.13	0.80	7.77	2.63	1.08	0.00	1.34	0.00	10.14	5.30	50.00
VINTAGE D T 26H - T 26H	P-DP	0.03	0.05	0.28	1.92	0.92	0.38	0.00	0.41	0.00	2.81	1.55	50.00
VINTAGE E C 04H - C 04H	P-DP	0.13	0.11	0.67	9.54	2.20	0.90	0.00	1.34	0.00	11.30	6.20	50.00
VINTAGE UNIT A U 19H - U 19H	P-DP	0.02	0.02	0.12	1.44	0.40	0.16	0.00	0.22	0.00	1.78	0.85	50.00
VIPER FOSTER B 4545WA - 4545	P-DP	0.80	0.07	0.44	61.25	1.96	0.86	0.00	4.80	0.00	59.26	32.40	45.19
VIPER FOSTER C 4525LS - 4525	P-DP	0.98	0.33	1.96	74.73	8.78	3.84	0.00	7.25	0.00	80.10	44.83	49.46
VIPER FOSTER D 4546WA - 4546	P-DP	1.22	0.32	1.87	93.24	8.37	3.66	0.00	8.48	0.00	96.79	52.01	50.00
WALKER 32-48 B UNIT A 5H - A	P-DP	1.32	0.02	0.11	100.54	0.50	0.22	0.00	7.30	0.00	93.96	50.73	50.00
WALKER 32-48 B UNIT L 6H - L	P-DP	0.86	0.06	0.36	65.65	1.60	0.70	0.00	5.04	0.00	62.91	34.56	50.00
WALKER 48-32 A UNIT A 1H - A	P-DP	2.00	0.05	0.31	152.06	1.37	0.60	0.00	11.17	0.00	142.86	78.11	50.00
WALKER 48-32 A UNIT L 1H - L	P-DP	0.01	0.00	0.00	0.71	0.01	0.00	0.00	0.05	0.00	0.67	0.60	2.38
WALKER-DRRC 30-56 EAST UN	P-DP	0.11	0.02	0.10	8.17	0.45	0.20	0.00	0.68	0.00	8.13	4.84	50.00
WALKER-DRRC 30-56 EAST UN	P-DP	0.02	0.01	0.08	1.27	0.37	0.16	0.00	0.17	0.00	1.63	0.86	41.59
WALKER-DRRC 30-56 EAST UN	P-DP	0.01	0.02	0.09	1.09	0.42	0.19	0.00	0.17	0.00	1.53	0.86	38.70
WALKER-DRRC 30-56 WEST UN	P-DP	0.05	0.02	0.10	3.61	0.43	0.19	0.00	0.35	0.00	3.88	2.22	50.00
WALKER-DRRC 30-56 WEST UN	P-DP	0.02	0.01	0.05	1.39	0.23	0.10	0.00	0.15	0.00	1.57	0.94	37.25
WALKER-DRRC 30-56 WEST UN	P-DP	0.03	0.01	0.05	1.97	0.21	0.09	0.00	0.19	0.00	2.09	1.26	40.00
WALLACE, T. L. 1 - 1	P-DP	0.00	0.00	0.00	0.20	0.00	0.00	0.00	0.02	0.00	0.18	0.09	27.00
WALLACE, T. L. 3 - 3	P-DP	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.01	0.00	0.07	0.05	7.76
WALLY A1 15UA - 15UA	P-DP	0.01	0.00	0.00	0.59	0.01	0.00	0.00	0.10	0.00	0.50	0.30	45.96
WALLY A1 21H - 21H	P-DP	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.01	0.00	0.05	0.03	16.18
WALLY A1 8LA - 8LA	P-DP	0.01	0.00	0.00	0.45	0.01	0.00	0.00	0.08	0.00	0.37	0.25	35.75

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
WALLY A2 7LA - 7LA	P-DP	0.01	0.00	0.00	0.46	0.01	0.00	0.00	0.08	0.00	0.39	0.23	42.55
WALLY A3 20H - 20H	P-DP	0.00	0.00	0.00	0.04	0.01	0.00	0.00	0.01	0.00	0.04	0.03	18.59
WALLY A4 14UA - 14UA	P-DP	0.02	0.00	0.00	1.43	0.06	0.00	0.00	0.17	0.00	1.31	0.73	50.00
WALLY A5 6LA - 6LA	P-DP	0.01	0.00	0.00	0.64	0.03	0.00	0.00	0.09	0.00	0.58	0.34	47.98
WARD 18CC 1803D - 1803D	P-DP	0.09	0.01	0.07	6.97	0.30	0.13	0.00	0.56	0.00	6.83	4.17	32.33
WARD 18CC 1804D - 1804D	P-DP	0.23	0.01	0.08	17.45	0.34	0.15	0.00	1.32	0.00	16.61	8.49	41.25
WASHINGTON EAST I 23-14 440	P-DP	0.05	0.04	0.12	3.94	0.59	0.24	0.00	0.48	0.00	4.29	2.20	50.00
WASHINGTON WEST A 23-14 42	P-DP	0.08	0.02	0.06	6.32	0.28	0.12	0.00	0.60	0.00	6.12	2.93	50.00
WASHINGTON WEST A 23-14 44	P-DP	0.05	0.06	0.22	3.56	1.04	0.43	0.00	0.57	0.00	4.46	2.24	50.00
WASHINGTON WEST B 23-14 43	P-DP	0.08	0.18	0.63	5.86	3.00	1.25	0.00	1.28	0.00	8.83	4.16	50.00
WASHINGTON WEST B 23-14 46	P-DP	0.02	0.10	0.34	1.88	1.63	0.68	0.00	0.59	0.00	3.61	1.72	48.89
WASHINGTON WEST D 23-14 44	P-DP	0.01	0.08	0.29	0.86	1.39	0.58	0.00	0.44	0.00	2.39	1.20	44.93
WASHINGTON WEST E 23-14 43	P-DP	0.02	0.11	0.37	1.77	1.79	0.75	0.00	0.62	0.00	3.69	1.87	50.00
WASHINGTON WEST F 23-14 44	P-DP	0.01	0.04	0.12	1.01	0.59	0.24	0.00	0.24	0.00	1.60	0.88	36.44
WASHINGTON WEST G 23-14 43	P-DP	0.06	0.16	0.55	4.53	2.63	1.10	0.00	1.07	0.00	7.19	3.61	50.00
WATKINS 7 1 - 1	P-DP	0.58	0.11	0.54	44.02	2.44	0.73	0.00	4.11	0.00	43.09	25.37	29.13
WELCH 39 1 - 1	P-DP	0.18	0.05	0.23	13.90	1.04	0.31	0.00	1.40	0.00	13.85	8.05	46.30
WELCH 39 2 - 2	P-DP	0.01	0.00	0.02	0.77	0.08	0.02	0.00	0.09	0.00	0.79	0.55	14.61
WELCH 39 3 - 3	P-DP	0.02	0.01	0.07	1.25	0.31	0.09	0.00	0.21	0.00	1.45	0.88	22.39
WELCH 39 4 - 4	P-DP	0.04	0.02	0.09	3.16	0.39	0.12	0.00	0.38	0.00	3.29	1.95	30.57
WELCH-COX E39A 301H - 301H	P-DP	0.13	0.01	0.06	10.05	0.26	0.08	0.00	0.82	0.00	9.56	5.48	48.43
WELCH-COX E39B 302H - 302H	P-DP	0.81	0.28	1.36	61.64	6.13	1.83	0.00	6.79	0.00	62.81	33.47	50.00
WELCH-COX E39C 303H - 303H	P-DP	0.15	0.03	0.15	11.54	0.66	0.20	0.00	1.09	0.00	11.31	6.59	50.00
WELCH-COX E39D 304H - 304H	P-DP	0.55	0.11	0.53	41.77	2.40	0.72	0.00	3.93	0.00	40.96	22.48	50.00
WELCH-COX E39S 319H - 319H	P-DP	0.30	0.08	0.39	23.09	1.76	0.53	0.00	2.34	0.00	23.04	13.06	50.00
WELCH-COX E39T 320H - 320H	P-DP	0.32	0.05	0.27	24.39	1.19	0.36	0.00	2.22	0.00	23.72	13.60	50.00
WELCH-COX E39U 321H - 321H	P-DP	0.41	0.23	1.13	31.27	5.07	1.51	0.00	4.19	0.00	33.66	18.48	50.00
WELCH-COX E39V 322H - 322H	P-DP	0.41	0.12	0.59	30.75	2.66	0.79	0.00	3.24	0.00	30.97	18.29	50.00
WELCH-COX E39W 323H - 323H	P-DP	0.03	0.01	0.05	1.93	0.21	0.06	0.00	0.22	0.00	1.98	1.10	50.00
WELCH-COX W39F 206H - 206H	P-DP	0.22	0.17	0.81	16.48	3.64	1.09	0.00	2.58	0.00	18.62	11.17	44.93
WELCH-COX W39G 207H - 207H	P-DP	0.43	0.09	0.44	32.44	2.00	0.60	0.00	3.10	0.00	31.93	18.65	50.00
WELCH-COX W39H 208H - 208H	P-DP	0.18	0.13	0.61	13.58	2.74	0.82	0.00	2.03	0.00	15.12	9.25	45.52
WELCH-COX W39I 209H - 209H	P-DP	0.20	0.06	0.29	15.39	1.30	0.39	0.00	1.61	0.00	15.47	9.22	44.33
WELCH-COX W39J 210H - 210H	P-DP	0.32	0.16	0.79	24.11	3.54	1.06	0.00	3.09	0.00	25.62	15.47	49.00
WELCH-COX W39K 211H - 211H	P-DP	0.27	0.10	0.47	20.50	2.11	0.63	0.00	2.29	0.00	20.96	13.00	49.04

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
WELCH-COX W39L 212H - 212H	P-DP	0.22	0.08	0.40	16.64	1.81	0.54	0.00	1.89	0.00	17.10	9.55	46.83
WELCH-COX W39M 213H - 213	P-DP	0.16	0.11	0.55	12.22	2.46	0.73	0.00	1.82	0.00	13.59	8.42	40.56
WELCH-COX W39N 214H - 214H	P-DP	0.19	0.10	0.46	14.29	2.08	0.62	0.00	1.83	0.00	15.17	8.92	43.96
WELCH-COX W39O 215H - 215H	P-DP	0.23	0.10	0.48	17.82	2.17	0.65	0.00	2.11	0.00	18.52	10.74	46.89
WELCH-COX W39P 216H - 216H	P-DP	0.39	0.15	0.74	29.87	3.34	1.00	0.00	3.43	0.00	30.78	18.90	50.00
WEREWOLF UNIT A 12-05 1AH	P-DP	0.03	0.00	0.03	2.48	0.00	0.11	0.00	0.19	0.00	2.40	1.30	50.00
WEREWOLF UNIT A 12-05 2AH	P-DP	0.02	0.00	0.02	1.79	0.00	0.08	0.00	0.14	0.00	1.73	0.99	49.25
WEREWOLF UNIT A 12-05 3AH	P-DP	0.03	0.00	0.12	2.57	0.01	0.40	0.00	0.25	0.00	2.73	1.60	45.71
WEREWOLF UNIT B 12-05 4AH	P-DP	0.03	0.00	0.05	2.50	0.00	0.17	0.00	0.20	0.00	2.46	1.42	50.00
WEREWOLF UNIT B 12-05 5AH	P-DP	0.02	0.00	0.04	1.75	0.00	0.12	0.00	0.14	0.00	1.73	0.99	49.47
WEREWOLF UNIT B 12-05 6AH	P-DP	0.04	0.00	0.05	2.85	0.00	0.17	0.00	0.23	0.00	2.79	1.60	50.00
WHIRLAWAY 99 1HA - 1HA	P-DP	0.02	0.01	0.01	1.23	0.12	0.00	0.00	0.14	0.00	1.21	0.69	31.52
WHISKEY RIVER 9596A-34 11H	P-DP	0.00	0.00	0.00	0.20	0.01	0.00	0.00	0.02	0.00	0.19	0.10	50.00
WHISKEY RIVER 9596A-34 12H	P-DP	0.00	0.00	0.00	0.06	0.01	0.00	0.00	0.01	0.00	0.07	0.04	39.67
WHISKEY RIVER 9596A-34 13H	P-DP	0.00	0.00	0.00	0.08	0.01	0.00	0.00	0.01	0.00	0.08	0.04	50.00
WHISKEY RIVER 9596B-34 1H -	P-DP	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.01	0.00	0.05	0.03	39.56
WHISKEY RIVER 9596B-34 31H	P-DP	0.00	0.00	0.00	0.09	0.01	0.00	0.00	0.01	0.00	0.09	0.05	44.57
WHISKEY RIVER 9596B-34 32H	P-DP	0.00	0.00	0.00	0.13	0.01	0.00	0.00	0.01	0.00	0.13	0.07	48.48
WHISKEY RIVER 9596C-34 1H -	P-DP	0.00	0.00	0.00	0.11	0.01	0.00	0.00	0.01	0.00	0.11	0.05	48.63
WHISKEY RIVER 9596D-34 81H	P-DP	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.04	0.02	38.19
WHITE 1-23C5 - 1-23C5	P-DP	0.01	0.00	0.01	0.31	0.00	0.01	0.00	0.01	0.00	0.31	0.19	21.66
WHITE 19 - 19	P-DP	0.01	0.00	0.00	0.40	0.00	0.00	0.00	0.03	0.00	0.36	0.17	27.17
WHITE 2-23C5 - 2-23C5	P-DP	0.02	0.00	0.05	1.17	0.00	0.09	0.00	0.04	0.00	1.22	0.64	41.21
WHITE 3-14C5 - 3-14C5	P-DP	0.18	0.00	0.38	10.96	0.00	0.65	0.00	0.31	0.00	11.31	5.38	43.13
WHITE TRUST 3-23C5 - 3-23C5	P-DP	0.02	0.00	0.04	1.46	0.00	0.06	0.00	0.04	0.00	1.49	0.70	47.21
WHITMIRE 36-37 (ALLOC-F) 6S	P-DP	0.01	0.00	0.01	0.57	0.05	0.02	0.00	0.05	0.00	0.59	0.31	36.29
WHITMIRE 36-37 (ALLOC-F) 6S	P-DP	0.01	0.00	0.02	0.50	0.08	0.04	0.00	0.05	0.00	0.56	0.30	36.80
WHITMIRE 36-37 (ALLOC-G) 7S	P-DP	0.01	0.01	0.04	0.71	0.17	0.08	0.00	0.09	0.00	0.87	0.45	42.54
WHITMIRE 36-37 (ALLOC-G) 7S	P-DP	0.07	0.03	0.18	5.60	0.82	0.36	0.00	0.58	0.00	6.19	3.06	47.74
WHITMIRE 36-37 (ALLOC-H) 8S	P-DP	0.09	0.02	0.11	7.20	0.49	0.21	0.00	0.62	0.00	7.28	3.63	49.84
WHITMIRE 36-37 (ALLOC-H) 8S	P-DP	0.07	0.01	0.04	5.08	0.19	0.08	0.00	0.40	0.00	4.95	2.66	42.18
WILEY 4 1 - 1	P-DP	0.11	0.06	0.27	8.00	1.21	0.36	0.00	1.04	0.00	8.53	4.95	35.25
WILEY 4 2 - 2	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WILLETT POT STILL 5-2C UNIT	P-DP	0.17	0.22	1.39	13.14	4.56	1.86	0.00	2.30	0.00	17.27	10.08	27.93
WILLIE THE WILDCAT 3-15 A 1J	P-DP	0.02	0.03	0.15	1.50	0.66	0.20	0.00	0.36	0.00	2.00	1.06	39.10

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
WILLIE THE WILDCAT 3-15 A 1L	P-DP	0.03	0.02	0.09	1.98	0.40	0.12	0.00	0.30	0.00	2.20	1.24	38.36
WILLIE THE WILDCAT 3-15 A 1	P-DP	0.07	0.13	0.64	5.04	2.87	0.86	0.00	1.46	0.00	7.31	3.74	50.00
WILLIE THE WILDCAT 3-15 B 2	P-DP	0.02	0.02	0.11	1.83	0.49	0.15	0.00	0.32	0.00	2.14	1.40	32.46
WILLIE THE WILDCAT 3-15 B 2	P-DP	0.04	0.03	0.16	3.30	0.70	0.21	0.00	0.51	0.00	3.71	2.01	44.98
WILLIE THE WILDCAT 3-15 B 2	P-DP	0.02	0.06	0.30	1.25	1.35	0.40	0.00	0.61	0.00	2.39	1.38	32.15
WILLIE THE WILDCAT 3-15 B 3J	P-DP	0.02	0.02	0.11	1.82	0.50	0.15	0.00	0.32	0.00	2.15	1.31	36.15
WILLIE THE WILDCAT 3-15 C 4	P-DP	0.02	0.01	0.04	1.14	0.16	0.05	0.00	0.14	0.00	1.21	0.71	30.64
WILLIE THE WILDCAT 3-15 C 4	P-DP	0.03	0.01	0.07	2.34	0.32	0.10	0.00	0.29	0.00	2.47	1.32	38.93
WILLIE THE WILDCAT 3-15 D 5J	P-DP	0.03	0.02	0.07	1.94	0.33	0.10	0.00	0.27	0.00	2.10	1.16	38.31
WILLIE THE WILDCAT 3-15 D 6	P-DP	0.06	0.07	0.36	4.18	1.64	0.49	0.00	0.93	0.00	5.38	2.85	50.00
WILLIE THE WILDCAT 3-15 D 6	P-DP	0.04	0.02	0.09	2.69	0.42	0.13	0.00	0.36	0.00	2.88	1.76	37.28
WILLIE THE WILDCAT 3-15 D 6	P-DP	0.04	0.07	0.35	2.70	1.59	0.47	0.00	0.80	0.00	3.96	2.14	42.31
WILLIE THE WILDCAT 3-15 E 7J	P-DP	0.06	0.00	0.02	4.20	0.07	0.02	0.00	0.33	0.00	3.96	2.33	43.04
WILLIE THE WILDCAT 3-15 E 7L	P-DP	0.10	0.04	0.20	7.75	0.88	0.26	0.00	0.90	0.00	8.00	4.48	50.00
WILLIE THE WILDCAT 3-15 E 7	P-DP	0.02	0.08	0.40	1.28	1.81	0.54	0.00	0.78	0.00	2.84	1.83	21.60
WILSON 184-185 UNIT 131H - 13	P-DP	0.08	0.08	0.08	5.64	1.72	0.05	0.00	0.91	0.00	6.51	3.42	50.00
WILSON 184-185 UNIT 132H - 13	P-DP	0.05	0.06	0.06	4.01	1.35	0.04	0.00	0.67	0.00	4.73	2.60	50.00
WILSON 184-185 UNIT 232H - 23	P-DP	0.04	0.07	0.07	3.32	1.58	0.05	0.00	0.67	0.00	4.28	2.42	49.59
WILSON 184-185 UNIT 2H - 2H	P-DP	0.04	0.07	0.07	3.30	1.62	0.05	0.00	0.68	0.00	4.29	2.20	50.00
WILSON 184-185 UNIT 332H - 33	P-DP	0.08	0.18	0.17	6.05	3.86	0.12	0.00	1.45	0.00	8.58	4.54	50.00
WINDY MOUNTAIN 7879 1U B 1	P-DP	0.02	0.01	0.09	1.56	0.29	0.12	0.00	0.20	0.00	1.77	0.95	43.33
WINDY MOUNTAIN 7879 2U B 2	P-DP	0.02	0.02	0.11	1.73	0.36	0.15	0.00	0.23	0.00	2.01	1.15	43.14
WINTERS BB 2 - 2	P-DP	0.03	0.00	0.01	2.04	0.03	0.01	0.00	0.15	0.00	1.93	1.15	14.68
WINTERS,FERN D 2 - 2	P-DP	0.04	0.00	0.00	2.93	0.00	0.00	0.00	0.21	0.00	2.72	1.75	11.48
WORTHY 13-12 (ALLOC-A) 1NA	P-DP	0.47	0.09	0.54	35.99	2.43	1.06	0.00	3.10	0.00	36.39	18.84	50.00
WORTHY 13-12 (ALLOC-A) 1NS	P-DP	0.26	0.03	0.20	19.57	0.91	0.40	0.00	1.60	0.00	19.28	10.00	50.00
WORTHY 13-12 (ALLOC-B) 2NB	P-DP	0.28	0.11	0.66	21.32	2.95	1.29	0.00	2.16	0.00	23.40	11.94	50.00
WORTHY 13-12 (ALLOC-C) 3NA	P-DP	0.33	0.11	0.63	25.50	2.84	1.24	0.00	2.44	0.00	27.14	14.08	50.00
WORTHY 13-12 (ALLOC-D) 4NB	P-DP	0.28	0.16	0.96	21.55	4.30	1.88	0.00	2.47	0.00	25.26	12.92	50.00
WORTHY 13-12 (ALLOC-D) 4NS	P-DP	0.19	0.11	0.66	14.22	2.94	1.29	0.00	1.65	0.00	16.79	8.54	50.00
WRAITH UNIT A 12-16 1AH - 1A	P-DP	1.56	0.01	3.25	115.05	0.17	10.86	0.00	9.94	0.00	116.14	63.17	50.00
WRAITH UNIT A 12-16 2AH - 2A	P-DP	1.86	0.01	2.77	136.87	0.14	9.28	0.00	11.24	0.00	135.04	76.10	50.00
WRAITH UNIT A 12-16 3AH - 3A	P-DP	1.57	0.01	2.65	115.75	0.14	8.87	0.00	9.67	0.00	115.09	61.09	50.00
WRAITH UNIT B 12-16 4AH - 4A	P-DP	1.94	0.00	1.68	143.27	0.09	5.63	0.00	11.11	0.00	137.87	83.84	50.00
WRAITH UNIT B 12-16 5AH - 5A	P-DP	1.51	0.01	3.13	111.13	0.16	10.46	0.00	9.60	0.00	112.16	71.23	43.72

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
WRAITH UNIT B 12-16 6AH - 6A	P-DP	1.63	0.00	1.41	120.19	0.07	4.71	0.00	9.32	0.00	115.65	74.89	44.33
WRANGLER A UNIT 1H - 1H	P-DP	0.11	0.05	0.15	8.29	1.25	-0.03	0.00	0.47	0.00	9.04	4.78	50.00
WRANGLER A UNIT 2H - 2H	P-DP	0.14	0.00	0.01	10.70	0.10	0.00	0.00	0.97	0.00	9.83	5.53	47.50
WRANGLER B UNIT 1H - 1H	P-DP	0.04	0.02	0.04	3.40	0.37	-0.02	0.00	0.22	0.00	3.53	2.14	38.03
WRANGLER B UNIT 2H - 2H	P-DP	0.09	0.03	0.08	6.75	0.64	-0.03	0.00	0.47	0.00	6.89	4.23	45.55
WRANGLER C UNIT 1H - 1H	P-DP	0.13	0.03	0.10	9.77	0.82	-0.02	0.00	0.71	0.00	9.87	5.57	50.00
WRANGLER C UNIT 2H - 2H	P-DP	0.15	0.03	0.10	11.12	0.84	-0.02	0.00	0.83	0.00	11.10	6.32	50.00
WRANGLER C UNIT 752H - 752	P-DP	0.11	0.05	0.15	8.65	1.26	-0.05	0.00	0.49	0.00	9.36	5.60	50.00
WRANGLER C UNIT 753H - 753	P-DP	0.36	0.08	0.22	27.40	1.84	-0.07	0.00	2.09	0.00	27.07	13.55	50.00
WRANGLER D UNIT 1H - 1H	P-DP	0.09	0.02	0.07	6.48	0.56	-0.02	0.00	0.46	0.00	6.56	3.71	47.41
WRANGLER D UNIT 2H - 2H	P-DP	0.13	0.04	0.11	10.27	0.94	-0.03	0.00	0.72	0.00	10.45	5.96	50.00
WRANGLER D UNIT 751H - 751	P-DP	0.17	0.06	0.17	13.03	1.43	-0.05	0.00	0.86	0.00	13.55	7.91	50.00
WRIGHT 1-22 E WRD UNIT 2H -	P-DP	0.00	0.00	0.00	0.13	0.01	0.00	0.00	0.01	0.00	0.13	0.09	13.72
WRIGHT 1-22 W WRD UNIT 2H	P-DP	0.01	0.00	0.00	0.45	0.03	0.00	0.00	0.05	0.00	0.43	0.23	28.05
WRIGHT 1-22E WRD 1H - 1H	P-DP	0.00	0.00	0.00	0.14	0.01	0.00	0.00	0.01	0.00	0.14	0.08	26.00
WRIGHT 1-22W WRD 1H - 1H	P-DP	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	7.64
WYNN 29 1 - 1	P-DP	0.02	0.01	0.04	1.31	0.17	0.07	0.00	0.13	0.00	1.42	0.65	33.26
WYNN FARMS 28 1 - 1	P-DP	0.00	0.00	0.00	0.08	0.01	0.00	0.00	0.01	0.00	0.08	0.07	4.28
XBC-CAROLINE 3B 302H - 302H	P-DP	0.08	0.10	0.58	5.80	1.56	0.85	0.00	1.80	0.00	6.41	3.60	37.40
XBC-CAROLINE 3C 303H - 303H	P-DP	0.08	0.10	0.58	6.34	1.54	0.85	0.00	1.83	0.00	6.90	3.73	39.38
XBC-CAROLINE 3K 311H - 311H	P-DP	0.06	0.10	0.56	4.59	1.51	0.83	0.00	1.66	0.00	5.27	3.03	34.23
XBC-CAROLINE 3L 312H - 312H	P-DP	0.07	0.10	0.59	5.50	1.57	0.86	0.00	1.78	0.00	6.15	3.49	36.28
XBC-CAROLINE 3M 313H - 313	P-DP	0.10	0.11	0.65	7.92	1.74	0.96	0.00	2.13	0.00	8.49	4.50	41.75
XBC-UNRUH 3A 16H - 16H	P-DP	0.14	0.07	0.41	10.79	1.09	0.60	0.00	1.81	0.00	10.66	5.67	45.20
XBC-UNRUH 3B 17H - 17H	P-DP	0.09	0.09	0.53	6.97	1.41	0.78	0.00	1.77	0.00	7.39	4.10	39.00
YANKEE 210475 5A - 5A	P-DP	0.00	0.00	0.01	0.00	0.00	0.03	0.00	0.00	0.00	0.02	0.01	31.13
YELLOW ROSE A UNIT 1H - 1H	P-DP	0.03	0.00	0.00	2.29	0.01	0.00	0.00	0.21	0.00	2.09	1.20	42.06
YELLOW ROSE A UNIT 2H - 2H	P-DP	0.03	0.00	0.00	2.07	0.02	0.00	0.00	0.19	0.00	1.90	1.11	43.64
YELLOW ROSE A UNIT 3H - 3H	P-DP	0.02	0.02	0.06	1.28	0.47	-0.02	0.00	0.00	0.00	1.72	0.89	37.90
YELLOW ROSE B UNIT 1H - 1H	P-DP	0.08	0.00	0.01	6.46	0.05	0.00	0.00	0.59	0.00	5.93	2.98	50.00
YELLOW ROSE B UNIT 2H - 2H	P-DP	0.03	0.00	0.00	2.18	0.02	0.00	0.00	0.20	0.00	2.00	1.10	45.51
YELLOW ROSE B UNIT 3H - 3H	P-DP	0.07	0.05	0.13	5.03	1.13	-0.04	0.00	0.19	0.00	5.92	3.11	50.00
YORK-LAW 139A 101H - 101H	P-DP	1.13	0.77	3.74	85.86	16.79	5.01	0.00	12.61	0.00	95.05	55.64	50.00
YORK-LAW 139B 102H - 102H	P-DP	1.18	0.34	1.64	89.21	7.37	2.20	0.00	9.25	0.00	89.53	54.59	50.00
YORK-LAW 139C 103H - 103H	P-DP	0.51	0.24	1.17	38.83	5.24	1.56	0.00	4.80	0.00	40.83	24.75	48.26

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
YORK-LAW 139D 104H - 104H	P-DP	1.01	0.30	1.45	76.78	6.51	1.94	0.00	8.03	0.00	77.21	45.25	50.00
YORK-LAW 139E 105H - 105H	P-DP	1.00	0.34	1.65	75.81	7.42	2.22	0.00	8.31	0.00	77.15	44.10	50.00
YORK-LAW 139F 106H - 106H	P-DP	0.86	0.46	2.23	65.16	10.02	2.99	0.00	8.53	0.00	69.64	40.25	50.00
YORK-LAW 139G 107H - 107H	P-DP	1.11	0.37	1.80	84.41	8.10	2.42	0.00	9.18	0.00	85.74	49.25	50.00
YORK-LAW 139H 108H - 108H	P-DP	0.81	0.28	1.36	61.67	6.11	1.82	0.00	6.78	0.00	62.81	36.45	50.00
ZPZ 34-196 WRD UNIT 1H - 1H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.25
ZPZ 34-196 WRD UNIT 2H - 2H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.50
ZPZ 34-196 WRD UNIT 3H - 3H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.06
ZPZ 34-196 WRD UNIT 4H - 4H	P-DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.24
	Total	**517.15**	**403.28**	**21,592.50**	**38,718.50**	**8,359.44**	**45,288.93**	**0.00**	**26,544.66**	**0.00**	**65,822.21**	**39,368.34**	**50.00**
Proved Behind Pipe Rsv Class & Category													
44 MAGNUM 9-4 H 2LS - H 2LS	P-BP	0.55	0.17	0.99	42.14	4.42	1.93	0.00	3.97	0.00	44.52	31.15	47.86
ATOMIC 55-1-18-6 A 12HR - 12H	P-BP	0.10	0.19	0.55	7.88	4.68	-0.20	0.00	-0.41	0.00	12.76	7.35	50.00
ATOMIC 55-1-18-6 B 13H - 13H	P-BP	0.10	0.19	0.55	7.88	4.68	-0.22	0.00	-0.42	0.00	12.75	7.83	50.00
ATOMIC 55-1-18-6 C 14H - 14H	P-BP	0.10	0.19	0.55	7.87	4.68	-0.22	0.00	-0.42	0.00	12.75	7.75	50.00
ATOMIC 55-1-18-6 D 15H - 15H	P-BP	0.06	0.11	0.32	4.53	2.69	-0.12	0.00	-0.24	0.00	7.33	4.46	50.00
BATES S CRC JF 7H - 7H	P-BP	0.00	0.00	1,514.16	0.00	0.00	2,999.39	0.00	1,867.96	0.00	1,131.43	784.85	39.36
BILLY BOBS STATE A 3472H - 34	P-BP	0.00	0.00	0.00	0.07	0.03	0.00	0.00	0.01	0.00	0.08	0.06	50.00
BOW TIE E 7MS - 7MS	P-BP	0.10	0.02	0.12	7.74	0.55	0.24	0.00	0.67	0.00	7.85	5.67	40.61
BOW TIE F 8MS - 8MS	P-BP	0.10	0.02	0.12	7.61	0.54	0.23	0.00	0.66	0.00	7.72	5.58	40.39
BROKEN ARROW 55-54-1-12 H	P-BP	0.25	0.05	0.31	19.42	1.37	0.60	0.00	1.69	0.00	19.70	13.98	39.99
BROKEN ARROW 55-54-1-12 H	P-BP	0.26	0.05	0.31	19.48	1.37	0.60	0.00	1.69	0.00	19.76	13.92	40.10
BROKEN ARROW 55-54-1-12 H	P-BP	0.24	0.05	0.29	18.65	1.31	0.57	0.00	1.62	0.00	18.92	13.43	39.48
BROKEN ARROW 55-54-1-12 H	P-BP	0.47	0.08	0.45	35.69	2.02	0.88	0.00	2.99	0.00	35.60	23.32	50.00
CHEST THUMPER 1-5 UNIT 1 14	P-BP	0.19	0.05	0.26	14.34	1.15	0.34	0.00	1.51	0.00	14.32	9.94	50.00
CHEVRON UNIT 03-38 3MH - 3M	P-BP	0.10	0.05	0.29	7.42	1.28	0.56	0.00	0.81	0.00	8.45	5.64	35.47
CHEVRON UNIT 03-38 3SH - 3S	P-BP	0.14	0.04	0.24	10.42	1.09	0.48	0.00	0.98	0.00	11.01	6.82	48.10
CHEVRON UNIT 03-38 4AH - 4A	P-BP	0.19	0.05	0.30	14.26	1.36	0.60	0.00	1.31	0.00	14.90	9.34	50.00
CHEVRON UNIT 03-38 4MH - 4M	P-BP	0.10	0.05	0.29	7.43	1.28	0.56	0.00	0.81	0.00	8.46	5.64	35.47
CHEVRON UNIT 03-56 4SH - 4S	P-BP	0.14	0.04	0.25	10.47	1.10	0.48	0.00	0.99	0.00	11.07	7.33	48.10
CHEVRON UNIT 03-56 5AH - 5A	P-BP	0.19	0.05	0.31	14.30	1.37	0.60	0.00	1.32	0.00	14.95	10.02	50.00
CHEVRON UNIT 03-56 5MH - 5M	P-BP	0.10	0.05	0.29	7.45	1.28	0.56	0.00	0.81	0.00	8.48	5.66	35.47
CHEVRON UNIT 03-56 5SH - 5S	P-BP	0.14	0.04	0.25	10.48	1.10	0.48	0.00	0.99	0.00	11.08	7.33	48.10
CHEVRON UNIT 03-56 6AH - 6A	P-BP	0.19	0.05	0.31	14.34	1.37	0.60	0.00	1.32	0.00	14.98	9.40	50.00
CHUMCHAL-GERGES 1H - 1H	P-BP	4.16	3.14	15.58	309.14	56.86	30.21	0.00	34.35	0.00	361.85	264.60	42.86

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
COWLEY C 3H - 3H	*P-BP*	7.31	5.52	27.43	543.92	100.07	53.16	0.00	60.45	0.00	636.70	450.51	41.97
COWLEY D 4H - 4H	*P-BP*	7.67	5.79	28.76	570.33	104.94	55.75	0.00	63.39	0.00	667.63	491.37	42.12
CROSS CREEK A S CRC JF - 4H	*P-BP*	0.00	0.00	512.28	0.00	0.00	1,014.78	0.00	631.98	0.00	382.80	259.95	49.14
CROSS CREEK A SE CRC JF 6H	*P-BP*	0.00	0.00	485.79	0.00	0.00	962.29	0.00	599.30	0.00	363.00	240.50	50.00
CROSS CREEK A SW CRC JF - 2	*P-BP*	0.00	0.00	664.15	0.00	0.00	1,315.62	0.00	819.34	0.00	496.28	323.69	43.75
DIRE WOLF B 5A - 5A	*P-BP*	0.58	0.69	0.68	43.65	15.19	0.46	0.00	7.47	0.00	51.84	35.01	46.48
DIRE WOLF C 6TB - 6TB	*P-BP*	0.58	0.69	0.68	43.69	15.20	0.46	0.00	7.47	0.00	51.88	35.01	46.50
DIRE WOLF D 7B - 7B	*P-BP*	0.58	0.69	0.68	43.72	15.21	0.47	0.00	7.48	0.00	51.92	35.01	46.52
ELIAS 16-9 UNIT 1 223 - 223	*P-BP*	0.08	0.04	0.20	6.07	0.91	0.27	0.00	0.79	0.00	6.47	4.41	50.00
ELIAS 16-9 UNIT 2 173 - 173	*P-BP*	0.06	0.04	0.21	4.48	0.96	0.29	0.00	0.69	0.00	5.04	3.66	43.54
ELIAS 16-9 UNIT 2 252 - 252	*P-BP*	0.08	0.04	0.20	5.93	0.89	0.27	0.00	0.77	0.00	6.31	4.16	50.00
ELIAS 16-9 UNIT 2 262 - 262	*P-BP*	0.08	0.04	0.20	6.06	0.91	0.27	0.00	0.78	0.00	6.45	4.26	50.00
ELIAS 16-9 UNIT 2 271 - 271	*P-BP*	0.08	0.04	0.20	6.09	0.91	0.27	0.00	0.79	0.00	6.49	4.44	50.00
ELIAS 16-9 UNIT 2 281 - 281	*P-BP*	0.08	0.04	0.21	6.16	0.92	0.28	0.00	0.80	0.00	6.56	4.51	50.00
ELIAS 16-9 UNIT 2 282 - 282	*P-BP*	0.08	0.04	0.21	6.19	0.93	0.28	0.00	0.80	0.00	6.59	4.54	50.00
FLASH WEST A 29-20 4201H - 42	*P-BP*	0.16	0.04	0.25	11.86	1.13	0.50	0.00	1.09	0.00	12.39	7.66	50.00
FLASH WEST B 29-20 4102H - 41	*P-BP*	0.16	0.04	0.26	12.43	1.19	0.52	0.00	1.15	0.00	12.99	7.94	50.00
FLASH WEST D 29-20 4204H - 4	*P-BP*	1.63	0.45	2.65	124.47	11.87	5.20	0.00	11.47	0.00	130.06	78.59	50.00
FLASH WEST F 29-20 4106H - 41	*P-BP*	0.16	0.05	0.27	12.50	1.19	0.52	0.00	1.15	0.00	13.06	7.87	50.00
FLASH WEST G 29-20 4207H - 42	*P-BP*	0.17	0.05	0.27	12.70	1.21	0.53	0.00	1.17	0.00	13.27	7.93	50.00
FRANCIS UNIT 1H - 1H	*P-BP*	3.79	0.04	0.40	278.68	0.54	0.68	0.00	23.73	0.00	256.17	166.27	46.94
GRAYSTONE UNIT 39-26 4AH -	*P-BP*	0.03	0.01	0.03	2.35	0.13	0.06	0.00	0.20	0.00	2.35	1.41	50.00
GRAYSTONE UNIT 39-26 4SH -	*P-BP*	0.02	0.00	0.03	1.63	0.12	0.05	0.00	0.14	0.00	1.66	1.06	45.03
GRAYSTONE UNIT 39-26 5AH -	*P-BP*	0.03	0.01	0.03	2.36	0.13	0.06	0.00	0.20	0.00	2.36	1.42	50.00
GRAYSTONE UNIT 39-26 5SH -	*P-BP*	0.02	0.00	0.03	1.64	0.12	0.05	0.00	0.14	0.00	1.67	1.06	45.03
GRAYSTONE UNIT 39-26 6AH -	*P-BP*	0.03	0.01	0.03	2.37	0.13	0.06	0.00	0.20	0.00	2.36	1.43	50.00
GRAYSTONE UNIT 39-26 6SH -	*P-BP*	0.02	0.00	0.03	1.64	0.12	0.05	0.00	0.14	0.00	1.67	1.02	45.03
HA RA SUD;RISN 17&20-11-10H	*P-BP*	0.00	0.00	740.09	0.00	0.00	1,592.15	0.00	413.71	0.00	1,178.44	976.29	33.16
HA RA SUD;RISN 17&20-11-10H	*P-BP*	0.00	0.00	746.61	0.00	0.00	1,606.18	0.00	417.35	0.00	1,188.82	985.98	31.08
HA RB SUKK;BAYOU5&8&17-1	*P-BP*	0.00	0.00	515.52	0.00	0.00	1,109.05	0.00	288.18	0.00	820.87	662.28	33.63
HA RB SUKK;BAYOU5&8&17-1	*P-BP*	0.00	0.00	483.62	0.00	0.00	1,040.41	0.00	270.34	0.00	770.07	621.79	32.87
KOLM-CHUMCHAL 1H - 1H	*P-BP*	2.34	1.76	8.76	174.14	31.95	16.97	0.00	19.34	0.00	203.73	147.96	36.15
LEAVITT FED 2-9-4MH - 2-9-4M	*P-BP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LEAVITT FED 4-9-4 MH - 4-9-4 M	*P-BP*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MADELEINE FAYE 133-137 A 1L	*P-BP*	0.86	0.24	1.16	65.07	5.21	1.55	0.00	6.68	0.00	65.15	44.61	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
MADELEINE FAYE 133-137 B 2J	P-BP	0.85	0.24	1.15	64.75	5.18	1.55	0.00	6.65	0.00	64.83	44.87	50.00
MADELEINE FAYE 133-137 C 2L	P-BP	0.85	0.24	1.15	64.64	5.17	1.54	0.00	6.64	0.00	64.72	43.91	50.00
MADELEINE FAYE 133-137 D 1	P-BP	0.52	0.24	1.16	39.36	5.23	1.56	0.00	4.84	0.00	41.31	29.58	44.53
MADELEINE FAYE 133-137 E 3L	P-BP	0.85	0.24	1.15	64.36	5.15	1.54	0.00	6.61	0.00	64.43	41.76	50.00
MADELEINE FAYE 133-137 F 1M	P-BP	0.85	0.24	1.15	64.39	5.15	1.54	0.00	6.61	0.00	64.47	41.79	50.00
MADELEINE FAYE 133-137 G 2	P-BP	0.52	0.24	1.16	39.23	5.21	1.56	0.00	4.82	0.00	41.17	29.36	44.53
MADELEINE FAYE 133-137 H 1U	P-BP	0.85	0.24	1.15	64.74	5.18	1.55	0.00	6.65	0.00	64.81	44.87	50.00
MANCHESTER WELL	P-BP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
MANGER UNIT 1H - 1H	P-BP	0.13	0.10	0.50	9.98	1.84	0.97	0.00	1.11	0.00	11.68	9.18	43.08
MCLINTOCK 15-27 B 2JM - 2JM	P-BP	1.14	0.51	2.48	86.81	11.16	3.33	0.00	12.17	0.17	88.96	59.30	50.00
MCLINTOCK 15-27 C 3JM - 3JM	P-BP	0.99	0.32	1.57	75.50	7.08	2.11	0.00	9.80	0.17	74.72	52.46	50.00
MCLINTOCK 15-27 G 7LS - 7LS	P-BP	0.98	0.32	1.55	74.47	6.98	2.08	0.00	9.68	0.17	73.68	50.82	50.00
MCLINTOCK 15-27 H 8LS - 8LS	P-BP	1.00	0.32	1.58	75.61	7.09	2.12	0.00	9.81	0.17	74.83	52.66	50.00
MCLINTOCK 15-27 L 12WA - 12	P-BP	1.02	0.28	1.37	77.12	6.17	1.84	0.00	9.56	0.17	75.40	53.22	50.00
MCLINTOCK 15-27 L 18WB - 18	P-BP	0.96	0.50	2.44	72.65	10.99	3.28	0.00	11.08	0.17	75.67	50.27	50.00
MCLINTOCK 15-27 L 23JM - 23J	P-BP	0.97	0.32	1.54	73.96	6.93	2.07	0.00	9.62	0.17	73.16	50.42	50.00
MCLINTOCK 15-27 L 6LS - 6LS	P-BP	0.98	0.32	1.55	74.57	6.99	2.09	0.00	9.69	0.17	73.78	51.09	50.00
MCLINTOCK 15-27 N 14WA - 14	P-BP	1.02	0.28	1.38	77.42	6.20	1.85	0.00	9.59	0.17	75.70	52.85	50.00
MCLINTOCK 15-27 S 19WB - 19	P-BP	0.96	0.50	2.45	72.75	11.00	3.28	0.00	11.09	0.17	75.76	51.00	50.00
MCLINTOCK 15-27H 20WB - 20	P-BP	0.94	0.49	2.39	71.01	10.74	3.21	0.00	10.87	0.17	73.91	50.50	50.00
MCLINTOCK 15-27M 13WA - 13	P-BP	1.02	0.28	1.38	77.39	6.19	1.85	0.00	9.59	0.17	75.67	52.78	50.00
MIRANDA 202H - 202H	P-BP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	45.03
MIRANDA A 1H - 1H	P-BP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.81
MIRANDA B 201H - 201H	P-BP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.76
MORGAN-NEAL 39-26 3SH - 3S	P-BP	0.02	0.00	0.03	1.63	0.12	0.05	0.00	0.14	0.00	1.66	1.06	45.03
MR. DYNAMITE A 3MS - 3MS	P-BP	0.87	0.18	1.04	66.05	4.66	2.04	0.00	5.73	0.00	67.01	48.36	40.70
MR. DYNAMITE C 5MS - 5MS	P-BP	0.86	0.18	1.03	65.65	4.63	2.03	0.00	5.70	0.00	66.60	48.08	40.62
PARKS, ROY 301LH - 301LH	P-BP	0.10	0.06	0.23	7.35	1.15	0.23	0.00	1.14	0.00	7.58	4.87	50.00
PELLETIER JN SAL 1H - 1H	P-BP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	47.35
PELLETIER JN SAL 3H - 3H	P-BP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.45
RATHKAMP UNIT 202H - 202H	P-BP	5.21	3.93	19.51	387.58	71.19	37.82	0.00	43.34	0.00	453.26	329.02	46.22
RATHKAMP UNIT 5H - 5H	P-BP	4.86	3.67	18.20	361.37	66.40	35.27	0.00	40.41	0.00	422.63	306.85	45.38
RENDEZVOUS NORTH POOLED	P-BP	0.11	0.03	0.03	8.14	0.66	0.02	0.00	0.88	0.00	7.95	5.67	49.18
RENDEZVOUS NORTH POOLED	P-BP	0.09	0.11	0.10	6.63	2.31	0.07	0.00	1.14	0.00	7.88	5.59	45.92
RENDEZVOUS NORTH POOLED	P-BP	0.11	0.03	0.03	8.14	0.66	0.02	0.00	0.88	0.00	7.95	5.67	49.19

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
REV CON STATE T8-50-17 I 0045	P-BP	0.37	0.08	0.49	28.25	1.63	0.66	0.00	2.59	0.00	27.94	17.93	49.68
REV CON STATE T8-50-21 A 009	P-BP	0.38	0.41	2.52	28.96	8.30	3.39	0.00	4.85	0.00	35.80	22.39	45.92
REV CON STATE T8-50-21 B 009	P-BP	0.42	0.45	2.79	31.96	9.15	3.74	0.00	5.35	0.00	39.50	24.70	45.92
RIO GRANDE 12-24-A 32LS - 32	P-BP	0.28	0.09	0.45	21.55	2.02	0.60	0.00	2.33	0.00	21.85	14.73	50.00
RIO GRANDE 12-24-B 32WA - 32	P-BP	0.29	0.08	0.39	21.69	1.74	0.52	0.00	2.23	0.00	21.72	14.90	50.00
SHENANDOAH 11-2-58 H 1WB -	P-BP	0.07	0.01	0.08	5.18	0.36	0.16	0.00	0.45	0.00	5.25	3.69	39.23
SHENANDOAH 11-2-58 XL H 3W	P-BP	0.07	0.01	0.08	5.20	0.37	0.16	0.00	0.45	0.00	5.27	3.71	39.25
STOCKYARDS C 3551H - 3551H	P-BP	0.00	0.00	0.00	0.08	0.03	0.00	0.00	0.02	0.00	0.10	0.06	50.00
STOCKYARDS STATE A 3401H -	P-BP	0.00	0.00	0.00	0.08	0.03	0.00	0.00	0.01	0.00	0.10	0.06	50.00
STOCKYARDS STATE B 3471H -	P-BP	0.00	0.00	0.00	0.08	0.03	0.00	0.00	0.01	0.00	0.10	0.06	50.00
SUNDANCE A 3501H - 3501H	P-BP	0.00	0.00	0.00	0.09	0.04	0.00	0.00	0.02	0.00	0.11	0.07	50.00
SUNDANCE B 3571H - 3571H	P-BP	0.00	0.00	0.00	0.09	0.04	0.00	0.00	0.02	0.00	0.11	0.07	50.00
TROLL UNIT A 08-04 2AH - 2AH	P-BP	8.42	0.04	21.13	620.29	1.09	70.66	0.00	55.54	0.00	636.50	411.69	50.00
TROLL UNIT A 08-04 3AH - 3AH	P-BP	8.44	0.05	21.18	621.70	1.09	70.82	0.00	55.67	0.00	637.94	411.98	50.00
WALKER 32-48 B UNIT A 6H - A	P-BP	2.18	0.36	2.10	166.07	9.38	4.11	0.00	13.91	0.00	165.66	112.18	50.00
WALKER 32-48 B UNIT A 7H - A	P-BP	7.21	1.17	6.93	549.22	31.04	13.59	0.00	46.00	0.00	547.85	371.86	50.00
WALKER 32-48 B UNIT L 5H - L	P-BP	1.19	0.25	1.49	90.99	6.66	2.92	0.00	7.95	0.00	92.62	65.63	45.03
WALKER 32-48 B UNIT L 7H - L	P-BP	1.13	0.24	1.41	86.23	6.32	2.76	0.00	7.53	0.00	87.78	62.35	45.03
WALKER 48-32 A UNIT A 2H - A	P-BP	1.19	0.19	1.14	90.72	5.13	2.24	0.00	7.60	0.00	90.49	60.43	50.00
WALKER 48-32 A UNIT A 3H - A	P-BP	1.74	0.28	1.68	132.88	7.51	3.29	0.00	11.13	0.00	132.54	88.71	50.00
WALKER 48-32 A UNIT L 2H - L	P-BP	1.85	0.39	2.31	141.04	10.33	4.52	0.00	12.32	0.00	143.56	101.50	45.03
WALKER 48-32 A UNIT L 3H - L	P-BP	3.77	0.61	3.62	286.98	16.21	7.10	0.00	24.03	0.00	286.26	192.05	50.00
WHIRLAWAY 101-99 A 1WA - 1W	P-BP	0.05	0.01	0.01	3.66	0.30	0.01	0.00	0.39	0.00	3.58	2.54	50.00
WHIRLAWAY 101-99 B 2TS - 2TS	P-BP	0.06	0.01	0.01	4.59	0.32	0.01	0.00	0.48	0.00	4.44	3.00	50.00
WHIRLAWAY 101-99 C 3WA - 3W	P-BP	0.05	0.01	0.01	3.67	0.30	0.01	0.00	0.39	0.00	3.58	2.53	50.00
WHIRLAWAY 101-99 D 4TS - 4TS	P-BP	0.05	0.01	0.01	3.66	0.30	0.01	0.00	0.39	0.00	3.57	2.56	50.00
WHIRLAWAY 101-99 E 5WA - 5W	P-BP	0.05	0.02	0.02	4.03	0.54	0.02	0.00	0.48	0.00	4.10	2.74	50.00
WHIRLAWAY 101-99 F 6TS - 6TS	P-BP	0.06	0.01	0.01	4.60	0.32	0.01	0.00	0.48	0.00	4.45	3.03	50.00
WHITE HORSE 1 - 1	P-BP	0.04	0.00	0.00	2.66	0.11	0.00	0.00	0.26	0.00	2.51	1.56	50.00
	Total	**103.64**	**40.37**	**5,899.34**	**7,778.56**	**817.71**	**12,128.42**	**0.00**	**6,112.38**	**2.09**	**14,610.22**	**10,551.28**	**50.00**
Proved Shut-In Rsv Class & Category													
ADAMEK UNIT 1H - 1H	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALEX TAMSULA 3 - 3	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALICO -A- 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALICO 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
ALLMAN 24 6H - 6H	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BAKER TRUST 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BAYES 16 2 - 2	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BIZZELL 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BLACK STONE 34-216 1H - 1H	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BLACK STONE 34-216 2H - 2H	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BLACK, S.E. -42- 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BLACK, S.E. 42 9 - 9	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BROWN, A. D. 2 - 2	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAMPBELL 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
CHILDRESS 140 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CHILDRESS 140 2 - 2	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CHILDRESS 140 5 - 5	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CHUMCHAL UNIT 2H - 2H	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CHUMCHAL UNIT 3H - 3H	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CLAWSON 6 - 6	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
COFFIELD -A- 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COURAGE 41-2827-23N - 41-282	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DAVIS 1_2 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DYER 3302 - 3302	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIREBIRD 52 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FISHERMAN -A- 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GUITAR 11 2 - 2	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HA RA SUA;NAC 36 H 001-ALT -	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HA RA SUA;WIGGINS 36-25 HC	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HA RA SUB;SHELBY INTEREST	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HA RA SUL;MADDEN 18 H 001 -	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HA RA SUL;MADDEN 18 H 002-	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HA RA SUL;MADDEN 18-19 HC	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HA RB SU74;NAC ROYALTY 28	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HA RB SU90;NRG 29-12-10 H 00	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HOLMES LIMESTONE 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
JANAK UNIT 1H - 1H	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
JERSEY 35-23-H 2815H - 2815H	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
JIM TOM 1 - 1	P-SI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
JOHN F. FERGUSON 3 - 3	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
LARRY CARLSON 1 - 1	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
LOBLEY, G. D. 1 - 1	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LONG UNIT 1 - 1	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00
MARY GRACE 201-202 UNIT 2H	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MEADOR, J. J. 3 - 3	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MERCHANT UNIT 6704A - 6704	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MORAN A2 2LA - 2LA	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NAC GAS UNIT B 3H-3 - 3H-3	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN COAL 1_1 -	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NUNN, J. F. -A- 20 - 20	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NUNN, J. F. -A- 9 - 9	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
O'NEAL -D- 1 - 1	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PHILLIPS 7 1 - 1	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RHOADES MOON 1-36B5 - 1-36	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RINGNECK DOVE 3 - 3	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RIPLEY UNIT 1 - 1	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RIPLEY UNIT 3 - 3	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SCHWALBE UNIT 01	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SCHWALBE UNIT 1 - 1	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SHERROD UNIT 3904 - 3904	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SHERROD UNIT 904 - 904	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SHIPPER GAS UNIT 1 - 1	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOUTH HILIGHT UNIT 1-41 - 1-4	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOUTH HILIGHT UNIT 13-39 - 1	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SPRABERRY DRIVER UNIT 343	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STELLA STATE 34-208 WRD UN	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TCM 1 - 1	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
THORPE 1-74 LOV 1H - 1H	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
THURMOND 132 ALLOC C 11H	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TIGIWON 2627-C23 E 1H - 1H	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WHITLEY 34-231 1H - 1H	*P-SI*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**50.00**
Proved Undeveloped Rsv Class & Category													
BARZONA STATE COM 303H - 3	*P-UD*	1.51	0.14	5.75	114.73	2.82	6.50	0.00	18.01	0.00	106.03	67.79	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
BARZONA STATE COM 503H - 5	P-UD	1.49	0.14	5.69	113.43	2.79	6.42	0.00	17.81	0.00	104.83	67.02	50.00
BARZONA STATE COM 603H - 6	P-UD	0.65	0.03	1.05	49.62	0.52	1.19	0.00	7.06	0.00	44.26	32.13	36.45
BARZONA STATE COM 703H - 7	P-UD	0.31	0.01	0.49	23.45	0.24	0.55	0.00	3.33	0.00	20.90	15.55	27.06
BARZONA STATE COM 803H - 8	P-UD	0.73	0.07	2.77	55.73	1.36	3.13	0.00	8.74	0.00	51.48	33.33	46.08
BTR 11E-35W-H5UB - 11E-35W-	P-UD	0.17	0.00	0.28	9.99	0.00	0.47	0.00	0.25	0.00	10.21	7.25	38.15
BTR 11E-35W-H6UB - 11E-35W-	P-UD	0.16	0.00	0.27	9.74	0.00	0.46	0.00	0.25	0.00	9.96	7.07	37.85
BTR 11E-35W-H7UB - 11E-35W-	P-UD	0.42	0.00	1.37	25.16	0.00	2.33	0.00	0.89	0.00	26.60	18.31	50.00
CHEVRON UNIT 03-38 3AH - 3A	P-UD	0.19	0.05	0.30	14.24	1.36	0.59	0.00	1.31	0.00	14.88	9.34	50.00
CLEMENTS ALLOCATION B 26-	P-UD	0.12	0.00	0.29	8.57	0.01	0.97	0.00	0.77	0.00	8.79	5.92	48.42
CLEMENTS ALLOCATION C 26-	P-UD	0.12	0.00	0.29	8.51	0.01	0.97	0.00	0.76	0.00	8.73	5.88	48.32
CLEMENTS ALLOCATION D 26-	P-UD	0.08	0.00	0.26	5.88	0.01	0.86	0.00	0.56	0.00	6.20	4.38	42.19
DANIELLE 183 UNIT 221H - 221	P-UD	0.04	0.04	0.04	3.09	0.82	0.03	0.00	0.50	0.00	3.44	2.07	50.00
DIRE WOLF 10 1BS A 1H - 1H	P-UD	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.01	0.00	0.04	0.03	50.00
DIRE WOLF 10 1BS B 2H - 2H	P-UD	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.01	0.00	0.04	0.03	46.67
DIRE WOLF 10 1BS C 3H - 3H	P-UD	0.00	0.00	0.00	0.04	0.01	0.00	0.00	0.01	0.00	0.04	0.03	47.97
DIRE WOLF 10 1BS D 4H - 4H	P-UD	0.23	0.28	0.27	17.63	6.12	0.19	0.00	3.01	0.00	20.93	13.51	48.30
DIRE WOLF 30 3BS B 2H - 2H	P-UD	0.58	0.69	0.68	43.53	15.16	0.46	0.00	7.45	0.00	51.71	36.56	45.97
DIRE WOLF 30 3BS C 3H - 3H	P-UD	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.01	0.00	0.04	0.03	50.00
DIRE WOLF 30 3BS D 4H - 4H	P-UD	0.24	0.28	0.28	17.69	6.14	0.19	0.00	3.02	0.00	21.00	13.55	48.33
DIRE WOLF 50 WA B 2H - 2H	P-UD	0.59	0.70	0.69	44.10	15.36	0.47	0.00	7.55	0.00	52.39	37.04	46.12
DIRE WOLF 50 WA C 3H - 3H	P-UD	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.01	0.00	0.04	0.03	46.75
DIRE WOLF 50 WA D 4H - 4H	P-UD	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.01	0.00	0.04	0.03	47.05
DIRE WOLF 50 WA E 5H - 5H	P-UD	0.00	0.00	0.00	0.04	0.01	0.00	0.00	0.01	0.00	0.04	0.03	48.33
DIRE WOLF 50 WA F 6H - 6H	P-UD	0.00	0.00	0.00	0.04	0.01	0.00	0.00	0.01	0.00	0.04	0.03	48.32
DIRE WOLF 60 WB B 2H - 2H	P-UD	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.01	0.00	0.04	0.03	46.07
DIRE WOLF 60 WB C 3H - 3H	P-UD	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.01	0.00	0.04	0.03	46.76
DIRE WOLF 60 WB D 4H - 4H	P-UD	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.01	0.00	0.04	0.03	47.04
DIRE WOLF 60 WB E 5H - 5H	P-UD	0.00	0.00	0.00	0.04	0.01	0.00	0.00	0.01	0.00	0.04	0.03	48.32
DIRE WOLF 70 WC B 2H - 2H	P-UD	0.58	0.70	0.68	43.82	15.26	0.47	0.00	7.50	0.00	52.05	36.80	46.05
DRIVER N5A 1H - 1H	P-UD	0.25	0.17	0.04	19.18	3.14	0.05	0.00	1.96	0.00	20.40	13.93	50.00
DRIVER N5B 2H - 2H	P-UD	0.25	0.17	0.04	19.08	3.12	0.05	0.00	1.95	0.00	20.30	13.86	50.00
DRIVER N5C 3H - 3H	P-UD	0.25	0.16	0.04	18.99	3.11	0.05	0.00	1.94	0.00	20.20	13.79	50.00
DRIVER N5D 4H - 4H	P-UD	0.25	0.16	0.04	18.91	3.09	0.05	0.00	1.93	0.00	20.12	13.73	50.00
DRIVER N5E 5H - 5H	P-UD	0.25	0.16	0.04	18.86	3.09	0.05	0.00	1.93	0.00	20.07	13.70	50.00
DRIVER N5F 6H - 6H	P-UD	0.25	0.16	0.04	18.88	3.09	0.05	0.00	1.93	0.00	20.09	13.72	50.00

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
DRIVER SE5S 119H - 119H	P-UD	0.25	0.17	0.04	19.35	3.16	0.05	0.00	1.98	0.00	20.58	14.05	50.00
DRIVER SE5T 120H - 120H	P-UD	0.25	0.17	0.04	19.29	3.16	0.05	0.00	1.97	0.00	20.53	14.01	50.00
DRIVER SE5U 121H - 121H	P-UD	0.26	0.17	0.04	19.43	3.18	0.05	0.00	1.99	0.00	20.67	14.11	50.00
DRIVER SE5V 122H - 122H	P-UD	0.26	0.17	0.04	19.54	3.20	0.05	0.00	2.00	0.00	20.79	14.19	50.00
DRIVER SE5W 123H - 123H	P-UD	0.26	0.17	0.04	19.67	3.22	0.05	0.00	2.01	0.00	20.93	14.29	50.00
DRIVER SE5X 124H - 124H	P-UD	0.26	0.17	0.04	19.81	3.24	0.05	0.00	2.02	0.00	21.07	14.39	50.00
HAWKS 55-1-33-28 A 13H - 13H	P-UD	0.11	0.17	0.49	8.71	4.18	-0.16	0.00	-0.21	0.00	12.94	8.29	46.41
HAWKS 55-1-33-28 B 14H - 14H	P-UD	0.11	0.17	0.49	8.67	4.15	-0.15	0.00	-0.21	0.00	12.88	8.09	46.41
HAWKS 55-1-33-28 C 21H - 21H	P-UD	0.11	0.17	0.49	8.67	4.16	-0.16	0.00	-0.21	0.00	12.88	8.25	46.41
HAWKS 55-1-33-28 D 15H - 15H	P-UD	0.11	0.17	0.49	8.67	4.16	-0.16	0.00	-0.21	0.00	12.88	8.25	46.41
HAWKS 55-1-33-28 E 22H - 22H	P-UD	0.11	0.17	0.49	8.67	4.16	-0.16	0.00	-0.21	0.00	12.88	8.25	46.41
HAWKS 55-1-33-28 F 16H - 16H	P-UD	0.11	0.17	0.49	8.68	4.16	-0.16	0.00	-0.21	0.00	12.90	8.26	46.41
HORNSILVER 2H - 2H	P-UD	0.06	0.04	0.04	4.52	0.90	0.03	0.00	0.61	0.00	4.84	3.18	50.00
MADELEINE FAYE 133-137 I 2U	P-UD	0.69	0.19	0.94	52.59	4.21	1.26	0.00	5.40	0.00	52.65	34.13	50.00
MADELEINE FAYE 133-137 J 1W	P-UD	0.52	0.24	1.16	39.41	5.23	1.56	0.00	4.84	0.00	41.36	28.38	44.99
MADELEINE FAYE 133-137 K 2	P-UD	0.52	0.24	1.16	39.24	5.21	1.55	0.00	4.82	0.00	41.18	28.26	44.94
MARY GRACE 201-202 UNIT 22	P-UD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.18
RAMBO FEE COM 302H - 302H	P-UD	0.12	0.00	0.20	9.29	0.10	0.22	0.00	1.32	0.00	8.28	6.01	37.20
RAMBO FEE COM 802H - 802H	P-UD	0.29	0.01	0.39	21.86	0.19	0.44	0.00	3.08	0.00	19.42	13.06	50.00
RAMBO STATE COM 303H - 303	P-UD	0.12	0.00	0.20	9.34	0.10	0.22	0.00	1.33	0.00	8.33	6.05	37.28
RAMBO STATE COM 503H - 503	P-UD	0.28	0.03	1.06	21.17	0.52	1.20	0.00	3.32	0.00	19.57	12.51	50.00
RAMBO STATE COM 803H - 803	P-UD	0.29	0.01	0.39	21.99	0.19	0.45	0.00	3.09	0.00	19.53	13.14	50.00
RANCH WATER UNIT 2 1904BH	P-UD	4.75	2.49	12.11	360.44	54.44	16.25	0.00	46.81	0.00	384.33	235.83	50.00
RANCH WATER UNIT 2 1905BH	P-UD	4.75	2.49	12.10	360.13	54.40	16.24	0.00	46.77	0.00	384.00	235.63	50.00
RANCH WATER UNIT 2 1964DH	P-UD	5.06	1.40	6.84	384.26	30.73	9.17	0.00	39.47	0.00	384.70	247.49	50.00
RANCH WATER UNIT 2 1965DH	P-UD	5.05	1.40	6.82	383.57	30.68	9.16	0.00	39.40	0.00	384.01	247.05	50.00
RANCH WATER UNIT 2 1966DH	P-UD	5.05	1.40	6.83	383.60	30.68	9.16	0.00	39.40	0.00	384.04	247.07	50.00
RANCH WATER UNIT 2 1974JH -	P-UD	5.80	2.58	12.57	439.87	56.48	16.86	0.00	53.32	0.00	459.90	281.22	50.00
RANCH WATER UNIT 2 1975JH -	P-UD	5.79	2.58	12.56	439.59	56.45	16.85	0.00	53.28	0.00	459.61	281.04	50.00
RANCH WATER UNIT 2 1976JH -	P-UD	5.80	2.58	12.56	439.79	56.47	16.86	0.00	53.31	0.00	459.81	281.16	50.00
RANCH WATER UNIT 2 1984NH	P-UD	3.35	1.54	7.49	254.16	33.69	10.06	0.00	31.21	0.00	266.69	181.50	46.34
RANCH WATER UNIT 2 1986NH	P-UD	3.35	1.54	7.50	254.28	33.71	10.06	0.00	31.23	0.00	266.83	181.59	46.35
RENDEZVOUS NORTH POOLED	P-UD	0.09	0.10	0.10	6.60	2.30	0.07	0.00	1.13	0.00	7.84	5.43	45.92
SILVER FOX 16-1-2-C5-4H - 16-1	P-UD	0.08	0.00	0.13	4.57	0.00	0.22	0.00	0.12	0.00	4.68	3.33	43.98
SILVER FOX 16-1-2-C5-5H - 16-1	P-UD	0.08	0.00	0.13	4.57	0.00	0.22	0.00	0.12	0.00	4.68	3.00	45.09

TABLE 7

Economic One-Liners

As of Date: 1/1/2025

Lease Name	Reserve Category	Net Sales Volumes Oil (Mbbl)	NGL (Mbbl)	Residue Gas (MMcf)	Net Revenue Oil (M$)	NGL (M$)	Residue Gas (M$)	Other (M$)	Expense & Tax (M$)	Invest. (M$)	Cash Flow Non-Disc. (M$)	Disc. 10% (M$)	Life (years)
SILVER FOX 9-1-2-C5-1H - 9-1-2	*P-UD*	0.08	0.00	0.13	4.61	0.00	0.22	0.00	0.12	0.00	4.72	3.36	44.09
SILVER FOX 9-1-2-C5-2H - 9-1-2	*P-UD*	0.08	0.00	0.13	4.59	0.00	0.22	0.00	0.12	0.00	4.70	3.35	44.04
SILVER FOX 9-1-2-C5-3H - 9-1-2	*P-UD*	0.08	0.00	0.13	4.58	0.00	0.22	0.00	0.12	0.00	4.68	3.34	43.99
SNOWBIRD 13-16-15-C5-7H - 13	*P-UD*	0.69	0.00	1.17	42.02	0.00	1.99	0.00	1.06	0.00	42.95	27.40	40.28
STEVENSON-STOKES 26A 1H -	*P-UD*	0.22	0.12	0.41	16.34	1.98	0.83	0.00	1.88	0.00	17.28	11.09	50.00
STEVENSON-STOKES 26B 2H -	*P-UD*	0.27	0.34	1.17	20.39	5.60	2.34	0.00	3.17	0.00	25.16	15.05	50.00
STEVENSON-STOKES 26C 3H -	*P-UD*	0.27	0.17	0.58	20.50	2.78	1.16	0.00	2.43	0.00	22.01	14.42	50.00
STEVENSON-STOKES 26D 4H -	*P-UD*	0.27	0.17	0.58	20.59	2.79	1.16	0.00	2.44	0.00	22.10	14.48	50.00
STICKLINE 2H - 2H	*P-UD*	0.01	0.01	0.01	0.79	0.16	0.00	0.00	0.11	0.00	0.84	0.56	50.00
STONE-WINSLOW E40F 6H - 6H	*P-UD*	2.54	0.74	0.18	193.18	14.00	0.22	0.00	17.66	0.00	189.74	124.62	50.00
STONE-WINSLOW E40G 7H - 7H	*P-UD*	2.54	0.74	0.18	192.80	13.97	0.22	0.00	17.62	0.00	189.36	124.37	50.00
STONE-WINSLOW E40H 8H - 8H	*P-UD*	2.54	0.74	0.18	193.09	13.99	0.22	0.00	17.65	0.00	189.65	124.56	50.00
TREBLE STATE COM 301H - 301	*P-UD*	0.17	0.01	0.28	13.26	0.14	0.32	0.00	1.89	0.00	11.83	9.48	35.11
TREBLE STATE COM 501H - 501	*P-UD*	0.39	0.04	1.50	29.86	0.74	1.69	0.00	4.69	0.00	27.60	19.41	50.00
VALENCIA 10-8 A UNIT A 1H - A	*P-UD*	0.13	0.02	0.12	9.77	0.55	0.24	0.00	0.82	0.00	9.74	6.27	50.00
VALENCIA 10-8 A UNIT L 1H - L	*P-UD*	0.13	0.02	0.12	9.73	0.55	0.24	0.00	0.82	0.00	9.71	6.30	50.00
WINDY MOUNTAIN 7978 7U A 7	*P-UD*	0.07	0.04	0.25	5.01	0.82	0.34	0.00	0.61	0.00	5.57	3.78	50.00
WINDY MOUNTAIN 7978 8U A 8	*P-UD*	0.07	0.04	0.25	4.99	0.82	0.34	0.00	0.60	0.00	5.54	3.76	50.00
WINDY MOUNTAIN 7978 9U A 9	*P-UD*	0.07	0.04	0.25	5.01	0.82	0.34	0.00	0.61	0.00	5.56	3.74	50.00
	Total	**74.40**	**30.28**	**135.83**	**5,618.35**	**647.28**	**176.34**	**0.00**	**648.97**	**0.00**	**5,793.00**	**3,726.41**	**50.00**
Grand Total Total		**695.19**	**473.92**	**27,627.67**	**52,115.40**	**9,824.43**	**57,593.69**	**0.00**	**33,306.01**	**2.09**	**86,225.42**	**53,646.03**	**50.00**

Gross Ultimates, Interests, & Prices

TABLE 8

As of: 01/01/2025

GROSS ULTIMATE RESERVES, CUMULATIVE PRODUCTION AND BASIC ECONOMIC DATA

LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
Proved Producing Rsv Class & Category												
21202 VECTOR 19 A 1	P-DP	21.92	33.01	18.59	33.01	0.0000000	0.0000000	0.0066410	0.0066410	76.00	1.19	0
44 MAGNUM 9-4 H 1LS	P-DP	516.87	848.43	308.91	332.32	0.0000000	0.0000000	0.0019390	0.0019390	76.19	1.96	0
44 MAGNUM 9-4 H 1WA	P-DP	275.02	890.78	186.05	307.99	0.0000000	0.0000000	0.0019390	0.0019390	76.19	1.96	0
44 MAGNUM 9-4 H 1WB	P-DP	173.05	1,248.05	114.55	341.95	0.0000000	0.0000000	0.0019390	0.0019390	76.19	1.96	0
44 MAGNUM 9-4 H 2WA	P-DP	346.47	940.52	196.03	345.94	0.0000000	0.0000000	0.0019390	0.0019390	76.19	1.96	0
44 MAGNUM 9-4 H 2WB	P-DP	224.87	911.80	130.98	392.47	0.0000000	0.0000000	0.0019390	0.0019390	76.19	1.96	0
44 MAGNUM 9-4 H 3WA	P-DP	371.41	1,434.05	213.23	637.91	0.0000000	0.0000000	0.0019390	0.0019390	76.19	1.96	0
ABIGAIL 218-219 UNIT 1H	P-DP	365.45	4,445.96	227.49	2,769.69	0.0000000	0.0000000	0.0001210	0.0001210	75.15	0.68	0
ACKERLY BROWN 9 1	P-DP	154.44	183.92	124.38	151.24	0.0000000	0.0000000	0.0006510	0.0006510	75.89	1.34	0
ADAMCHIK 4	P-DP	0.00	213.21	0.00	169.35	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
ADAMCHIK 5	P-DP	0.00	137.02	0.00	102.01	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
ADAMCHIK 7	P-DP	0.00	197.60	0.00	141.26	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
ADAMEK UNIT 2H	P-DP	130.36	1,708.66	101.11	1,372.24	0.0000000	0.0000000	0.0105380	0.0105380	74.40	1.94	0
ADAMS EAST H 23-26 4208H	P-DP	186.27	745.49	116.18	342.26	0.0000000	0.0000000	0.0004810	0.0004810	75.14	2.00	0
ADAMS EAST H 23-26 4408H	P-DP	418.01	1,549.46	255.72	846.44	0.0000000	0.0000000	0.0004790	0.0004790	75.14	2.00	0
ADAMS WEST A 23-26 4301H	P-DP	798.46	4,040.56	464.95	1,525.55	0.0000000	0.0000000	0.0004710	0.0004710	75.14	2.00	0
ADAMS WEST B 23-26 4202H	P-DP	111.17	397.33	87.37	267.65	0.0000000	0.0000000	0.0004730	0.0004730	75.14	2.00	0
ADAMS WEST B 23-26 4402H	P-DP	258.29	1,196.54	193.71	663.78	0.0000000	0.0000000	0.0005080	0.0005080	75.14	2.00	0
ADAMS WEST D 23-26 4304H	P-DP	236.84	6,059.79	175.33	1,595.78	0.0000000	0.0000000	0.0004800	0.0004800	75.14	2.00	0
ADAMS WEST E 23-26 4205H	P-DP	127.94	1,267.73	97.64	665.60	0.0000000	0.0000000	0.0004780	0.0004780	75.14	2.00	0
ADAMS WEST E 23-26 4405H	P-DP	286.05	1,639.35	213.77	745.65	0.0000000	0.0000000	0.0004790	0.0004790	75.14	2.00	0
ADAMS WEST G 23-26 4307H	P-DP	343.85	4,558.00	259.20	1,848.16	0.0000000	0.0000000	0.0004800	0.0004800	75.14	2.00	0
ADMIRAL 4-48 47 1H	P-DP	670.19	3,468.05	485.99	2,511.33	0.0000000	0.0000000	0.0005430	0.0005430	75.81	1.34	0
AGGIE THE BULLDOG 39-46 A 1LS	P-DP	214.65	204.28	174.88	137.94	0.0000000	0.0000000	0.0102090	0.0102090	75.89	1.34	0
AGGIE THE BULLDOG 39-46 A 1MS	P-DP	163.41	689.29	75.55	248.28	0.0000000	0.0000000	0.0102240	0.0102240	75.89	1.34	0
AGGIE THE BULLDOG 39-46 A 1WA	P-DP	512.17	855.33	439.07	671.42	0.0000000	0.0000000	0.0101900	0.0101900	75.89	1.34	0
AGGIE THE BULLDOG 39-46 A 1WB	P-DP	378.94	552.06	310.63	421.93	0.0000000	0.0000000	0.0102040	0.0102040	75.89	1.34	0
AGGIE THE BULLDOG 39-46 B 2DN	P-DP	409.39	1,121.46	346.81	858.21	0.0000000	0.0000000	0.0101990	0.0101990	75.89	1.34	0
AGGIE THE BULLDOG 39-46 B 2WA	P-DP	216.40	725.70	197.31	540.61	0.0000000	0.0000000	0.0102030	0.0102030	75.89	1.34	0
AGGIE THE BULLDOG 39-46 C 3LS	P-DP	307.66	2,080.76	259.75	1,299.95	0.0000000	0.0000000	0.0102000	0.0102000	75.89	1.34	0
AGGIE THE BULLDOG 39-46 C 3WB	P-DP	190.72	261.85	160.48	206.13	0.0000000	0.0000000	0.0101960	0.0101960	75.89	1.34	0
AGGIE THE BULLDOG 39-46 C 4WA	P-DP	393.12	584.49	343.95	423.37	0.0000000	0.0000000	0.0102040	0.0102040	75.89	1.34	0
AGGIE THE BULLDOG 39-46 D 5LS	P-DP	304.67	610.01	255.81	361.51	0.0000000	0.0000000	0.0101970	0.0101970	75.89	1.34	0
AGGIE THE BULLDOG 39-46 D 5WB	P-DP	191.44	1,142.73	173.37	681.26	0.0000000	0.0000000	0.0101990	0.0101990	75.89	1.34	0
AGGIE THE BULLDOG 39-46 D 6JD	P-DP	96.79	267.32	45.58	79.80	0.0000000	0.0000000	0.0102230	0.0102230	75.89	1.34	0
AGGIE THE BULLDOG 39-46 D 6WA	P-DP	343.41	1,474.60	287.42	775.27	0.0000000	0.0000000	0.0102060	0.0102060	75.89	1.34	0

TABLE 8

As of: 01/01/2025

GROSS ULTIMATE RESERVES, CUMULATIVE PRODUCTION
AND BASIC ECONOMIC DATA

LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
AGGIE THE BULLDOG 39-46 E 6DN	P-DP	401.96	496.39	360.10	325.67	0.0000000	0.0000000	0.0102060	0.0102060	75.89	1.34	0
AGGIE THE BULLDOG 39-46 E 7LS	P-DP	343.96	916.04	269.87	456.38	0.0000000	0.0000000	0.0102080	0.0102080	75.89	1.34	0
AGGIE THE BULLDOG 39-46 E 7MS	P-DP	177.43	364.29	80.88	115.09	0.0000000	0.0000000	0.0102290	0.0102290	75.89	1.34	0
AGGIE THE BULLDOG 39-46 E 7WA	P-DP	573.48	446.26	488.32	249.20	0.0000000	0.0000000	0.0102100	0.0102100	75.89	1.34	0
AGGIE THE BULLDOG 39-46 E 7WB	P-DP	385.08	2,088.85	334.55	1,361.57	0.0000000	0.0000000	0.0102080	0.0102080	75.89	1.34	0
ALEX TAMSULA 2	P-DP	0.00	74.33	0.00	74.33	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
ALEX TAMSULA 4	P-DP	0.00	32.31	0.00	32.31	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
ALLMAN 24 1H	P-DP	317.43	8,153.06	247.21	5,463.98	0.0000000	0.0000000	0.0043020	0.0043020	75.81	1.34	0
ALLRED UNIT B 08-05 5AH	P-DP	668.09	1,314.71	591.26	907.60	0.0000000	0.0000000	0.0005800	0.0005800	76.19	1.96	0
ALLRED UNIT B 08-05 5BH	P-DP	244.03	1,875.58	222.42	1,017.37	0.0000000	0.0000000	0.0005800	0.0005800	76.19	1.96	0
ALLRED UNIT B 08-05 5MH	P-DP	260.83	1,820.79	176.77	625.08	0.0000000	0.0000000	0.0005800	0.0005800	76.19	1.96	0
ALLRED UNIT B 08-05 5SH	P-DP	261.05	1,543.14	173.55	534.71	0.0000000	0.0000000	0.0005800	0.0005800	76.19	1.96	0
ALLRED UNIT B 08-05 6AH	P-DP	417.06	2,086.11	280.23	723.06	0.0000000	0.0000000	0.0005800	0.0005800	76.19	1.96	0
ALLRED UNIT B 08-05 6MH	P-DP	246.63	1,155.66	179.03	457.05	0.0000000	0.0000000	0.0005800	0.0005800	76.19	1.96	0
ALLRED UNIT B 08-05 6SH	P-DP	219.59	2,811.66	152.18	889.00	0.0000000	0.0000000	0.0005800	0.0005800	76.19	1.96	0
ALLRED UNIT B 08-05 7AH	P-DP	283.34	2,172.62	191.18	754.83	0.0000000	0.0000000	0.0005800	0.0005800	76.19	1.96	0
ALLRED UNIT B 08-05 7BH	P-DP	159.42	2,272.58	110.36	878.45	0.0000000	0.0000000	0.0005800	0.0005800	76.19	1.96	0
ALLRED UNIT B 08-05 8AH	P-DP	876.12	557.48	704.44	429.66	0.0000000	0.0000000	0.0005800	0.0005800	76.19	1.96	0
ALLRED UNIT B 08-05 8SH	P-DP	439.06	660.79	386.37	472.03	0.0000000	0.0000000	0.0005800	0.0005800	76.19	1.96	0
ALPHA 210488 1A	P-DP	0.00	6,867.91	0.00	5,974.83	0.0000000	0.0000000	0.0003240	0.0003240	67.06	2.04	0
ALPHA 210488 2B	P-DP	0.00	8,044.01	0.00	6,898.93	0.0000000	0.0000000	0.0003240	0.0003240	67.06	2.04	0
ALPHA 210488 3C	P-DP	0.00	10,445.06	0.00	8,357.17	0.0000000	0.0000000	0.0003240	0.0003240	67.06	2.04	0
AMAZON 3304-02H	P-DP	325.88	370.39	254.56	173.39	0.0000000	0.0000000	0.0003120	0.0003120	74.04	4.41	0
AMAZON 3304-03H	P-DP	610.89	549.78	446.20	275.12	0.0000000	0.0000000	0.0003120	0.0003120	74.04	4.41	0
AMAZON 3304-05H	P-DP	415.30	5,056.02	306.77	2,849.04	0.0000000	0.0000000	0.0003120	0.0003120	74.04	4.41	0
AMAZON 3304-4H	P-DP	308.64	4,886.37	229.68	3,026.46	0.0000000	0.0000000	0.0003120	0.0003120	74.04	4.41	0
AMBER NE WEL JF 3H	P-DP	0.00	19,871.97	0.00	10,632.31	0.0000000	0.0000000	0.0007120	0.0007120	73.94	1.98	0
AMBER NW WEL JF 1H	P-DP	0.00	18,212.18	0.00	11,028.93	0.0000000	0.0000000	0.0010080	0.0010080	73.94	1.98	0
AMPHITHEATER A1 4LA	P-DP	227.83	392.36	220.96	340.85	0.0011686	0.0011686	0.0011686	0.0011686	75.15	0.68	1,200
AMPHITHEATER A2 3LA	P-DP	164.04	265.95	150.95	217.28	0.0011764	0.0011764	0.0011764	0.0011764	75.15	0.68	1,200
AMPHITHEATER A3 15UA	P-DP	754.38	1,045.81	566.50	677.26	0.0011227	0.0011227	0.0011227	0.0011227	75.15	0.68	1,200
AMPHITHEATER A4 2LA	P-DP	184.27	384.03	161.32	267.62	0.0010901	0.0010901	0.0010901	0.0010901	75.15	0.68	1,200
AMPHITHEATER A5 14UA	P-DP	711.69	868.05	589.95	712.66	0.0011196	0.0011196	0.0011196	0.0011196	75.15	0.68	1,200
AMPHITHEATER A6 16UA	P-DP	440.40	495.21	416.88	463.22	0.0011861	0.0011861	0.0011861	0.0011861	75.15	0.68	1,200
ANN COLE TRUST 1	P-DP	182.52	270.09	151.63	172.97	0.0000000	0.0000000	0.0131250	0.0131250	75.89	1.34	0
ANNABEL 1	P-DP	11.94	0.00	6.23	0.00	0.0000000	0.0000000	0.0367940	0.0367940	76.19	1.96	0
ARCH BENGE B10 1504MH	P-DP	647.90	1,094.94	49.13	53.73	0.0000000	0.0000000	0.0001550	0.0001550	76.66	1.00	0

TABLE 8

As of: 01/01/2025

GROSS ULTIMATE RESERVES, CUMULATIVE PRODUCTION
AND BASIC ECONOMIC DATA

LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
ARCH BENGE B9 1502MH	P-DP	647.76	1,094.83	48.99	53.61	0.0000000	0.0000000	0.0001550	0.0001550	76.66	1.00	0
ARCHIE E WYN JF 6H	P-DP	0.00	11,017.43	0.00	8,181.41	0.0000000	0.0000000	0.0312850	0.0312850	73.94	1.98	0
ARCHIE E WYN JF 8H	P-DP	0.00	8,681.48	0.00	6,715.58	0.0000000	0.0000000	0.0312850	0.0312850	73.94	1.98	0
ARENA A1 1LA	P-DP	219.79	416.62	162.78	289.29	0.0000860	0.0000860	0.0000860	0.0000860	75.15	0.68	1,200
ARENA A2 9UA	P-DP	558.76	787.17	375.42	507.79	0.0000000	0.0000000	0.0000330	0.0000330	75.15	0.68	0
ARENA A3 2LA	P-DP	198.27	415.55	135.71	240.51	0.0000000	0.0000000	0.0000350	0.0000350	75.15	0.68	0
ARENA A4 3LA	P-DP	657.72	889.40	252.54	416.83	0.0000000	0.0000000	0.0000350	0.0000350	75.15	0.68	0
ARENA A5 10UA	P-DP	472.82	615.87	287.03	371.51	0.0000000	0.0000000	0.0000350	0.0000350	75.15	0.68	0
ARLINGTON 33-40 C UNIT 4H	P-DP	195.32	616.57	124.44	415.22	0.0000000	0.0000000	0.0003300	0.0003300	76.19	1.96	0
ARLINGTON 33-40 D UNIT 5H	P-DP	307.36	1,033.52	195.96	516.92	0.0000000	0.0000000	0.0003300	0.0003300	76.19	1.96	0
ARON 41-32 1AH	P-DP	277.92	262.87	236.25	173.47	0.0000000	0.0000000	0.0083770	0.0083770	76.19	1.96	0
ARON 41-32 2SH	P-DP	154.04	705.39	119.33	316.19	0.0000000	0.0000000	0.0083770	0.0083770	76.19	1.96	0
ARON 41-32 3AH	P-DP	308.75	701.78	254.61	443.25	0.0000000	0.0000000	0.0083770	0.0083770	76.19	1.96	0
ARON 41-32 3SH	P-DP	138.83	75.16	121.42	51.68	0.0000000	0.0000000	0.0083770	0.0083770	76.19	1.96	0
ATHENA N SMF JF 3H	P-DP	0.00	16,620.90	0.00	10,946.62	0.0000000	0.0000000	0.0392070	0.0392070	73.94	1.98	0
ATHENA NE SMF JF 5H	P-DP	0.00	16,052.04	0.00	10,190.54	0.0000000	0.0000000	0.0574110	0.0574110	73.94	1.98	0
ATHENA NE SMF JF 7H	P-DP	0.00	17,209.18	0.00	9,929.43	0.0000000	0.0000000	0.0574110	0.0574110	73.94	1.98	0
ATHENA NW SMF JF 1H	P-DP	0.00	19,880.73	0.00	10,863.02	0.0000000	0.0000000	0.0289380	0.0289380	73.94	1.98	0
AUSTIN 5H	P-DP	0.00	8,979.79	0.00	4,606.80	0.0000000	0.0000000	0.0060725	0.0060725	73.94	1.87	0
AUSTIN 6H	P-DP	0.00	9,664.72	0.00	4,751.10	0.0000000	0.0000000	0.0060730	0.0060730	73.94	1.87	0
AUSTIN 7H	P-DP	0.00	9,930.85	0.00	4,971.48	0.0000000	0.0000000	0.0060730	0.0060730	73.94	1.87	0
AUSTIN 8H	P-DP	0.00	10,367.84	0.00	4,789.28	0.0000000	0.0000000	0.0060730	0.0060730	73.94	1.87	0
B AND B 1H	P-DP	354.46	3,025.04	214.64	1,596.85	0.0000000	0.0000000	0.0005310	0.0005310	76.15	-0.83	0
B AND B 2H	P-DP	434.59	4,752.22	277.41	2,404.48	0.0000000	0.0000000	0.0005310	0.0005310	76.15	-0.83	0
B AND B 6H	P-DP	158.75	1,759.27	83.15	869.56	0.0000000	0.0000000	0.0005310	0.0005310	76.15	-0.83	0
B AND B STATE 4H	P-DP	276.17	2,069.72	160.91	1,101.28	0.0000000	0.0000000	0.0004530	0.0004530	76.15	-0.83	0
B AND B STATE A 5H	P-DP	410.34	5,338.74	242.89	2,277.49	0.0000000	0.0000000	0.0004530	0.0004530	76.15	-0.83	0
B AND B STATE B 7H	P-DP	156.19	7,575.48	73.45	2,745.02	0.0000000	0.0000000	0.0004530	0.0004530	76.15	-0.83	0
BADFISH 31-43 A 1JM	P-DP	854.07	1,435.88	450.53	602.68	0.0000000	0.0000000	0.0005400	0.0005400	75.89	1.34	0
BADFISH 31-43 A 4LS	P-DP	75.00	940.00	55.85	378.27	0.0000000	0.0000000	0.0005390	0.0005390	75.89	1.34	0
BADFISH 31-43 B 9LS	P-DP	669.96	1,863.42	342.67	633.68	0.0000000	0.0000000	0.0005350	0.0005350	75.89	1.34	0
BADFISH 31-43 E 5WA	P-DP	448.95	784.05	276.66	281.62	0.0000000	0.0000000	0.0005550	0.0005550	75.89	1.34	0
BADFISH 31-43 E 7WB	P-DP	537.11	1,608.86	341.12	830.72	0.0000000	0.0000000	0.0005390	0.0005390	75.89	1.34	0
BADFISH 31-43 F 6WA	P-DP	358.06	662.27	218.92	367.93	0.0000000	0.0000000	0.0005370	0.0005370	75.89	1.34	0
BADFISH 31-43 F 8WB	P-DP	576.44	2,525.93	333.78	1,014.67	0.0000000	0.0000000	0.0005470	0.0005470	75.89	1.34	0
BADFISH 31-43 J 10WA	P-DP	354.70	1,449.51	214.33	530.58	0.0000000	0.0000000	0.0005350	0.0005350	75.89	1.34	0
BADFISH 31-43 J 11WB	P-DP	594.21	3,355.90	369.36	1,195.18	0.0000000	0.0000000	0.0005360	0.0005360	75.89	1.34	0

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BADFISH 31-43 L 12MS	P-DP	376.93	1,020.02	187.95	327.24	0.0000000	0.0000000	0.0005390	0.0005390	75.89	1.34	0
BADFISH 31-43 M 13JM	P-DP	52.34	89.06	37.42	41.58	0.0000000	0.0000000	0.0005610	0.0005610	75.89	1.34	0
BADFISH 31-43 M 3LS	P-DP	1,065.12	2,213.53	585.57	851.79	0.0000000	0.0000000	0.0005360	0.0005360	75.89	1.34	0
BARNES, D. E. ESTATE 2	P-DP	281.75	229.29	228.18	122.67	0.0000000	0.0000000	0.0000900	0.0000900	75.15	0.68	0
BARNES, D. E. ESTATE 3H	P-DP	277.61	633.83	226.45	435.66	0.0000000	0.0000000	0.0003550	0.0003550	75.15	0.68	0
BARNES, D. E. ESTATE 4H	P-DP	503.37	427.06	328.78	286.81	0.0000000	0.0000000	0.0003550	0.0003550	75.15	0.68	0
BARR 10-8 B UNIT A 5H	P-DP	314.35	287.84	115.78	69.17	0.0000000	0.0000000	0.0003160	0.0003160	76.19	1.96	0
BARR 10-8 B UNIT L 5H	P-DP	265.51	87.18	106.83	22.17	0.0000000	0.0000000	0.0003160	0.0003160	76.19	1.96	0
BARSTOW -14- 10	P-DP	87.90	532.06	33.50	121.15	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
BARSTOW -18- 1	P-DP	190.46	1,041.33	180.87	957.69	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -18- 2	P-DP	125.61	225.27	122.83	187.37	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -18- 3	P-DP	102.92	298.55	90.60	173.60	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -18- 4	P-DP	86.33	451.99	83.66	411.91	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -18- 5	P-DP	137.25	601.34	134.44	515.86	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -18- 6	P-DP	222.83	181.02	64.84	91.35	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -19- 8	P-DP	431.35	1,654.20	57.31	96.71	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
BARSTOW -19- 9	P-DP	1,265.36	3,186.92	107.66	232.83	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
BARSTOW -23- 1	P-DP	189.52	421.73	181.31	376.14	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -23- 10	P-DP	164.38	242.70	56.91	102.62	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -23- 2	P-DP	85.17	335.05	75.07	268.49	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -23- 3	P-DP	239.34	526.74	172.84	319.85	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -23- 4	P-DP	247.02	792.43	203.88	595.36	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -23- 5	P-DP	60.93	434.27	51.38	368.76	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -23- 6A	P-DP	66.90	198.37	57.47	87.31	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -23- 7	P-DP	123.98	558.51	113.12	491.08	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -23- 8	P-DP	99.40	217.02	90.18	142.65	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW -23- 9	P-DP	100.02	1,175.17	91.63	999.77	0.0000000	0.0000000	0.0000040	0.0000040	75.15	0.68	0
BARSTOW 155 1	P-DP	37.64	38.14	37.09	36.46	0.0000000	0.0000000	0.0000080	0.0000080	75.15	0.68	0
BARSTOW 155 2	P-DP	211.82	310.63	114.47	164.12	0.0000000	0.0000000	0.0000080	0.0000080	75.15	0.68	0
BARSTOW 155 3	P-DP	1,265.36	3,186.92	107.66	232.83	0.0000000	0.0000000	0.0000075	0.0000075	75.15	0.68	0
BARSTOW 155 4	P-DP	1,265.36	3,186.92	107.66	232.83	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
BARSTOW 18 7	P-DP	1,265.36	3,186.92	107.66	232.83	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
BARSTOW 27 1	P-DP	192.02	242.27	189.44	214.93	0.0000000	0.0000000	0.0000050	0.0000050	75.15	0.68	0
BARSTOW 27 2	P-DP	69.57	150.91	65.33	105.77	0.0000000	0.0000000	0.0000050	0.0000050	75.15	0.68	0
BARSTOW 27 3	P-DP	224.63	144.49	172.87	87.64	0.0000000	0.0000000	0.0000050	0.0000050	75.15	0.68	0
BARSTOW 27 4	P-DP	126.46	622.19	122.78	381.12	0.0000000	0.0000000	0.0000050	0.0000050	75.15	0.68	0
BARSTOW 27 5	P-DP	77.64	498.28	72.62	446.63	0.0000000	0.0000000	0.0000050	0.0000050	75.15	0.68	0

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BARSTOW 27 6	P-DP	128.98	477.53	94.67	402.43	0.0000000	0.0000000	0.0000050	0.0000050	75.15	0.68	0
BARSTOW 27 7	P-DP	85.82	423.86	83.77	392.60	0.0000000	0.0000000	0.0000050	0.0000050	75.15	0.68	0
BARSTOW 27 8	P-DP	183.40	349.58	98.67	165.15	0.0000000	0.0000000	0.0000050	0.0000050	75.15	0.68	0
BARSTOW 33 UA 1BS	P-DP	210.16	1,434.56	178.23	1,136.87	0.0000000	0.0000000	0.0000230	0.0000230	75.15	0.68	0
BARSTOW 33 UB 2H	P-DP	449.59	1,785.86	338.17	961.05	0.0000000	0.0000000	0.0000230	0.0000230	75.15	0.68	0
BARSTOW 33-34 1H	P-DP	724.24	1,373.77	624.29	1,237.61	0.0000000	0.0000000	0.0000030	0.0000030	75.15	0.68	0
BARSTOW 33-35 1H	P-DP	303.99	663.75	297.00	647.70	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
BARSTOW 33-35 2H	P-DP	344.04	731.60	271.41	530.36	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
BARSTOW 33-35 3H	P-DP	694.16	3,063.27	543.07	2,306.51	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
BARSTOW A 3652H	P-DP	1,178.41	5,184.85	793.35	3,184.42	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
BATES S CRC JF 5H	P-DP	0.00	17,386.08	0.00	13,804.77	0.0000000	0.0000000	0.0802990	0.0802990	73.94	1.98	0
BAYES 16 1	P-DP	42.00	230.65	40.47	230.41	0.0000000	0.0000000	0.0003350	0.0003350	75.89	1.34	0
BAYES 16A 1	P-DP	68.47	438.78	65.89	438.17	0.0000000	0.0000000	0.0003720	0.0003720	75.89	1.34	0
BAYES 4 1	P-DP	97.58	519.03	84.46	439.76	0.0000000	0.0000000	0.0003720	0.0003720	75.89	1.34	0
BAYES 4 3	P-DP	80.61	288.38	80.61	288.38	0.0000000	0.0000000	0.0003350	0.0003350	75.89	1.34	0
BAYES 4A 2	P-DP	36.12	238.46	31.17	158.87	0.0000000	0.0000000	0.0003600	0.0003600	75.89	1.34	0
BAYES 4A 3	P-DP	25.87	62.46	22.83	52.72	0.0000000	0.0000000	0.0003600	0.0003600	75.89	1.34	0
BAYES 4A 4	P-DP	57.50	623.53	44.60	465.50	0.0000000	0.0000000	0.0003600	0.0003600	75.89	1.34	0
BBC 4-20C5	P-DP	76.91	540.08	55.73	368.47	0.0000000	0.0000000	0.0007530	0.0007530	60.48	1.70	0
BELL 1A	P-DP	0.00	70.60	0.00	67.86	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
BIG EL 45-04 1AH	P-DP	504.40	373.33	367.28	198.44	0.0000000	0.0000000	0.0032540	0.0032540	76.19	1.96	0
BIG EL 45-04 1SH	P-DP	355.23	1,702.76	291.90	790.28	0.0000000	0.0000000	0.0032540	0.0032540	76.19	1.96	0
BIG EL 45-04 B 2MS	P-DP	364.55	1,460.15	177.62	430.75	0.0000000	0.0000000	0.0037310	0.0037310	76.19	1.96	0
BIG EL 45-04 C 3SA	P-DP	343.94	1,132.32	197.68	370.36	0.0000000	0.0000000	0.0037310	0.0037310	76.19	1.96	0
BIG EL 45-04 C 3SS	P-DP	407.05	1,342.24	227.82	407.74	0.0000000	0.0000000	0.0037410	0.0037410	76.19	1.96	0
BIG EL 45-04 D 4MS	P-DP	391.87	1,388.13	230.71	453.27	0.0000000	0.0000000	0.0037160	0.0037160	76.19	1.96	0
BIG EL 45-04 D 4SA	P-DP	276.07	1,626.24	151.61	418.33	0.0000000	0.0000000	0.0037240	0.0037240	76.19	1.96	0
BIG EL 45-04 D 4SS	P-DP	449.78	1,832.50	259.15	510.49	0.0000000	0.0000000	0.0037310	0.0037310	76.19	1.96	0
BIG JAY 10-15 A 1JD	P-DP	397.03	230.25	302.28	132.18	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 A 1LS	P-DP	420.83	578.52	282.13	302.95	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 A 1MS	P-DP	327.87	788.63	238.50	462.65	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 A 1WA	P-DP	429.29	5,111.19	324.40	2,716.34	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 B 2DN	P-DP	245.84	1,595.43	204.76	976.69	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 B 2LS	P-DP	219.63	1,982.24	182.49	1,151.97	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 B 2WB	P-DP	198.75	1,897.23	167.01	1,076.64	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 B 3JC	P-DP	256.10	1,347.32	207.63	788.63	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 C 4LS	P-DP	255.76	3,855.14	207.31	1,308.14	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0

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BIG JAY 10-15 C 4WA	P-DP	203.39	4,369.10	188.99	1,850.38	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 D 5JC	P-DP	104.94	1,093.93	85.57	608.53	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 D 6DN	P-DP	254.07	1,812.53	223.22	1,062.15	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 D 6LS	P-DP	287.57	2,233.72	230.49	997.33	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 D 6WB	P-DP	208.37	3,292.44	164.12	1,636.62	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 E 7JD	P-DP	295.80	1,798.34	225.64	801.66	0.0000000	0.0000000	0.0004660	0.0004660	75.89	1.34	0
BIG JAY 10-15 E 7LS	P-DP	346.79	2,140.87	267.68	991.44	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 E 7MS	P-DP	75.99	1,056.73	68.98	634.69	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 E 7WA	P-DP	301.17	2,150.73	256.63	1,252.45	0.0000000	0.0000000	0.0004640	0.0004640	75.89	1.34	0
BIG JAY 10-15 F 4MS	P-DP	184.54	1,265.86	164.17	680.44	0.0000000	0.0000000	0.0004650	0.0004650	75.89	1.34	0
BIGHORN 33E 2HJ	P-DP	360.61	906.80	243.55	418.07	0.0000000	0.0000000	0.0007140	0.0007140	76.19	1.96	0
BIGHORN 33G 3HJ	P-DP	360.76	1,333.02	281.02	589.58	0.0000000	0.0000000	0.0007140	0.0007140	76.19	1.96	0
BIGHORN HORIZONTAL UNIT 1HJ	P-DP	78.23	65.82	77.33	65.24	0.0000000	0.0000000	0.0010370	0.0010370	76.19	1.96	0
BILLINGSLEY 12 1	P-DP	54.34	46.22	31.91	31.90	0.0000000	0.0000000	0.0003910	0.0003910	73.67	3.34	0
BIZZELL -B- 1	P-DP	112.63	228.15	102.71	223.07	0.0000000	0.0000000	0.0006610	0.0006610	76.66	1.00	0
BIZZELL -B- 2	P-DP	111.73	230.19	103.91	223.15	0.0000000	0.0000000	0.0006610	0.0006610	76.66	1.00	0
BIZZELL-IRVIN 15L UNIT 116H	P-DP	339.53	342.20	263.92	195.53	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BIZZELL-IRVIN 15L UNIT 13H	P-DP	342.39	3,216.26	238.34	1,314.78	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BIZZELL-IRVIN 15L UNIT 18H	P-DP	250.26	1,517.15	176.00	669.51	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BIZZELL-IRVIN 15U UNIT 113H	P-DP	265.35	815.46	177.44	431.14	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BIZZELL-IRVIN 15U UNIT 114H	P-DP	455.11	1,417.18	283.20	613.24	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BIZZELL-IRVIN 15U UNIT 115H	P-DP	372.00	723.16	242.63	391.89	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BIZZELL-IRVIN 15U UNIT 117H	P-DP	312.58	973.25	204.50	459.20	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BIZZELL-IRVIN 15U UNIT 118H	P-DP	462.89	1,348.24	300.53	622.45	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BIZZELL-IRVIN 15U UNIT 14H	P-DP	388.02	893.41	233.02	457.48	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BIZZELL-IRVIN 15U UNIT 15H	P-DP	350.15	1,074.34	223.68	474.01	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BIZZELL-IRVIN 15U UNIT 16H	P-DP	404.47	1,276.75	273.83	625.14	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BIZZELL-IRVIN 15U UNIT 17H	P-DP	711.64	994.80	476.79	571.61	0.0000000	0.0000000	0.0021910	0.0021910	76.66	1.00	0
BLUEBELL 16-24-23-C5-9H	P-DP	134.22	890.95	132.72	877.90	0.0000000	0.0000000	0.0002820	0.0002820	60.48	1.70	0
BLUEBELL 24/23-25/26-C5-1H	P-DP	129.69	784.65	129.69	784.65	0.0000000	0.0000000	0.0001410	0.0001410	60.48	1.70	0
BOBCAT 55-1-16-21 E 12H	P-DP	758.08	3,033.89	349.71	1,535.02	0.0000000	0.0000000	0.0000440	0.0000440	76.15	-0.83	0
BOBCAT 55-1-16-21 F 13H	P-DP	745.48	4,235.48	362.31	1,660.85	0.0000000	0.0000000	0.0000440	0.0000440	76.15	-0.83	0
BOBCAT 55-1-16-21 G 14H	P-DP	911.29	4,043.31	372.98	1,564.15	0.0000000	0.0000000	0.0000440	0.0000440	76.15	-0.83	0
BOBCAT 55-1-16-21 H 15H	P-DP	893.13	3,875.82	354.55	1,352.48	0.0000000	0.0000000	0.0000460	0.0000460	76.15	-0.83	0
BOBCAT 55-1-16-21 I 21H	P-DP	415.30	4,634.27	197.80	2,039.31	0.0000000	0.0000000	0.0000440	0.0000440	76.15	-0.83	0
BOBCAT 55-1-16-21 J 22H	P-DP	493.66	4,871.25	197.03	1,582.31	0.0000000	0.0000000	0.0000450	0.0000450	76.15	-0.83	0
BOBCAT 55-1-28 UNIT 1H	P-DP	760.39	3,312.61	533.67	2,208.94	0.0000000	0.0000000	0.0000900	0.0000900	76.15	-0.83	0

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BOENING UNIT 1H	P-DP	161.94	936.85	155.29	921.90	0.0000000	0.0000000	0.0106680	0.0106680	74.40	1.94	0
BOENING UNIT 2H	P-DP	167.84	1,631.78	152.05	1,314.75	0.0000000	0.0000000	0.0106680	0.0106680	74.40	1.94	0
BOENING UNIT 3H	P-DP	293.36	2,136.66	220.53	1,575.21	0.0000000	0.0000000	0.0106680	0.0106680	74.40	1.94	0
BOENING UNIT 4H	P-DP	242.46	1,763.63	201.86	1,389.48	0.0000000	0.0000000	0.0106680	0.0106680	74.40	1.94	0
BOENING UNIT 6L	P-DP	198.01	1,404.30	159.97	1,095.27	0.0000000	0.0000000	0.0106680	0.0106680	74.40	1.94	0
BOENING UNIT 6U	P-DP	274.93	1,886.76	180.19	1,053.10	0.0000000	0.0000000	0.0106680	0.0106680	74.40	1.94	0
BOLT 15-33H	P-DP	261.88	226.05	199.18	117.12	0.0000000	0.0000000	0.0006200	0.0006200	74.04	4.41	0
BOLT 406-0904H	P-DP	387.32	631.25	350.07	480.62	0.0000000	0.0000000	0.0080600	0.0080600	74.04	4.41	0
BOLT 407-0904H	P-DP	526.57	565.07	481.92	508.58	0.0000000	0.0000000	0.0080600	0.0080600	74.04	4.41	0
BONACCI 1	P-DP	0.00	90.85	0.00	90.85	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
BONACCI 2	P-DP	0.00	77.93	0.00	77.93	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
BOND 223A	P-DP	75.29	359.24	71.88	343.80	0.0000000	0.0000000	0.0000000	0.0000000	75.89	1.34	0
BOREAS 79 1H	P-DP	337.27	640.35	276.83	637.05	0.0000000	0.0000000	0.0002690	0.0002690	75.81	1.34	0
BORUM E SMF JF 4H	P-DP	0.00	14,377.89	0.00	12,048.28	0.0000000	0.0000000	0.0211290	0.0211290	73.94	1.98	0
BORUM E SMF JF 6H	P-DP	0.00	14,134.56	0.00	11,338.59	0.0000000	0.0000000	0.0211290	0.0211290	73.94	1.98	0
BORUM W SMF JF 2H	P-DP	0.00	14,484.74	0.00	10,942.16	0.0000000	0.0000000	0.0013050	0.0013050	73.94	1.98	0
BOW TIE 41-44 1AH	P-DP	279.33	1,022.86	223.30	551.09	0.0000000	0.0000000	0.0004922	0.0004922	76.19	1.96	0
BOW TIE 41-44 1BH	P-DP	205.95	50.78	164.93	36.74	0.0000000	0.0000000	0.0004926	0.0004926	76.19	1.96	0
BOW TIE 41-44 2AH	P-DP	144.77	164.31	110.79	83.56	0.0000000	0.0000000	0.0004923	0.0004923	76.19	1.96	0
BOW TIE 41-44 2SH	P-DP	145.51	462.60	111.72	243.73	0.0000000	0.0000000	0.0004922	0.0004922	76.19	1.96	0
BOW TIE 41-44 3AH	P-DP	276.69	618.18	212.00	309.32	0.0000000	0.0000000	0.0004922	0.0004922	76.19	1.96	0
BOW TIE 41-44 3SH	P-DP	203.58	694.67	155.48	346.83	0.0000000	0.0000000	0.0004922	0.0004922	76.19	1.96	0
BOX 42-55 UNIT 1AH	P-DP	305.34	625.54	165.13	202.30	0.0000000	0.0000000	0.0002460	0.0002460	76.19	1.96	0
BOX 42-55 UNIT 1SH	P-DP	280.95	868.36	127.12	469.89	0.0000000	0.0000000	0.0002460	0.0002460	76.19	1.96	0
BOX 42-55 UNIT 2AH	P-DP	324.76	586.13	144.69	245.83	0.0000000	0.0000000	0.0002460	0.0002460	76.19	1.96	0
BOX 42-55 UNIT 2SH	P-DP	170.79	335.69	104.49	175.05	0.0000000	0.0000000	0.0002460	0.0002460	76.19	1.96	0
BOX 42-55 UNIT 3LS	P-DP	800.77	724.59	489.12	302.80	0.0000000	0.0000000	0.0002460	0.0002460	76.19	1.96	0
BOX 42-55 UNIT 4WA	P-DP	213.60	843.15	98.30	365.72	0.0000000	0.0000000	0.0002460	0.0002460	76.19	1.96	0
BOX NAIL 2LM	P-DP	325.34	915.52	266.93	503.69	0.0000000	0.0000000	0.0000710	0.0000710	75.89	1.34	0
BOX NAIL 3LL	P-DP	372.81	1,031.71	306.01	580.51	0.0000000	0.0000000	0.0000710	0.0000710	75.89	1.34	0
BOX NAIL E 1LM	P-DP	332.27	1,128.31	258.64	621.40	0.0000000	0.0000000	0.0000710	0.0000710	75.89	1.34	0
BOYD, FANNIE 4	P-DP	30.83	170.70	28.34	152.10	0.0000000	0.0000000	0.0083860	0.0083860	76.00	1.19	0
BOYD, FANNIE 5	P-DP	143.20	43.41	143.20	43.41	0.0000000	0.0000000	0.0083860	0.0083860	76.00	1.19	0
BOYD, FANNIE 8	P-DP	8.09	14.42	8.09	14.42	0.0000000	0.0000000	0.0083860	0.0083860	76.00	1.19	0
BRACERO 226-34 UNIT 1H	P-DP	233.51	2,582.81	148.34	1,457.60	0.0000000	0.0000000	0.0011740	0.0011740	75.15	0.68	0
BRAMBLETT 34-216 1H	P-DP	172.26	906.98	132.02	691.20	0.0000000	0.0000000	0.0014650	0.0014650	75.15	0.68	0
BRAUN B S1 2008LH	P-DP	614.04	1,182.60	350.74	413.00	0.0000000	0.0000000	0.0000670	0.0000670	76.66	1.00	0

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BRAUN B S10 2014JH	P-DP	440.91	1,782.69	270.81	614.84	0.0000000	0.0000000	0.0000730	0.0000730	76.66	1.00	0
BRAUN B S11 2004LH	P-DP	373.40	865.30	224.08	383.22	0.0000000	0.0000000	0.0001760	0.0001760	76.66	1.00	0
BRAUN B S12 2004MH	P-DP	491.13	1,142.57	350.85	522.33	0.0000000	0.0000000	0.0001940	0.0001940	76.66	1.00	0
BRAUN B S13 2003LH	P-DP	575.18	976.00	317.09	415.80	0.0000000	0.0000000	0.0001880	0.0001880	76.66	1.00	0
BRAUN B S14 2003MH	P-DP	429.73	920.02	329.51	429.06	0.0000000	0.0000000	0.0001940	0.0001940	76.66	1.00	0
BRAUN B S2 2008MH	P-DP	545.33	972.49	256.79	340.93	0.0000000	0.0000000	0.0000660	0.0000660	76.66	1.00	0
BRAUN B S3 2007LH	P-DP	478.48	961.11	312.53	464.36	0.0000000	0.0000000	0.0000530	0.0000530	76.66	1.00	0
BRAUN B S4 2007MH	P-DP	426.15	1,344.90	268.61	494.40	0.0000000	0.0000000	0.0000570	0.0000570	76.66	1.00	0
BRAUN B S5 2016JH	P-DP	639.47	1,710.78	393.75	607.81	0.0000000	0.0000000	0.0000560	0.0000560	76.66	1.00	0
BRAUN B S6 2006LH	P-DP	414.77	1,316.18	260.92	448.68	0.0000000	0.0000000	0.0000560	0.0000560	76.66	1.00	0
BRAUN B S7 2006MH	P-DP	505.94	1,685.28	319.29	535.77	0.0000000	0.0000000	0.0000590	0.0000590	76.66	1.00	0
BRAUN B S8 2005LH	P-DP	369.11	1,255.32	228.94	465.31	0.0000000	0.0000000	0.0000550	0.0000550	76.66	1.00	0
BRAUN B S9 2005MH	P-DP	615.17	2,066.55	366.48	634.34	0.0000000	0.0000000	0.0001160	0.0001160	76.66	1.00	0
BRAUN B W1 2001MH	P-DP	1,081.88	1,765.86	650.84	714.86	0.0000000	0.0000000	0.0001970	0.0001970	76.66	1.00	0
BRAUN B W3 2001LH	P-DP	821.66	1,456.61	545.33	660.83	0.0000000	0.0000000	0.0001960	0.0001960	76.66	1.00	0
BRAUN C W10 2106LH	P-DP	944.71	2,384.68	536.73	853.00	0.0000000	0.0000000	0.0001070	0.0001070	76.66	1.00	0
BRAUN C W11 2106BH	P-DP	373.21	3,506.30	255.35	1,561.26	0.0000000	0.0000000	0.0001100	0.0001100	76.66	1.00	0
BRAUN C W5 2108LH	P-DP	686.54	941.31	405.63	522.34	0.0000000	0.0000000	0.0002840	0.0002840	76.66	1.00	0
BRAUN C W6 2108BH	P-DP	359.73	2,426.76	255.77	988.68	0.0000000	0.0000000	0.0001130	0.0001130	76.66	1.00	0
BRAUN C W7 2107MH	P-DP	630.44	1,053.03	387.64	533.95	0.0000000	0.0000000	0.0000930	0.0000930	76.66	1.00	0
BRAUN C W8 2107LH	P-DP	820.91	1,937.77	510.92	812.52	0.0000000	0.0000000	0.0000990	0.0000990	76.66	1.00	0
BRAUN C W9 2106MH	P-DP	603.78	1,547.80	396.86	698.89	0.0000000	0.0000000	0.0000880	0.0000880	76.66	1.00	0
BROKEN ARROW 55-54-1-12 H 3LS	P-DP	238.79	650.83	162.71	359.49	0.0000000	0.0000000	0.0013180	0.0013180	76.19	1.96	0
BROKEN ARROW 55-54-1-12 H 4W	P-DP	354.90	1,165.09	259.63	692.92	0.0000000	0.0000000	0.0013180	0.0013180	76.19	1.96	0
BROOKE 184-185 UNIT 132H	P-DP	329.99	3,578.10	158.66	1,671.83	0.0000000	0.0000000	0.0005640	0.0005640	75.15	0.68	0
BROOKE 184-185 UNIT 221H	P-DP	495.15	4,041.44	205.86	1,796.90	0.0000000	0.0000000	0.0005640	0.0005640	75.15	0.68	0
BROOKE 184-185 UNIT 232H	P-DP	377.67	4,094.06	148.30	1,487.41	0.0000000	0.0000000	0.0005640	0.0005640	75.15	0.68	0
BROOKE 184-185 UNIT 233H	P-DP	239.85	2,622.58	122.01	1,208.47	0.0000000	0.0000000	0.0005640	0.0005640	75.15	0.68	0
BROOKE 184-185 UNIT 2H	P-DP	591.12	7,616.35	412.34	4,473.28	0.0000000	0.0000000	0.0005640	0.0005640	75.15	0.68	0
BROOKE 184-185 UNIT 331H	P-DP	320.23	4,686.74	144.10	1,529.25	0.0000000	0.0000000	0.0005640	0.0005640	75.15	0.68	0
BROOKS 1	P-DP	96.30	175.55	74.23	125.21	0.0000000	0.0000000	0.0112500	0.0112500	75.89	1.34	0
BRUT 40-33 1AH	P-DP	351.15	731.60	246.99	306.91	0.0000000	0.0000000	0.0140910	0.0140910	76.19	1.96	0
BRUT A 1MS	P-DP	218.18	155.54	79.69	51.43	0.0000000	0.0000000	0.0106720	0.0106720	76.19	1.96	0
BRUT B 2LS	P-DP	154.35	201.57	76.35	94.25	0.0000000	0.0000000	0.0106620	0.0106620	76.19	1.96	0
BRUT C 3A	P-DP	452.53	981.89	184.28	223.24	0.0000000	0.0000000	0.0070670	0.0070670	76.19	1.96	0
BRUT D 5A	P-DP	324.99	424.94	164.48	187.48	0.0000000	0.0000000	0.0003190	0.0003190	76.19	1.96	0
BRUT E 6LS	P-DP	236.74	725.33	98.86	170.07	0.0000000	0.0000000	0.0107040	0.0107040	76.19	1.96	0

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BUCHANAN 3111 2	P-DP	77.04	146.83	44.72	145.40	0.0000000	0.0000000	0.0012600	0.0012600	76.19	1.96	0
BUCKEYE 55-1-28 UNIT 1H	P-DP	675.21	3,070.30	474.39	2,116.35	0.0000000	0.0000000	0.0000900	0.0000900	76.15	-0.83	0
BUELL 10-11-5 10H	P-DP	16.01	17,971.16	16.01	13,716.62	0.0000000	0.0000000	0.0940790	0.0940790	69.42	2.07	0
BUELL 10-11-5 1H	P-DP	48.12	6,919.58	46.96	5,216.68	0.0000000	0.0000000	0.0209880	0.0209880	69.42	2.07	0
BUELL 10-11-5 206H	P-DP	45.56	19,217.32	45.52	14,233.90	0.0000000	0.0000000	0.0749940	0.0749940	69.42	2.07	0
BUELL 10-11-5 210H	P-DP	13.40	17,808.81	13.27	13,508.81	0.0000000	0.0000000	0.0940790	0.0940790	69.42	2.07	0
BUELL 10-11-5 2H	P-DP	38.53	6,429.58	37.91	5,293.57	0.0000000	0.0000000	0.0209880	0.0209880	69.42	2.07	0
BUELL 10-11-5 3H	P-DP	43.06	6,666.36	42.77	5,432.09	0.0000000	0.0000000	0.0209880	0.0209880	69.42	2.07	0
BUELL 10-11-5 4H	P-DP	48.17	8,438.64	46.88	6,533.89	0.0000000	0.0000000	0.0209880	0.0209880	69.42	2.07	0
BUELL 10-11-5 6H	P-DP	24.59	16,236.11	24.59	12,789.05	0.0000000	0.0000000	0.0452070	0.0452070	69.42	2.07	0
BURKHOLDER A UNIT 1	P-DP	0.01	65,778.11	0.01	65,758.25	0.0000000	0.0000000	0.0001480	0.0001480	75.15	0.68	0
BUSH-NUNN 13A 1H	P-DP	463.80	3,158.40	57.73	121.99	0.0000000	0.0000000	0.0007290	0.0007290	75.14	2.00	0
BUSH-NUNN 13B 2H	P-DP	465.77	3,157.08	59.69	120.67	0.0000000	0.0000000	0.0007290	0.0007290	75.14	2.00	0
BUSH-NUNN 13C 3H	P-DP	463.30	3,157.31	57.22	120.91	0.0000000	0.0000000	0.0009260	0.0009260	75.14	2.00	0
BUSH-NUNN 13D 4H	P-DP	464.25	3,155.45	58.18	119.04	0.0000000	0.0000000	0.0009260	0.0009260	75.14	2.00	0
BUSH-NUNN 13E 5H	P-DP	468.22	3,159.66	62.14	123.25	0.0000000	0.0000000	0.0009260	0.0009260	75.14	2.00	0
BUTCHEE 21 1	P-DP	122.57	68.75	93.07	51.63	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
BUTCHEE 21 2	P-DP	44.15	41.05	34.50	36.94	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
BUTCHEE 21 3	P-DP	143.60	45.80	105.06	42.27	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
BUTCHEE 21 4	P-DP	45.92	20.37	33.76	16.64	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
BUTCHEE 21 5	P-DP	30.67	24.05	26.29	23.46	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
BUTCHEE 21 6	P-DP	95.47	120.88	70.74	114.91	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
BUTCHEE 21 7	P-DP	52.08	59.96	36.31	56.31	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
BUTCHEE 21 8	P-DP	127.53	60.28	96.84	47.89	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
BUTCHER BUTTE 27-144EWH-23	P-DP	456.59	521.60	418.95	473.18	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
BUTTERBUMPS 39-46 A 2DN	P-DP	973.41	955.95	448.96	301.93	0.0000000	0.0000000	0.0000030	0.0000030	77.02	1.02	0
BUZZARD NORTH 6972 A 1H	P-DP	964.38	2,801.50	853.25	2,497.08	0.0000000	0.0000000	0.0009750	0.0009750	75.81	1.34	0
BUZZARD NORTH 6972 B 2H	P-DP	393.75	2,714.63	250.26	1,213.31	0.0000000	0.0000000	0.0009750	0.0009750	75.81	1.34	0
BUZZARD NORTH 6972 S 3H	P-DP	449.27	2,719.01	249.38	1,111.95	0.0000000	0.0000000	0.0009750	0.0009750	75.81	1.34	0
BUZZARD SOUTH 6972 A 3H	P-DP	544.87	2,816.50	334.39	1,424.92	0.0000000	0.0000000	0.0011550	0.0011550	75.81	1.34	0
BUZZARD SOUTH 6972 A 4H	P-DP	483.75	2,699.35	279.94	1,431.19	0.0000000	0.0000000	0.0011550	0.0011550	75.81	1.34	0
BUZZARD SOUTH 6972 B 1H	P-DP	730.23	2,643.33	609.99	1,961.67	0.0000000	0.0000000	0.0011550	0.0011550	75.81	1.34	0
BYRD 34-170 UNIT 3H	P-DP	451.74	1,097.84	337.77	849.20	0.0000000	0.0000000	0.0002010	0.0002010	75.15	0.68	0
BYRD 34-170 UNIT 4H	P-DP	172.46	306.17	172.46	306.17	0.0000000	0.0000000	0.0002010	0.0002010	75.15	0.68	0
CALIFORNIA CHROME UNIT 2H	P-DP	683.47	7,819.75	487.40	5,148.13	0.0000000	0.0000000	0.0008220	0.0008220	75.15	0.68	0
CALIFORNIA CHROME UNIT 5003HR	P-DP	634.22	6,422.24	436.04	4,295.79	0.0000000	0.0000000	0.0008220	0.0008220	75.15	0.68	0
CALVERLEY-LANE 30G 7H	P-DP	551.08	3,108.79	303.70	825.92	0.0000000	0.0000000	0.0033490	0.0033490	76.00	1.19	0

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CALVERLEY-LANE 30H 8H	P-DP	316.58	3,839.03	166.14	850.21	0.0000000	0.0000000	0.0033500	0.0033500	76.00	1.19	0
CALVERLEY-LANE 30I 9H	P-DP	627.88	2,365.50	310.73	802.45	0.0000000	0.0000000	0.0033520	0.0033520	76.00	1.19	0
CALVERLEY-LANE 30J 10H	P-DP	353.77	3,617.56	179.19	873.10	0.0000000	0.0000000	0.0033040	0.0033040	76.00	1.19	0
CALVERLEY-LANE 30K 11H	P-DP	452.07	1,382.54	228.03	517.34	0.0000000	0.0000000	0.0033050	0.0033050	76.00	1.19	0
CALVERLEY-LANE 30L 12H	P-DP	413.23	4,389.25	194.03	958.96	0.0000000	0.0000000	0.0032910	0.0032910	76.00	1.19	0
CARALYNE 24 1	P-DP	15.15	1,284.57	13.50	983.04	0.0000000	0.0000000	0.0011720	0.0011720	76.66	1.00	0
CARELESS WHISPER I 19-15 5SH	P-DP	827.07	929.17	111.12	68.93	0.0000000	0.0000000	0.0000210	0.0000210	76.19	1.96	0
CARELESS WHISPER J 19-15 5AH	P-DP	830.63	930.86	114.68	70.63	0.0000000	0.0000000	0.0003870	0.0003870	76.19	1.96	0
CARELESS WHISPER K 19-15 6SH	P-DP	773.51	930.55	106.47	70.32	0.0000000	0.0000000	0.0003870	0.0003870	76.19	1.96	0
CARELESS WHISPER L 19-15 6AH	P-DP	837.90	934.01	121.95	73.78	0.0000000	0.0000000	0.0000210	0.0000210	76.19	1.96	0
CASPER A1 8LA	P-DP	366.24	504.55	229.98	339.28	0.0001538	0.0001538	0.0001538	0.0001538	75.15	0.68	1,200
CASPER A2 15UA	P-DP	319.09	501.46	236.75	386.40	0.0000000	0.0000000	0.0002250	0.0002250	75.15	0.68	0
CASPER A3 7LA	P-DP	324.11	439.93	223.02	313.05	0.0000000	0.0000000	0.0002250	0.0002250	75.15	0.68	0
CASSIDY UNIT 26-23 1H	P-DP	132.24	195.87	126.98	142.12	0.0000000	0.0000000	0.0121540	0.0121540	73.67	3.34	0
CASSIDY UNIT 26-23 5AH	P-DP	394.20	339.31	275.14	210.70	0.0000000	0.0000000	0.0121540	0.0121540	73.67	3.34	0
CASSIDY UNIT 26-23 7AH	P-DP	653.64	779.95	97.78	63.37	0.0000000	0.0000000	0.0119870	0.0119870	73.67	3.34	0
CATES 24 1	P-DP	61.72	68.99	43.69	68.77	0.0000000	0.0000000	0.0043750	0.0043750	76.19	1.96	0
CENA WYN JF 2H	P-DP	0.00	19,193.93	0.00	14,060.46	0.0000000	0.0000000	0.0717890	0.0717890	73.94	1.98	0
CENA WYN JF 4H	P-DP	0.00	12,495.22	0.00	10,086.38	0.0000000	0.0000000	0.0717890	0.0717890	73.94	1.98	0
CHALUPA 34-153 UNIT 1H	P-DP	607.10	1,658.66	481.01	1,137.83	0.0000000	0.0000000	0.0030210	0.0030210	75.15	0.68	0
CHALUPA 34-153 UNIT 2H	P-DP	1,122.66	1,811.25	879.03	1,332.05	0.0000000	0.0000000	0.0030210	0.0030210	75.15	0.68	0
CHAMBERS FED W-39138 1-25	P-DP	19.58	1,937.72	19.53	1,867.96	0.0000000	0.0000000	0.0033960	0.0033960	74.04	4.41	0
CHAPARRAL UNIT A1 15SH	P-DP	514.71	911.97	337.59	478.98	0.0000000	0.0000000	0.0010400	0.0010400	76.19	1.96	0
CHAPARRAL UNIT A1 21H	P-DP	432.32	690.99	331.06	441.04	0.0000000	0.0000000	0.0010370	0.0010370	76.19	1.96	0
CHAPARRAL UNIT A1 8AH	P-DP	641.80	1,033.54	456.13	541.30	0.0000000	0.0000000	0.0010430	0.0010430	76.19	1.96	0
CHAPARRAL UNIT A2 7AH	P-DP	253.34	588.72	223.33	456.63	0.0000000	0.0000000	0.0010530	0.0010530	73.67	3.34	0
CHAPARRAL UNIT A3 14SH	P-DP	337.06	1,045.44	189.71	383.37	0.0000000	0.0000000	0.0010600	0.0010600	73.67	3.34	0
CHAPARRAL UNIT A3 20H	P-DP	387.88	1,431.72	200.92	508.79	0.0000000	0.0000000	0.0010690	0.0010690	73.67	3.34	0
CHAPARRAL UNIT A4 6AH	P-DP	438.28	1,352.98	243.40	443.41	0.0000000	0.0000000	0.0010590	0.0010590	73.67	3.34	0
CHAPARRAL UNIT A5 13SH	P-DP	258.02	719.98	166.94	326.19	0.0000000	0.0000000	0.0010590	0.0010590	77.02	1.02	0
CHAPARRAL UNIT A5 19H	P-DP	192.47	612.78	161.49	330.45	0.0000000	0.0000000	0.0010540	0.0010540	77.02	1.02	0
CHAPARRAL UNIT A5 5AH	P-DP	552.89	1,061.77	397.73	438.67	0.0000000	0.0000000	0.0010530	0.0010530	77.02	1.02	0
CHARLIE 210468 7A	P-DP	0.00	15,893.72	0.00	11,668.93	0.0000000	0.0000000	0.0018190	0.0018190	67.06	2.04	0
CHARLIE 210468 8B	P-DP	0.00	13,977.18	0.00	10,800.19	0.0000000	0.0000000	0.0018190	0.0018190	67.06	2.04	0
CHARLIE 210469 10B	P-DP	0.00	18,000.78	0.00	13,956.05	0.0000000	0.0000000	0.0172840	0.0172840	67.06	2.04	0
CHARLIE 210469 9A	P-DP	0.00	18,232.95	0.00	14,015.42	0.0000000	0.0000000	0.0172840	0.0172840	67.06	2.04	0
CHARLIE 210472 4A	P-DP	0.00	9,241.43	0.00	8,359.10	0.0000000	0.0000000	0.0386490	0.0386490	67.06	2.04	0

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CHARLIE 210472 5B	P-DP	0.00	10,516.10	0.00	9,303.13	0.0000000	0.0000000	0.0386490	0.0386490	67.06	2.04	0
CHARLIE 210472 6C	P-DP	0.00	9,380.62	0.00	8,804.86	0.0000000	0.0000000	0.0386490	0.0386490	67.06	2.04	0
CHAROLAIS 28 21 B2NC STATE COM 001HP-DP		337.70	300.40	262.34	234.26	0.0000000	0.0000000	0.0013990	0.0013990	76.17	1.13	0
CHAROLAIS 28 21 W1MD STATE COM 001HP-DP		154.70	125.57	80.32	62.10	0.0000000	0.0000000	0.0007250	0.0007250	76.17	1.13	0
CHAROLAIS 33 21 B1GB STATE COM 001HP-DP		532.63	737.93	264.59	305.42	0.0000000	0.0000000	0.0052210	0.0052210	76.17	1.13	0
CHAROLAIS 33 21 B1HA STATE COM 001HP-DP		698.87	1,072.47	328.43	372.35	0.0000000	0.0000000	0.0052210	0.0052210	76.17	1.13	0
CHEST THUMPER 1-5 UNIT 1 112 P-DP		544.42	1,819.09	180.95	276.93	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1 122 P-DP		575.76	2,445.17	182.08	279.02	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1 123 P-DP		602.11	2,527.51	197.70	270.04	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1 125 P-DP		731.55	3,247.73	239.66	419.11	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1 126 P-DP		821.78	3,049.39	266.37	387.07	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1 132 P-DP		537.80	2,434.56	171.90	263.76	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1 133 P-DP		298.37	1,269.93	100.22	144.23	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1 135 P-DP		653.65	2,829.64	208.62	362.53	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1 136 P-DP		631.14	2,692.89	207.87	322.58	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1 142 P-DP		733.32	2,938.72	241.43	347.37	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1 143R P-DP		387.08	1,450.44	130.36	189.04	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1A 221 P-DP		331.17	632.78	151.70	226.15	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1A 231 P-DP		250.61	483.84	114.31	168.24	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1A 241 P-DP		334.94	666.85	151.86	220.07	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1B 211 P-DP		299.23	1,378.13	91.44	190.50	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1B 224 P-DP		412.49	2,212.70	128.52	273.28	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEST THUMPER 1-5 UNIT 1B 234 P-DP		449.87	1,894.54	138.51	261.40	0.0000000	0.0000000	0.0003150	0.0003150	75.89	1.34	0
CHEVRON UNIT 03-38 1H P-DP		435.49	3,062.64	307.32	997.15	0.0000000	0.0000000	0.0004370	0.0004370	76.19	1.96	0
CHEVRON UNIT 03-38 2AH P-DP		375.94	522.44	259.86	297.50	0.0000000	0.0000000	0.0004370	0.0004370	76.19	1.96	0
CHEVRON UNIT 03-38 2SH P-DP		548.44	274.79	282.83	148.11	0.0000000	0.0000000	0.0004370	0.0004370	76.19	1.96	0
CHINOOK 55-1-7 UNIT 1H P-DP		518.04	2,685.16	347.49	1,705.89	0.0000000	0.0000000	0.0001410	0.0001410	76.15	-0.83	0
CHRIESMAN 2 P-DP		87.46	716.80	82.31	688.79	0.0000000	0.0000000	0.0014580	0.0014580	75.14	2.00	0
CHRIESMAN 3 P-DP		17.60	238.90	17.29	236.25	0.0000000	0.0000000	0.0014540	0.0014540	75.14	2.00	0
CHUMCHAL UNIT 1H P-DP		116.43	604.68	115.85	601.23	0.0000000	0.0000000	0.0101900	0.0101900	74.40	1.94	0
CHUMCHAL UNIT 4H P-DP		118.06	696.67	116.54	690.14	0.0000000	0.0000000	0.0101900	0.0101900	74.40	1.94	0
CHUMCHAL UNIT 6L P-DP		242.20	1,479.18	188.23	1,157.96	0.0000000	0.0000000	0.0101900	0.0101900	74.40	1.94	0
CHUMCHAL UNIT 7L P-DP		256.90	1,591.88	201.35	1,289.93	0.0000000	0.0000000	0.0101900	0.0101900	74.40	1.94	0
CHUMCHAL UNIT B 2H P-DP		208.65	1,098.85	57.47	229.61	0.0000000	0.0000000	0.0101900	0.0101900	74.40	1.94	0
CHURRO 34-157/158 UNIT 1H P-DP		1,183.95	2,070.70	832.37	1,353.96	0.0000000	0.0000000	0.0001400	0.0001400	75.15	0.68	0
CLARICE STARLING SUNDOWN B 4521LS P-DP		677.77	1,918.94	422.66	856.59	0.0000000	0.0000000	0.0053340	0.0053340	76.19	1.96	0
CLARICE STARLING SUNDOWN D 4542WAP-DP		749.97	2,216.83	518.98	941.51	0.0000000	0.0000000	0.0038700	0.0038700	76.19	1.96	0

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CLAWSON 3	P-DP	0.00	193.41	0.00	162.12	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
CLEMENTS ALLOCATION A 26-35 4HA	P-DP	210.10	390.19	79.72	88.84	0.0000000	0.0000000	0.0002050	0.0002050	73.67	3.34	0
COLE 36-37 A UNIT A 2H	P-DP	143.95	42.97	106.59	35.70	0.0000000	0.0000000	0.0001090	0.0001090	76.19	1.96	0
COLLE UNIT 1H	P-DP	207.47	1,447.85	166.14	1,218.69	0.0000000	0.0000000	0.0199170	0.0199170	74.40	1.94	0
COLLINS WYN JF 2H	P-DP	0.00	9,869.63	0.00	7,943.53	0.0000000	0.0000000	0.1005280	0.1005280	73.94	1.98	0
COLLINS WYN JF 4H	P-DP	0.00	10,207.37	0.00	8,367.12	0.0000000	0.0000000	0.1005280	0.1005280	73.94	1.98	0
COLLINS WYN JF 6H	P-DP	0.00	11,390.68	0.00	8,958.42	0.0000000	0.0000000	0.1005280	0.1005280	73.94	1.98	0
COLUMBINE 34-167 1H	P-DP	222.30	302.96	190.88	251.99	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
COLUMBINE 34-167 2H	P-DP	348.21	809.61	292.77	613.90	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
COLUMBINE 34-167 3H	P-DP	90.03	438.51	83.15	366.54	0.0000000	0.0000000	0.0000340	0.0000340	75.15	0.68	0
COLUMBINE 34-167 4H	P-DP	431.82	900.97	330.77	746.36	0.0000000	0.0000000	0.0000340	0.0000340	75.15	0.68	0
CONNER 15 1	P-DP	19.22	75.12	19.22	75.12	0.0000000	0.0000000	0.0312500	0.0000000	76.19	1.96	0
CONNER 15 1504N	P-DP	49.49	252.71	48.25	234.01	0.0000000	0.0000000	0.0594900	0.0594900	76.19	1.96	0
CONNER 15 2	P-DP	11.60	26.02	11.60	26.02	0.0000000	0.0000000	0.0596184	0.0000000	76.19	1.96	0
CONNER 15 3	P-DP	23.97	197.18	23.13	182.84	0.0000000	0.0000000	0.0595000	0.0595000	76.19	1.96	0
CONNER 15-10 (ALLOC-A) 1NA	P-DP	470.96	1,718.12	300.71	552.29	0.0000000	0.0000000	0.0146684	0.0146684	76.19	1.96	0
CONNER 15-10 (ALLOC-B) 2NB	P-DP	242.77	666.71	169.34	314.09	0.0000000	0.0000000	0.0143260	0.0143260	76.19	1.96	0
CONNER 15-10 (ALLOC-B) 2NS	P-DP	300.23	889.35	206.51	364.52	0.0000000	0.0000000	0.0144590	0.0144590	76.19	1.96	0
CONNER 15-10 (ALLOC-C) 3NA	P-DP	450.05	1,445.60	310.07	494.28	0.0000000	0.0000000	0.0146690	0.0146690	76.19	1.96	0
CONNER 15-10 (ALLOC-D) 4NB	P-DP	661.88	2,108.62	419.76	583.73	0.0000000	0.0000000	0.0146290	0.0146290	76.19	1.96	0
CONNER 15-10 (ALLOC-D) 4NS	P-DP	130.73	1,840.26	98.65	479.80	0.0000000	0.0000000	0.0139880	0.0139880	76.19	1.96	0
CONNER 15-3 (ALLOC-E) 5NA	P-DP	566.19	1,449.52	354.38	576.06	0.0000000	0.0000000	0.0088160	0.0088160	76.19	1.96	0
CONNER 15-3 (ALLOC-F) 6NB	P-DP	544.40	2,541.90	345.54	609.76	0.0000000	0.0000000	0.0085540	0.0085540	76.19	1.96	0
CONNER 15-3 (ALLOC-F) 6NS	P-DP	286.25	1,303.91	180.58	320.84	0.0000000	0.0000000	0.0066850	0.0066850	76.19	1.96	0
CONNER 15-3 (ALLOC-G) 7NA	P-DP	450.30	1,359.79	311.36	572.19	0.0000000	0.0000000	0.0094300	0.0094300	76.19	1.96	0
CONNER 15-3 (ALLOC-H) 8NB	P-DP	670.10	2,096.47	402.42	670.63	0.0000000	0.0000000	0.0088770	0.0088770	76.19	1.96	0
CONNER 15-3 (ALLOC-H) 8NS	P-DP	380.64	1,549.65	222.27	457.85	0.0000000	0.0000000	0.0095940	0.0095940	76.19	1.96	0
CONSTANTAN 34-174 (N) 1H	P-DP	621.76	3,454.05	540.03	2,835.18	0.0000000	0.0000000	0.0000090	0.0000090	75.15	0.68	0
COOK 21 1	P-DP	65.84	30.71	57.54	30.33	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
COOK 21 2	P-DP	43.54	34.62	36.43	34.14	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
COOK 21 3	P-DP	62.97	39.08	52.44	35.84	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
COOK 21 4	P-DP	68.19	52.66	56.96	48.99	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
COOK 21 5	P-DP	32.91	51.03	28.26	47.06	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
COOK 21 6	P-DP	48.32	55.57	40.85	50.29	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
COOK 21 7	P-DP	56.03	68.56	47.09	65.04	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
COOK 21 8	P-DP	27.48	47.17	23.52	42.82	0.0000000	0.0000000	0.0116670	0.0116670	75.89	1.34	0
COOKIE 55-2728-23S	P-DP	594.44	511.19	296.75	267.93	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0

TABLE 8

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COOKIE 57-2728-23K	P-DP	381.70	236.14	132.95	134.80	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
COOKIE 58-2728-23R	P-DP	722.80	1,096.66	304.40	291.38	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
COOKIE 78-2728-23G	P-DP	390.21	531.35	161.10	132.57	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
COPPER CREEK A8 44H	P-DP	257.64	1,050.45	117.81	323.12	0.0000000	0.0000000	0.0006455	0.0006455	77.02	1.02	0
COPPER CREEK A9 12SH	P-DP	280.88	955.04	127.91	262.60	0.0000000	0.0000000	0.0006407	0.0006407	77.02	1.02	0
CORNELL 226-34 1H	P-DP	455.93	5,402.50	254.83	2,646.87	0.0000000	0.0000000	0.0008200	0.0008200	75.15	0.68	0
COURAGE 53-2827-23P	P-DP	420.67	311.84	191.11	172.06	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
COURAGE 63-2827-23K	P-DP	562.03	727.61	307.29	307.60	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
COURAGE 67-2827-23M	P-DP	710.05	1,035.77	337.28	359.63	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
COURAGE 75-2827-23O	P-DP	468.23	375.07	202.92	149.71	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
COWDEN F 2402	P-DP	21.86	30.47	20.67	29.43	0.0000000	0.0000000	0.0009380	0.0009380	76.66	1.00	0
COWDEN F 2403	P-DP	32.25	88.37	31.65	87.31	0.0000000	0.0000000	0.0009380	0.0009380	76.66	1.00	0
COWDEN F 2404	P-DP	52.17	91.22	41.29	86.18	0.0000000	0.0000000	0.0009380	0.0009380	76.66	1.00	0
COWDEN F 2405	P-DP	41.19	90.87	33.13	88.05	0.0000000	0.0000000	0.0009380	0.0009380	76.66	1.00	0
CRAZY CAMEL 1	P-DP	31.77	30.44	21.29	26.78	0.0000000	0.0000000	0.0021150	0.0021150	75.15	0.68	0
CRAZY CAMEL 2	P-DP	92.14	57.42	62.77	45.80	0.0000000	0.0000000	0.0021150	0.0021150	75.15	0.68	0
CRAZY CAMEL 5	P-DP	2.33	24.26	2.33	24.26	0.0000000	0.0000000	0.0021150	0.0021150	75.15	0.68	0
CRAZY CAMEL 6	P-DP	10.83	19.05	8.07	7.86	0.0000000	0.0000000	0.0021150	0.0021150	75.15	0.68	0
CRAZY CAMEL 7	P-DP	21.22	101.23	13.01	44.90	0.0000000	0.0000000	0.0021150	0.0021150	75.15	0.68	0
CRAZY CAT 41-32 1SH	P-DP	184.92	48.88	153.71	36.43	0.0000000	0.0000000	0.0083920	0.0083920	76.19	1.96	0
CRAZY CAT 41-32 2AH	P-DP	344.26	697.01	298.94	473.35	0.0000000	0.0000000	0.0083920	0.0083920	76.19	1.96	0
CRAZY CAT 41-32 3SH	P-DP	214.80	724.31	189.65	549.24	0.0000000	0.0000000	0.0083920	0.0083920	76.19	1.96	0
CRAZY CAT 41-32 4AH	P-DP	176.51	95.53	154.25	78.61	0.0000000	0.0000000	0.0083920	0.0083920	76.19	1.96	0
CROSS CREEK A 5H-20	P-DP	0.00	10,157.16	0.00	7,761.14	0.0000000	0.0000000	0.1190620	0.1190620	73.94	1.98	0
CROSS V RANCH 34-170 UNIT 1H	P-DP	602.01	829.58	390.24	755.29	0.0000000	0.0000000	0.0004010	0.0004010	75.15	0.68	0
CROWIE E RCH BL 3H	P-DP	0.00	19,908.99	0.00	12,986.65	0.0000000	0.0000000	0.0018970	0.0018970	67.06	2.04	0
CROWIE RCH BL 1H	P-DP	0.00	11,561.44	0.00	7,358.52	0.0000000	0.0000000	0.0018970	0.0018970	67.06	2.04	0
CUATRO HIJOS FEE 003H	P-DP	152.59	101.03	117.22	85.60	0.0000000	0.0000000	0.0019340	0.0019340	76.17	1.13	0
CUATRO HIJOS FEE 004H	P-DP	192.61	111.96	117.71	77.58	0.0000000	0.0000000	0.0019340	0.0019340	76.17	1.13	0
CUATRO HIJOS FEE 008H	P-DP	149.02	173.05	140.58	151.66	0.0000000	0.0000000	0.0019340	0.0019340	76.17	1.13	0
CV RB SU58;SJ MONDELLO ETAL 18 001	P-DP	0.00	378.76	0.00	378.76	0.0000000	0.0000000	0.0156250	0.0156250	66.78	2.34	0
CV RB SUV;SHELBY INTERESTS 31 001	P-DP	1.24	483.87	1.24	483.87	0.0000000	0.0000000	0.0192860	0.0192860	66.78	2.04	0
CV RB SUW;LESHE 36 001	P-DP	0.27	1,222.53	0.27	1,131.52	0.0000000	0.0000000	0.0986160	0.0986160	66.78	2.04	0
CV RB SUW;NAC 36 001-ALT	P-DP	0.26	598.38	0.26	568.41	0.0000000	0.0000000	0.0986160	0.0986160	66.78	2.04	0
DANIEL D & EDNA MILLER 1	P-DP	0.00	93.94	0.00	93.94	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
DANIELLE 183 UNIT 1H	P-DP	558.36	3,679.81	417.56	2,632.92	0.0000000	0.0000000	0.0001310	0.0001310	75.15	0.68	0
DANIELLE 183 UNIT 2H	P-DP	677.90	5,604.05	436.71	3,374.16	0.0000000	0.0000000	0.0001310	0.0001310	75.15	0.68	0

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DARWIN 22 1	P-DP	49.33	118.52	34.86	79.22	0.0000000	0.0000000	0.0041070	0.0041070	75.89	1.34	0
DARWIN 22 2	P-DP	50.83	28.34	39.48	28.34	0.0000000	0.0000000	0.0041070	0.0041070	75.89	1.34	0
DAVID 1	P-DP	116.84	56.65	83.10	51.55	0.0000000	0.0000000	0.0031250	0.0031250	77.02	1.02	0
DAVID L BONACCI 0031	P-DP	0.00	41.72	0.00	41.72	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
DAVIS 1_1	P-DP	132.63	362.87	107.46	244.60	0.0000000	0.0000000	0.0297751	0.0297751	76.19	1.96	0
DAVIS 2	P-DP	0.00	41.82	0.00	41.82	0.0000000	0.0000000	0.0297470	0.0297470	73.94	1.41	0
DAVIS 36-5 (ALLOC-E) 5SA	P-DP	392.82	1,485.08	271.98	639.09	0.0000000	0.0000000	0.0002730	0.0002730	76.19	1.96	0
DAVIS 36-5 (ALLOC-F) 6SB	P-DP	609.00	1,849.53	349.40	715.09	0.0000000	0.0000000	0.0003280	0.0003280	76.19	1.96	0
DAVIS 36-5 (ALLOC-F) 6SS	P-DP	300.09	1,322.08	189.72	563.09	0.0000000	0.0000000	0.0003370	0.0003370	76.19	1.96	0
DAVIS 36-5 (ALLOC-G) 7SA	P-DP	418.58	963.46	285.88	433.83	0.0000000	0.0000000	0.0003270	0.0003270	76.19	1.96	0
DAVIS 36-5 (ALLOC-H) 8SB	P-DP	504.80	2,241.89	332.74	737.56	0.0000000	0.0000000	0.0003750	0.0003750	76.19	1.96	0
DAVIS 36-5 (ALLOC-H) 8SS	P-DP	280.12	972.07	200.96	338.80	0.0000000	0.0000000	0.0003290	0.0003290	76.19	1.96	0
DEMANGONE 1	P-DP	0.00	177.78	0.00	165.08	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
DICKSON CRC JF 1H	P-DP	0.00	14,102.05	0.00	12,291.10	0.0000000	0.0000000	0.1203240	0.1203240	73.94	1.98	0
DICKSON CRC JF 3H	P-DP	0.00	12,507.08	0.00	10,975.44	0.0000000	0.0000000	0.1203240	0.1203240	73.94	1.98	0
DILLES BOTTOM 210744 3B	P-DP	0.00	15,841.09	0.00	13,175.62	0.0000000	0.0000000	0.0000140	0.0000140	67.06	2.04	0
DIRE WOLF 30 3BS A 1H	P-DP	343.91	771.56	167.70	338.60	0.0000000	0.0000000	0.0002030	0.0002030	75.15	0.68	0
DIRE WOLF 50 WA A 1H	P-DP	608.07	1,015.95	197.32	347.09	0.0000000	0.0000000	0.0002130	0.0002130	75.15	0.68	0
DIRE WOLF 60 WB A 1H	P-DP	359.26	993.57	170.73	425.88	0.0000000	0.0000000	0.0002100	0.0002100	75.15	0.68	0
DIRE WOLF 70 WC A 1H	P-DP	253.87	919.35	90.25	407.77	0.0000000	0.0000000	0.0002480	0.0002480	75.15	0.68	0
DIRE WOLF UNIT 1 0402BH	P-DP	404.16	3,407.64	201.38	820.67	0.0000000	0.0000000	0.0034180	0.0034180	75.89	1.34	0
DIRE WOLF UNIT 1 0404BH	P-DP	267.41	4,219.43	223.60	1,608.63	0.0000000	0.0000000	0.0034180	0.0034180	75.89	1.34	0
DIRE WOLF UNIT 1 0411AH	P-DP	31.40	634.68	31.13	300.56	0.0000000	0.0000000	0.0034180	0.0034180	75.89	1.34	0
DIRE WOLF UNIT 1 0413AH	P-DP	69.71	451.72	69.44	250.98	0.0000000	0.0000000	0.0034180	0.0034180	75.89	1.34	0
DIRE WOLF UNIT 1 0414AH	P-DP	483.97	161.86	320.33	56.52	0.0000000	0.0000000	0.0034180	0.0034180	75.89	1.34	0
DIRE WOLF UNIT 1 0422SH	P-DP	30.86	585.94	30.60	175.69	0.0000000	0.0000000	0.0034180	0.0034180	75.89	1.34	0
DIRE WOLF UNIT 1 0424SH	P-DP	387.93	1,193.03	231.46	348.33	0.0000000	0.0000000	0.0034180	0.0034180	75.89	1.34	0
DIRE WOLF UNIT 1 0433SH	P-DP	311.16	123.63	153.74	105.32	0.0000000	0.0000000	0.0034180	0.0034180	75.89	1.34	0
DIRE WOLF UNIT 1 0471JH	P-DP	308.80	233.37	147.90	117.56	0.0000000	0.0000000	0.0034180	0.0034180	75.89	1.34	0
DIRE WOLF UNIT 1 0474JH	P-DP	436.62	135.35	257.66	78.25	0.0000000	0.0000000	0.0034180	0.0034180	75.89	1.34	0
DIRE WOLF UNIT 2 0406BH	P-DP	874.20	4,931.30	466.04	1,434.26	0.0000000	0.0000000	0.0013020	0.0013020	75.89	1.34	0
DIRE WOLF UNIT 2 0407BH	P-DP	909.80	4,567.29	491.46	1,411.28	0.0000000	0.0000000	0.0013020	0.0013020	75.89	1.34	0
DIRE WOLF UNIT 2 0415AH	P-DP	621.21	2,999.35	384.37	936.00	0.0000000	0.0000000	0.0013020	0.0013020	75.89	1.34	0
DIRE WOLF UNIT 2 0416AH	P-DP	570.77	690.65	302.11	468.05	0.0000000	0.0000000	0.0013020	0.0013020	75.89	1.34	0
DIRE WOLF UNIT 2 0417AH	P-DP	524.90	2,263.09	296.13	665.21	0.0000000	0.0000000	0.0013020	0.0013020	75.89	1.34	0
DIRE WOLF UNIT 2 0426SH	P-DP	267.13	1,551.72	131.91	461.86	0.0000000	0.0000000	0.0013020	0.0013020	75.89	1.34	0
DIRE WOLF UNIT 2 0427SH	P-DP	258.60	4,090.34	165.16	982.46	0.0000000	0.0000000	0.0013020	0.0013020	75.89	1.34	0

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DIRE WOLF UNIT 2 0428SH	P-DP	279.93	903.21	187.99	408.73	0.0000000	0.0000000	0.0013020	0.0013020	75.89	1.34	0
DIRE WOLF UNIT 2 0435SH	P-DP	21.73	2.34	15.85	1.13	0.0000000	0.0000000	0.0013020	0.0013020	75.89	1.34	0
DIRE WOLF UNIT 2 0437SH	P-DP	82.34	352.03	58.67	106.29	0.0000000	0.0000000	0.0013020	0.0013020	75.89	1.34	0
DOBBY 43D 1HF	P-DP	257.64	917.86	153.06	367.89	0.0000000	0.0000000	0.0007570	0.0007570	76.19	1.96	0
DONALDSON 4-54 1H	P-DP	91.29	3,516.18	79.88	2,714.99	0.0000000	0.0000000	0.0002250	0.0002250	75.81	1.34	0
DONALDSON 4-54 U 34H	P-DP	155.29	3,119.05	107.42	2,104.13	0.0000000	0.0000000	0.0002250	0.0002250	75.81	1.34	0
DOYEN NE WEL JF 3H	P-DP	0.00	16,676.75	0.00	11,375.22	0.0000000	0.0000000	0.0093250	0.0093250	73.94	1.98	0
DOYEN NW WEL JF 1H	P-DP	0.00	22,593.70	0.00	14,276.51	0.0000000	0.0000000	0.0002370	0.0002370	73.94	1.98	0
DRAINAGE 34-136 1H	P-DP	161.28	359.28	157.54	338.89	0.0000000	0.0000000	0.0003760	0.0003760	75.15	0.68	0
DRAINAGE 34-136 2H	P-DP	233.83	546.93	204.53	451.52	0.0000000	0.0000000	0.0003760	0.0003760	75.15	0.68	0
DRAINAGE 34-136 3H	P-DP	554.87	544.91	498.10	517.96	0.0000000	0.0000000	0.0003760	0.0003760	75.15	0.68	0
DRAINAGE 34-136 4H	P-DP	599.04	634.63	497.92	587.28	0.0000000	0.0000000	0.0003760	0.0003760	75.15	0.68	0
DRAINAGE A3 6LA	P-DP	591.58	946.20	356.04	526.20	0.0000000	0.0000000	0.0001540	0.0001540	75.15	0.68	0
DRIVER-LANE 30A 1H	P-DP	582.40	2,279.79	329.84	741.04	0.0000000	0.0000000	0.0026680	0.0026680	76.00	1.19	0
DRIVER-LANE 30B 2H	P-DP	375.62	2,099.74	186.57	682.45	0.0000000	0.0000000	0.0026680	0.0026680	76.00	1.19	0
DRIVER-LANE 30C 3H	P-DP	534.92	2,642.01	257.36	684.77	0.0000000	0.0000000	0.0026770	0.0026770	76.00	1.19	0
DRIVER-LANE 30D 4H	P-DP	375.28	2,002.60	182.25	690.02	0.0000000	0.0000000	0.0026790	0.0026790	76.00	1.19	0
DRIVER-LANE 30E 5H	P-DP	605.86	2,827.01	323.19	817.91	0.0000000	0.0000000	0.0027090	0.0027090	76.00	1.19	0
DRIVER-LANE 30F 6H	P-DP	417.51	4,565.25	187.26	733.87	0.0000000	0.0000000	0.0026260	0.0026260	76.00	1.19	0
DUCHESNE LAND 4-10C5	P-DP	240.32	1,038.03	189.27	810.68	0.0000000	0.0000000	0.0010750	0.0010750	60.48	1.70	0
DYER 33 A	P-DP	24.96	113.02	21.74	113.02	0.0000000	0.0000000	0.0183330	0.0183330	75.89	1.34	0
DYER 3301	P-DP	88.25	139.92	77.56	138.50	0.0000000	0.0000000	0.0183330	0.0183330	75.89	1.34	0
DYER 3303	P-DP	53.89	155.97	47.88	153.85	0.0000000	0.0000000	0.0183330	0.0183330	75.89	1.34	0
DYER 33B	P-DP	13.18	103.05	12.62	102.45	0.0000000	0.0000000	0.0183330	0.0183330	75.89	1.34	0
DYER 33D	P-DP	99.87	147.41	88.36	145.89	0.0000000	0.0000000	0.0183330	0.0183330	75.89	1.34	0
DYER 33F	P-DP	23.77	84.81	21.39	83.89	0.0000000	0.0000000	0.0183330	0.0183330	75.89	1.34	0
DYER 33H	P-DP	15.65	78.65	14.29	77.81	0.0000000	0.0000000	0.0183330	0.0183330	75.89	1.34	0
EASON UNIT 1	P-DP	391.66	755.74	356.18	637.48	0.0000000	0.0000000	0.0121250	0.0121250	76.19	1.96	0
EAST ACKERLY DEAN UNIT 99	P-DP	130.28	64.07	114.94	57.16	0.0000000	0.0000000	0.0000220	0.0000220	77.02	1.02	0
EILAND 1806A-33 1H	P-DP	476.41	886.05	374.92	707.43	0.0000000	0.0000000	0.0003120	0.0003120	75.15	0.68	0
EILAND 1806B-33 1H	P-DP	697.56	835.06	518.22	634.01	0.0000000	0.0000000	0.0002850	0.0002850	75.15	0.68	0
EILAND 1806B-33 62H	P-DP	574.28	1,308.60	477.15	945.86	0.0000000	0.0000000	0.0002850	0.0002850	75.15	0.68	0
EILAND 1806C-33 1H	P-DP	504.48	1,185.12	414.41	788.43	0.0000000	0.0000000	0.0002850	0.0002850	75.15	0.68	0
EILAND 1806C-33 81H	P-DP	238.45	482.81	170.83	304.03	0.0000000	0.0000000	0.0002850	0.0002850	75.15	0.68	0
EILAND 1806C-33 82H	P-DP	889.72	737.68	579.86	453.43	0.0000000	0.0000000	0.0002850	0.0002850	75.15	0.68	0
EILAND 1806C-33 83H	P-DP	427.56	767.88	329.57	447.10	0.0000000	0.0000000	0.0002850	0.0002850	75.15	0.68	0
EILAND 6047A-34 41H	P-DP	625.76	1,263.69	466.89	765.09	0.0000000	0.0000000	0.0007590	0.0007590	75.15	0.68	0

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EL KABONG UNIT 48-17-8 301H	P-DP	440.18	389.51	330.44	297.42	0.0000000	0.0000000	0.0002630	0.0002630	75.90	0.68	0
EL KABONG UNIT 48-17-8 302H	P-DP	664.84	669.12	485.60	433.86	0.0000000	0.0000000	0.0002630	0.0002630	75.90	0.68	0
EL KABONG UNIT 48-17-8 303H	P-DP	149.00	101.62	54.47	30.80	0.0000000	0.0000000	0.0002630	0.0002630	75.90	0.68	0
EL KABONG UNIT 48-17-8 701H	P-DP	422.27	427.06	304.00	257.32	0.0000000	0.0000000	0.0002630	0.0002630	75.90	0.68	0
EL KABONG UNIT 48-17-8 702H	P-DP	569.05	1,388.77	351.71	653.79	0.0000000	0.0000000	0.0002630	0.0002630	75.90	0.68	0
EL KABONG UNIT 48-17-8 703H	P-DP	595.31	409.18	412.85	244.92	0.0000000	0.0000000	0.0002630	0.0002630	75.90	0.68	0
EL KABONG UNIT 48-17-8 704H	P-DP	525.32	556.90	376.77	399.16	0.0000000	0.0000000	0.0002630	0.0002630	75.90	0.68	0
EL KABONG UNIT 48-17-8 705H	P-DP	359.44	177.47	193.91	141.20	0.0000000	0.0000000	0.0002630	0.0002630	75.90	0.68	0
EL KABONG UNIT 48-17-8 801H	P-DP	147.42	770.38	135.84	522.11	0.0000000	0.0000000	0.0002630	0.0002630	75.90	0.68	0
EL PASO 4-29B5	P-DP	118.31	267.59	89.35	213.38	0.0000000	0.0000000	0.0011390	0.0011390	60.48	1.70	0
ELIAS 16-9 D 143	P-DP	402.11	1,181.73	64.28	61.92	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELIAS 16-9 UNIT 1 111	P-DP	4,178.27	14,183.91	904.12	844.88	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELIAS 16-9 UNIT 1 122	P-DP	422.28	1,551.43	155.55	224.18	0.0000000	0.0000000	0.0001858	0.0001858	75.89	1.34	0
ELIAS 16-9 UNIT 1 124	P-DP	421.03	1,546.79	153.45	219.75	0.0000000	0.0000000	0.0001858	0.0001858	75.89	1.34	0
ELIAS 16-9 UNIT 1 132	P-DP	318.43	1,579.48	53.75	58.41	0.0000000	0.0000000	0.0001858	0.0001858	75.89	1.34	0
ELIAS 16-9 UNIT 1 141	P-DP	325.26	2,106.62	76.23	94.39	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELIAS 16-9 UNIT 1 221	P-DP	221.97	993.58	39.77	44.33	0.0000000	0.0000000	0.0001858	0.0001858	75.89	1.34	0
ELIAS 16-9 UNIT 1 231	P-DP	432.09	1,953.58	77.12	85.98	0.0000000	0.0000000	0.0001858	0.0001858	75.89	1.34	0
ELIAS 16-9 UNIT 1 233	P-DP	4,050.21	13,920.89	859.14	832.52	0.0000000	0.0000000	0.0001858	0.0001858	75.89	1.34	0
ELIAS 16-9 UNIT 1 242	P-DP	430.40	1,945.98	76.82	85.64	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELIAS 16-9 UNIT 2 151	P-DP	317.05	2,052.19	74.32	92.03	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELIAS 16-9 UNIT 2 161	P-DP	314.50	1,558.17	53.11	57.71	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELIAS 16-9 UNIT 2 163	P-DP	322.07	2,085.00	75.49	93.48	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELIAS 16-9 UNIT 2 172	P-DP	3,186.95	12,166.39	690.34	699.06	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELKHEAD 4144 A 2H	P-DP	959.54	6,625.51	704.77	3,963.22	0.0000000	0.0000000	0.0004600	0.0004600	75.81	1.34	0
ELKHEAD 4144 A 5H	P-DP	512.02	4,337.53	340.73	2,283.12	0.0000000	0.0000000	0.0004600	0.0004600	75.81	1.34	0
ELKHEAD 4144 A 7H	P-DP	623.44	5,349.27	438.75	3,115.65	0.0000000	0.0000000	0.0004600	0.0004600	75.81	1.34	0
ELKHEAD 4144 B 1H	P-DP	789.54	3,353.75	609.55	2,326.35	0.0000000	0.0000000	0.0004600	0.0004600	75.81	1.34	0
ELKHEAD 4144 B 6H	P-DP	337.19	3,157.30	237.00	1,749.01	0.0000000	0.0000000	0.0004600	0.0004600	75.81	1.34	0
ELKHEAD 4144 B 8H	P-DP	408.66	3,390.70	308.09	2,224.38	0.0000000	0.0000000	0.0004600	0.0004600	75.81	1.34	0
ELKHEAD 4144 C 4H	P-DP	416.01	3,046.69	284.64	1,744.59	0.0000000	0.0000000	0.0004600	0.0004600	75.81	1.34	0
ELKHEAD 4144 S 3H	P-DP	458.03	2,328.72	326.73	1,574.72	0.0000000	0.0000000	0.0004600	0.0004600	75.81	1.34	0
ELUSIVE JAZZ 167-168 2HA	P-DP	644.39	1,296.99	451.46	881.49	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
ELY GAS UNIT NO. 2 1	P-DP	0.00	1,551.40	0.00	1,314.12	0.0000000	0.0000000	0.0079570	0.0079570	73.94	1.75	0
EMMA 218-219 UNIT 1H	P-DP	598.18	8,567.49	356.92	5,193.79	0.0000000	0.0000000	0.0001210	0.0001210	75.15	0.68	0
EP ENERGY 8-13-14-C5-1H	P-DP	160.94	648.97	112.72	499.14	0.0000000	0.0000000	0.0027590	0.0027590	60.48	1.70	0
EP ENERGY 8-13-14-C5-2H	P-DP	349.25	1,635.18	320.52	1,242.13	0.0000000	0.0000000	0.0027590	0.0027590	60.48	1.70	0

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GROSS ULTIMATE RESERVES, CUMULATIVE PRODUCTION AND BASIC ECONOMIC DATA

LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
EP ENERGY 8-24-23-C5-2H	P-DP	371.09	3,062.99	328.32	1,461.69	0.0000000	0.0000000	0.0002820	0.0002820	60.48	1.70	0
EP ENERGY 8-24-23-C5-3H	P-DP	158.39	1,193.42	137.96	600.07	0.0000000	0.0000000	0.0002820	0.0002820	60.48	1.70	0
EPLEY, J. C. 9	P-DP	78.54	104.00	50.24	102.99	0.0000000	0.0000000	0.0010990	0.0010990	75.89	1.34	0
EUGENE L CONDOR NT243	P-DP	0.00	266.33	0.00	266.33	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
EXTREME 210716 3A	P-DP	0.01	19,058.61	0.01	12,529.38	0.0000000	0.0000000	0.0008190	0.0008190	73.94	1.98	0
EXTREME 210716 4B	P-DP	0.02	17,822.38	0.02	12,509.79	0.0000000	0.0000000	0.0008190	0.0008190	73.94	1.98	0
FAIREY UNIT 1H	P-DP	135.28	384.25	118.52	382.45	0.0000000	0.0000000	0.0187020	0.0187020	73.55	1.70	0
FEARLESS 136-137 A 8WB	P-DP	653.82	1,218.04	333.01	634.93	0.0000000	0.0000000	0.0028670	0.0028670	75.89	1.34	0
FED W-18346 2-11	P-DP	38.20	3,275.82	32.78	2,711.78	0.0000000	0.0000000	0.0017060	0.0017060	74.04	4.41	0
FED W-18346 3-33	P-DP	41.04	1,097.70	40.30	1,069.55	0.0000000	0.0000000	0.0033970	0.0033970	74.04	4.41	0
FEDERAL W-7037 30-11	P-DP	19.89	1,537.43	19.61	1,474.88	0.0000000	0.0000000	0.0124850	0.0124850	74.04	4.41	0
FERGUSON 6	P-DP	0.00	29.51	0.00	28.12	0.0000000	0.0000000	0.0054340	0.0054340	73.94	1.41	0
FIELDS UNIT 1H	P-DP	125.67	1,073.62	109.56	946.90	0.0000000	0.0000000	0.0217250	0.0217250	74.40	1.94	0
FIELDS UNIT 2H	P-DP	84.33	919.44	73.49	837.04	0.0000000	0.0000000	0.0217250	0.0217250	74.40	1.94	0
FIELDS UNIT 3H	P-DP	93.66	717.54	88.35	681.76	0.0000000	0.0000000	0.0217250	0.0217250	74.40	1.94	0
FIELDS UNIT 4H	P-DP	91.68	834.07	84.88	688.37	0.0000000	0.0000000	0.0217250	0.0217250	74.40	1.94	0
FINLEY 1-11 WRD 1H	P-DP	331.36	1,171.13	263.18	838.41	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
FINLEY 1-11 WRD 2H	P-DP	474.75	153.50	345.04	98.68	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
FIRE EYES 47-38 1NA	P-DP	716.31	1,804.95	382.18	454.32	0.0000000	0.0000000	0.0008860	0.0008860	76.19	1.96	0
FIRE EYES 47-38 1NS	P-DP	501.33	995.49	269.38	294.97	0.0000000	0.0000000	0.0008860	0.0008860	76.19	1.96	0
FIRE EYES 47-38 3NA	P-DP	525.88	1,389.79	287.64	369.42	0.0000000	0.0000000	0.0008860	0.0008860	76.19	1.96	0
FIRE EYES 47-38 3NS	P-DP	278.94	804.82	155.50	207.73	0.0000000	0.0000000	0.0008860	0.0008860	76.19	1.96	0
FIRE EYES 47-38 4AH	P-DP	603.16	568.88	336.20	211.04	0.0000000	0.0000000	0.0008860	0.0008860	76.19	1.96	0
FIRE EYES 47-38 4NS	P-DP	269.90	757.92	151.18	384.65	0.0000000	0.0000000	0.0008860	0.0008860	76.19	1.96	0
FIRE FROG 57-32 A 1WA	P-DP	545.75	1,822.66	327.06	1,100.96	0.0000000	0.0000000	0.0005030	0.0005030	75.15	0.68	0
FIRE FROG 57-32 B 2BS	P-DP	956.27	3,303.33	557.51	1,744.62	0.0000000	0.0000000	0.0005660	0.0005660	75.15	0.68	0
FIRE FROG 57-32 C 3WA	P-DP	655.57	2,115.70	366.54	1,192.74	0.0000000	0.0000000	0.0005290	0.0005290	75.15	0.68	0
FIRE FROG 57-32 D 4BS	P-DP	884.74	3,444.56	529.02	1,815.53	0.0000000	0.0000000	0.0006020	0.0006020	75.15	0.68	0
FIRESTORM 54-1-12-13-24 AL1 H 1LS	P-DP	227.17	458.32	101.15	172.06	0.0000000	0.0000000	0.0002860	0.0002860	76.19	1.96	0
FIRESTORM 54-1-12-13-24 AL2 H 1WA	P-DP	261.43	523.47	127.14	174.68	0.0000000	0.0000000	0.0002860	0.0002860	76.19	1.96	0
FIRESTORM 54-1-12-13-24 AL3 H 2WB	P-DP	281.16	845.60	156.26	216.90	0.0000000	0.0000000	0.0002860	0.0002860	76.19	1.96	0
FIRESTORM 54-1-12-13-24 AL4 H 2WA	P-DP	268.85	658.25	157.55	229.00	0.0000000	0.0000000	0.0002860	0.0002860	76.19	1.96	0
FIRESTORM 54-1-12-13-24 AL5 H 2LS	P-DP	289.76	525.58	150.59	181.85	0.0000000	0.0000000	0.0002860	0.0002860	76.19	1.96	0
FIRESTORM 54-1-12-13-24 AL6 H 3WB	P-DP	332.28	842.40	180.12	259.86	0.0000000	0.0000000	0.0002860	0.0002860	76.19	1.96	0
FISHERMAN -A- 2	P-DP	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0052080	0.0052080	75.89	1.34	0
FISHERMAN-BRISTOW 23A 1H	P-DP	644.21	1,094.86	428.71	602.13	0.0000000	0.0000000	0.0037050	0.0037050	75.89	1.34	0
FISHERMAN-BRISTOW 23B 2H	P-DP	572.06	914.59	386.63	542.84	0.0000000	0.0000000	0.0037780	0.0037780	75.89	1.34	0

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LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
FISHERMAN-BRISTOW 23C 3H	P-DP	698.40	1,126.50	460.48	583.86	0.0000000	0.0000000	0.0037010	0.0037010	75.89	1.34	0
FISHERMAN-BRISTOW 23D 4H	P-DP	820.65	1,584.13	514.12	697.41	0.0000000	0.0000000	0.0037700	0.0037700	75.89	1.34	0
FLAMING STAR 02-11 1SA	P-DP	409.58	1,480.80	180.28	473.81	0.0000000	0.0000000	0.0024060	0.0024060	76.19	1.96	0
FLAMING STAR 02-11 1SS	P-DP	300.64	655.39	138.00	265.79	0.0000000	0.0000000	0.0024060	0.0024060	76.19	1.96	0
FLAMING STAR 02-11 2SS	P-DP	513.09	608.81	261.17	300.12	0.0000000	0.0000000	0.0024060	0.0024060	76.19	1.96	0
FLAMING STAR 02-11 3SA	P-DP	494.31	864.29	245.39	275.57	0.0000000	0.0000000	0.0024060	0.0024060	76.19	1.96	0
FLAMING STAR 02-11 4AH	P-DP	399.95	1,716.59	389.09	622.82	0.0000000	0.0000000	0.0024040	0.0024040	76.19	1.96	0
FLAMING STAR 02-11 4SH	P-DP	233.14	1,441.05	226.82	425.73	0.0000000	0.0000000	0.0024040	0.0024040	76.19	1.96	0
FLEMING 13 10H	P-DP	109.93	4,249.53	78.01	2,557.33	0.0000000	0.0000000	0.0040390	0.0040390	75.81	1.34	0
FLYING DUTCHMAN 1-13C5	P-DP	132.75	247.65	124.07	230.68	0.0000000	0.0000000	0.0003950	0.0003950	60.48	1.70	0
FORT KNOX 11-2 H 1LS	P-DP	119.75	1,026.09	83.34	366.22	0.0000000	0.0000000	0.0007920	0.0007920	76.19	1.96	0
FORT KNOX 11-2 H 1WA	P-DP	290.05	744.17	179.19	429.55	0.0000000	0.0000000	0.0007920	0.0007920	76.19	1.96	0
FORT KNOX 11-2 H 1WB	P-DP	215.79	956.36	137.64	354.67	0.0000000	0.0000000	0.0007920	0.0007920	76.19	1.96	0
FORT KNOX 11-2 H 2WA	P-DP	233.77	1,753.28	152.98	539.50	0.0000000	0.0000000	0.0007920	0.0007920	76.19	1.96	0
FORT KNOX 11-2 H 2WB	P-DP	187.54	1,975.60	127.57	508.07	0.0000000	0.0000000	0.0007920	0.0007920	76.19	1.96	0
FORT KNOX 11-2 R 2LS	P-DP	104.14	670.27	71.84	232.93	0.0000000	0.0000000	0.0007920	0.0007920	76.19	1.96	0
FORT KNOX 11-2-58EX H 3WA	P-DP	337.50	1,390.41	196.28	468.40	0.0000000	0.0000000	0.0007600	0.0007600	76.19	1.96	0
FORT KNOX 11-2-58X H 3WB	P-DP	227.97	1,059.62	158.52	458.73	0.0000000	0.0000000	0.0007570	0.0007570	76.19	1.96	0
FRED HALL UNIT 1	P-DP	101.23	707.75	91.27	693.18	0.0000000	0.0000000	0.0029610	0.0029610	76.66	1.00	0
FRED HALL UNIT 2	P-DP	51.57	144.31	41.37	88.77	0.0000000	0.0000000	0.0029610	0.0029610	76.66	1.00	0
FRED HALL UNIT 3	P-DP	73.98	200.35	58.48	114.74	0.0000000	0.0000000	0.0029610	0.0029610	76.66	1.00	0
FRYAR 18 2	P-DP	37.08	117.88	22.16	71.83	0.0000000	0.0000000	0.0123960	0.0123960	76.19	1.96	0
FRYING PAN A 22202 175-176 01H	P-DP	409.45	1,124.69	126.07	303.41	0.0000195	0.0000195	0.0000162	0.0000162	75.15	0.68	1,200
FRYING PAN B 22202 175-176 02H	P-DP	349.60	737.99	113.63	242.22	0.0000184	0.0000184	0.0000153	0.0000153	75.15	0.68	1,200
FULLER 1	P-DP	110.69	327.78	86.58	327.78	0.0000000	0.0000000	0.0077290	0.0077290	75.89	1.34	0
FUNKY BOSS B 8251H	P-DP	1,204.58	5,670.77	913.14	4,045.73	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
FUNKY BOSS C 8270H	P-DP	778.23	4,510.54	467.86	2,737.42	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
GADDIE 1-31 UNIT 1H	P-DP	594.45	1,366.71	493.31	1,083.46	0.0000000	0.0000000	0.0007690	0.0007690	75.15	0.68	0
GADDIE 1-31 UNIT 2H	P-DP	281.34	601.63	220.33	490.39	0.0000000	0.0000000	0.0007690	0.0007690	75.15	0.68	0
GADDIE 1-31 UNIT 3H	P-DP	235.03	39.36	213.52	39.30	0.0000000	0.0000000	0.0007690	0.0007690	75.15	0.68	0
GASTON 1	P-DP	0.00	74.55	0.00	70.03	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
GASTON 4	P-DP	0.00	160.42	0.00	121.83	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
GELETKA 1	P-DP	0.00	130.39	0.00	97.31	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
GENFIVE ENERGY LLC UNIT	P-DP	0.00	4,893.27	0.00	4,472.67	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
GEORGE T STAGG 5-2 UNIT 1H	P-DP	74.68	2,280.91	69.99	2,021.87	0.0000000	0.0000000	0.0034290	0.0034290	75.81	1.34	0
GEORGIA 39 1	P-DP	156.75	509.70	93.68	302.50	0.0000000	0.0000000	0.0023440	0.0023440	75.89	1.34	0
GERDES UNIT 1H	P-DP	169.35	952.78	166.85	940.70	0.0000000	0.0000000	0.0176400	0.0176400	74.40	1.94	0

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GERDES UNIT 2H	P-DP	134.36	773.03	133.07	723.78	0.0000000	0.0000000	0.0176400	0.0176400	74.40	1.94	0
GERDES UNIT 3H	P-DP	151.37	877.57	146.76	774.36	0.0000000	0.0000000	0.0176400	0.0176400	74.40	1.94	0
GERDES UNIT 4H	P-DP	164.73	1,119.96	159.93	1,054.68	0.0000000	0.0000000	0.0176400	0.0176400	74.40	1.94	0
GERDES UNIT 5H	P-DP	184.41	1,008.41	154.28	929.62	0.0000000	0.0000000	0.0176400	0.0176400	74.40	1.94	0
GERDES UNIT 6H	P-DP	208.55	1,234.65	162.43	986.93	0.0000000	0.0000000	0.0176400	0.0176400	74.40	1.94	0
GERDES-LANGHOFF 1L	P-DP	260.99	1,355.89	247.29	1,328.77	0.0000000	0.0000000	0.0140590	0.0140590	74.40	1.94	0
GERDES-RATHKAMP 1L	P-DP	360.52	1,962.91	263.72	1,448.03	0.0000000	0.0000000	0.0124530	0.0124530	74.40	1.94	0
GILLESPIE UNIT 1H	P-DP	160.58	446.69	144.43	443.01	0.0000000	0.0000000	0.0262020	0.0262020	73.55	1.70	0
GINGER 22-27 1AH	P-DP	640.97	1,347.21	454.63	617.45	0.0000000	0.0000000	0.0009890	0.0009890	76.19	1.96	0
GINGER 22-27 1MS	P-DP	316.90	188.29	230.46	82.27	0.0000000	0.0000000	0.0009890	0.0009890	76.19	1.96	0
GINGER 22-27 2AH	P-DP	562.97	2,058.01	383.72	1,028.49	0.0000000	0.0000000	0.0009890	0.0009890	76.19	1.96	0
GINGER 22-27 2SH	P-DP	584.27	1,921.89	402.87	897.45	0.0000000	0.0000000	0.0009890	0.0009890	76.19	1.96	0
GIST '4' 1	P-DP	24.94	85.95	19.55	62.14	0.0000000	0.0000000	0.0062500	0.0062500	76.00	1.19	0
GIST '4' 4	P-DP	36.79	135.87	26.72	88.01	0.0000000	0.0000000	0.0062500	0.0062500	76.00	1.19	0
GLASS -Y- 1	P-DP	140.86	197.59	92.84	179.62	0.0000000	0.0000000	0.0000860	0.0000860	75.89	1.34	0
GLASS RANCH 19 1	P-DP	152.13	540.62	124.06	369.54	0.0000000	0.0000000	0.0000000	0.0000000	75.89	1.34	0
GLASS RANCH 19 2HA	P-DP	85.56	224.21	62.06	215.54	0.0000000	0.0000000	0.0000000	0.0000000	75.89	1.34	0
GOERGEN 9-13-14-C5-3H	P-DP	337.88	2,013.43	294.55	1,498.34	0.0000000	0.0000000	0.0027590	0.0027590	60.48	1.70	0
GOERGEN 9-13-14-C5-4H	P-DP	345.51	2,236.44	315.53	1,470.85	0.0000000	0.0000000	0.0027590	0.0027590	60.48	1.70	0
GOLD LION 39-46 A 2DN	P-DP	1,398.39	1,193.06	713.30	493.92	0.0000000	0.0000000	0.0000060	0.0000060	77.02	1.02	0
GOLD LION 39-46 B 6DN	P-DP	1,053.36	1,392.12	594.78	412.11	0.0000000	0.0000000	0.0000030	0.0000030	77.02	1.02	0
GOLINSKI 4-24B5	P-DP	152.18	337.97	138.59	324.98	0.0000000	0.0000000	0.0058590	0.0058590	60.48	1.70	0
GORDON SE CRC JF 4H	P-DP	0.00	12,656.00	0.00	10,212.10	0.0000000	0.0000000	0.0752590	0.0752590	73.94	1.98	0
GORDON SE CRC JF 6H	P-DP	0.00	12,614.97	0.00	9,707.03	0.0000000	0.0000000	0.0752590	0.0752590	73.94	1.98	0
GORDON SW CRC JF 2H	P-DP	0.00	10,646.03	0.00	8,854.00	0.0000000	0.0000000	0.0871080	0.0871080	73.94	1.98	0
GRAFF 1	P-DP	0.00	139.71	0.00	128.56	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
GRANT 18A 4HK	P-DP	389.30	992.62	316.52	730.03	0.0000000	0.0000000	0.0009550	0.0009550	76.19	1.96	0
GRANT 18B 5HJ	P-DP	517.18	1,490.48	381.87	737.25	0.0000000	0.0000000	0.0009510	0.0009510	76.19	1.96	0
GRANT 18B 6HK	P-DP	543.14	1,926.30	382.29	968.64	0.0000000	0.0000000	0.0009550	0.0009550	76.19	1.96	0
GRANTHAM WEST 50-48 UNIT 1LS	P-DP	328.85	574.09	119.26	130.93	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0
GRANTHAM WEST 50-48 UNIT 1MS	P-DP	9.32	57.31	4.25	14.95	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0
GRANTHAM WEST 50-48 UNIT 1WA	P-DP	560.22	2,806.12	211.30	595.72	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0
GRANTHAM WEST 50-48 UNIT 1WB	P-DP	446.44	4,158.43	171.04	579.21	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0
GRANTHAM WEST 50-48 UNIT 2LS	P-DP	438.43	728.12	195.64	193.48	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0
GRANTHAM WEST 50-48 UNIT 2MS	P-DP	243.12	546.67	84.29	122.13	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0
GRANTHAM WEST 50-48 UNIT 2WA	P-DP	483.94	833.32	175.99	186.63	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0
GRANTHAM WEST 50-48 UNIT 3LS	P-DP	210.53	1,075.84	108.08	187.03	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0

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LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
GRANTHAM WEST 50-48 UNIT 3MS	P-DP	99.89	75.83	33.39	11.25	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0
GRANTHAM WEST 50-48 UNIT 3WA	P-DP	378.49	1,609.06	183.47	360.50	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0
GRANTHAM WEST 50-48 UNIT 3WB	P-DP	130.57	926.38	86.87	366.10	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0
GRANTHAM WEST 50-48 UNIT 4WA	P-DP	250.24	974.15	140.52	254.54	0.0000000	0.0000000	0.0023010	0.0023010	75.89	1.34	0
GREER SIKES 42-41 E 251	P-DP	196.34	2,029.06	117.68	788.27	0.0000000	0.0000000	0.0007230	0.0007230	75.14	2.00	0
GREER SIKES 42-41 F 261	P-DP	229.75	7,553.39	126.94	1,899.58	0.0000000	0.0000000	0.0007220	0.0007220	75.14	2.00	0
GREER SIKES 42-41 F 262	P-DP	403.78	2,920.65	214.12	929.06	0.0000000	0.0000000	0.0007230	0.0007230	75.14	2.00	0
GREER SIKES 42-41 G 271	P-DP	394.14	3,297.59	229.21	1,055.26	0.0000000	0.0000000	0.0007350	0.0007350	75.14	2.00	0
GREER SIKES 42-41 G 272	P-DP	147.74	2,795.74	84.91	1,033.15	0.0000000	0.0000000	0.0007350	0.0007350	75.14	2.00	0
GREER SIKES 42-41 H 281	P-DP	139.62	1,570.66	89.86	658.17	0.0000000	0.0000000	0.0007300	0.0007300	75.14	2.00	0
GRIFFIN RANCH UNIT 23-31 1AH	P-DP	790.09	653.10	492.95	155.34	0.0000000	0.0000000	0.0007300	0.0007300	76.19	1.96	0
GRIFFIN RANCH UNIT 23-31 1SH	P-DP	540.30	1,054.43	332.36	386.82	0.0000000	0.0000000	0.0007300	0.0007300	76.19	1.96	0
GRIFFIN RANCH UNIT 23-31 2AH	P-DP	442.37	1,184.08	301.87	677.91	0.0000000	0.0000000	0.0007300	0.0007300	76.19	1.96	0
GRIFFIN RANCH UNIT 23-31 2SH	P-DP	456.46	2,321.44	309.84	1,393.41	0.0000000	0.0000000	0.0007300	0.0007300	76.19	1.96	0
GRIFFIN RANCH UNIT 23-31 3AH	P-DP	571.61	1,043.55	367.74	428.74	0.0000000	0.0000000	0.0007300	0.0007300	76.19	1.96	0
GRIFFIN RANCH UNIT 23-31 3SH	P-DP	261.97	2,463.12	194.04	898.17	0.0000000	0.0000000	0.0007300	0.0007300	76.19	1.96	0
GRISWOLD S WYN JF 4H	P-DP	0.00	13,968.14	0.00	12,079.00	0.0000000	0.0000000	0.0365370	0.0365370	73.94	1.98	0
GRISWOLD SW WYN JF 2H	P-DP	0.00	14,655.68	0.00	12,508.70	0.0000000	0.0000000	0.0092240	0.0092240	73.94	1.98	0
GRISWOLD WYN JF 6H	P-DP	0.00	10,138.54	0.00	8,454.66	0.0000000	0.0000000	0.0740680	0.0740680	73.94	1.98	0
GRISWOLD WYN JF 8H	P-DP	0.00	10,281.68	0.00	8,690.13	0.0000000	0.0000000	0.0740680	0.0740680	73.94	1.98	0
GRIZZLY BEAR 7780 2U A 2H	P-DP	343.46	1,327.21	302.32	1,071.93	0.0000000	0.0000000	0.0006490	0.0006490	75.81	1.34	0
GRIZZLY BEAR 7780 3U A 3H	P-DP	226.29	1,590.65	196.68	1,182.88	0.0000000	0.0000000	0.0006490	0.0006490	75.81	1.34	0
GRIZZLY BEAR 7780 4U A 4H	P-DP	391.77	2,433.29	303.04	1,240.10	0.0000000	0.0000000	0.0006540	0.0006540	75.81	1.34	0
GRIZZLY BEAR 7780 5U A 5H	P-DP	223.36	1,314.59	189.01	993.12	0.0000000	0.0000000	0.0006460	0.0006460	75.81	1.34	0
GRIZZLY BEAR 7780 6U A 6H	P-DP	500.83	2,181.12	410.67	1,439.87	0.0000000	0.0000000	0.0006490	0.0006490	75.81	1.34	0
GRIZZLY SOUTH 7673 A 1H	P-DP	474.31	1,212.77	474.31	1,212.77	0.0000000	0.0000000	0.0019950	0.0019950	75.81	1.34	0
GRIZZLY SOUTH 7673 A 3H	P-DP	306.15	802.59	214.82	506.52	0.0000000	0.0000000	0.0019950	0.0019950	75.81	1.34	0
GRIZZLY SOUTH 7673 A 5H	P-DP	372.44	1,245.03	268.04	864.59	0.0000000	0.0000000	0.0019950	0.0019950	75.81	1.34	0
GRIZZLY SOUTH 7673 A 8H	P-DP	518.47	2,006.91	368.47	1,260.75	0.0000000	0.0000000	0.0019950	0.0019950	75.81	1.34	0
GRIZZLY SOUTH 7673 B 2H	P-DP	739.24	1,752.03	650.38	1,643.67	0.0000000	0.0000000	0.0019950	0.0019950	75.81	1.34	0
GRIZZLY SOUTH 7673 B 4H	P-DP	164.64	938.15	118.53	609.09	0.0000000	0.0000000	0.0019950	0.0019950	75.81	1.34	0
GRIZZLY SOUTH 7673 B 6H	P-DP	345.36	1,983.05	235.87	1,020.32	0.0000000	0.0000000	0.0019950	0.0019950	75.81	1.34	0
GRIZZLY WEST 77 1H	P-DP	387.89	1,656.61	316.31	1,048.04	0.0000000	0.0000000	0.0010080	0.0010080	75.81	1.34	0
GRIZZLY WEST 77 A 3H	P-DP	203.67	684.67	168.46	590.97	0.0000000	0.0000000	0.0010080	0.0010080	75.81	1.34	0
GRIZZLY WEST 77 C 2H	P-DP	154.29	781.89	123.69	596.00	0.0000000	0.0000000	0.0010080	0.0010080	75.81	1.34	0
GUARDIAN A 12-22 6SH	P-DP	322.66	1,297.50	179.07	347.45	0.0000000	0.0000000	0.0004380	0.0004380	76.19	1.96	0
GUARDIAN UNIT 12-21 5AH	P-DP	683.74	909.48	318.23	289.55	0.0000000	0.0000000	0.0009520	0.0009520	76.19	1.96	0

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GUARDIAN UNIT 12-21 5SH	P-DP	355.37	1,025.02	235.60	344.74	0.0000000	0.0000000	0.0009520	0.0009520	76.19	1.96	0
GUARDIAN UNIT 12-21 6AH	P-DP	481.82	872.03	280.26	329.85	0.0000000	0.0000000	0.0009520	0.0009520	76.19	1.96	0
GUARDIAN UNIT 12-22 4AH	P-DP	469.24	1,930.77	158.94	410.63	0.0000000	0.0000000	0.0009520	0.0009520	76.19	1.96	0
GUARDIAN UNIT 12-22 4SH	P-DP	316.58	1,799.31	120.14	462.40	0.0000000	0.0000000	0.0009520	0.0009520	76.19	1.96	0
GUITAR 11 1	P-DP	45.41	97.76	44.29	86.33	0.0000000	0.0000000	0.0041670	0.0041670	76.19	1.96	0
GUITAR 13 1	P-DP	64.54	162.67	62.96	154.34	0.0000000	0.0000000	0.0041110	0.0041110	76.19	1.96	0
GUNNER C 3LS	P-DP	245.54	783.25	110.18	203.57	0.0000000	0.0000000	0.0000390	0.0000390	76.19	1.96	0
GUNNER C 4A	P-DP	342.61	698.26	149.22	156.27	0.0000000	0.0000000	0.0000390	0.0000390	76.19	1.96	0
GUNNER D 5MS	P-DP	264.54	1,673.37	104.28	278.33	0.0000000	0.0000000	0.0000390	0.0000390	76.19	1.96	0
GUNNER D 6LS	P-DP	366.79	891.60	147.58	134.36	0.0000000	0.0000000	0.0000390	0.0000390	76.19	1.96	0
GUNSLINGER UNIT L 4H	P-DP	609.45	686.88	417.64	364.91	0.0000000	0.0000000	0.0002890	0.0002890	76.19	1.96	0
GUNSMOKE 1-40 A 1JM	P-DP	684.54	2,674.02	361.81	750.27	0.0000000	0.0000000	0.0016150	0.0016150	75.89	1.34	0
GUNSMOKE 1-40 B 2LS	P-DP	476.29	1,448.32	287.51	523.41	0.0000000	0.0000000	0.0016240	0.0016240	75.89	1.34	0
GUNSMOKE 1-40 C 3WA	P-DP	623.42	2,036.23	397.68	702.72	0.0000000	0.0000000	0.0016160	0.0016160	75.89	1.34	0
GUNSMOKE 1-40 D 4LB	P-DP	574.60	2,786.43	408.53	920.66	0.0000000	0.0000000	0.0016110	0.0016110	75.89	1.34	0
GUNSMOKE 40-1 F 6LS	P-DP	455.79	1,629.29	261.55	612.28	0.0000000	0.0000000	0.0016360	0.0016360	75.89	1.34	0
GUNSMOKE 40-1 G 7WA	P-DP	562.68	2,627.08	415.89	1,189.77	0.0000000	0.0000000	0.0016350	0.0016350	75.89	1.34	0
GUNSMOKE 40-1 H 8WB	P-DP	397.83	1,635.47	240.52	901.11	0.0000000	0.0000000	0.0016360	0.0016360	75.89	1.34	0
GUNSMOKE 40-1 I 9LS	P-DP	542.53	628.96	322.22	298.07	0.0000000	0.0000000	0.0016280	0.0016280	75.89	1.34	0
GUNSMOKE 40-1 J 10WA	P-DP	620.32	3,378.23	513.64	1,311.53	0.0000000	0.0000000	0.0016350	0.0016350	75.89	1.34	0
GUNSMOKE 40-1 K 11WB	P-DP	381.08	2,289.70	245.54	829.04	0.0000000	0.0000000	0.0016350	0.0016350	75.89	1.34	0
GUNSMOKE 40-1 L R009LS	P-DP	509.66	1,625.02	329.89	592.26	0.0000000	0.0000000	0.0016280	0.0016280	75.89	1.34	0
GUY COWDEN UNIT 1 2502BH	P-DP	338.87	1,771.97	91.48	267.52	0.0000000	0.0000000	0.0004800	0.0004800	76.66	1.00	0
GUY COWDEN UNIT 1 2504BH	P-DP	338.77	1,740.37	97.01	277.22	0.0000000	0.0000000	0.0004800	0.0004800	76.66	1.00	0
GUY COWDEN UNIT 1 2514AH	P-DP	438.56	1,699.50	113.19	205.67	0.0000000	0.0000000	0.0004800	0.0004800	76.66	1.00	0
GUY COWDEN UNIT 1 2571JH	P-DP	376.57	772.49	104.99	96.26	0.0000000	0.0000000	0.0004800	0.0004800	76.66	1.00	0
GUY COWDEN UNIT 1 2573JH	P-DP	180.29	218.84	51.56	44.04	0.0000000	0.0000000	0.0004800	0.0004800	76.66	1.00	0
GUY COWDEN UNIT 1 2575JH	P-DP	367.68	546.70	110.21	96.34	0.0000000	0.0000000	0.0004800	0.0004800	76.66	1.00	0
GUY COWDEN UNIT 2 2505BH	P-DP	246.16	546.54	192.82	432.09	0.0000000	0.0000000	0.0005090	0.0005090	76.66	1.00	0
GUY COWDEN UNIT 2 2506BH	P-DP	376.53	4,471.44	319.43	2,887.65	0.0000000	0.0000000	0.0005090	0.0005090	76.66	1.00	0
GUY COWDEN UNIT 2 2507BH	P-DP	129.09	1,504.15	96.24	1,265.88	0.0000000	0.0000000	0.0005090	0.0005090	76.66	1.00	0
GUY COWDEN UNIT 2 2508BH	P-DP	660.30	4,198.94	512.18	2,172.92	0.0000000	0.0000000	0.0005090	0.0005090	76.66	1.00	0
GUY COWDEN UNIT 2 2515AH	P-DP	173.89	365.99	154.10	322.31	0.0000000	0.0000000	0.0005090	0.0005090	76.66	1.00	0
GUY COWDEN UNIT 2 2516AH	P-DP	327.94	1,600.26	260.83	1,197.06	0.0000000	0.0000000	0.0005090	0.0005090	76.66	1.00	0
GUY COWDEN UNIT 2 2517AH	P-DP	219.49	2,076.22	175.82	1,631.93	0.0000000	0.0000000	0.0005090	0.0005090	76.66	1.00	0
GUY COWDEN UNIT 2 2518AH	P-DP	1,231.23	2,559.80	895.98	2,005.06	0.0000000	0.0000000	0.0005090	0.0005090	76.66	1.00	0
HA RA SU77;LEE 25-36 HC 001-ALT	P-DP	0.00	6,214.36	0.00	5,040.15	0.0000000	0.0000000	0.0092010	0.0092010	66.78	2.04	0

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HA RA SU98;ONEAL 8&17-14-16 HC 001-ALPT-DP		0.00	17,463.80	0.00	12,547.58	0.0000000	0.0000000	0.0007330	0.0007330	73.94	2.13	0
HA RA SU98;ONEAL 8&17-14-16 HC 002-ALPT-DP		0.00	15,223.14	0.00	9,036.89	0.0000000	0.0000000	0.0007320	0.0007320	73.94	2.13	0
HA RA SU98;PACE 8-14-16 H 001	P-DP	0.00	5,502.92	0.00	4,947.47	0.0000000	0.0000000	0.0014600	0.0014600	73.94	2.13	0
HA RA SUA;GOLSON 36-25 HC 001-ALT	P-DP	0.00	10,059.68	0.00	7,559.97	0.0000000	0.0000000	0.0889720	0.0889720	66.78	2.34	0
HA RA SUA;GOLSON 36-25 HC 002-ALT	P-DP	0.00	9,041.35	0.00	6,383.93	0.0000000	0.0000000	0.0891290	0.0891290	66.78	2.34	0
HA RA SUA;WIGGINS 36-25 HC 001	P-DP	0.00	11,840.77	0.00	11,256.47	0.0000000	0.0000000	0.0493230	0.0493230	66.78	2.34	0
HA RA SUB;LAWSON 31-30 HC 001-ALT	P-DP	0.00	16,786.89	0.00	15,384.57	0.0000000	0.0000000	0.0099300	0.0099300	66.78	2.34	0
HA RA SUB;LAWSON 31-30-19 HC 002-ALTP-DP		0.00	21,691.25	0.00	19,225.95	0.0000000	0.0000000	0.0073240	0.0073240	66.78	2.34	0
HA RA SUB;LAWSON 31-30-19 HC 003-ALTP-DP		0.00	23,274.88	0.00	20,417.59	0.0000000	0.0000000	0.0073300	0.0073300	66.78	2.34	0
HA RA SUL;L & L INV 18-19 HC 001-ALT	P-DP	0.00	11,393.97	0.00	10,361.63	0.0000000	0.0000000	0.0012590	0.0012590	66.78	2.34	0
HA RA SUL;L & L INV 18-19 HC 002-ALT	P-DP	0.00	12,790.08	0.00	11,071.04	0.0000000	0.0000000	0.0013870	0.0013870	66.78	2.34	0
HA RA SUL;SCHION 18-19 HC 001-ALT	P-DP	0.00	14,277.39	0.00	11,578.06	0.0000000	0.0000000	0.0078140	0.0078140	66.78	2.34	0
HA RA SUL;TALBERT 9-14-16 H 001	P-DP	0.00	5,863.77	0.00	5,314.77	0.0000000	0.0000000	0.0011080	0.0011080	73.94	2.13	0
HA RA SUS;MJR FAMLLC 21-39HC 002-ALTP-DP		0.00	8,508.16	0.00	3,687.49	0.0000000	0.0000000	0.1177170	0.1177170	66.78	2.34	0
HA RA SUS;MJR FAMLLC21-28-33HC 001-APL-TDP		0.00	18,949.45	0.00	12,984.52	0.0000000	0.0000000	0.1163690	0.1163690	66.78	2.34	0
HA RA SUS;MJR FAMLLC21-28-33HC 002-APL-TDP		0.00	35,251.96	0.00	23,549.07	0.0000000	0.0000000	0.1078020	0.1078020	66.78	2.34	0
HA RA SUS;POOLE-DRAKE 21 H 001	P-DP	0.00	10,410.91	0.00	8,694.20	0.0000000	0.0000000	0.1177170	0.1177170	66.78	2.34	0
HA RA SUSS;JORDAN 16-21 HC 001-ALT	P-DP	0.00	9,742.11	0.00	9,639.99	0.0000000	0.0000000	0.0004530	0.0004530	73.94	2.15	0
HA RA SUTT;BSMC LA 21 HZ 001	P-DP	0.00	4,712.77	0.00	4,136.93	0.0000000	0.0000000	0.0006880	0.0006880	73.94	2.15	0
HA RA SUZ;GLOVER 20 001	P-DP	0.00	9,128.78	0.00	9,128.78	0.0000000	0.0000000	0.0078080	0.0078080	66.78	2.34	0
HA RA SUZ;GLOVER 20 002-ALT	P-DP	0.00	10,857.87	0.00	9,617.88	0.0000000	0.0000000	0.0078080	0.0078080	66.78	2.34	0
HA RA SUZ;GLOVER 20 003-ALT	P-DP	0.00	11,150.11	0.00	9,996.55	0.0000000	0.0000000	0.0078080	0.0078080	66.78	2.34	0
HA RA SUZ;JUNCACEAE 20 001-ALT	P-DP	0.00	7,719.26	0.00	7,719.26	0.0000000	0.0000000	0.0078080	0.0078080	66.78	2.34	0
HA RA SUZ;JUNCACEAE 20 002-ALT	P-DP	0.00	8,995.07	0.00	8,762.75	0.0000000	0.0000000	0.0078080	0.0078080	66.78	2.34	0
HA RA SUZ;JUNCACEAE 20 003-ALT	P-DP	0.00	9,755.65	0.00	9,613.60	0.0000000	0.0000000	0.0078080	0.0078080	66.78	2.34	0
HA RB SU69;NAC ROYALTY 33 H 001	P-DP	0.00	6,723.80	0.00	6,059.70	0.0000000	0.0000000	0.0792480	0.0792480	66.78	2.34	0
HA RB SU77;NAC ROYALTY 27-41HC 002-APL-TDP		0.00	9,068.90	0.00	4,766.72	0.0000000	0.0000000	0.0412010	0.0412010	66.78	2.34	0
HA RB SU77;WAHL 27 H 001	P-DP	0.00	21,168.44	0.00	14,833.47	0.0000000	0.0000000	0.0412010	0.0412010	66.78	2.34	0
HA RB SU90;BYU PIERRE29-12-10H 001-ALPT-DP		0.00	10,379.53	0.00	9,586.37	0.0000000	0.0000000	0.0375770	0.0375770	66.78	2.34	0
HA RB SU90;BYU PIERRE29-12-10H 002-ALPT-DP		0.00	6,895.07	0.00	5,935.71	0.0000000	0.0000000	0.0375770	0.0375770	66.78	2.34	0
HA RB SU90;NRG 29-12-10 H 001	P-DP	0.00	9,762.69	0.00	9,022.46	0.0000000	0.0000000	0.0375770	0.0375770	66.78	2.34	0
HA RB SU90;NRG 29-12-10 H 003-ALT	P-DP	0.00	8,534.69	0.00	7,663.19	0.0000000	0.0000000	0.0375770	0.0375770	66.78	2.34	0
HA RB SU90;NRG 29-12-10 H 004-ALT	P-DP	0.00	8,807.52	0.00	7,819.66	0.0000000	0.0000000	0.0375770	0.0375770	66.78	2.34	0
HA RB SU92;NAC ROYALTY 34 H 001	P-DP	0.00	1,637.54	0.00	1,637.54	0.0000000	0.0000000	0.1572810	0.1572810	66.78	2.34	0
HA RB SU92;NAC ROYALTY 34 H 002-ALT	P-DP	0.00	13,905.50	0.00	7,112.78	0.0000000	0.0000000	0.1572810	0.1572810	66.78	2.34	0
HA RB SU92;NAC ROYALTY 34 H 003-ALT	P-DP	0.00	16,249.11	0.00	8,718.77	0.0000000	0.0000000	0.1572810	0.1572810	66.78	2.34	0
HA RB SUZZ;BIER 15&10-11-10 HC 001-ALTP-DP		0.00	20,509.38	0.00	17,336.73	0.0000000	0.0000000	0.0007500	0.0007500	73.94	2.15	0

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LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
HALL 18 1	P-DP	40.90	167.90	31.62	167.77	0.0000000	0.0000000	0.0011910	0.0011910	76.19	1.96	0
HALL 18 2	P-DP	17.49	31.65	16.74	31.63	0.0000000	0.0000000	0.0011910	0.0011910	76.19	1.96	0
HALL 18 3	P-DP	11.29	39.78	11.25	39.77	0.0000000	0.0000000	0.0011910	0.0011910	76.19	1.96	0
HALL 18 4	P-DP	5.09	6.41	5.09	6.41	0.0000000	0.0000000	0.0011910	0.0011910	76.19	1.96	0
HALL TRUST 38 1	P-DP	189.15	414.84	155.45	293.06	0.0000000	0.0000000	0.0039060	0.0039060	75.89	1.34	0
HALL TRUST 38 2	P-DP	125.54	336.58	114.16	267.43	0.0000000	0.0000000	0.0039060	0.0039060	75.89	1.34	0
HALL-PORTER 621-596 UNIT 1 112	P-DP	65.52	204.46	51.23	120.94	0.0000000	0.0000000	0.0014740	0.0014740	76.66	1.00	0
HALL-PORTER 621-596 UNIT 1 122	P-DP	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0014740	0.0014740	76.66	1.00	0
HALL-PORTER 621-596 UNIT 1 132	P-DP	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0014740	0.0014740	76.66	1.00	0
HALL-PORTER 621-596 UNIT 1 142	P-DP	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0014740	0.0014740	76.66	1.00	0
HALL-PORTER 621-596 UNIT 1 211	P-DP	111.82	393.47	79.38	214.59	0.0000000	0.0000000	0.0014740	0.0014740	76.66	1.00	0
HALL-PORTER 621-596 UNIT 1 221	P-DP	108.79	341.51	78.89	201.93	0.0000000	0.0000000	0.0014740	0.0014740	76.66	1.00	0
HALL-PORTER 621-596 UNIT 1 224	P-DP	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0014740	0.0014740	76.66	1.00	0
HALL-PORTER 621-596 UNIT 1 231R	P-DP	110.94	392.85	87.74	228.74	0.0000000	0.0000000	0.0014740	0.0014740	76.66	1.00	0
HALL-PORTER 621-596 UNIT 1 233	P-DP	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0014740	0.0014740	76.66	1.00	0
HALL-PORTER 621-596 UNIT 1 241	P-DP	116.76	379.96	85.26	224.85	0.0000000	0.0000000	0.0014740	0.0014740	76.66	1.00	0
HARA SUS;MJR FAMLLC 21-39HC 001-ALT	P-DP	0.00	6,937.68	0.00	3,087.88	0.0000000	0.0000000	0.1177170	0.1177170	66.78	2.34	0
HARGROVE, BETTY 1	P-DP	0.00	1,797.58	0.00	1,797.58	0.0000000	0.0000000	0.0159710	0.0159710	75.81	1.34	0
HARPER-BAYES 16 1	P-DP	146.03	198.82	94.71	161.62	0.0000000	0.0000000	0.0003720	0.0003720	75.89	1.34	0
HAWKS 55-1-28 UNIT 1H	P-DP	819.29	2,979.48	565.10	2,003.34	0.0000000	0.0000000	0.0000620	0.0000620	76.15	-0.83	0
HEMLOCK 0409-03H	P-DP	72.20	3,000.55	35.86	1,053.32	0.0000000	0.0000000	0.0001560	0.0001560	74.04	4.41	0
HEMLOCK 0409-04H	P-DP	128.25	4,392.43	50.67	1,294.85	0.0000000	0.0000000	0.0001560	0.0001560	74.04	4.41	0
HEMLOCK 0409-14H	P-DP	145.96	3,361.18	59.31	1,211.35	0.0000000	0.0000000	0.0001560	0.0001560	74.04	4.41	0
HEMLOCK 0409-15H	P-DP	143.82	3,446.69	62.64	1,378.56	0.0000000	0.0000000	0.0001560	0.0001560	74.04	4.41	0
HEMLOCK 0409-16H	P-DP	320.21	5,760.16	101.19	1,605.35	0.0000000	0.0000000	0.0001560	0.0001560	74.04	4.41	0
HENDERSHOT 210471 1A	P-DP	0.00	17,479.95	0.00	12,595.21	0.0000000	0.0000000	0.0003040	0.0003040	67.06	2.04	0
HENDERSHOT 210471 2B	P-DP	0.00	18,469.14	0.00	12,480.61	0.0000000	0.0000000	0.0003040	0.0003040	67.06	2.04	0
HENDERSHOT 210501 6A-M	P-DP	235.76	6,233.80	148.55	1,476.87	0.0000000	0.0000000	0.0231180	0.0231180	67.06	2.04	0
HENDERSHOT 211824 5A-M	P-DP	394.70	3,484.56	167.60	1,655.27	0.0000000	0.0000000	0.0177660	0.0177660	67.06	2.04	0
HEREFORD 29 20 W1NC STATE COM 001H	P-DP	586.72	456.68	342.59	241.04	0.0000000	0.0000000	0.0049500	0.0049500	76.17	1.13	0
HIGGINBOTHAM UNIT A 30-18 2AH	P-DP	524.07	2,093.46	387.37	1,190.81	0.0000000	0.0000000	0.0011510	0.0011510	73.67	3.34	0
HIGGINBOTHAM UNIT A 30-18 3AH	P-DP	331.84	165.15	238.72	67.64	0.0000000	0.0000000	0.0011510	0.0011510	73.67	3.34	0
HIGGINBOTHAM UNIT A 30-18 4AH	P-DP	426.64	234.19	347.89	139.93	0.0000000	0.0000000	0.0011510	0.0011510	73.67	3.34	0
HIGGINBOTHAM UNIT B 30-19 1H	P-DP	536.87	241.92	379.53	136.70	0.0000000	0.0000000	0.0013530	0.0013530	73.67	3.34	0
HIGGINBOTHAM UNIT B 30-19 7AH	P-DP	221.14	1,182.77	169.30	578.16	0.0000000	0.0000000	0.0013530	0.0013530	73.67	3.34	0
HIGGINBOTHAM UNIT C 30-18 5AH	P-DP	304.53	895.50	216.15	346.49	0.0000000	0.0000000	0.0011500	0.0011500	73.67	3.34	0
HIGGINBOTHAM UNIT C 30-18 6AH	P-DP	314.51	771.25	211.11	326.29	0.0000000	0.0000000	0.0011500	0.0011500	73.67	3.34	0

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HOCHSTETLER 7-11-5 5H	P-DP	58.51	14,193.29	57.69	9,038.38	0.0000000	0.0000000	0.0147060	0.0147060	69.42	2.07	0
HOERMANN UNIT 1H	P-DP	151.10	684.91	150.50	683.10	0.0000000	0.0000000	0.0100960	0.0100960	74.40	1.94	0
HOERMANN UNIT 2H	P-DP	194.30	1,013.95	180.66	950.88	0.0000000	0.0000000	0.0100960	0.0100960	74.40	1.94	0
HOERMANN UNIT 3H	P-DP	363.02	2,012.86	272.97	1,645.62	0.0000000	0.0000000	0.0100960	0.0100960	74.40	1.94	0
HOERMANN UNIT 4H	P-DP	314.16	1,429.86	241.39	1,231.95	0.0000000	0.0000000	0.0100960	0.0100960	74.40	1.94	0
HOERMANN-KOLM 1H	P-DP	505.88	1,307.63	281.30	640.07	0.0000000	0.0000000	0.0017240	0.0017240	74.40	1.94	0
HOERMANN-KOLM 201H	P-DP	214.98	725.95	110.97	338.02	0.0000000	0.0000000	0.0029040	0.0029040	74.40	1.94	0
HOERMANN-KOLM A 2H	P-DP	274.39	1,447.58	75.39	301.21	0.0000000	0.0000000	0.0100960	0.0100960	74.40	1.94	0
HOERMANN-KOLM B 3H	P-DP	455.64	2,405.38	124.81	498.63	0.0000000	0.0000000	0.0100960	0.0100960	74.40	1.94	0
HOERMANN-LANGHOFF B 1H	P-DP	348.31	2,058.73	182.91	954.87	0.0000000	0.0000000	0.0038970	0.0038970	74.40	1.94	0
HOERMANN-LANGHOFF B 201H	P-DP	338.44	2,709.83	151.27	907.54	0.0000000	0.0000000	0.0053340	0.0053340	74.40	1.94	0
HOERMANN-LANGHOFF B A 2H	P-DP	138.15	941.26	74.20	376.83	0.0000000	0.0000000	0.0040910	0.0040910	74.40	1.94	0
HOFFERKAMP 1	P-DP	119.08	287.84	98.66	265.13	0.0000000	0.0000000	0.0002580	0.0002580	76.66	1.00	0
HONEY BEE A 20-29 4201H	P-DP	192.37	510.92	75.53	181.74	0.0000000	0.0000000	0.0003850	0.0003850	75.14	2.00	0
HONEY BEE C 20-29 4303H	P-DP	303.53	4,099.54	113.84	486.36	0.0000000	0.0000000	0.0003880	0.0003880	75.14	2.00	0
HONEY BEE E 20-29 4205H	P-DP	203.48	1,074.75	87.65	217.71	0.0000000	0.0000000	0.0003870	0.0003870	75.14	2.00	0
HONEY BEE E 20-29 4405H	P-DP	232.69	4,389.25	92.25	465.58	0.0000000	0.0000000	0.0003850	0.0003850	75.14	2.00	0
HONEY BEE G 20-29 4307H	P-DP	324.29	2,852.36	122.41	446.28	0.0000000	0.0000000	0.0003890	0.0003890	75.14	2.00	0
HONOR 41-2728-23R	P-DP	229.12	316.70	164.90	168.84	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
HONOR 51-2728-23O	P-DP	640.24	534.77	302.59	252.95	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
HONOR 71-2728-23G	P-DP	495.61	382.00	209.73	143.92	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
HORNSILVER 1H	P-DP	477.63	6,019.76	313.08	3,805.87	0.0000000	0.0000000	0.0001200	0.0001200	75.15	0.68	0
HOUSE 47 1	P-DP	169.15	271.26	146.74	244.45	0.0000000	0.0000000	0.0156250	0.0156250	76.66	1.00	0
HUBBARD 18-B 2	P-DP	54.94	166.91	35.83	166.91	0.0000000	0.0000000	0.0023150	0.0023150	76.00	1.19	0
HULING 'A' 18-7 ESL (ALLOC) 1HA	P-DP	261.39	1,032.33	194.87	764.69	0.0000000	0.0000000	0.0004420	0.0004420	76.00	1.19	0
HULING 'D' 18-7 ESL (ALLOC) 4HS	P-DP	130.65	376.59	112.31	299.90	0.0000000	0.0000000	0.0004430	0.0004430	76.00	1.19	0
HULING 7-19 B 221	P-DP	274.07	1,070.31	129.57	240.72	0.0000000	0.0000000	0.0010840	0.0010840	76.00	1.19	0
HULING 7-19 D 241	P-DP	251.90	440.44	131.25	151.57	0.0000000	0.0000000	0.0009620	0.0009620	76.00	1.19	0
HUTCHINS CHIODO 13-21-22-C5-2H	P-DP	209.28	2,118.54	180.19	1,300.49	0.0000000	0.0000000	0.0013200	0.0013200	60.48	1.70	0
HUTCHINS-CHIODO 12-21-22-C5-3H	P-DP	202.36	1,596.62	164.78	1,233.02	0.0000000	0.0000000	0.0013200	0.0013200	60.48	1.70	0
HYDEN UNIT 47-35 1H	P-DP	448.26	951.91	377.07	423.69	0.0000000	0.0000000	0.0011670	0.0011670	76.19	1.96	0
HYDEN UNIT 47-35 1SH	P-DP	182.55	205.95	102.40	109.58	0.0000000	0.0000000	0.0010040	0.0010040	76.19	1.96	0
HYDEN UNIT 47-35 2AH	P-DP	425.88	760.20	256.71	371.78	0.0000000	0.0000000	0.0010040	0.0010040	76.19	1.96	0
HYDEN UNIT 47-35 2SH	P-DP	397.58	360.19	225.48	171.30	0.0000000	0.0000000	0.0010040	0.0010040	76.19	1.96	0
HYDEN UNIT 47-35 3AH	P-DP	613.36	516.15	373.81	225.99	0.0000000	0.0000000	0.0010040	0.0010040	76.19	1.96	0
HYDRA 45-4 UNIT 1 112	P-DP	350.17	1,600.90	232.42	599.29	0.0000000	0.0000000	0.0007590	0.0007590	75.89	1.34	0
HYDRA 45-4 UNIT 1 122	P-DP	291.85	1,381.67	190.33	499.41	0.0000000	0.0000000	0.0007590	0.0007590	75.89	1.34	0

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HYDRA 45-4 UNIT 1 124	P-DP	475.28	2,215.41	308.39	769.35	0.0000000	0.0000000	0.0007590	0.0007590	75.89	1.34	0
HYDRA 45-4 UNIT 1 132	P-DP	527.34	2,932.34	349.12	959.18	0.0000000	0.0000000	0.0007590	0.0007590	75.89	1.34	0
HYDRA 45-4 UNIT 1 142	P-DP	310.46	1,407.87	201.06	566.32	0.0000000	0.0000000	0.0007590	0.0007590	75.89	1.34	0
HYDRA 45-4 UNIT 1 211	P-DP	401.11	1,900.77	262.47	683.49	0.0000000	0.0000000	0.0007590	0.0007590	75.89	1.34	0
HYDRA 45-4 UNIT 1 221	P-DP	733.16	780.46	472.85	268.33	0.0000000	0.0000000	0.0007590	0.0007590	75.89	1.34	0
HYDRA 45-4 UNIT 1 223	P-DP	455.80	2,374.56	296.73	764.16	0.0000000	0.0000000	0.0007590	0.0007590	75.89	1.34	0
HYDRA 45-4 UNIT 1 231	P-DP	317.10	1,313.32	208.05	474.84	0.0000000	0.0000000	0.0007590	0.0007590	75.89	1.34	0
HYDRA 45-4 UNIT 1 241	P-DP	575.97	2,667.99	374.79	962.28	0.0000000	0.0000000	0.0007590	0.0007590	75.89	1.34	0
HYDRA 45-4 UNIT 2 151	P-DP	373.69	1,765.14	211.73	963.72	0.0000000	0.0000000	0.0007570	0.0007570	75.89	1.34	0
HYDRA 45-4 UNIT 2 161	P-DP	233.17	1,481.50	133.10	300.88	0.0000000	0.0000000	0.0007570	0.0007570	75.89	1.34	0
HYDRA 45-4 UNIT 2 164	P-DP	465.36	1,810.90	263.28	514.17	0.0000000	0.0000000	0.0007570	0.0007570	75.89	1.34	0
HYDRA 45-4 UNIT 2 171	P-DP	191.75	1,086.70	110.45	243.90	0.0000000	0.0000000	0.0007570	0.0007570	75.89	1.34	0
HYDRA 45-4 UNIT 2 173	P-DP	546.55	1,457.33	313.03	403.54	0.0000000	0.0000000	0.0007570	0.0007570	75.89	1.34	0
HYDRA 45-4 UNIT 2 181	P-DP	205.76	1,491.85	117.63	292.53	0.0000000	0.0000000	0.0007570	0.0007570	75.89	1.34	0
HYDRA 45-4 UNIT 2 262	P-DP	522.03	1,723.49	263.87	498.13	0.0000000	0.0000000	0.0007570	0.0007570	75.89	1.34	0
HYDRA 45-4 UNIT 2 263	P-DP	103.15	1,757.87	59.20	465.90	0.0000000	0.0000000	0.0007570	0.0007570	75.89	1.34	0
HYDRA 45-4 UNIT 2 272	P-DP	417.51	1,718.35	237.56	446.89	0.0000000	0.0000000	0.0007570	0.0007570	75.89	1.34	0
HYDRA 45-4 UNIT 2 274	P-DP	127.59	2,147.02	73.28	508.68	0.0000000	0.0000000	0.0007570	0.0007570	75.89	1.34	0
HYDRA 45-4 UNIT 2 282	P-DP	454.96	1,597.07	255.94	499.01	0.0000000	0.0000000	0.0007570	0.0007570	75.89	1.34	0
IORG 4-12B3	P-DP	368.70	666.42	292.30	528.59	0.0000000	0.0000000	0.0026040	0.0026040	60.48	1.70	0
JACKSON A 34-166-175 5201H	P-DP	477.75	928.41	353.83	754.44	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
JANAK UNIT 3H	P-DP	102.27	897.50	91.15	860.75	0.0000000	0.0000000	0.0251620	0.0251620	74.40	1.94	0
JANAK UNIT 4H	P-DP	145.07	1,227.03	128.34	1,114.74	0.0000000	0.0000000	0.0251620	0.0251620	74.40	1.94	0
JANAK UNIT 5H	P-DP	121.06	1,117.80	108.11	1,000.41	0.0000000	0.0000000	0.0251620	0.0251620	74.40	1.94	0
JANAK UNIT 7L	P-DP	68.67	572.38	56.54	478.67	0.0000000	0.0000000	0.0251620	0.0251620	74.40	1.94	0
JANAK-LOOS 6L	P-DP	121.38	1,049.44	96.97	860.07	0.0000000	0.0000000	0.0180520	0.0180520	74.40	1.94	0
JENKINS 2-12B3	P-DP	659.65	1,546.54	627.22	1,536.12	0.0000000	0.0000000	0.0026040	0.0026040	60.48	1.70	0
JERSEY 35-23-A 4401H	P-DP	319.23	838.79	191.51	463.76	0.0000000	0.0000000	0.0004296	0.0004296	76.00	1.19	0
JERSEY 35-23-B 4203H	P-DP	595.67	1,206.24	372.74	616.50	0.0000000	0.0000000	0.0001135	0.0001135	76.00	1.19	0
JERSEY 35-23-C 4305H	P-DP	567.14	1,954.25	415.46	980.29	0.0000000	0.0000000	0.0001137	0.0001137	76.00	1.19	0
JERSEY 35-23-H 4215H	P-DP	575.04	978.63	455.39	644.26	0.0000000	0.0000000	0.0001188	0.0001188	76.00	1.19	0
JERSEY 35-23-H 4315H	P-DP	529.02	1,053.75	385.98	704.38	0.0000000	0.0000000	0.0000856	0.0000856	76.00	1.19	0
JH SELMAN ALLOCATION A 26-35 1HA	P-DP	234.08	253.37	113.77	84.48	0.0000000	0.0000000	0.0002043	0.0002043	73.67	3.34	0
JH SELMAN ALLOCATION B 26-35 5LS	P-DP	239.38	387.46	84.50	106.69	0.0000000	0.0000000	0.0002042	0.0002042	73.67	3.34	0
JMW NAIL 10 1	P-DP	66.28	157.34	64.17	134.46	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
JMW NAIL 10 2	P-DP	39.29	149.44	35.77	120.50	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
JMW NAIL 10A 3	P-DP	43.18	160.95	38.06	119.64	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0

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LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
JMW NAIL 10A 4	P-DP	58.91	161.43	46.52	118.24	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
JOHN F FERGUSON 1	P-DP	0.00	219.26	0.00	217.94	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
JOHN F FERGUSON 2	P-DP	0.00	293.12	0.00	289.79	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
JOHN F. FERGUSON 4	P-DP	0.00	315.86	0.00	314.16	0.0000000	0.0000000	0.0054340	0.0054340	73.94	1.41	0
JOTUNN UNIT A 25-24 3AH	P-DP	283.40	1,346.53	208.91	461.42	0.0000000	0.0000000	0.0015620	0.0015620	73.67	3.34	0
JOTUNN UNIT A 25-24 4AH	P-DP	437.55	940.65	326.00	329.66	0.0000000	0.0000000	0.0015620	0.0015620	73.67	3.34	0
JOTUNN UNIT A 25-24 5AH	P-DP	322.49	1,249.73	260.42	540.75	0.0000000	0.0000000	0.0015620	0.0015620	73.67	3.34	0
JOTUNN UNIT B 25-13 6AH	P-DP	512.31	1,181.76	351.38	427.53	0.0000000	0.0000000	0.0012790	0.0012790	73.67	3.34	0
JOTUNN UNIT B 25-13 7AH	P-DP	386.20	1,383.04	268.67	504.18	0.0000000	0.0000000	0.0012790	0.0012790	73.67	3.34	0
JOYCE 1	P-DP	0.00	335.17	0.00	328.80	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
JUDY '16' 1	P-DP	73.43	174.57	57.02	174.57	0.0000000	0.0000000	0.0003350	0.0003350	75.89	1.34	0
JUR RA SUG;OLYMPIA MIN 30 H 001	P-DP	0.00	7,387.88	0.00	7,243.32	0.0000000	0.0000000	0.0026730	0.0026730	66.78	2.04	0
KAISER UNIT 1H	P-DP	95.60	1,018.91	89.43	951.93	0.0000000	0.0000000	0.0189370	0.0189370	74.40	1.94	0
KAISER UNIT 4H	P-DP	112.77	1,174.88	100.77	989.15	0.0000000	0.0000000	0.0189370	0.0189370	74.40	1.94	0
KAISER UNIT 5H	P-DP	129.34	1,265.09	109.74	1,189.53	0.0000000	0.0000000	0.0189370	0.0189370	74.40	1.94	0
KEELINE 2-13	P-DP	143.00	1,299.23	127.21	1,201.89	0.0000000	0.0000000	0.0139480	0.0139480	74.04	4.41	0
KEMPER 16 1	P-DP	62.22	118.29	49.58	117.69	0.0000000	0.0000000	0.0003350	0.0003350	75.89	1.34	0
KEMPER 16 2	P-DP	38.53	114.55	34.79	114.04	0.0000000	0.0000000	0.0003350	0.0003350	75.89	1.34	0
KEMPER 16A 1	P-DP	33.01	438.77	32.42	424.37	0.0000000	0.0000000	0.0003350	0.0003350	75.89	1.34	0
KEMPER 16A 3	P-DP	44.55	546.47	38.59	449.91	0.0000000	0.0000000	0.0003350	0.0003350	75.89	1.34	0
KENOSHA 4441 1H	P-DP	822.45	6,621.95	660.34	4,930.95	0.0000000	0.0000000	0.0004250	0.0004250	75.81	1.34	0
KENOSHA 4441 B 2H	P-DP	629.47	4,826.64	463.42	2,705.27	0.0000000	0.0000000	0.0004250	0.0004250	75.81	1.34	0
KENOSHA-KEYHOLE 4341 1U A 1H	P-DP	644.75	4,347.51	337.80	2,072.68	0.0000000	0.0000000	0.0004210	0.0004210	75.81	1.34	0
KENOSHA-KEYHOLE 4341 2U B 2H	P-DP	458.34	4,750.67	295.99	2,578.36	0.0000000	0.0000000	0.0004210	0.0004210	75.81	1.34	0
KENTEX-HARRISON 35A 1H	P-DP	759.68	1,101.59	489.31	508.94	0.0000000	0.0000000	0.0041020	0.0041020	75.89	1.34	0
KENTEX-HARRISON 35B 2H	P-DP	589.75	1,420.16	354.15	651.58	0.0000000	0.0000000	0.0041890	0.0041890	75.89	1.34	0
KENTEX-HARRISON 35C 3H	P-DP	713.67	1,126.04	443.69	543.03	0.0000000	0.0000000	0.0040990	0.0040990	75.89	1.34	0
KENTEX-HARRISON 35D 4H	P-DP	401.54	1,185.41	269.20	580.25	0.0000000	0.0000000	0.0041870	0.0041870	75.89	1.34	0
KEYHOLE 43 1H	P-DP	656.52	1,654.89	487.30	1,501.35	0.0000000	0.0000000	0.0004030	0.0004030	75.81	1.34	0
KILLER BEE I 8-44 4209H	P-DP	407.43	2,107.99	125.33	238.17	0.0000000	0.0000000	0.0005050	0.0005050	75.14	2.00	0
KILLER BEE J 8-44 4310H	P-DP	426.17	1,658.51	134.76	325.25	0.0000000	0.0000000	0.0005050	0.0005050	75.14	2.00	0
KILLER BEE K 8-44 4411HR	P-DP	379.87	2,809.30	111.59	305.06	0.0000000	0.0000000	0.0004580	0.0004580	75.14	2.00	0
KILLER BEE M 8-44 4213H	P-DP	366.93	2,102.27	117.10	257.59	0.0000000	0.0000000	0.0005080	0.0005080	75.14	2.00	0
KILLER BEE N 8-44 4314H	P-DP	454.98	3,476.73	130.43	417.32	0.0000000	0.0000000	0.0004580	0.0004580	75.14	2.00	0
KINGSLEY 10HK	P-DP	555.29	1,393.50	352.73	569.79	0.0000000	0.0000000	0.0010710	0.0010710	76.19	1.96	0
KINGSLEY 1HJ	P-DP	411.44	1,178.82	263.22	488.05	0.0000000	0.0000000	0.0014350	0.0014350	76.19	1.96	0
KINGSLEY 2HF	P-DP	473.48	1,122.71	289.12	504.89	0.0000000	0.0000000	0.0014270	0.0014270	76.19	1.96	0

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KINGSLEY 3HK	P-DP	383.52	1,374.10	266.41	523.58	0.0000000	0.0000000	0.0014260	0.0014260	76.19	1.96	0
KINGSLEY 4HJ	P-DP	493.76	1,433.03	319.17	613.31	0.0000000	0.0000000	0.0038610	0.0038610	76.19	1.96	0
KINGSLEY 5HK	P-DP	443.06	1,486.82	277.04	538.92	0.0000000	0.0000000	0.0038420	0.0038420	76.19	1.96	0
KINGSLEY 6HF	P-DP	379.69	1,754.94	233.37	580.29	0.0000000	0.0000000	0.0038580	0.0038580	76.19	1.96	0
KINGSLEY 7HJ	P-DP	515.21	1,385.92	324.14	584.81	0.0000000	0.0000000	0.0010880	0.0010880	76.19	1.96	0
KINGSLEY 8HK	P-DP	455.29	1,330.74	285.89	625.33	0.0000000	0.0000000	0.0010710	0.0010710	76.19	1.96	0
KINGSLEY 9HJ	P-DP	442.74	982.21	264.51	413.92	0.0000000	0.0000000	0.0010800	0.0010800	76.19	1.96	0
KODIAK 7677 1U B 1H	P-DP	258.22	1,035.28	144.11	672.78	0.0000000	0.0000000	0.0005790	0.0005790	75.81	1.34	0
KODIAK 7677 2U B 2H	P-DP	171.95	1,100.31	99.86	577.24	0.0000000	0.0000000	0.0005780	0.0005780	75.81	1.34	0
KODIAK 7677 3U A 3H	P-DP	413.89	1,347.40	225.30	705.03	0.0000000	0.0000000	0.0005770	0.0005770	75.81	1.34	0
KODIAK 7677 4U A 4H	P-DP	250.19	930.37	146.98	726.19	0.0000000	0.0000000	0.0005740	0.0005740	75.81	1.34	0
KOFFORD 2-36B5	P-DP	423.22	1,664.64	422.33	1,660.56	0.0000000	0.0000000	0.0020310	0.0020310	60.48	1.70	0
KOOS 1	P-DP	0.00	54.86	0.00	54.77	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
KOOS 2	P-DP	0.00	190.38	0.00	174.76	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
KRAKEN 10-3 E1 251	P-DP	435.02	3,331.96	395.16	1,268.91	0.0000000	0.0000000	0.0005530	0.0005530	76.19	1.96	0
KRAKEN 10-3 UNIT 2 153	P-DP	417.08	1,797.10	300.40	846.68	0.0000000	0.0000000	0.0010770	0.0010770	76.19	1.96	0
KRAKEN 10-3 UNIT 2 162	P-DP	513.69	2,107.69	350.40	962.45	0.0000000	0.0000000	0.0010770	0.0010770	76.19	1.96	0
KRAKEN 10-3 UNIT 2 171	P-DP	481.31	2,042.22	320.15	919.82	0.0000000	0.0000000	0.0010770	0.0010770	76.19	1.96	0
KRAKEN 10-3 UNIT 2 181	P-DP	493.41	1,875.84	322.21	934.69	0.0000000	0.0000000	0.0010770	0.0010770	75.89	1.34	0
KRAKEN 10-3 UNIT 2 183	P-DP	294.72	1,706.70	210.90	656.89	0.0000000	0.0000000	0.0010770	0.0010770	75.89	1.34	0
KRAKEN 10-3 UNIT 2 252	P-DP	327.29	659.03	250.62	333.86	0.0000000	0.0000000	0.0010770	0.0010770	76.19	1.96	0
KRAKEN 10-3 UNIT 2 261	P-DP	367.71	1,774.60	263.38	735.27	0.0000000	0.0000000	0.0010770	0.0010770	76.19	1.96	0
KRAKEN 10-3 UNIT 2 272	P-DP	467.56	2,572.33	318.41	923.21	0.0000000	0.0000000	0.0010770	0.0010770	76.19	1.96	0
KRAKEN 10-3 UNIT 2 273	P-DP	199.68	986.77	145.69	348.97	0.0000000	0.0000000	0.0010770	0.0010770	75.89	1.34	0
KRAKEN 10-3 UNIT 2 282	P-DP	578.68	2,061.69	385.32	1,111.69	0.0000000	0.0000000	0.0010770	0.0010770	75.89	1.34	0
KRONOS 61-7 E1 151	P-DP	650.17	815.35	330.36	251.42	0.0000000	0.0000000	0.0030370	0.0030370	75.89	1.34	0
KRONOS 61-7 E1 252	P-DP	279.08	1,613.11	126.80	457.49	0.0000000	0.0000000	0.0030370	0.0030370	75.89	1.34	0
KRONOS 61-7 UNIT 2 153	P-DP	499.84	1,624.78	243.39	308.00	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRONOS 61-7 UNIT 2 154	P-DP	23.87	129.05	12.56	29.12	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRONOS 61-7 UNIT 2 161	P-DP	597.64	2,148.95	297.47	402.60	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRONOS 61-7 UNIT 2 163	P-DP	481.73	1,373.39	234.86	291.86	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRONOS 61-7 UNIT 2 171	P-DP	56.06	221.82	28.20	50.47	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRONOS 61-7 UNIT 2 173	P-DP	543.68	2,094.29	268.04	391.15	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRONOS 61-7 UNIT 2 181	P-DP	592.43	1,912.18	286.85	376.41	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRONOS 61-7 UNIT 2 182	P-DP	85.80	295.15	38.91	59.13	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRONOS 61-7 UNIT 2 255	P-DP	395.94	4,167.74	196.99	800.46	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRONOS 61-7 UNIT 2 262	P-DP	382.80	2,885.34	184.23	616.05	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0

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KRONOS 61-7 UNIT 2 272	P-DP	703.58	2,085.97	314.30	407.95	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRONOS 61-7 UNIT 2 274	P-DP	257.18	3,345.33	123.78	600.83	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRONOS 61-7 UNIT 2 283	P-DP	588.75	1,910.36	286.00	376.66	0.0000000	0.0000000	0.0060740	0.0060740	75.89	1.34	0
KRUPA 210483 3A	P-DP	0.00	14,741.57	0.00	11,775.48	0.0000000	0.0000000	0.0425470	0.0425470	67.06	2.04	0
KRUPA 211259 2A	P-DP	0.00	17,751.86	0.00	13,758.06	0.0000000	0.0000000	0.0130600	0.0130600	67.06	2.04	0
KUBENKA UNIT 1H	P-DP	110.38	238.78	97.91	220.69	0.0000000	0.0000000	0.0279630	0.0279630	73.55	1.70	0
L E STARTZELL 2	P-DP	0.00	112.68	0.00	112.68	0.0000000	0.0000000	0.0301780	0.0301780	73.94	1.41	0
L E STARTZELL UNIT BR 19 4	P-DP	0.00	124.33	0.00	124.33	0.0000000	0.0000000	0.0301780	0.0301780	73.94	1.41	0
L E STARTZELL UNIT BR 19 5	P-DP	0.00	79.55	0.00	79.55	0.0000000	0.0000000	0.0301780	0.0301780	73.94	1.41	0
LAITALA UNIT B 21-24 4AH	P-DP	267.54	829.22	144.16	232.47	0.0000000	0.0000000	0.0001270	0.0001270	76.19	1.96	0
LAITALA UNIT B 21-24 4SH	P-DP	243.72	1,789.47	125.64	338.57	0.0000000	0.0000000	0.0001270	0.0001270	76.19	1.96	0
LAITALA UNIT B 21-24 5AH	P-DP	519.86	453.66	252.88	173.48	0.0000000	0.0000000	0.0001270	0.0001270	76.19	1.96	0
LAITALA UNIT B 21-24 5SH	P-DP	419.17	353.03	206.52	134.89	0.0000000	0.0000000	0.0001270	0.0001270	76.19	1.96	0
LAITALA UNIT B 21-24 6AH	P-DP	601.02	4,017.52	297.62	1,062.54	0.0000000	0.0000000	0.0001270	0.0001270	76.19	1.96	0
LAITALA UNIT B 21-24 6SH	P-DP	547.52	143.97	276.62	80.19	0.0000000	0.0000000	0.0001270	0.0001270	76.19	1.96	0
LAMAR 13-1-A 03LS	P-DP	641.72	796.89	216.16	247.76	0.0000000	0.0000000	0.0007850	0.0007850	75.89	1.34	0
LAMAR 13-1-B 03WA	P-DP	543.16	555.28	262.84	243.04	0.0000000	0.0000000	0.0007850	0.0007850	75.89	1.34	0
LAMAR 13-1-C 08WB	P-DP	544.73	1,376.09	221.88	367.07	0.0000000	0.0000000	0.0007800	0.0007800	75.89	1.34	0
LAMAR 13-1-D 10JM	P-DP	476.79	672.89	215.97	236.68	0.0000000	0.0000000	0.0007810	0.0007810	75.89	1.34	0
LAMAR 13-1-E 13WA	P-DP	475.46	1,058.00	250.85	366.23	0.0000000	0.0000000	0.0007860	0.0007860	75.89	1.34	0
LAMAR 13-1-F 17LS	P-DP	407.03	700.37	225.54	268.37	0.0000000	0.0000000	0.0007720	0.0007720	75.89	1.34	0
LAMAR 13-1-G 18WB	P-DP	450.71	1,419.34	200.90	338.94	0.0000000	0.0000000	0.0007840	0.0007840	75.89	1.34	0
LAMAR 13-1-H 22JM	P-DP	505.26	952.01	227.85	255.40	0.0000000	0.0000000	0.0007840	0.0007840	75.89	1.34	0
LAMAR 13-1-I 22WA	P-DP	428.47	1,179.67	266.77	339.73	0.0000000	0.0000000	0.0007840	0.0007840	75.89	1.34	0
LANDRY 23 1	P-DP	144.66	1,213.94	130.97	1,024.42	0.0000000	0.0000000	0.0004860	0.0004860	76.00	1.19	0
LANDRY 23 2	P-DP	14.20	281.88	13.65	246.82	0.0000000	0.0000000	0.0004720	0.0004720	76.00	1.19	0
LANDRY 23 3	P-DP	1.79	33.06	1.41	31.79	0.0000000	0.0000000	0.0004860	0.0004860	76.00	1.19	0
LANDRY UNIT 23 4	P-DP	72.55	815.87	62.86	545.60	0.0000000	0.0000000	0.0004860	0.0004860	76.00	1.19	0
LANGHOFF UNIT A 1H	P-DP	212.55	2,119.36	212.21	1,782.78	0.0000000	0.0000000	0.0103540	0.0103540	74.40	1.94	0
LANGHOFF UNIT A 2H	P-DP	129.40	849.32	127.04	843.51	0.0000000	0.0000000	0.0103540	0.0103540	74.40	1.94	0
LANGHOFF UNIT A 3H	P-DP	64.11	639.06	62.35	608.91	0.0000000	0.0000000	0.0103540	0.0103540	74.40	1.94	0
LANGHOFF UNIT A 4H	P-DP	118.58	1,052.70	117.57	1,013.07	0.0000000	0.0000000	0.0103540	0.0103540	74.40	1.94	0
LANGHOFF UNIT A 8L	P-DP	148.40	1,689.80	110.14	1,209.81	0.0000000	0.0000000	0.0103540	0.0103540	74.40	1.94	0
LANGHOFF UNIT A 9L	P-DP	102.31	1,183.37	71.35	777.37	0.0000000	0.0000000	0.0103540	0.0103540	74.40	1.94	0
LANGHOFF UNIT B 701	P-DP	355.36	2,987.12	314.77	2,526.60	0.0000000	0.0000000	0.0006820	0.0006820	74.40	1.94	0
LAURA WILDER 72-69 UNIT A 3H	P-DP	937.72	3,789.45	786.66	2,882.52	0.0000000	0.0000000	0.0002100	0.0002100	75.81	1.34	0
LAURA WILDER 72-69 UNIT B 4HL	P-DP	555.50	1,715.55	417.94	1,223.87	0.0000000	0.0000000	0.0001450	0.0001450	75.81	1.34	0

TABLE 8

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GROSS ULTIMATE RESERVES, CUMULATIVE PRODUCTION
AND BASIC ECONOMIC DATA

LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
LEAVITT FED 1-9-4NH	P-DP	158.81	831.59	73.63	299.31	0.0000000	0.0000000	0.0080600	0.0080600	74.04	4.41	0
LEAVITT FED 1-9-4PH	P-DP	565.74	790.20	410.83	433.50	0.0000000	0.0000000	0.0080600	0.0080600	74.04	4.41	0
LEAVITT FED 1-9-4TH	P-DP	320.72	2,915.60	248.31	1,835.49	0.0000000	0.0000000	0.0080600	0.0080600	74.04	4.41	0
LEAVITT FED 2-9-4NH	P-DP	250.69	1,342.06	94.18	335.87	0.0000000	0.0000000	0.0080600	0.0080600	74.04	4.41	0
LEAVITT FED 2-9-4PH	P-DP	663.54	1,256.52	403.53	620.63	0.0000000	0.0000000	0.0080600	0.0080600	74.04	4.41	0
LEAVITT FED 2-9-4TH	P-DP	272.15	2,166.12	111.17	559.61	0.0000000	0.0000000	0.0080600	0.0080600	74.04	4.41	0
LEE 34-154 1H	P-DP	179.40	305.73	140.83	223.84	0.0000000	0.0000000	0.0045310	0.0045310	75.15	0.68	0
LEECH 32-41 UNIT A 1LS	P-DP	352.03	175.70	242.38	156.68	0.0000000	0.0000000	0.0011771	0.0011771	76.19	1.96	0
LEECH EAST 5SA	P-DP	135.07	57.82	95.92	39.94	0.0000000	0.0000000	0.0020200	0.0020200	76.19	1.96	0
LEECH EAST 7SB	P-DP	55.31	70.56	43.23	54.10	0.0000000	0.0000000	0.0020200	0.0020200	76.19	1.96	0
LEECH EAST 8SA	P-DP	231.69	312.29	135.78	173.21	0.0000000	0.0000000	0.0020200	0.0020200	76.19	1.96	0
LEECH WEST 2SB	P-DP	522.60	164.29	238.86	81.18	0.0000000	0.0000000	0.0074487	0.0074487	76.19	1.96	0
LEECH WEST 3SA	P-DP	596.62	564.25	294.05	262.68	0.0000000	0.0000000	0.0074769	0.0074769	76.19	1.96	0
LEECH WEST 4SB	P-DP	517.86	364.90	224.66	134.05	0.0000000	0.0000000	0.0074769	0.0074769	76.19	1.96	0
LEEDE UNIT 7 1	P-DP	515.01	732.02	401.78	580.02	0.0000000	0.0000000	0.0005500	0.0005500	75.15	0.68	0
LEEDE UNIT 7 2H	P-DP	308.19	572.89	233.53	427.58	0.0000000	0.0000000	0.0005500	0.0005500	75.15	0.68	0
LEVIATHAN UNIT A 29-17 4AH	P-DP	327.28	1,747.37	221.80	691.49	0.0000000	0.0000000	0.0011530	0.0011530	73.67	3.34	0
LEVIATHAN UNIT A 29-17 5AH	P-DP	470.90	217.52	316.11	139.67	0.0000000	0.0000000	0.0011530	0.0011530	73.67	3.34	0
LEVIATHAN UNIT A 29-17 6AH	P-DP	434.01	1,168.60	295.16	434.70	0.0000000	0.0000000	0.0011530	0.0011530	73.67	3.34	0
LEVIATHAN UNIT B 29-20 7AH	P-DP	292.26	1,513.92	246.87	695.79	0.0000000	0.0000000	0.0017400	0.0017400	73.67	3.34	0
LEVIATHAN UNIT B 29-20 8SH	P-DP	145.37	351.75	123.59	156.57	0.0000000	0.0000000	0.0017400	0.0017400	73.67	3.34	0
LEVIATHAN UNIT B 29-20 9AH	P-DP	247.30	646.97	216.55	346.34	0.0000000	0.0000000	0.0017400	0.0017400	73.67	3.34	0
LGM A 1H	P-DP	318.09	1,458.50	201.64	692.21	0.0000000	0.0000000	0.0010060	0.0010060	74.40	1.94	0
LGM B 2H	P-DP	314.42	1,395.45	193.55	678.92	0.0000000	0.0000000	0.0094800	0.0094800	74.40	1.94	0
LGM C 201H	P-DP	215.84	1,333.11	91.79	452.86	0.0000000	0.0000000	0.0102650	0.0102650	74.40	1.94	0
LIMBER PINE A1 1LA	P-DP	636.06	674.07	437.55	511.00	0.0000777	0.0000777	0.0000777	0.0000777	75.15	0.68	1,200
LIMBER PINE A1 28SB	P-DP	181.80	233.67	119.13	155.36	0.0000000	0.0000000	0.0000140	0.0000140	75.15	0.68	0
LIMBER PINE A2 5LA	P-DP	386.94	382.02	334.18	323.05	0.0000000	0.0000000	0.0000140	0.0000140	75.15	0.68	0
LIMBER PINE A3 16H	P-DP	208.31	389.97	141.48	230.42	0.0000000	0.0000000	0.0000140	0.0000140	75.15	0.68	0
LIMBER PINE A3 9UA	P-DP	501.93	679.87	258.35	381.01	0.0007663	0.0007663	0.0007663	0.0007663	75.15	0.68	1,200
LIMBER PINE A4 2LA	P-DP	588.01	774.26	319.08	436.79	0.0000874	0.0000874	0.0000874	0.0000874	75.15	0.68	1,200
LIMBER PINE A5 3LA	P-DP	376.07	454.96	253.27	281.42	0.0000765	0.0000765	0.0000765	0.0000765	75.15	0.68	1,200
LIMBER PINE A6 10UA	P-DP	258.19	389.25	182.31	243.45	0.0000644	0.0000644	0.0000644	0.0000644	75.15	0.68	1,200
LIMBER PINE A7 11UA	P-DP	533.11	795.91	306.13	364.25	0.0000758	0.0000758	0.0000758	0.0000758	75.15	0.68	1,200
LION 1H	P-DP	395.28	3,704.17	361.87	3,038.63	0.0000000	0.0000000	0.0003660	0.0003660	75.22	1.21	0
LION 3H	P-DP	437.02	4,880.24	367.36	2,967.53	0.0000000	0.0000000	0.0003660	0.0003660	75.22	1.21	0
LISA MARIE 34-27 4AH	P-DP	232.12	205.29	206.92	148.67	0.0000000	0.0000000	0.0001740	0.0001740	76.19	1.96	0

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LOBLOLLY A1 12UA	P-DP	175.31	222.81	63.15	78.91	0.0000000	0.0000000	0.0000760	0.0000760	75.15	0.68	0
LOBLOLLY A2 13UA	P-DP	151.59	166.95	59.71	62.08	0.0000000	0.0000000	0.0000760	0.0000760	75.15	0.68	0
LOBO 34-147 1H	P-DP	195.60	607.91	143.13	313.59	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
LOBO 34-147 2H	P-DP	255.50	632.08	189.69	406.55	0.0000000	0.0000000	0.0000840	0.0000840	75.15	0.68	0
LONE WOLF 12 1HB	P-DP	370.80	1,873.95	249.12	922.89	0.0000000	0.0000000	0.0014580	0.0014580	75.14	2.00	0
LONG 18 1	P-DP	27.18	35.80	24.61	35.80	0.0000000	0.0000000	0.0032220	0.0032220	76.19	1.96	0
LONGLEAF A2 2LA	P-DP	471.95	874.54	123.07	125.96	0.0000000	0.0000000	0.0000756	0.0000756	75.15	0.68	0
LOOS UNIT 10H	P-DP	93.92	472.48	90.06	445.80	0.0000000	0.0000000	0.0124810	0.0124810	74.40	1.94	0
LOOS UNIT 11L	P-DP	271.15	1,725.74	203.28	1,334.16	0.0000000	0.0000000	0.0124810	0.0124810	74.40	1.94	0
LOOS UNIT 12L	P-DP	194.47	1,677.82	144.01	1,231.91	0.0000000	0.0000000	0.0124810	0.0124810	74.40	1.94	0
LOOS UNIT 1H	P-DP	151.42	731.22	150.44	728.29	0.0000000	0.0000000	0.0124810	0.0124810	74.40	1.94	0
LOOS UNIT 2H	P-DP	97.48	615.47	97.48	614.08	0.0000000	0.0000000	0.0124810	0.0124810	74.40	1.94	0
LOOS UNIT 3H	P-DP	70.87	447.44	70.87	442.32	0.0000000	0.0000000	0.0124810	0.0124810	74.40	1.94	0
LOOS UNIT 8H	P-DP	75.79	514.50	71.15	479.20	0.0000000	0.0000000	0.0124810	0.0124810	74.40	1.94	0
LOOS UNIT 9H	P-DP	255.03	1,234.51	186.95	937.57	0.0000000	0.0000000	0.0124810	0.0124810	74.40	1.94	0
LOST KEYS 4345 1U B 1H	P-DP	304.86	2,744.12	180.43	1,549.57	0.0000000	0.0000000	0.0001280	0.0001280	75.81	1.34	0
LOST KEYS 4345 2U A 2H	P-DP	461.31	2,954.74	207.60	1,055.17	0.0000000	0.0000000	0.0001310	0.0001310	75.81	1.34	0
LOST KEYS 4345 3U A 3H	P-DP	341.76	1,848.07	164.32	836.56	0.0000000	0.0000000	0.0001380	0.0001380	75.81	1.34	0
LOST KEYS 4345 4U A 4H	P-DP	377.65	3,487.87	184.39	1,593.32	0.0000000	0.0000000	0.0000700	0.0000700	75.81	1.34	0
LOST KEYS 4345 5U B 5H	P-DP	293.03	4,293.06	134.03	1,730.84	0.0000000	0.0000000	0.0000690	0.0000690	75.81	1.34	0
LOST KEYS 4345 6U A 6H	P-DP	408.95	3,366.18	183.61	1,347.66	0.0000000	0.0000000	0.0000410	0.0000410	75.81	1.34	0
LRT UNIT 2 ALLOCATION 2318AH	P-DP	603.70	1,338.14	445.95	1,220.51	0.0000000	0.0000000	0.0002400	0.0002400	76.66	1.00	0
LUKCIK 4	P-DP	0.00	80.85	0.00	76.72	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
LUKCIK 5	P-DP	0.00	119.43	0.00	94.10	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
LULO 2531LP 4H	P-DP	519.28	479.26	218.43	206.38	0.0000000	0.0000000	0.0010160	0.0010160	76.19	1.96	0
LULO 2533LP 8H	P-DP	271.54	399.15	136.33	135.62	0.0000000	0.0000000	0.0010160	0.0010160	76.19	1.96	0
LULO 2543DP 6H	P-DP	655.92	1,628.56	363.86	464.29	0.0000000	0.0000000	0.0010160	0.0010160	76.19	1.96	0
LULO 2551AP 5H	P-DP	821.48	804.53	424.87	406.25	0.0000000	0.0000000	0.0010160	0.0010160	76.19	1.96	0
LULO 2553AP 9H	P-DP	531.56	848.27	274.71	364.75	0.0000000	0.0000000	0.0010160	0.0010160	76.19	1.96	0
LULO 3641DP 2H	P-DP	930.74	986.66	436.82	397.29	0.0000000	0.0000000	0.0010160	0.0010160	76.19	1.96	0
MABEE 22A 1H	P-DP	338.95	1,117.18	224.33	535.33	0.0000000	0.0000000	0.0000160	0.0000160	76.66	1.00	0
MABEE-ELKIN W16B 2H	P-DP	387.58	1,129.05	250.55	662.95	0.0000000	0.0000000	0.0000070	0.0000070	76.66	1.00	0
MABEE-STIMSON 22B 2H	P-DP	407.33	1,327.61	266.43	770.70	0.0000000	0.0000000	0.0000540	0.0000540	76.66	1.00	0
MABEE-TREDAWAY W16A 1H	P-DP	371.30	1,179.06	263.33	721.03	0.0000000	0.0000000	0.0066310	0.0066310	76.66	1.00	0
MARY GRACE 201-202 UNIT 1H	P-DP	511.27	4,856.49	331.17	2,902.76	0.0000000	0.0000000	0.0001950	0.0001950	75.15	0.68	0
MARY GRACE 201-202 UNIT 3H	P-DP	489.54	4,491.45	322.38	3,023.06	0.0000000	0.0000000	0.0001950	0.0001950	75.15	0.68	0
MARYRUTH-ANDERSON 47C 103H	P-DP	859.17	1,131.61	617.51	688.57	0.0000000	0.0000000	0.0002700	0.0002700	75.89	1.34	0

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MARYRUTH-ANDERSON 47D 104H	P-DP	711.53	986.66	507.94	599.93	0.0000000	0.0000000	0.0002700	0.0002700	75.89	1.34	0
MARYRUTH-ANDERSON 47E 105H	P-DP	645.33	1,015.43	469.27	598.78	0.0000000	0.0000000	0.0002700	0.0002700	75.89	1.34	0
MARYRUTH-ANDERSON 47F 106H	P-DP	839.45	699.60	594.97	460.91	0.0000000	0.0000000	0.0002700	0.0002700	75.89	1.34	0
MATTIE 18-11-5 6H	P-DP	36.15	7,061.59	34.01	5,459.53	0.0000000	0.0000000	0.0413910	0.0413910	69.42	2.07	0
MATTIE 18-11-5 7H	P-DP	36.78	6,620.74	35.36	4,857.87	0.0000000	0.0000000	0.0413910	0.0413910	69.42	2.07	0
MATTIE 18-11-5 8H	P-DP	39.39	7,849.16	37.17	5,863.17	0.0000000	0.0000000	0.0413910	0.0413910	69.42	2.07	0
MCCALL, JACK O. ET AL 2	P-DP	93.14	119.12	88.14	116.36	0.0000000	0.0000000	0.0039060	0.0039060	75.81	1.34	0
MCCALL, JACK O. ET AL 3	P-DP	99.10	719.62	95.56	711.27	0.0000000	0.0000000	0.0039060	0.0039060	75.81	1.34	0
MCCALL, JACK O. ET AL 4	P-DP	91.60	116.79	88.13	113.44	0.0000000	0.0000000	0.0039060	0.0039060	75.81	1.34	0
MCCLANE 2	P-DP	61.52	120.19	49.71	103.14	0.0000000	0.0000000	0.0039060	0.0039060	75.89	1.34	0
MCCLANE 3	P-DP	87.74	56.16	66.80	46.65	0.0000000	0.0000000	0.0039060	0.0039060	75.89	1.34	0
MCCONNELL 4	P-DP	0.00	124.45	0.00	124.45	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
MCDANIEL A 1	P-DP	0.77	1,602.46	0.68	1,530.59	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
MCDANIEL A 2	P-DP	0.26	336.90	0.26	336.90	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
MCDANIEL, LOIS 2	P-DP	519.32	213.81	24.02	212.94	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
MCINTIRE 1	P-DP	0.00	178.75	0.00	177.34	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
MEDUSA UNIT A 28-21 1AH	P-DP	266.77	781.74	212.92	345.60	0.0000000	0.0000000	0.0020270	0.0020270	73.67	3.34	0
MEDUSA UNIT A 28-21 2AH	P-DP	278.77	1,187.98	214.03	508.74	0.0000000	0.0000000	0.0020270	0.0020270	73.67	3.34	0
MEDUSA UNIT B 28-21 7AH	P-DP	282.46	654.06	223.40	312.01	0.0000000	0.0000000	0.0020250	0.0020250	73.67	3.34	0
MEDUSA UNIT B 28-21 8AH	P-DP	341.72	1,009.15	264.31	499.44	0.0000000	0.0000000	0.0020250	0.0020250	73.67	3.34	0
MEDUSA UNIT C 28-09 3AH	P-DP	540.53	591.12	379.13	283.32	0.0000000	0.0000000	0.0011540	0.0011540	73.67	3.34	0
MEDUSA UNIT C 28-09 6AH	P-DP	304.31	784.83	209.24	428.20	0.0000000	0.0000000	0.0011540	0.0011540	73.67	3.34	0
MEHAFFEY - BURNEM 1	P-DP	0.96	194.86	0.96	194.86	0.0000000	0.0000000	0.0625000	0.0625000	73.94	1.98	0
MELISSA 2	P-DP	300.20	231.97	300.09	231.57	0.0000000	0.0000000	0.0003640	0.0003640	75.15	0.68	0
MELISSA A 1	P-DP	27.16	365.49	25.05	364.11	0.0000000	0.0000000	0.0003640	0.0003640	75.15	0.68	0
MEMPHIS FLASH 39-27 1LS	P-DP	130.84	457.45	66.53	96.44	0.0000000	0.0000000	0.0000480	0.0000480	76.19	1.96	0
MEMPHIS FLASH 39-27 2A	P-DP	217.07	814.76	105.44	189.73	0.0000000	0.0000000	0.0000480	0.0000480	76.19	1.96	0
MEMPHIS FLASH 39-27 4AH	P-DP	610.15	721.79	410.32	348.99	0.0000000	0.0000000	0.0000480	0.0000480	76.19	1.96	0
MIDDLETON 21 1	P-DP	26.27	208.40	20.09	162.17	0.0000000	0.0000000	0.0041670	0.0041670	76.19	1.96	0
MIKE SCOTT 19-30-H 4315H	P-DP	721.53	3,195.21	508.64	1,868.56	0.0000000	0.0000000	0.0003890	0.0003890	75.14	2.00	0
MIKE SCOTT 19-30-H 4415H	P-DP	425.33	2,039.28	296.78	1,210.96	0.0000000	0.0000000	0.0003870	0.0003870	75.14	2.00	0
MILES 3-12B5	P-DP	124.86	197.89	124.86	197.89	0.0000000	0.0000000	0.0015630	0.0015630	60.48	1.70	0
MILLETT 2-14C5	P-DP	290.84	977.45	206.43	787.63	0.0000000	0.0000000	0.0055190	0.0055190	60.48	1.70	0
MIMS 32H 3306BH	P-DP	523.63	1,215.88	445.90	864.37	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
MIMS 32H 3307BH	P-DP	318.79	999.34	268.21	743.82	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
MIMS 32H 3315AH	P-DP	582.20	1,636.21	509.46	1,141.50	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
MIMS 32H 3317AH	P-DP	391.18	1,797.36	349.54	1,203.28	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0

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MIMS 32H 3318AH	P-DP	349.17	774.44	311.53	557.76	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
MIMS 32H 3326SH	P-DP	233.24	553.24	211.73	428.93	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
MIMS 32H 3327SH	P-DP	283.95	562.62	255.11	418.02	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
MIMS 32H 3345SH	P-DP	402.97	427.05	363.43	307.66	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
MIMS 32H 3347SH	P-DP	157.16	929.20	134.23	679.16	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
MIMS 32H 3348SH	P-DP	157.78	1,010.24	134.62	751.89	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
MINGO S CRC JF 4H	P-DP	0.00	15,135.26	0.00	12,844.32	0.0000000	0.0000000	0.0209790	0.0209790	73.94	1.98	0
MINGO SE CRC JF 6H	P-DP	0.00	16,202.91	0.00	13,344.26	0.0000000	0.0000000	0.0409380	0.0409380	73.94	1.98	0
MINGO SW CRC JF 2H	P-DP	0.00	14,876.98	0.00	12,076.07	0.0000000	0.0000000	0.0095070	0.0095070	73.94	1.98	0
MINGO W CRC JF 8H	P-DP	0.00	10,294.53	0.00	8,583.02	0.0000000	0.0000000	0.0412220	0.0412220	73.94	1.98	0
MIPA NO SLEEP 8201 4H	P-DP	265.75	1,105.08	108.38	442.47	0.0000000	0.0000000	0.0001040	0.0001040	75.15	0.68	0
MIPA NO SLEEP 8202 2H	P-DP	380.67	2,000.24	147.11	802.39	0.0000000	0.0000000	0.0001050	0.0001050	75.15	0.68	0
MIPA NO SLEEP 8252 3H	P-DP	795.85	2,643.30	319.15	1,115.80	0.0000000	0.0000000	0.0000980	0.0000980	75.15	0.68	0
MITCHELL 47-31 A UNIT A 2H	P-DP	462.34	358.59	196.20	119.51	0.0000000	0.0000000	0.0009880	0.0009880	76.19	1.96	0
MITCHELL 47-31 A UNIT L 2H	P-DP	333.65	275.21	144.62	88.67	0.0000000	0.0000000	0.0009880	0.0009880	76.19	1.96	0
MITCHELL 47-31 B UNIT A 7H	P-DP	526.77	484.08	182.77	134.20	0.0000000	0.0000000	0.0057920	0.0057920	76.19	1.96	0
MITCHELL 47-31 B UNIT L 6H	P-DP	360.07	25.92	275.00	21.77	0.0000000	0.0000000	0.0005270	0.0005270	76.19	1.96	0
MOLNOSKEY UNIT 1H	P-DP	177.58	721.78	174.87	671.48	0.0000000	0.0000000	0.0230360	0.0230360	73.55	1.70	0
MOLNOSKEY UNIT 2H	P-DP	143.32	125.48	110.05	125.38	0.0000000	0.0000000	0.0230370	0.0230370	73.55	1.70	0
MONROE 34-158 UNIT 1H	P-DP	380.31	795.23	378.91	716.36	0.0000000	0.0000000	0.0002790	0.0002790	75.15	0.68	0
MONROE 34-158 UNIT 2H	P-DP	479.41	649.84	471.77	640.57	0.0000000	0.0000000	0.0002790	0.0002790	75.15	0.68	0
MONROE 34-158 UNIT 3H	P-DP	523.06	587.99	454.79	491.84	0.0000000	0.0000000	0.0002790	0.0002790	75.15	0.68	0
MONROE 34-158 UNIT 4H	P-DP	194.87	221.11	175.12	178.68	0.0000000	0.0000000	0.0002790	0.0002790	75.15	0.68	0
MONSEN 1-21A3	P-DP	753.09	1,535.01	705.38	1,285.47	0.0000000	0.0000000	0.0017360	0.0017360	60.48	1.70	0
MOOSE HOLLOW 16-24-23-C5-8H	P-DP	168.04	1,080.07	153.47	1,004.34	0.0000000	0.0000000	0.0002820	0.0002820	60.48	1.70	0
MOOSE HOLLOW 9-24-23-C5-6H	P-DP	137.13	755.71	100.28	483.05	0.0000000	0.0000000	0.0002820	0.0002820	60.48	1.70	0
MOOSE HOLLOW 9-24-23-C5-7H	P-DP	291.16	2,061.17	156.56	1,061.28	0.0000000	0.0000000	0.0002820	0.0002820	60.48	1.70	0
MORAN 28SB	P-DP	234.08	474.66	160.26	303.68	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
MORAN 8LA	P-DP	305.23	396.73	191.75	264.85	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
MORAN A1 16H	P-DP	263.50	960.00	171.44	657.52	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
MORAN A1 1LA	P-DP	568.14	1,636.05	420.33	1,078.31	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
MORAN A1 9UA	P-DP	439.04	1,353.12	275.15	982.36	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
MORGAN-NEAL 39-26 2LS	P-DP	323.49	1,033.57	227.04	544.82	0.0000000	0.0000000	0.0001130	0.0001130	76.19	1.96	0
MORGAN-NEAL 39-26 3WA	P-DP	488.77	1,394.80	353.99	656.13	0.0000000	0.0000000	0.0001130	0.0001130	76.19	1.96	0
MORGAN-NEAL UNIT NO.2 39-26 1LS	P-DP	343.70	1,234.98	275.47	742.43	0.0000000	0.0000000	0.0001060	0.0001060	76.19	1.96	0
MORGAN-NEAL UNIT NO.2 39-26 1WA	P-DP	326.78	651.70	245.27	320.06	0.0000000	0.0000000	0.0001060	0.0001060	76.19	1.96	0
MORGAN-NEAL UNIT NO.2 39-26 2WA	P-DP	263.80	993.10	209.87	480.12	0.0000000	0.0000000	0.0001060	0.0001060	76.19	1.96	0

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MORTAL STORM 12-13-24 H 1W	P-DP	355.78	894.20	252.45	450.11	0.0000000	0.0000000	0.0005100	0.0005100	76.19	1.96	0
MOTHMAN UNIT A 45-04 2AH	P-DP	366.80	477.58	250.37	270.86	0.0000000	0.0000000	0.0033420	0.0033420	73.67	3.34	0
MR. HOBBS 11-14 H 1W	P-DP	331.18	528.83	178.74	330.44	0.0000000	0.0000000	0.0005180	0.0005180	76.19	1.96	0
MR. HOBBS 11-14-23 H 1LS	P-DP	279.03	865.47	187.56	262.68	0.0000000	0.0000000	0.0003970	0.0003970	76.19	1.96	0
MR. HOBBS 11-14-23A H 2W	P-DP	297.89	920.32	205.20	381.36	0.0000000	0.0000000	0.0003480	0.0003480	76.19	1.96	0
MR. PHILLIPS 11-02 A 1NA	P-DP	441.89	2,449.96	236.58	517.45	0.0000000	0.0000000	0.0024950	0.0024950	76.19	1.96	0
MR. PHILLIPS 11-02 A 1NS	P-DP	493.94	1,173.59	266.92	409.80	0.0000000	0.0000000	0.0024390	0.0024390	76.19	1.96	0
MR. PHILLIPS 11-02 B 2AH	P-DP	413.92	1,051.11	273.29	503.63	0.0000000	0.0000000	0.0024060	0.0024060	76.19	1.96	0
MR. PHILLIPS 11-02 B 2SH	P-DP	377.61	797.03	238.34	410.55	0.0000000	0.0000000	0.0024200	0.0024200	76.19	1.96	0
MR. PHILLIPS 11-02 D 4SA	P-DP	335.21	1,564.63	162.06	445.43	0.0000000	0.0000000	0.0024320	0.0024320	76.19	1.96	0
MR. PHILLIPS 11-2 1SH	P-DP	515.07	810.67	481.23	568.81	0.0000000	0.0000000	0.0024140	0.0024140	76.19	1.96	0
MUD HEN 57-31 A 1WA	P-DP	405.37	1,957.03	290.24	965.43	0.0000000	0.0000000	0.0002890	0.0002890	75.15	0.68	0
MUD HEN 57-31 B 2BS	P-DP	690.46	2,403.43	477.37	1,541.13	0.0000000	0.0000000	0.0004520	0.0004520	75.15	0.68	0
MUD HEN 57-31 C 3WA	P-DP	484.37	2,175.42	291.94	1,020.46	0.0000000	0.0000000	0.0003640	0.0003640	75.15	0.68	0
MUD HEN 57-31 D 4BS	P-DP	783.77	2,682.78	465.94	1,534.80	0.0000000	0.0000000	0.0004280	0.0004280	75.15	0.68	0
MULLINS 1-24-23-C5-6H	P-DP	325.66	1,481.79	199.28	521.44	0.0000000	0.0000000	0.0002820	0.0002820	60.48	1.70	0
MULSEN 24/23-13-14-C5-2H	P-DP	298.38	1,839.11	157.03	498.29	0.0000000	0.0000000	0.0014780	0.0014780	60.48	1.70	0
MURDOCK 2-34B5	P-DP	232.81	907.74	229.00	895.37	0.0000000	0.0000000	0.0004200	0.0004200	60.48	1.70	0
MURPH 69-2221-23R	P-DP	511.99	436.31	296.10	257.08	0.0000000	0.0000000	0.0078130	0.0078130	60.48	1.70	0
MUSGROVE MILLER 0904 2HM	P-DP	376.63	559.78	288.78	360.96	0.0000000	0.0000000	0.0012630	0.0012630	76.19	1.96	0
MUSSER 1	P-DP	0.00	31.11	0.00	31.11	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
N A C R C 1-15 ACRES 1	P-DP	0.00	35.27	0.00	35.27	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
N A C R C 5-132	P-DP	0.00	78.42	0.00	78.42	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
NAC 3H-20	P-DP	0.00	6,899.92	0.00	5,991.32	0.0000000	0.0000000	0.1190620	0.1190620	73.94	1.98	0
NAC 4H-20	P-DP	0.00	7,001.16	0.00	5,591.29	0.0000000	0.0000000	0.1190620	0.1190620	73.94	1.98	0
NAC B WYN JF 1H	P-DP	0.00	7,936.63	0.00	6,245.90	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.98	0
NAC B WYN JF 3H	P-DP	0.00	6,292.39	0.00	4,542.81	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.98	0
NAC B WYN JF 5H	P-DP	0.00	9,557.58	0.00	7,153.26	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.98	0
NAC ROYALTY 27-41 HC 001	P-DP	0.00	7,930.31	0.00	3,960.31	0.0000000	0.0000000	0.0412010	0.0412010	66.78	2.34	0
NAIL -A- 1	P-DP	78.12	258.18	60.86	214.17	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NAIL -C- 1	P-DP	119.06	374.17	113.05	343.19	0.0000000	0.0000000	0.0000860	0.0000860	75.89	1.34	0
NAIL -E- 2	P-DP	114.10	172.30	106.65	164.93	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NAIL -E- 3	P-DP	88.14	193.51	80.56	180.22	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NAIL -K- 1	P-DP	88.31	174.67	66.15	149.90	0.0000000	0.0000000	0.0001080	0.0001080	75.89	1.34	0
NAIL -P- 1	P-DP	72.66	181.30	66.58	165.67	0.0000000	0.0000000	0.0001340	0.0001340	75.89	1.34	0
NAIL J 1	P-DP	105.08	220.97	82.84	177.94	0.0000000	0.0000000	0.0000860	0.0000860	75.89	1.34	0
NAIL O 1	P-DP	101.83	179.24	90.77	164.06	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0

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NAIL RANCH 10 1	P-DP	61.25	179.51	52.09	138.05	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NAIL RANCH 10 2	P-DP	65.27	118.45	56.76	92.71	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NAIL RANCH 10 3	P-DP	66.06	78.33	58.52	73.21	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NAIL RANCH 10 4	P-DP	81.75	242.98	73.66	189.37	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NANCY 1H	P-DP	149.66	1,057.67	122.14	801.51	0.0000000	0.0000000	0.0044360	0.0044360	73.55	1.70	0
NE AXIS 2H	P-DP	255.56	6,152.97	170.92	3,636.88	0.0000000	0.0000000	0.0007720	0.0007720	75.22	1.21	0
NE NAIL 10 1	P-DP	74.30	152.90	57.65	96.05	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NE NAIL 10 2	P-DP	86.21	352.52	66.09	237.48	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NE NAIL 10 3	P-DP	99.96	217.23	94.46	174.46	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NE NAIL 10 4	P-DP	15.93	99.29	11.45	70.05	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NE NAIL 10 5	P-DP	20.76	100.38	16.39	72.87	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
NEIHART 2-2C5	P-DP	345.17	845.45	292.12	715.36	0.0000000	0.0000000	0.0004830	0.0004830	60.48	1.70	0
NESSIE UNIT A 34-46 1AH	P-DP	873.55	509.85	490.25	266.60	0.0000000	0.0000000	0.0216940	0.0216940	73.67	3.34	0
NESSIE UNIT A 34-46 2AH	P-DP	766.33	1,510.37	512.25	596.99	0.0000000	0.0000000	0.0216940	0.0216940	73.67	3.34	0
NESSIE UNIT A 34-46 3AH	P-DP	409.11	678.76	267.04	333.90	0.0000000	0.0000000	0.0216940	0.0216940	76.19	1.96	0
NESSIE UNIT A 34-46 3SH	P-DP	386.01	3,006.89	205.21	876.55	0.0000000	0.0000000	0.0216940	0.0216940	73.67	3.34	0
NESSIE UNIT B 34-46 7AH	P-DP	847.21	1,664.33	553.22	710.12	0.0000000	0.0000000	0.0216940	0.0216940	73.67	3.34	0
NESSIE UNIT B 34-46 8AH	P-DP	349.93	1,827.42	271.07	652.85	0.0000000	0.0000000	0.0216940	0.0216940	73.67	3.34	0
NEWTON 43A 1HE	P-DP	364.15	1,470.22	211.87	600.17	0.0000000	0.0000000	0.0011940	0.0011940	76.19	1.96	0
NEWTON 43A 2HK	P-DP	275.95	1,142.62	166.58	521.68	0.0000000	0.0000000	0.0011910	0.0011910	76.19	1.96	0
NEWTON 43B 3HJ	P-DP	220.70	1,048.04	193.72	551.03	0.0000000	0.0000000	0.0004990	0.0004990	76.19	1.96	0
NEWTON 43BK 4HE	P-DP	173.67	858.30	109.72	588.80	0.0000000	0.0000000	0.0010780	0.0010780	76.19	1.96	0
NEWTON 43BK 5HK	P-DP	469.20	1,196.07	366.31	576.55	0.0000000	0.0000000	0.0010800	0.0010800	76.19	1.96	0
NM HARRISON 16-11-5 10H	P-DP	19.78	5,607.64	19.40	4,697.36	0.0000000	0.0000000	0.0155020	0.0155020	69.42	2.07	0
NM HARRISON 16-11-5 6H	P-DP	56.63	6,640.71	55.61	5,702.32	0.0000000	0.0000000	0.0155020	0.0155020	69.42	2.07	0
NM HARRISON 16-11-5 8H	P-DP	45.55	7,412.52	45.15	6,454.61	0.0000000	0.0000000	0.0155020	0.0155020	69.42	2.07	0
NOELLE SW CRC JF 4H	P-DP	0.00	13,158.18	0.00	4,415.21	0.0000000	0.0000000	0.0230040	0.0230040	73.94	1.98	0
NOELLE SW CRC JF 6H	P-DP	0.00	13,179.11	0.00	4,416.19	0.0000000	0.0000000	0.0230040	0.0230040	73.94	1.98	0
NOELLE W CRC JF 2H	P-DP	0.00	11,748.14	0.00	3,877.97	0.0000000	0.0000000	0.0286760	0.0286760	73.94	1.98	0
NOLAN NE CRC JF 3H	P-DP	0.00	8,980.26	0.00	8,398.07	0.0000000	0.0000000	0.0915910	0.0915910	73.94	1.98	0
NOLAN NW CRC JF 1H	P-DP	0.00	23,385.82	0.00	19,503.55	0.0000000	0.0000000	0.0972460	0.0972460	73.94	1.98	0
NOLAN S CRC JF 2H	P-DP	0.00	11,811.48	0.00	10,192.60	0.0000000	0.0000000	0.1036510	0.1036510	73.94	1.98	0
NOLAN S CRC JF 4H	P-DP	0.00	10,312.31	0.00	8,590.49	0.0000000	0.0000000	0.1036510	0.1036510	73.94	1.98	0
NOLAN S CRC JF 6H	P-DP	0.00	11,374.38	0.00	9,564.48	0.0000000	0.0000000	0.1036510	0.1036510	73.94	1.98	0
NORRIS UNIT 32-H 3301BH	P-DP	135.24	899.03	91.34	422.50	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS UNIT 32-H 3303BH	P-DP	176.27	1,059.12	128.78	507.17	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS UNIT 32-H 3304BH	P-DP	184.79	209.87	133.66	102.72	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0

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NORRIS UNIT 32-H 3312AH	P-DP	114.43	969.96	80.50	443.82	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS UNIT 32-H 3313AH	P-DP	153.87	1,505.63	112.40	764.30	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS UNIT 32-H 3322SH	P-DP	256.10	1,431.08	175.21	671.89	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS UNIT 32-H 3323SH	P-DP	517.34	4,125.98	379.74	1,961.59	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS UNIT 32-H 3361DH	P-DP	290.15	2,048.04	198.15	934.07	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS UNIT 32-H 3363DH	P-DP	269.05	1,940.21	186.36	904.63	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS UNIT 32-H 3364DH	P-DP	268.20	1,426.73	188.51	600.06	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS UNIT 32-H 3371JH	P-DP	172.16	910.29	127.69	444.04	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS UNIT 32-H 3373JH	P-DP	164.69	926.13	123.07	464.82	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS UNIT 32-H 3374JH	P-DP	178.07	915.84	123.43	427.92	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS-MIMS ALLOCATION 3315AH	P-DP	157.09	780.98	120.59	436.28	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORRIS-MIMS ALLOCATION 3325SH	P-DP	172.27	1,545.71	147.54	948.32	0.0000000	0.0000000	0.0045830	0.0045830	75.89	1.34	0
NORTH AMERICAN COAL 1S	P-DP	0.00	38.15	0.00	38.15	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
NORTH AMERICAN COAL 2S	P-DP	0.00	21.12	0.00	21.12	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
NORTH AMERICAN COAL 3A	P-DP	0.00	97.72	0.00	97.72	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
NORTH AMERICAN COAL CO 4	P-DP	2.70	77.39	2.70	77.39	0.0000000	0.0000000	0.0919390	0.0919390	73.94	1.98	0
NORTH AMERICAN COAL CORP 1	P-DP	1.76	60.69	1.76	60.69	0.0000000	0.0000000	0.0560430	0.0560430	73.94	1.98	0
NORTH AMERICAN COAL CORP 1_2	P-DP	0.00	142.01	0.00	142.01	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
NORTH AMERICAN COAL CORP 1_3	P-DP	0.00	113.61	0.00	113.61	0.0000000	0.0000000	0.7500000	0.7500000	73.94	1.41	0
NORTH AMERICAN COAL CORP 2	P-DP	0.00	94.11	0.00	94.11	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
NORTH AMERICAN COAL CORP 3	P-DP	0.00	94.54	0.00	94.54	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
NORTH AMERICAN COAL CORP BR 19 UNIT	P-DP	0.00	135.08	0.00	135.08	0.0000000	0.0000000	0.0301780	0.0301780	73.94	1.41	0
NORTH AMERICAN COAL ROYALTY CO BUELL 8H	P-DP	33.16	10,615.43	32.69	9,169.91	0.0000000	0.0000000	0.0788860	0.0788860	69.42	2.07	0
NORTH AMERICAN COAL ROYALTY CO. 1	P-DP	0.00	120.96	0.00	120.96	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
NORTH AMERICAN COAL ROYALTY CO. 2	P-DP	0.00	67.43	0.00	67.43	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
NUNN '5-44' 4303H	P-DP	401.64	3,919.76	307.88	1,925.30	0.0000000	0.0000000	0.0009850	0.0009850	75.14	2.00	0
NUNN '5-44' 4403H	P-DP	232.16	1,554.62	165.21	793.62	0.0000000	0.0000000	0.0009840	0.0009840	75.14	2.00	0
NUNN '5-44' 4803H	P-DP	185.23	2,111.88	130.61	1,082.54	0.0000000	0.0000000	0.0009820	0.0009820	75.14	2.00	0
NUNN 1	P-DP	62.63	192.49	55.72	178.67	0.0000000	0.0000000	0.0007290	0.0007290	75.14	2.00	0
NUNN 2	P-DP	61.43	199.48	54.47	178.60	0.0000000	0.0000000	0.0007290	0.0007290	75.14	2.00	0
NUNN 5-44 1HB	P-DP	437.03	4,547.78	352.07	2,231.72	0.0000000	0.0000000	0.0009840	0.0009840	75.14	2.00	0
NUNN A 2	P-DP	54.44	250.93	45.75	224.86	0.0000000	0.0000000	0.0007290	0.0007290	75.14	2.00	0
NUNN A 3	P-DP	68.12	463.65	53.39	463.65	0.0000000	0.0000000	0.0014580	0.0014580	75.14	2.00	0
NUNN B 3	P-DP	40.15	647.43	40.15	647.43	0.0000000	0.0000000	0.0014580	0.0014580	75.14	2.00	0
NUNN, J. F. B 3	P-DP	44.26	309.06	44.26	309.06	0.0000000	0.0000000	0.0014590	0.0014590	75.14	2.00	0
O'NEAL 1	P-DP	90.61	236.90	83.30	219.41	0.0000000	0.0000000	0.0156250	0.0156250	76.66	1.00	0
OAK VALLEY 2 1	P-DP	84.43	116.34	60.26	90.10	0.0000000	0.0000000	0.0035810	0.0035810	77.02	1.02	0

TABLE 8

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GROSS ULTIMATE RESERVES, CUMULATIVE PRODUCTION AND BASIC ECONOMIC DATA

LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
OLDHAM 38-27 B UNIT A 7H	P-DP	57.68	202.38	57.01	186.34	0.0000000	0.0000000	0.0001620	0.0001620	76.19	1.96	0
OLDHAM 38-27 B UNIT A 8H	P-DP	13.47	133.47	13.46	126.49	0.0000000	0.0000000	0.0001620	0.0001620	76.19	1.96	0
OLDHAM 38-27 B UNIT L 7H	P-DP	1,009.28	680.52	752.31	492.20	0.0000000	0.0000000	0.0001620	0.0001620	76.19	1.96	0
OLDHAM 38-27 B UNIT L 8H	P-DP	34.61	508.82	33.70	362.03	0.0000000	0.0000000	0.0006890	0.0006890	76.19	1.96	0
OLDHAM TRUST EAST 1SH	P-DP	208.96	419.51	58.64	45.23	0.0000000	0.0000000	0.0001620	0.0001620	76.19	1.96	0
OLDHAM TRUST EAST 2AH	P-DP	450.18	1,319.20	117.26	118.44	0.0000000	0.0000000	0.0001620	0.0001620	76.19	1.96	0
OLDHAM TRUST EAST 3871WA	P-DP	599.28	1,301.20	413.64	875.75	0.0000000	0.0000000	0.0001620	0.0001620	76.19	1.96	0
OLDHAM TRUST EAST 3875LS	P-DP	651.06	654.64	450.54	357.04	0.0000000	0.0000000	0.0001620	0.0001620	76.19	1.96	0
OLDHAM TRUST EAST 3876WA	P-DP	628.14	485.49	385.96	342.17	0.0000000	0.0000000	0.0001620	0.0001620	76.19	1.96	0
OLDHAM TRUST EAST 3AH	P-DP	340.41	400.54	101.17	62.98	0.0000000	0.0000000	0.0001620	0.0001620	76.19	1.96	0
OLDHAM TRUST EAST 3SH	P-DP	338.15	297.48	79.12	60.56	0.0000000	0.0000000	0.0001620	0.0001620	76.19	1.96	0
OLDHAM TRUST EAST 4AH	P-DP	220.84	275.54	70.35	59.50	0.0000000	0.0000000	0.0001620	0.0001620	76.19	1.96	0
OLDHAM TRUST WEST 1SH	P-DP	403.62	435.85	163.92	213.14	0.0000000	0.0000000	0.0002540	0.0002540	76.19	1.96	0
OLDHAM TRUST WEST 2AH	P-DP	280.64	1,241.79	137.89	360.57	0.0000000	0.0000000	0.0002440	0.0002440	76.19	1.96	0
OLDHAM TRUST WEST 4051WA	P-DP	611.49	873.22	470.15	605.91	0.0000000	0.0000000	0.0002700	0.0002700	76.19	1.96	0
OLDHAM TRUST WEST 4058LS	P-DP	470.04	531.64	350.75	392.47	0.0000000	0.0000000	0.0002690	0.0002690	76.19	1.96	0
OLDHAM TRUST WEST 4AH	P-DP	217.46	894.35	89.73	175.71	0.0000000	0.0000000	0.0002760	0.0002760	76.19	1.96	0
OLDHAM TRUST WEST 4SH	P-DP	229.79	1,143.43	90.56	185.51	0.0000000	0.0000000	0.0002760	0.0002760	76.19	1.96	0
OLDHAM TRUST WEST 5AH	P-DP	180.65	1,535.70	96.99	232.67	0.0000000	0.0000000	0.0002760	0.0002760	76.19	1.96	0
OLDHAM TRUST WEST 5MH	P-DP	164.97	725.45	74.07	88.96	0.0000000	0.0000000	0.0002740	0.0002740	76.19	1.96	0
OLDHAM TRUST WEST 5SH	P-DP	181.29	1,753.89	91.10	289.76	0.0000000	0.0000000	0.0002750	0.0002750	76.19	1.96	0
OLDHAM TRUST WEST 6AH	P-DP	230.91	1,201.64	84.59	155.18	0.0000000	0.0000000	0.0002700	0.0002700	76.19	1.96	0
OLDHAM TRUST WEST LONG 25-56 3SH	P-DP	343.71	1,523.22	202.29	369.86	0.0000000	0.0000000	0.0002280	0.0002280	76.19	1.96	0
OLDHAM TRUST WEST UNIT 25-41 2SH	P-DP	437.25	1,286.27	233.94	357.11	0.0000000	0.0000000	0.0002280	0.0002280	76.19	1.96	0
OLDHAM TRUST WEST UNIT 25-41 3AH	P-DP	416.13	1,304.60	272.17	316.88	0.0000000	0.0000000	0.0002280	0.0002280	76.19	1.96	0
OLDHAM-GRAHAM 35A 1H	P-DP	204.09	892.07	157.03	431.19	0.0000000	0.0000000	0.0026450	0.0026450	76.66	1.00	0
OLDHAM-GRAHAM 35B 2H	P-DP	246.29	1,437.55	167.78	654.32	0.0000000	0.0000000	0.0023380	0.0023380	76.66	1.00	0
OLDHAM-GRAHAM 35C 3H	P-DP	245.61	1,427.81	192.26	574.47	0.0000000	0.0000000	0.0026490	0.0026490	76.66	1.00	0
OLDHAM-GRAHAM 35D 4H	P-DP	240.04	1,418.24	167.39	608.16	0.0000000	0.0000000	0.0023570	0.0023570	76.66	1.00	0
OLDHAM-GRAHAM 35E 5H	P-DP	284.06	913.68	189.62	418.25	0.0000000	0.0000000	0.0026470	0.0026470	76.66	1.00	0
OLDHAM-GRAHAM 35F 6H	P-DP	354.06	1,136.09	212.68	467.47	0.0000000	0.0000000	0.0023370	0.0023370	76.66	1.00	0
OLSEN 13/14-24/23-C5-1H	P-DP	180.81	316.69	122.66	229.89	0.0000000	0.0000000	0.0014780	0.0014780	60.48	1.70	0
OLSEN 16-13-14-C5-5H	P-DP	405.00	2,256.73	266.00	716.02	0.0000000	0.0000000	0.0029570	0.0029570	60.48	1.70	0
ONEAL-ANNIE 15G 7H	P-DP	352.99	859.35	165.50	338.54	0.0000000	0.0000000	0.0032497	0.0032497	76.66	1.00	0
ONEAL-ANNIE 15H 8H	P-DP	511.36	1,554.05	178.31	260.81	0.0000000	0.0000000	0.0031016	0.0031016	76.66	1.00	0
ONEAL-ANNIE 15H 9H	P-DP	670.04	2,973.68	254.11	410.15	0.0000000	0.0000000	0.0033422	0.0033422	76.66	1.00	0
ONEAL-ANNIE 15J 10H	P-DP	487.67	2,373.49	132.77	164.86	0.0000000	0.0000000	0.0032441	0.0032441	76.66	1.00	0

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ONEAL-ANNIE 15K 11H	P-DP	696.52	1,677.45	217.63	293.61	0.0000000	0.0000000	0.0032630	0.0032630	76.66	1.00	0
ONEAL-ANNIE 15K 12H	P-DP	383.62	1,353.78	140.35	239.06	0.0000000	0.0000000	0.0031033	0.0031033	76.66	1.00	0
ONEAL-ANNIE 15M 13H	P-DP	435.54	3,093.47	123.06	359.77	0.0000000	0.0000000	0.0026760	0.0026760	76.66	1.00	0
ONEAL-ANNIE 15M 14H	P-DP	831.61	530.67	209.68	81.14	0.0000000	0.0000000	0.0029479	0.0029479	76.66	1.00	0
ONEAL-ANNIE 15O 15H	P-DP	402.92	1,041.70	166.21	323.93	0.0000000	0.0000000	0.0035089	0.0035089	76.66	1.00	0
ONEAL-ANNIE 15P 16H	P-DP	519.11	1,343.63	190.87	230.66	0.0000000	0.0000000	0.0020000	0.0020000	76.66	1.00	0
ONEAL-ANNIE 15P 17H	P-DP	656.21	2,556.37	240.92	412.38	0.0000000	0.0000000	0.0032129	0.0032129	76.66	1.00	0
ONEAL-ANNIE 15R 18H	P-DP	216.14	517.74	112.98	146.04	0.0000000	0.0000000	0.0029122	0.0029122	76.66	1.00	0
ORSON-BILLY 139A 1H	P-DP	487.19	729.28	192.70	283.72	0.0000000	0.0000000	0.0020350	0.0020350	75.89	1.34	0
ORSON-BILLY 139B 2H	P-DP	571.62	869.02	289.71	349.80	0.0000000	0.0000000	0.0020320	0.0020320	75.89	1.34	0
ORSON-BILLY 139C 3H	P-DP	566.04	1,147.57	264.59	353.91	0.0000000	0.0000000	0.0021180	0.0021180	75.89	1.34	0
ORSON-BILLY 139D 4H	P-DP	365.26	522.78	178.90	221.95	0.0000000	0.0000000	0.0020500	0.0020500	75.89	1.34	0
ORSON-BILLY 139E 5H	P-DP	330.70	582.73	173.85	327.53	0.0000000	0.0000000	0.0020130	0.0020130	75.89	1.34	0
ORSON-BILLY 139F 6H	P-DP	704.94	1,690.56	327.98	606.87	0.0000000	0.0000000	0.0020990	0.0020990	75.89	1.34	0
ORSON-BILLY 139G 7H	P-DP	482.45	1,279.37	224.97	492.75	0.0000000	0.0000000	0.0020110	0.0020110	75.89	1.34	0
ORTHRUS UNIT A 34-22 1AH	P-DP	472.73	1,100.16	289.20	500.09	0.0000000	0.0000000	0.0134290	0.0134290	73.67	3.34	0
ORTHRUS UNIT A 34-22 2AH	P-DP	485.82	1,013.74	313.02	363.77	0.0000000	0.0000000	0.0134290	0.0134290	73.67	3.34	0
ORTHRUS UNIT A 34-22 3AH	P-DP	302.07	674.30	162.23	252.83	0.0000000	0.0000000	0.0134290	0.0134290	73.67	3.34	0
ORTHRUS UNIT B 34-22 7AH	P-DP	285.42	1,180.09	220.44	550.92	0.0000000	0.0000000	0.0134220	0.0134220	73.67	3.34	0
ORTHRUS UNIT B 34-22 8AH	P-DP	468.55	661.68	333.43	336.58	0.0000000	0.0000000	0.0134220	0.0134220	73.67	3.34	0
OV UNIT 1	P-DP	67.19	103.76	57.31	96.27	0.0000000	0.0000000	0.0034310	0.0034310	77.02	1.02	0
OVMLC 1	P-DP	96.41	215.63	75.61	200.37	0.0000000	0.0000000	0.0035810	0.0035810	77.02	1.02	0
OVMLC 2	P-DP	78.03	25.42	61.72	23.15	0.0000000	0.0000000	0.0035810	0.0035810	77.02	1.02	0
OWL & HAWK 2-21C5	P-DP	161.99	741.57	106.04	576.92	0.0000000	0.0000000	0.0014160	0.0014160	60.48	1.70	0
OWL & HAWK 3-16C5	P-DP	61.73	99.42	48.77	80.78	0.0000000	0.0000000	0.0008440	0.0008440	60.48	1.70	0
OWL & HAWK 3-21C5	P-DP	84.88	334.78	73.74	261.45	0.0000000	0.0000000	0.0014160	0.0014160	60.48	1.70	0
OWL AND HAWK 2-31B5	P-DP	168.36	203.86	137.62	158.44	0.0000000	0.0000000	0.0026040	0.0026040	60.48	1.70	0
OWL AND HAWK 3-10C5	P-DP	328.56	1,207.35	266.21	931.17	0.0000000	0.0000000	0.0010750	0.0010750	60.48	1.70	0
OYSTER 001	P-DP	24.14	0.35	24.13	0.35	0.0000000	0.0000000	0.0091406	0.0091406	76.17	1.13	0
P LAMANTIA 1	P-DP	0.00	101.46	0.00	99.40	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
P LONG 1	P-DP	0.00	137.16	0.00	134.06	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
P LONG 4	P-DP	0.00	124.89	0.00	123.78	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
PALMER 52 UNIT 222H	P-DP	478.16	5,038.60	220.55	1,894.09	0.0000000	0.0000000	0.0012230	0.0012230	75.15	0.68	0
PALMER 52 UNIT 332H	P-DP	287.54	4,810.03	163.52	2,480.84	0.0000000	0.0000000	0.0012230	0.0012230	75.15	0.68	0
PALOS 01-12-241	P-DP	0.00	233.91	0.00	213.58	0.0000000	0.0000000	0.1591250	0.1591250	73.94	2.58	0
PALOS 02-10-239	P-DP	0.00	319.35	0.00	279.72	0.0000000	0.0000000	0.0800420	0.0800420	73.94	2.58	0
PALOS 02-16-240	P-DP	0.00	436.47	0.00	323.52	0.0000000	0.0000000	0.1587290	0.1587290	73.94	2.58	0

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PALOS 03-06-245	P-DP	0.00	294.87	0.00	250.77	0.0000000	0.0000000	0.1666670	0.1666670	73.94	2.58	0
PALOS 03-10-232	P-DP	0.00	369.42	0.00	333.92	0.0000000	0.0000000	0.1666670	0.1666670	73.94	2.58	0
PALOS 03-14-233	P-DP	0.00	358.74	0.00	337.27	0.0000000	0.0000000	0.1666670	0.1666670	73.94	2.58	0
PALOS 03-16-231	P-DP	0.00	532.62	0.00	502.45	0.0000000	0.0000000	0.1666670	0.1666670	73.94	2.58	0
PAMOLA UNIT A 35-23 1AH	P-DP	321.01	235.56	253.29	160.27	0.0000000	0.0000000	0.0127580	0.0127580	73.67	3.34	0
PAMOLA UNIT A 35-23 2AH	P-DP	176.12	425.05	133.80	217.49	0.0000000	0.0000000	0.0127580	0.0127580	73.67	3.34	0
PAMOLA UNIT A 35-23 3AH	P-DP	331.13	846.57	199.06	314.45	0.0000000	0.0000000	0.0127580	0.0127580	73.67	3.34	0
PAMOLA UNIT A 35-23 4AH	P-DP	344.86	1,415.77	181.68	357.65	0.0000000	0.0000000	0.0127580	0.0127580	73.67	3.34	0
PAPER RINGS 136-137 A 1WB	P-DP	446.37	625.02	292.28	416.61	0.0000000	0.0000000	0.0026940	0.0026940	75.89	1.34	0
PARKS 1	P-DP	108.28	121.63	92.40	121.63	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS 6 2	P-DP	55.17	53.75	33.53	39.28	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT #2 2314	P-DP	201.25	463.01	199.69	460.46	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1450BH	P-DP	356.52	1,638.49	286.78	928.18	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1450LH	P-DP	492.34	1,981.12	412.12	1,210.94	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1451LH	P-DP	702.88	1,223.05	564.41	736.53	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1454H	P-DP	277.13	543.74	252.68	397.70	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1454LH	P-DP	967.81	1,452.48	776.38	851.58	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1455LH	P-DP	433.59	692.65	365.31	383.87	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1458CH	P-DP	876.94	6,692.25	709.01	3,816.89	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1458LH	P-DP	873.03	7,387.06	686.24	3,855.03	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1863BH	P-DP	395.46	2,395.23	369.68	1,794.24	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1863LH	P-DP	632.35	2,131.10	576.71	1,515.08	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1904BH	P-DP	389.47	579.88	307.09	345.93	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 1921H	P-DP	343.52	1,378.27	300.66	1,070.66	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2001BH	P-DP	338.74	2,976.30	248.54	1,294.40	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2101	P-DP	230.54	633.07	229.97	631.02	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2210	P-DP	60.31	47.10	54.89	40.84	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2307LH	P-DP	324.21	381.15	244.65	275.79	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2307MH	P-DP	923.17	426.47	651.11	281.02	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2308BH	P-DP	411.50	1,115.46	342.57	623.54	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2308LH	P-DP	898.75	2,603.59	627.22	1,229.59	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2308MH	P-DP	846.98	2,346.30	642.75	1,168.76	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2329LH	P-DP	221.29	922.38	216.11	711.35	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2336BH	P-DP	52.70	1,145.21	50.46	943.28	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2346CH	P-DP	17.91	244.40	17.48	207.07	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2348H	P-DP	584.77	622.12	474.28	446.86	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2606	P-DP	259.19	129.01	259.02	128.75	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0

TABLE 8

As of: 01/01/2025

GROSS ULTIMATE RESERVES, CUMULATIVE PRODUCTION AND BASIC ECONOMIC DATA

LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
PARKS FIELD UNIT 2 2630H	P-DP	341.63	2,284.69	307.36	1,735.04	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 2709H	P-DP	979.71	2,000.18	945.59	1,454.94	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT 2 911	P-DP	30.30	93.06	28.19	80.27	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT NO. 2 1320H	P-DP	44.62	1,800.75	30.12	1,395.08	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT NO. 2 1421H	P-DP	188.32	9,121.73	177.98	8,202.32	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT NO. 2 1422H	P-DP	160.22	8,468.67	142.98	7,278.65	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT NO. 2 1423H	P-DP	48.50	1,579.02	44.90	1,503.95	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT NO. 2 1829H	P-DP	56.28	3,183.46	53.33	3,161.63	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT NO. 2 1831H	P-DP	221.11	9,639.97	221.11	9,615.37	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT NO. 2 1917H	P-DP	57.08	3,594.86	53.75	3,330.07	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT NO. 2 2324H	P-DP	116.15	3,822.91	106.04	3,417.82	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT NO. 2 2401	P-DP	79.63	2,652.09	79.61	2,642.43	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS FIELD UNIT NO. 2 2417H	P-DP	54.32	2,370.12	53.98	2,318.70	0.0000000	0.0000000	0.0008040	0.0008040	76.66	1.00	0
PARKS, ROY 10	P-DP	30.04	63.53	30.02	62.39	0.0000000	0.0000000	0.0002700	0.0002700	76.66	1.00	0
PARKS, ROY 301MH	P-DP	374.65	1,195.53	55.11	56.31	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 302LH	P-DP	412.91	2,510.36	23.82	24.60	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 302MH	P-DP	388.40	1,627.44	53.34	64.84	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 303BH	P-DP	414.02	1,649.99	78.97	87.39	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 303LH	P-DP	389.64	2,486.80	49.30	69.93	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 303MH	P-DP	312.19	1,305.23	43.95	54.25	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 306BH	P-DP	532.37	2,089.68	432.41	1,472.83	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 306LH	P-DP	732.16	863.28	560.45	521.27	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 307BH	P-DP	474.10	1,119.76	380.52	683.38	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 307LH	P-DP	35.05	1,253.52	35.05	762.87	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 308BH	P-DP	466.74	499.85	360.10	287.10	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 308LH	P-DP	5.07	990.60	5.07	739.80	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 308MH	P-DP	1,109.73	921.39	789.70	583.49	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 31	P-DP	44.71	279.01	44.30	262.84	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 311JH	P-DP	441.91	2,898.75	55.82	101.56	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 316CH	P-DP	190.53	522.78	165.62	363.60	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 316LH	P-DP	562.82	626.77	372.17	375.15	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 34	P-DP	22.90	197.11	22.90	160.13	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 4	P-DP	144.39	419.59	144.39	419.59	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 53	P-DP	191.63	78.26	186.51	31.18	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS, ROY 99H	P-DP	203.11	1,941.80	200.01	1,328.43	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PARKS-COYOTE 1506 A 15HJ	P-DP	462.49	559.90	281.35	280.67	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 A 1HM	P-DP	618.75	1,437.43	445.92	946.45	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0

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PARKS-COYOTE 1506 A 8HS	P-DP	701.13	1,044.17	423.10	504.12	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 B 2HM	P-DP	350.42	1,064.21	276.37	786.22	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 B 9HS	P-DP	356.22	774.40	218.69	340.90	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 C 10HS	P-DP	565.90	918.00	306.00	395.30	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 C 16HJ	P-DP	537.63	843.69	296.23	341.99	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 C 3HM	P-DP	436.28	1,644.63	331.28	989.40	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 D 11HS	P-DP	340.16	782.85	208.66	375.81	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 D 17HS	P-DP	260.53	532.93	159.19	273.04	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 D 4HM	P-DP	844.84	2,215.97	560.60	1,209.31	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 E 12HS	P-DP	507.08	1,373.74	313.36	466.52	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 E 18HJ	P-DP	441.34	1,006.27	265.98	407.60	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 E 5HM	P-DP	513.61	1,448.12	384.20	838.39	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 F 13HS	P-DP	537.44	1,798.91	278.00	542.11	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 F 6HM	P-DP	586.92	952.44	406.42	655.47	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 G 14HS	P-DP	925.51	873.06	514.87	416.00	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 G 19HS	P-DP	311.61	309.65	171.41	161.54	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PARKS-COYOTE 1506 G 7HM	P-DP	782.07	1,143.29	549.56	777.09	0.0000000	0.0000000	0.0020090	0.0020090	76.66	1.00	0
PATRICIA-NORRIS ALLOCATION 3311AH	P-DP	133.70	1,155.37	115.60	606.58	0.0000000	0.0000000	0.0022920	0.0022920	75.89	1.34	0
PATRICIA-NORRIS ALLOCATION 3321SH	P-DP	194.45	1,524.55	168.34	832.69	0.0000000	0.0000000	0.0022920	0.0022920	75.89	1.34	0
PATTERSON 3	P-DP	0.00	122.85	0.00	118.98	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
PAULSEN 2-15C5	P-DP	200.54	849.25	173.73	694.92	0.0000000	0.0000000	0.0063230	0.0063230	60.48	1.70	0
PERCY 39 1R	P-DP	74.40	285.14	52.44	179.36	0.0000000	0.0000000	0.0023440	0.0023440	75.89	1.34	0
PERRY 48 1	P-DP	52.91	218.98	45.29	153.48	0.0000000	0.0000000	0.0000000	0.0000000	76.00	1.19	0
PHILLIPS 1	P-DP	0.00	139.95	0.00	117.12	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
PHILLIPS 2	P-DP	0.00	123.10	0.00	114.98	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
PHILLIPS 3	P-DP	0.00	111.22	0.00	103.66	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
PHILLIPS-GUTHRIE 1	P-DP	150.08	262.45	149.48	261.09	0.0000000	0.0000000	0.0039060	0.0039060	75.89	1.34	0
PHILLIPS-GUTHRIE 2	P-DP	78.34	207.16	77.86	206.17	0.0000000	0.0000000	0.0039060	0.0039060	75.89	1.34	0
PHOENIX UNIT 35-38 8AH	P-DP	340.63	545.16	266.51	301.04	0.0000000	0.0000000	0.0215670	0.0215670	73.67	3.34	0
PIXIE UNIT A 35-47 1AH	P-DP	610.21	286.19	451.27	233.91	0.0000000	0.0000000	0.0210730	0.0210730	73.67	3.34	0
PIXIE UNIT A 35-47 2AH	P-DP	213.69	980.32	170.99	650.71	0.0000000	0.0000000	0.0210730	0.0210730	73.67	3.34	0
PIXIE UNIT A 35-47 3AH	P-DP	432.12	958.44	96.60	95.74	0.0000000	0.0000000	0.0210730	0.0210730	73.67	3.34	0
PIXIE UNIT A 35-47 3SH	P-DP	279.50	659.56	67.48	62.38	0.0000000	0.0000000	0.0210730	0.0210730	73.67	3.34	0
PIXIE UNIT B 35-47 5AH	P-DP	832.01	1,305.66	505.19	584.46	0.0000000	0.0000000	0.0210730	0.0210730	73.67	3.34	0
PIXIE UNIT B 35-47 6AH	P-DP	443.94	658.41	85.32	54.96	0.0000000	0.0000000	0.0210730	0.0210730	73.67	3.34	0
POCONO WEST A2 1LA	P-DP	174.19	3,337.84	76.85	1,102.07	0.0000000	0.0000000	0.0025900	0.0025900	75.81	1.34	0
POCONO WEST A2 5H	P-DP	60.15	1,600.19	54.70	1,112.09	0.0000000	0.0000000	0.0026110	0.0026110	75.81	1.34	0

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POCONO WEST A3 7CH	P-DP	81.65	1,338.80	53.62	723.00	0.0000000	0.0000000	0.0013800	0.0013800	75.81	1.34	0
POCONO WEST A3 9UA	P-DP	274.60	3,854.24	97.19	1,065.20	0.0000000	0.0000000	0.0012600	0.0012600	75.81	1.34	0
POCONO WEST A4 2LA	P-DP	108.18	2,975.50	70.23	1,076.27	0.0000000	0.0000000	0.0012720	0.0012720	75.81	1.34	0
POCONO WEST A4 6H	P-DP	198.94	3,899.60	78.29	1,194.94	0.0000000	0.0000000	0.0012640	0.0012640	75.81	1.34	0
POCONO WEST A5 10UA	P-DP	275.78	2,269.49	125.86	978.36	0.0000000	0.0000000	0.0013090	0.0013090	75.81	1.34	0
POCONO WEST A6 3LA	P-DP	218.63	2,789.26	92.62	811.32	0.0000000	0.0000000	0.0012730	0.0012730	75.81	1.34	0
POINTER N CRC JF 7H	P-DP	0.00	18,030.39	0.00	8,649.40	0.0000000	0.0000000	0.0089250	0.0089250	73.94	1.98	0
POINTER N CRC JF 9H	P-DP	0.00	25,384.42	0.00	11,422.25	0.0000000	0.0000000	0.0089250	0.0089250	73.94	1.98	0
POINTER W CRC JF 5H	P-DP	0.00	18,627.70	0.00	8,861.09	0.0000000	0.0000000	0.0007280	0.0007280	73.94	1.98	0
POLTERGEIST GUARDIAN A 12-02 2SH	P-DP	380.85	1,355.92	131.23	210.91	0.0000000	0.0000000	0.0000670	0.0000670	76.19	1.96	0
POLTERGEIST GUARDIAN B 12-02 2AH	P-DP	473.41	1,335.88	172.52	180.51	0.0000000	0.0000000	0.0002590	0.0002590	76.19	1.96	0
POLTERGEIST GUARDIAN C 12-02 3SH	P-DP	374.09	1,283.10	135.56	196.51	0.0000000	0.0000000	0.0002220	0.0002220	76.19	1.96	0
POLTERGEIST UNIT B 11-02 5SH	P-DP	610.58	518.11	134.09	47.41	0.0000000	0.0000000	0.0002700	0.0002700	76.19	1.96	0
POLTERGEIST-PIXIE A 11-38 6SH	P-DP	297.87	694.62	73.02	59.61	0.0000000	0.0000000	0.0095921	0.0095921	76.19	1.96	0
POLTERGEIST-PIXIE B 11-38 6AH	P-DP	403.86	927.13	96.88	84.79	0.0000000	0.0000000	0.0098991	0.0098991	76.19	1.96	0
POTH UNIT 1H	P-DP	167.22	1,499.54	140.69	1,342.74	0.0000000	0.0000000	0.0073980	0.0073980	74.40	1.94	0
POWELL 43 1	P-DP	76.47	120.27	62.00	101.12	0.0000000	0.0000000	0.0027780	0.0027780	75.89	1.34	0
POWELL A 2	P-DP	183.90	393.08	139.90	301.50	0.0000000	0.0000000	0.0031250	0.0031250	75.89	1.34	0
POWELL A 3	P-DP	12.40	45.20	12.30	43.86	0.0000000	0.0000000	0.0031250	0.0031250	75.89	1.34	0
POWELL B 1	P-DP	98.94	195.77	75.57	152.95	0.0000000	0.0000000	0.0031250	0.0031250	75.89	1.34	0
POWELL C 1	P-DP	112.53	236.33	81.44	177.42	0.0000000	0.0000000	0.0031250	0.0031250	75.89	1.34	0
PRIMA 1H	P-DP	418.35	5,156.63	245.44	2,961.86	0.0000000	0.0000000	0.0003640	0.0003640	75.15	0.68	0
PRIMERO 42 1	P-DP	182.46	293.94	124.49	210.78	0.0000000	0.0000000	0.0295840	0.0295840	76.19	1.96	0
PRIMERO 42 A 2	P-DP	13.15	0.18	10.71	0.18	0.0000000	0.0000000	0.0295840	0.0295840	76.19	1.96	0
PRIMERO 42 B3 3	P-DP	85.03	59.06	57.37	42.36	0.0000000	0.0000000	0.0295840	0.0295840	76.19	1.96	0
PRIMERO 42 C 5	P-DP	34.58	20.59	27.45	20.59	0.0000000	0.0000000	0.0295840	0.0295840	76.19	1.96	0
PRIMERO 42 D 6	P-DP	8.21	1.64	6.57	1.64	0.0000000	0.0000000	0.0369800	0.0369800	76.19	1.96	0
PRISCILLA 23-14 1LS	P-DP	346.85	1,600.03	148.51	353.40	0.0000000	0.0000000	0.0003366	0.0003366	76.19	1.96	0
PRISCILLA 23-14 2MS	P-DP	229.02	1,360.59	110.69	314.15	0.0000000	0.0000000	0.0002950	0.0002950	76.19	1.96	0
PRISCILLA 23-14 3A	P-DP	518.57	1,158.44	213.40	314.11	0.0000000	0.0000000	0.0003038	0.0003038	76.19	1.96	0
PRISCILLA 23-14 4AH	P-DP	482.47	916.47	411.24	594.10	0.0000000	0.0000000	0.0002950	0.0002950	76.19	1.96	0
PRISCILLA 23-14 4LS	P-DP	450.06	933.28	189.17	263.19	0.0000000	0.0000000	0.0003038	0.0003038	76.19	1.96	0
PRISCILLA 23-14 4SH	P-DP	579.89	764.84	483.40	466.48	0.0000000	0.0000000	0.0002950	0.0002950	76.19	1.96	0
PRISCILLA 23-14 5A	P-DP	333.09	1,797.92	160.94	459.22	0.0000000	0.0000000	0.0003038	0.0003038	76.19	1.96	0
PRISCILLA 23-14 6LS	P-DP	448.19	2,691.65	186.16	654.88	0.0000000	0.0000000	0.0003038	0.0003038	76.19	1.96	0
PRISCILLA 23-14 7MS	P-DP	344.10	118.35	249.19	87.50	0.0000000	0.0000000	0.0002950	0.0002950	76.19	1.96	0
PRONGHORN B 34-166-165 WA 2H	P-DP	696.56	1,864.05	206.03	523.92	0.0000110	0.0000110	0.0000088	0.0000088	75.15	0.68	1,200

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PRONGHORN C 34-166-165 WB 3H	P-DP	487.52	1,355.97	182.77	407.17	0.0000110	0.0000110	0.0000088	0.0000088	75.15	0.68	1,200
PRONTO 1H	P-DP	294.14	3,270.53	163.52	1,673.78	0.0000000	0.0000000	0.0003630	0.0003630	75.15	0.68	0
PRUETT 20 2	P-DP	232.34	422.45	186.99	321.77	0.0000000	0.0000000	0.0000410	0.0000410	75.15	0.68	0
PRUETT 20 4	P-DP	190.32	173.93	154.39	136.46	0.0000000	0.0000000	0.0000410	0.0000410	75.15	0.68	0
PRUETT 20 5H	P-DP	80.56	231.76	58.58	155.90	0.0000000	0.0000000	0.0000410	0.0000410	75.15	0.68	0
PRUETT 20 6H	P-DP	395.97	731.87	294.99	519.13	0.0000000	0.0000000	0.0000410	0.0000410	75.15	0.68	0
PRUETT 23 1	P-DP	103.32	17,256.73	70.17	16,891.46	0.0000000	0.0000000	0.0000690	0.0000690	75.15	0.68	0
PRUETT 23 2H	P-DP	155.71	98.15	121.50	97.75	0.0000000	0.0000000	0.0000690	0.0000690	75.15	0.68	0
PRUETT 23A 1	P-DP	333.88	535.13	252.48	400.77	0.0000000	0.0000000	0.0000690	0.0000690	75.15	0.68	0
PRUETT 23A 2H	P-DP	229.48	340.34	140.79	211.61	0.0000000	0.0000000	0.0000690	0.0000690	75.15	0.68	0
PUGGLE E WYN JF 4H	P-DP	0.00	14,573.73	0.00	10,992.47	0.0000000	0.0000000	0.1107180	0.1107180	73.94	1.98	0
PUGGLE E WYN JF 6H	P-DP	0.00	15,005.61	0.00	10,885.33	0.0000000	0.0000000	0.1107180	0.1107180	73.94	1.98	0
PUGGLE W WYN JF 2H	P-DP	0.00	9,648.74	0.00	9,164.85	0.0000000	0.0000000	0.1033930	0.1033930	73.94	1.98	0
QUESO 34-153 UNIT 1H	P-DP	739.25	2,274.06	583.18	1,545.46	0.0000000	0.0000000	0.0030210	0.0030210	75.15	0.68	0
QUESO 34-153 UNIT 2H	P-DP	796.54	2,515.00	627.00	1,838.28	0.0000000	0.0000000	0.0030210	0.0030210	75.15	0.68	0
QUICK SILVER 55-1-18-19 A 12H	P-DP	435.04	2,612.45	138.94	734.34	0.0000000	0.0000000	0.0000710	0.0000710	76.15	-0.83	0
QUICK SILVER 55-1-18-19 B 21H	P-DP	377.04	2,616.55	126.11	858.70	0.0000000	0.0000000	0.0000710	0.0000710	76.15	-0.83	0
QUICK SILVER 55-1-18-19 C 13H	P-DP	756.76	5,698.39	250.61	1,480.82	0.0000000	0.0000000	0.0000710	0.0000710	76.15	-0.83	0
QUICK SILVER 55-1-7 UNIT 1H	P-DP	684.04	3,471.23	458.71	2,203.65	0.0000000	0.0000000	0.0001410	0.0001410	76.15	-0.83	0
QUITO, S. W. (DELAWARE) UNIT 801	P-DP	0.38	18.72	0.38	18.72	0.0000000	0.0000000	0.0003640	0.0003640	75.15	0.68	0
RAGLAND 2 6	P-DP	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0062500	0.0062500	75.89	1.34	0
RAGLAND-ANDERSON 47A 1H	P-DP	509.45	834.82	361.27	499.10	0.0000000	0.0000000	0.0050370	0.0050370	75.89	1.34	0
RAGLAND-ANDERSON 47B 2H	P-DP	537.67	1,208.97	364.76	576.68	0.0000000	0.0000000	0.0050320	0.0050320	75.89	1.34	0
RAGLAND-ANDERSON 47C 3H	P-DP	439.81	913.02	315.22	512.94	0.0000000	0.0000000	0.0050330	0.0050330	75.89	1.34	0
RAINIER 55-1-28 UNIT 1H	P-DP	834.64	3,333.00	583.03	2,078.62	0.0000000	0.0000000	0.0000620	0.0000620	76.15	-0.83	0
RAMBO E2 08 17 STATE COM 001H	P-DP	291.62	172.20	179.88	93.72	0.0000000	0.0000000	0.0004830	0.0004830	76.17	1.13	0
RAMBO E2 08 17 STATE COM 002H	P-DP	369.62	295.47	223.84	164.77	0.0000000	0.0000000	0.0004830	0.0004830	76.17	1.13	0
RATHKAMP UNIT 1H	P-DP	168.51	1,002.21	164.75	974.54	0.0000000	0.0000000	0.0097130	0.0097130	74.40	1.94	0
RATHKAMP UNIT 2H	P-DP	121.04	726.43	121.04	726.43	0.0000000	0.0000000	0.0097130	0.0097130	74.40	1.94	0
RATHKAMP UNIT 3H	P-DP	133.22	1,218.05	126.32	1,166.88	0.0000000	0.0000000	0.0097130	0.0097130	74.40	1.94	0
RATHKAMP UNIT 4H	P-DP	78.28	1,050.24	78.28	821.50	0.0000000	0.0000000	0.0097130	0.0097130	74.40	1.94	0
REBEL 3-35B5	P-DP	173.87	850.50	173.40	818.20	0.0000000	0.0000000	0.0006770	0.0006770	60.48	1.70	0
REED 24 UNIT 2H	P-DP	601.94	709.88	520.71	707.27	0.0000000	0.0000000	0.0002960	0.0002960	76.15	-0.83	0
REED 24 UNIT 4H	P-DP	235.94	395.28	201.10	320.93	0.0000000	0.0000000	0.0002960	0.0002960	76.15	-0.83	0
REED 24 UNIT 5H	P-DP	707.71	1,993.93	568.54	1,465.45	0.0000000	0.0000000	0.0002960	0.0002960	76.15	-0.83	0
REED 24 UNIT 7H	P-DP	736.88	2,081.46	597.82	1,637.13	0.0000000	0.0000000	0.0002960	0.0002960	76.15	-0.83	0
REED 24 UNIT 8H	P-DP	614.15	652.33	498.39	613.53	0.0000000	0.0000000	0.0002960	0.0002960	76.15	-0.83	0

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LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
REITZ UNIT 3H	P-DP	0.00	12,802.18	0.00	6,562.98	0.0000000	0.0000000	0.0040320	0.0040320	67.06	2.04	0
REITZ UNIT 5H	P-DP	0.00	12,283.13	0.00	10,769.78	0.0000000	0.0000000	0.0040320	0.0040320	67.06	2.04	0
RENDEZVOUS NORTH POOLED UNIT	1LAP-DP	1,099.48	798.54	822.01	534.36	0.0000000	0.0000000	0.0002750	0.0002750	75.15	0.68	0
RENDEZVOUS NORTH POOLED UNIT	9UAP-DP	745.12	1,316.15	534.59	912.77	0.0000000	0.0000000	0.0002750	0.0002750	75.15	0.68	0
RICHARD E LEHMAN SWITZ9BHSU	P-DP	0.00	17,547.69	0.00	12,990.19	0.0000000	0.0000000	0.0005060	0.0005060	73.94	1.81	0
RICHARD E LEHMAN SWITZ9DHSU	P-DP	0.00	16,038.00	0.00	13,385.54	0.0000000	0.0000000	0.0005060	0.0005060	73.94	1.81	0
RICHMOND 39 2H	P-DP	536.22	2,698.42	447.07	2,030.89	0.0000000	0.0000000	0.0001200	0.0001200	75.81	1.34	0
RICHMOND 39 3H	P-DP	486.88	3,364.63	332.63	1,683.96	0.0000000	0.0000000	0.0001200	0.0001200	75.81	1.34	0
RICHMOND W STATE 4239 A-A 70H	P-DP	387.43	2,520.64	243.66	1,424.20	0.0000000	0.0000000	0.0000420	0.0000420	75.81	1.34	0
RICHMOND W STATE 4239 A-B 71H	P-DP	382.57	3,221.83	255.65	1,767.36	0.0000000	0.0000000	0.0000420	0.0000420	75.81	1.34	0
RICHMOND W STATE 4239 A-C 72H	P-DP	184.00	1,751.91	117.51	950.36	0.0000000	0.0000000	0.0000420	0.0000420	75.81	1.34	0
RICHMOND W STATE 4239 A-D 73H	P-DP	217.37	2,067.81	139.27	1,129.30	0.0000000	0.0000000	0.0000420	0.0000420	75.81	1.34	0
RICHMOND W. STATE 4239 A5 6H	P-DP	180.47	3,269.73	62.35	1,004.87	0.0000000	0.0000000	0.0000440	0.0000440	75.81	1.34	0
RICHMOND W. STATE 4239 A6 11UA	P-DP	261.90	2,436.97	114.93	768.96	0.0000000	0.0000000	0.0000420	0.0000420	75.81	1.34	0
RICHMOND W. STATE 4239 A7 7LA	P-DP	142.05	1,143.28	63.68	467.52	0.0000000	0.0000000	0.0000040	0.0000040	75.81	1.34	0
RIO GRANDE 12-24-C 36WB	P-DP	542.60	1,824.71	148.18	206.05	0.0000000	0.0000000	0.0004270	0.0004270	75.89	1.34	0
RIO GRANDE 12-24-D 42LS	P-DP	487.64	553.04	111.23	105.62	0.0000000	0.0000000	0.0005200	0.0005200	75.89	1.34	0
RIO GRANDE 12-24-E 42WA	P-DP	560.30	1,257.59	203.26	237.93	0.0000000	0.0000000	0.0005210	0.0005210	75.89	1.34	0
RIO GRANDE 12-24-F 48WB	P-DP	384.34	1,336.27	148.97	222.07	0.0000000	0.0000000	0.0004570	0.0004570	75.89	1.34	0
RIO GRANDE 12-24-G 52WA	P-DP	517.18	1,408.57	173.02	203.66	0.0000000	0.0000000	0.0005380	0.0005380	75.89	1.34	0
RIO GRANDE 12-24-H 52LS	P-DP	418.80	947.04	150.26	144.04	0.0000000	0.0000000	0.0005360	0.0005360	75.89	1.34	0
RISING SUN 40-33 1AH	P-DP	429.14	900.79	309.10	346.85	0.0000000	0.0000000	0.0140130	0.0140130	76.19	1.96	0
RISING SUN B 1LS	P-DP	293.64	907.68	119.88	220.57	0.0000000	0.0000000	0.0106210	0.0106210	76.19	1.96	0
RISING SUN C 2A	P-DP	369.49	646.67	198.41	256.23	0.0000000	0.0000000	0.0069960	0.0069960	76.19	1.96	0
RISING SUN C 3LS	P-DP	145.08	173.97	76.46	64.30	0.0000000	0.0000000	0.0106500	0.0106500	76.19	1.96	0
RISING SUN D 4A	P-DP	417.19	1,023.05	207.46	228.20	0.0000000	0.0000000	0.0070220	0.0070220	76.19	1.96	0
RIVER CAT 57-33 A 1WA	P-DP	780.01	2,670.67	431.02	1,389.83	0.0000000	0.0000000	0.0006220	0.0006220	75.15	0.68	0
RIVER CAT 57-33 B 2BS	P-DP	352.12	1,108.96	194.70	509.97	0.0000000	0.0000000	0.0007020	0.0007020	75.15	0.68	0
RIVER CAT 57-33 C 3TS	P-DP	396.78	1,311.59	196.55	518.93	0.0000000	0.0000000	0.0014010	0.0014010	75.15	0.68	0
ROADRUNNER 1	P-DP	30.73	101.88	25.07	80.09	0.0000000	0.0000000	0.0035090	0.0035090	75.15	0.68	0
ROADRUNNER 2	P-DP	42.77	967.70	34.11	946.82	0.0000000	0.0000000	0.0035090	0.0035090	75.15	0.68	0
ROBYN LEE C 3H	P-DP	155.29	413.35	26.92	36.63	0.0000000	0.0000000	0.0001621	0.0001621	77.02	1.02	0
ROBYN LEE D 4H	P-DP	200.68	367.01	35.05	43.63	0.0000000	0.0000000	0.0001621	0.0001621	77.02	1.02	0
ROBYN LEE I 9H	P-DP	236.90	336.65	30.58	41.91	0.0000000	0.0000000	0.0004880	0.0004880	77.02	1.02	0
ROBYN LEE J 10H	P-DP	167.78	236.26	23.36	29.94	0.0000000	0.0000000	0.0004880	0.0004880	77.02	1.02	0
ROCA UNIT 7 1	P-DP	511.40	715.01	426.66	638.65	0.0000000	0.0000000	0.0006590	0.0006590	75.15	0.68	0
ROCA UNIT 7 2H	P-DP	285.61	452.06	233.73	408.72	0.0000000	0.0000000	0.0006590	0.0006590	75.15	0.68	0

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ROI TAN A 1A	P-DP	264.98	797.89	96.49	173.48	0.0000000	0.0000000	0.0028210	0.0028210	76.19	1.96	0
ROI TAN B 2A	P-DP	427.61	635.14	137.39	139.74	0.0000000	0.0000000	0.0028210	0.0028210	76.19	1.96	0
ROI TAN B 3LS	P-DP	243.14	869.30	88.39	153.55	0.0000000	0.0000000	0.0028210	0.0028210	76.19	1.96	0
ROI TAN C 4A	P-DP	346.14	949.57	125.25	199.73	0.0000000	0.0000000	0.0028210	0.0028210	76.19	1.96	0
ROI TAN D 5A	P-DP	400.06	750.43	132.31	167.68	0.0000000	0.0000000	0.0028210	0.0028210	76.19	1.96	0
ROI TAN E 6A	P-DP	163.62	293.74	90.35	113.84	0.0000000	0.0000000	0.0028210	0.0028210	76.19	1.96	0
ROI TAN F 7LS	P-DP	305.42	280.79	85.40	74.09	0.0000000	0.0000000	0.0028210	0.0028210	76.19	1.96	0
ROI TAN F 8A	P-DP	129.61	257.97	49.27	63.98	0.0000000	0.0000000	0.0028210	0.0028210	76.19	1.96	0
ROSS NW WHL BL 1H	P-DP	0.00	34,752.59	0.00	10,833.67	0.0000000	0.0000000	0.0244950	0.0244950	67.06	2.04	0
ROUGAROU UNIT 36-48 5AH	P-DP	769.03	484.43	435.63	245.12	0.0000000	0.0000000	0.0225450	0.0225450	73.67	3.34	0
ROUGAROU UNIT 36-48 6AH	P-DP	235.81	205.91	85.86	63.86	0.0000000	0.0000000	0.0225450	0.0225450	73.67	3.34	0
ROXY CRC JF 1H	P-DP	0.00	9,440.06	0.00	7,819.66	0.0000000	0.0000000	0.0396140	0.0396140	73.94	1.98	0
ROXY N CRC JF 3H	P-DP	0.00	10,924.42	0.00	9,209.56	0.0000000	0.0000000	0.0099980	0.0099980	73.94	1.98	0
ROXY NE CRC JF 5H	P-DP	0.00	11,026.36	0.00	9,365.19	0.0000000	0.0000000	0.0034340	0.0034340	73.94	1.98	0
RUSTLER A UNIT 3H	P-DP	559.31	2,376.03	378.29	1,673.90	0.0000000	0.0000000	0.0004680	0.0004680	76.15	-0.83	0
RUSTLER A UNIT 4H	P-DP	1,220.13	382.78	807.94	367.29	0.0000000	0.0000000	0.0004680	0.0004680	76.15	-0.83	0
RUSTLER B UNIT 1H	P-DP	886.31	1,825.22	685.28	1,261.19	0.0000000	0.0000000	0.0004680	0.0004680	76.15	-0.83	0
RUSTLER B UNIT 3H	P-DP	967.28	1,564.34	712.50	1,067.95	0.0000000	0.0000000	0.0004680	0.0004680	76.15	-0.83	0
RUSTLER C UNIT 1H	P-DP	710.52	2,642.94	567.92	1,670.85	0.0000000	0.0000000	0.0004680	0.0004680	76.15	-0.83	0
RUSTLER C UNIT 2H	P-DP	563.20	199.59	368.57	197.28	0.0000000	0.0000000	0.0004680	0.0004680	76.15	-0.83	0
RUSTLER D UNIT 1H	P-DP	190.33	237.07	172.98	213.93	0.0000000	0.0000000	0.0004680	0.0004680	76.15	-0.83	0
RUSTLER D UNIT 2H	P-DP	322.48	2,226.32	256.83	1,402.96	0.0000000	0.0000000	0.0004680	0.0004680	76.15	-0.83	0
RUSTLER D UNIT 4H	P-DP	476.38	365.83	385.75	340.74	0.0000000	0.0000000	0.0004680	0.0004680	76.15	-0.83	0
RUSTLER D UNIT 5H	P-DP	429.06	318.94	348.83	298.69	0.0000000	0.0000000	0.0004680	0.0004680	76.15	-0.83	0
SABINE 39 1	P-DP	142.96	608.14	103.46	440.79	0.0000000	0.0000000	0.0023440	0.0023440	75.89	1.34	0
SABINE 39 2	P-DP	14.50	160.92	11.41	130.17	0.0000000	0.0000000	0.0023440	0.0023440	75.89	1.34	0
SADIE 33-10-4 1H	P-DP	1.06	12,346.26	1.06	9,689.09	0.0000000	0.0000000	0.0704640	0.0704640	69.42	2.07	0
SADIE 33-10-4 201H	P-DP	2.35	13,101.07	2.35	9,679.02	0.0000000	0.0000000	0.0704640	0.0704640	69.42	2.07	0
SADIE 33-10-4 205H	P-DP	0.67	16,996.10	0.67	12,681.72	0.0000000	0.0000000	0.0082760	0.0082760	69.42	2.07	0
SADIE 33-10-4 3H	P-DP	4.36	14,986.23	4.36	11,743.61	0.0000000	0.0000000	0.0306220	0.0306220	69.42	2.07	0
SADIE 33-10-4 5H	P-DP	1.74	13,950.50	1.74	10,976.16	0.0000000	0.0000000	0.0309100	0.0309100	69.42	2.07	0
SAND DOLLAR UNIT 1	P-DP	35.00	38.16	30.93	38.16	0.0000000	0.0000000	0.0032220	0.0032220	76.19	1.96	0
SANTANA 29 2H	P-DP	231.93	4,873.70	182.69	4,015.68	0.0000000	0.0000000	0.0035480	0.0035480	75.81	1.34	0
SASQUATCH UNIT 36-24 1AH	P-DP	580.46	615.76	342.31	421.19	0.0000000	0.0000000	0.0133640	0.0133640	73.67	3.34	0
SASQUATCH UNIT 36-24 2AH	P-DP	308.03	883.20	164.54	323.46	0.0000000	0.0000000	0.0133640	0.0133640	73.67	3.34	0
SASQUATCH UNIT 36-24 3AH	P-DP	302.25	459.28	162.60	117.88	0.0000000	0.0000000	0.0133640	0.0133640	73.67	3.34	0
SAU 25 1B	P-DP	46.78	298.70	42.29	254.57	0.0000000	0.0000000	0.0014580	0.0014580	75.14	2.00	0

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SAU 25 1C	P-DP	26.91	185.37	25.98	177.07	0.0000000	0.0000000	0.0014580	0.0014580	75.14	2.00	0
SAU 25-2 2C	P-DP	31.13	161.52	29.95	156.36	0.0000000	0.0000000	0.0014580	0.0014580	75.14	2.00	0
SAU MARINER 25-2A 2A	P-DP	58.01	196.95	55.00	187.57	0.0000000	0.0000000	0.0014580	0.0014580	75.14	2.00	0
SAU MARINER 29-3 3	P-DP	27.24	280.46	27.24	280.46	0.0000000	0.0000000	0.0014580	0.0014580	75.14	2.00	0
SAU MARINER 29-3B 3B	P-DP	19.26	253.34	19.26	253.34	0.0000000	0.0000000	0.0014580	0.0014580	75.14	2.00	0
SAU MARINER 29-3B 3C	P-DP	57.23	317.60	57.23	317.60	0.0000000	0.0000000	0.0014580	0.0014580	75.14	2.00	0
SCATTER 15-10 1AH	P-DP	527.25	470.55	410.02	272.04	0.0000000	0.0000000	0.0006310	0.0006310	76.19	1.96	0
SCATTER 15-10 2AH	P-DP	409.25	1,437.59	323.50	842.81	0.0000000	0.0000000	0.0006310	0.0006310	76.19	1.96	0
SCATTER 15-10 2SH	P-DP	577.36	1,487.05	439.08	841.63	0.0000000	0.0000000	0.0006310	0.0006310	76.19	1.96	0
SCATTER GINGER 15-27 (ALLOC-D) 4SA	P-DP	506.49	1,848.98	271.57	486.34	0.0000000	0.0000000	0.0006580	0.0006580	76.19	1.96	0
SCATTER GINGER 15-27 (ALLOC-D) 4SS	P-DP	501.51	2,119.78	269.60	547.60	0.0000000	0.0000000	0.0006580	0.0006580	76.19	1.96	0
SCATTER TISH 10-46 (ALLOC-D) 4NA	P-DP	560.68	2,069.71	310.18	530.72	0.0000000	0.0000000	0.0180470	0.0180470	76.19	1.96	0
SCATTER TISH 10-46 (ALLOC-D) 4NS	P-DP	471.43	1,563.14	261.43	400.24	0.0000000	0.0000000	0.0180700	0.0180700	76.19	1.96	0
SCHWALBE-SONOMA STATE 120 1H	P-DP	269.38	3,134.15	202.82	2,061.83	0.0000000	0.0000000	0.0000390	0.0000390	75.81	1.34	0
SHADRACH 68 UNIT 134H	P-DP	332.72	4,145.29	280.04	2,119.62	0.0000000	0.0000000	0.0009550	0.0009550	75.81	1.34	0
SHADRACH 68 UNIT 1H	P-DP	700.92	5,500.90	527.67	3,890.41	0.0000000	0.0000000	0.0009550	0.0009550	75.81	1.34	0
SHADRACH 68 UNIT 223H	P-DP	513.97	3,599.32	364.39	2,033.36	0.0000000	0.0000000	0.0009550	0.0009550	75.81	1.34	0
SHADRACH 68 UNIT 2H	P-DP	687.95	2,698.42	486.30	1,796.18	0.0000000	0.0000000	0.0009550	0.0009550	75.81	1.34	0
SHADRACH 68 UNIT 324H	P-DP	488.48	3,542.02	390.55	2,010.82	0.0000000	0.0000000	0.0009550	0.0009550	75.81	1.34	0
SHADRACH 68 UNIT 332H	P-DP	480.37	3,106.30	337.47	1,623.06	0.0000000	0.0000000	0.0009550	0.0009550	75.81	1.34	0
SHADRACH MOSES CANTALOUPE 221H	P-DP	363.52	4,384.79	302.98	1,863.83	0.0000000	0.0000000	0.0004690	0.0004690	75.81	1.34	0
SHANNON 210470 3C	P-DP	0.01	17,145.43	0.01	12,751.32	0.0000000	0.0000000	0.0000130	0.0000130	67.06	2.04	0
SHANNON 210470 4B	P-DP	0.02	19,782.79	0.02	14,322.59	0.0000000	0.0000000	0.0000130	0.0000130	67.06	2.04	0
SHANNON 211271 1B	P-DP	0.01	15,259.08	0.01	11,990.25	0.0000000	0.0000000	0.0147320	0.0147320	67.06	2.04	0
SHANNON 211271 2A	P-DP	0.01	16,779.44	0.01	12,615.98	0.0000000	0.0000000	0.0147320	0.0147320	67.06	2.04	0
SHENANDOAH 11-2-58 H 1W	P-DP	323.79	420.34	240.17	251.84	0.0000000	0.0000000	0.0003770	0.0003770	76.19	1.96	0
SHENANDOAH 11-2-58 H 2WA	P-DP	277.95	954.13	197.71	517.57	0.0000000	0.0000000	0.0003770	0.0003770	76.19	1.96	0
SHEPARD 5-2C5	P-DP	153.39	580.28	118.45	490.88	0.0000000	0.0000000	0.0004830	0.0004830	60.48	1.70	0
SHERROD UNIT 3903	P-DP	30.26	86.84	26.10	85.83	0.0000000	0.0000000	0.0014590	0.0014590	75.14	2.00	0
SHERROD UNIT 903	P-DP	20.99	27.68	17.61	27.12	0.0000000	0.0000000	0.0014590	0.0014590	75.14	2.00	0
SHINABERRY MILDRED K 1	P-DP	3.99	124.72	3.99	124.72	0.0000000	0.0000000	0.0749400	0.0749400	73.94	1.98	0
SHIRLEY -B- 3815R	P-DP	92.25	134.63	70.45	82.71	0.0000000	0.0000000	0.0140630	0.0140630	76.66	1.00	0
SHIRLEY 3806	P-DP	77.82	88.92	65.30	75.66	0.0000000	0.0000000	0.0140630	0.0140630	76.66	1.00	0
SHIRLEY 3807	P-DP	26.99	52.99	21.24	43.61	0.0000000	0.0000000	0.0140630	0.0140630	76.66	1.00	0
SHIRLEY 3808	P-DP	50.17	73.99	39.70	60.46	0.0000000	0.0000000	0.0140630	0.0140630	76.66	1.00	0
SHOSHONE A 34-166-165 5201H	P-DP	630.32	1,528.03	471.38	1,490.74	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
SHOSHONE B 34-166-165 TB 2H	P-DP	417.84	985.82	154.24	305.07	0.0000227	0.0000227	0.0000266	0.0000266	75.15	0.68	1,200

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LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
SHOSHONE C 34-166-165 WA 3H	P-DP	614.55	2,441.95	190.34	460.83	0.0000222	0.0000222	0.0000267	0.0000267	75.15	0.68	1,200
SHRINERS 2-10C5	P-DP	244.75	1,628.70	207.59	1,305.26	0.0000000	0.0000000	0.0004710	0.0004710	60.48	1.70	0
SIDWELL SE WHL BL 10H	P-DP	0.00	8,213.28	0.00	6,558.33	0.0000000	0.0000000	0.0340850	0.0340850	67.06	2.04	0
SIDWELL SE WHL BL 8H	P-DP	0.00	9,332.13	0.00	6,880.82	0.0000000	0.0000000	0.0340850	0.0340850	67.06	2.04	0
SIDWELL SW WHL BL 2H	P-DP	0.00	10,144.14	0.00	5,660.51	0.0000000	0.0000000	0.0068420	0.0068420	67.06	2.04	0
SIDWELL SW WHL BL 4H	P-DP	0.00	10,310.66	0.00	9,791.36	0.0000000	0.0000000	0.0068420	0.0068420	67.06	2.04	0
SILVERADO 40-1 A 1JM	P-DP	757.70	2,224.85	437.95	709.16	0.0000000	0.0000000	0.0016330	0.0016330	75.89	1.34	0
SILVERADO 40-1 B 2LS	P-DP	505.88	1,042.87	366.40	542.27	0.0000000	0.0000000	0.0016340	0.0016340	75.89	1.34	0
SILVERADO 40-1 C 3WA	P-DP	434.98	894.83	265.47	395.11	0.0000000	0.0000000	0.0016340	0.0016340	75.89	1.34	0
SILVERADO 40-1 E 5JM	P-DP	596.51	1,512.89	382.62	680.61	0.0000000	0.0000000	0.0016280	0.0016280	75.89	1.34	0
SILVERADO 40-1 F 6LS	P-DP	413.63	1,254.48	277.86	591.85	0.0000000	0.0000000	0.0016340	0.0016340	75.89	1.34	0
SILVERADO 40-1 G 7LS	P-DP	419.62	1,908.62	287.48	767.23	0.0000000	0.0000000	0.0016340	0.0016340	75.89	1.34	0
SILVERADO 40-1 H 8WA	P-DP	660.44	2,083.66	492.17	938.90	0.0000000	0.0000000	0.0016340	0.0016340	75.89	1.34	0
SILVERADO 40-1 I 9WB	P-DP	417.90	1,774.23	268.69	773.25	0.0000000	0.0000000	0.0016330	0.0016330	75.89	1.34	0
SILVERADO 40-1 J 10WB	P-DP	359.65	2,937.96	234.81	1,307.51	0.0000000	0.0000000	0.0016300	0.0016300	75.89	1.34	0
SILVERADO 40-1 K 11WA	P-DP	673.65	3,119.04	492.56	1,279.48	0.0000000	0.0000000	0.0016330	0.0016330	75.89	1.34	0
SIMPSON SMITH 0844 A 1WH	P-DP	898.08	1,434.77	640.24	575.38	0.0000000	0.0000000	0.0078080	0.0078080	76.19	1.96	0
SIMPSON SMITH A 08-44 1SH	P-DP	556.51	1,654.58	233.57	395.51	0.0000000	0.0000000	0.0022670	0.0022670	76.19	1.96	0
SIMPSON SMITH B 08-44 2AH	P-DP	510.04	1,445.52	239.67	285.13	0.0000000	0.0000000	0.0051130	0.0051130	76.19	1.96	0
SIMPSON SMITH C 08-44 2SH	P-DP	477.28	1,580.84	221.60	355.78	0.0000000	0.0000000	0.0072210	0.0072210	76.19	1.96	0
SIMPSON SMITH D 08-44 3AH	P-DP	458.04	1,208.77	218.35	264.02	0.0000000	0.0000000	0.0080200	0.0080200	76.19	1.96	0
SIMPSON SMITH E 08-44 3SH	P-DP	568.54	2,146.62	255.31	405.32	0.0000000	0.0000000	0.0022560	0.0022560	76.19	1.96	0
SIREN UNIT 36-48 1AH	P-DP	858.79	1,579.74	501.25	656.28	0.0000000	0.0000000	0.0216830	0.0216830	73.67	3.34	0
SIXTEEN PENNY NAIL 310 1LL	P-DP	260.82	554.03	248.02	502.61	0.0000000	0.0000000	0.0001430	0.0001430	75.89	1.34	0
SIXTEEN PENNY NAIL 310 2LM	P-DP	143.08	220.44	138.52	207.03	0.0000000	0.0000000	0.0001430	0.0001430	75.89	1.34	0
SIXTEEN PENNY NAIL 310 8JM	P-DP	488.32	2,364.89	294.98	1,065.67	0.0000000	0.0000000	0.0001450	0.0001450	75.89	1.34	0
SIXTEEN PENNY NAIL 310A 3LL	P-DP	228.49	493.37	176.88	362.54	0.0000000	0.0000000	0.0001440	0.0001440	75.89	1.34	0
SIXTEEN PENNY NAIL 310A 9JM	P-DP	146.15	1,666.55	101.95	746.44	0.0000000	0.0000000	0.0001440	0.0001440	75.89	1.34	0
SIXTEEN PENNY NAIL 310B 10JM	P-DP	204.36	78.58	140.51	48.09	0.0000000	0.0000000	0.0001450	0.0001450	75.89	1.34	0
SIXTEEN PENNY NAIL 310B 4LM	P-DP	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0001430	0.0001430	75.89	1.34	0
SIXTEEN PENNY NAIL 310B 5LL	P-DP	207.98	1,090.56	204.36	813.29	0.0000000	0.0000000	0.0001430	0.0001430	75.89	1.34	0
SIXTEEN PENNY NAIL 310C 11JM	P-DP	314.83	1,153.65	199.89	561.44	0.0000000	0.0000000	0.0001450	0.0001450	75.89	1.34	0
SIXTEEN PENNY NAIL 310C 6LM	P-DP	287.18	1,184.57	256.73	821.88	0.0000000	0.0000000	0.0001440	0.0001440	75.89	1.34	0
SIXTEEN PENNY NAIL 310C 7LL	P-DP	167.09	599.45	155.23	421.54	0.0000000	0.0000000	0.0001430	0.0001430	75.89	1.34	0
SMASHOSAURUS 3	P-DP	0.00	23,807.19	0.00	19,304.02	0.0000000	0.0000000	0.0000760	0.0000760	67.06	2.04	0
SMASHOSAURUS 5	P-DP	0.00	19,395.10	0.00	16,541.87	0.0000000	0.0000000	0.0115190	0.0115190	67.06	2.04	0
SON 136 1	P-DP	46.70	141.87	33.40	93.68	0.0000000	0.0000000	0.0072890	0.0072890	75.89	1.34	0

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SON 136 2	P-DP	46.65	138.86	30.95	83.19	0.0000000	0.0000000	0.0072890	0.0072890	75.89	1.34	0
SPARROW 22 001	P-DP	21.93	20.66	18.12	15.96	0.0000000	0.0000000	0.0174023	0.0174023	76.17	1.13	0
SPIRE 226-34 UNIT 1H	P-DP	282.17	5,159.87	197.23	2,838.44	0.0000000	0.0000000	0.0011700	0.0011700	75.15	0.68	0
SPITFIRE 1H	P-DP	0.00	10,992.55	0.00	10,369.82	0.0000000	0.0000000	0.0001650	0.0001650	67.06	2.04	0
SPITFIRE 3H	P-DP	0.00	7,975.55	0.00	7,542.77	0.0000000	0.0000000	0.0001650	0.0001650	67.06	2.04	0
SPORT E WYN JF 3H	P-DP	0.00	16,123.63	0.00	9,259.40	0.0000000	0.0000000	0.0750150	0.0750150	73.94	1.98	0
SPORT W WYN JF 1H	P-DP	0.00	16,220.64	0.00	9,840.49	0.0000000	0.0000000	0.0906970	0.0906970	73.94	1.98	0
SPRABERRY DRIVER UNIT 132A	P-DP	77.70	85.86	69.84	69.06	0.0000000	0.0000000	0.0167720	0.0167720	76.00	1.19	0
SPRABERRY DRIVER UNIT 134A	P-DP	53.54	89.56	46.79	75.61	0.0000000	0.0000000	0.0167720	0.0167720	76.00	1.19	0
SPRABERRY DRIVER UNIT 135A	P-DP	197.41	96.17	195.08	84.84	0.0000000	0.0000000	0.0167720	0.0167720	76.00	1.19	0
SPRABERRY DRIVER UNIT 136A	P-DP	41.36	117.11	34.63	96.91	0.0000000	0.0000000	0.0167720	0.0167720	76.00	1.19	0
STATE EILAND 3-33 11H	P-DP	538.82	1,842.45	436.78	1,172.04	0.0000000	0.0000000	0.0005020	0.0005020	75.15	0.68	0
STATE EILAND 6047B-34 51H	P-DP	512.87	1,105.85	444.72	898.24	0.0000000	0.0000000	0.0004970	0.0004970	75.15	0.68	0
STATE MUDDY WATERS UNIT 2H	P-DP	240.00	3,461.97	194.58	2,527.89	0.0000000	0.0000000	0.0016880	0.0016880	75.81	1.34	0
STATE MUDDY WATERS UNIT 711H	P-DP	109.52	945.09	58.66	546.36	0.0000000	0.0000000	0.0016880	0.0016880	75.81	1.34	0
STATE MUDDY WATERS UNIT 731H	P-DP	104.51	2,198.70	86.20	1,488.73	0.0000000	0.0000000	0.0016880	0.0016880	75.81	1.34	0
STATE MUDDY WATERS UNIT 732H	P-DP	296.41	8,499.91	134.76	2,259.94	0.0000000	0.0000000	0.0016880	0.0016880	75.81	1.34	0
STATE MUDDY WATERS UNIT 733H	P-DP	160.41	1,863.57	109.54	1,262.67	0.0000000	0.0000000	0.0016880	0.0016880	75.81	1.34	0
STATE MUDDY WATERS UNIT 751H	P-DP	70.32	5,168.46	34.97	2,107.00	0.0000000	0.0000000	0.0016880	0.0016880	75.81	1.34	0
STELLA STATE 34-208 WRD UNIT 2H	P-DP	301.98	2,006.47	189.92	1,245.51	0.0000000	0.0000000	0.0002120	0.0002120	75.15	0.68	0
STICKLINE 1H	P-DP	681.19	8,189.59	391.54	4,382.83	0.0000000	0.0000000	0.0000280	0.0000280	75.15	0.68	0
STIMSON BURLEY -B- 1	P-DP	98.79	255.07	94.25	247.15	0.0000000	0.0000000	0.0002150	0.0002150	76.66	1.00	0
STIMSON BURLEY -B- 4	P-DP	84.54	271.77	79.58	257.35	0.0000000	0.0000000	0.0002150	0.0002150	76.66	1.00	0
STIMSON BURLEY -D- 1	P-DP	193.51	154.46	183.97	146.93	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
STIMSON BURLEY -E- 3DW	P-DP	26.46	70.09	9.93	18.05	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
STIMSON BURLEY -M- 1	P-DP	73.53	219.34	69.79	206.65	0.0000000	0.0000000	0.0002150	0.0002150	76.66	1.00	0
STIMSON-BURLEY -C- 1	P-DP	140.80	240.89	136.04	224.67	0.0000000	0.0000000	0.0001340	0.0001340	75.89	1.34	0
STIMSON-BURLEY -C- 3	P-DP	133.41	222.96	111.55	187.71	0.0000000	0.0000000	0.0001340	0.0001340	75.89	1.34	0
STIMSON-BURLEY 18 1	P-DP	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0002150	0.0002150	76.66	1.00	0
STIMSON-BURLEY 4	P-DP	63.83	302.88	63.61	300.24	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
STIMSON-BURLEY 6	P-DP	39.27	70.09	39.27	70.09	0.0000000	0.0000000	0.0002150	0.0002150	75.89	1.34	0
STIMSON-BURLEY K 1	P-DP	85.72	263.50	75.73	244.14	0.0000000	0.0000000	0.0002150	0.0002150	76.66	1.00	0
STIMSON-NAIL E17K 111H	P-DP	444.11	2,026.24	54.23	63.51	0.0000000	0.0000000	0.0001920	0.0001920	76.66	1.00	0
STIMSON-NAIL E17L 112H	P-DP	444.80	2,029.58	73.86	93.85	0.0000000	0.0000000	0.0001920	0.0001920	76.66	1.00	0
STIMSON-NAIL E17M 113H	P-DP	444.91	2,029.84	54.33	63.62	0.0000000	0.0000000	0.0001920	0.0001920	76.66	1.00	0
STIMSON-NAIL E17N 114H	P-DP	515.62	2,000.21	50.19	49.51	0.0000000	0.0000000	0.0001920	0.0001920	76.66	1.00	0
STIMSON-NAIL E17O 115H	P-DP	506.45	1,964.59	49.29	48.63	0.0000000	0.0000000	0.0001920	0.0001920	76.66	1.00	0

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STIMSON-NAIL E17P 116H	P-DP	506.13	1,963.41	49.26	48.60	0.0000000	0.0000000	0.0001920	0.0001920	76.66	1.00	0
STIMSON-NAIL E17Q 117H	P-DP	430.71	1,217.70	47.83	45.65	0.0000000	0.0000000	0.0001920	0.0001920	76.66	1.00	0
STIMSON-NAIL E17R 118H	P-DP	515.06	1,998.01	50.13	49.46	0.0000000	0.0000000	0.0001920	0.0001920	76.66	1.00	0
STIMSON-NAIL E17S 119H	P-DP	443.30	1,253.31	49.23	46.98	0.0000000	0.0000000	0.0001920	0.0001920	76.66	1.00	0
STIMSON-NAIL E17T 120H	P-DP	438.04	1,238.42	48.64	46.42	0.0000000	0.0000000	0.0001920	0.0001920	76.66	1.00	0
STIMSON-NAIL W17K 11H	P-DP	355.45	653.58	137.21	171.91	0.0000000	0.0000000	0.0000130	0.0000130	76.66	1.00	0
STIMSON-NAIL W17L 12H	P-DP	419.50	602.59	139.73	161.90	0.0000000	0.0000000	0.0000210	0.0000210	76.66	1.00	0
STIMSON-NAIL W17M 13H	P-DP	522.39	1,508.01	212.63	308.43	0.0000000	0.0000000	0.0000210	0.0000210	76.66	1.00	0
STIMSON-NAIL W17N 14H	P-DP	304.59	481.80	132.76	149.29	0.0000000	0.0000000	0.0000210	0.0000210	76.66	1.00	0
STIMSON-NAIL W17O 15H	P-DP	591.36	1,467.87	265.58	421.25	0.0000000	0.0000000	0.0000210	0.0000210	76.66	1.00	0
STIMSON-NAIL W17P 16H	P-DP	416.78	1,397.16	182.83	295.12	0.0000000	0.0000000	0.0000130	0.0000130	76.66	1.00	0
STIMSON-NAIL W17Q 17H	P-DP	357.87	758.64	141.55	167.90	0.0000000	0.0000000	0.0000130	0.0000130	76.66	1.00	0
STIMSON-NAIL W17R 18H	P-DP	369.06	637.57	134.27	219.43	0.0000000	0.0000000	0.0000130	0.0000130	76.66	1.00	0
STIMSON-NAIL W17S 19H	P-DP	774.59	3,126.20	276.03	427.00	0.0000000	0.0000000	0.0000130	0.0000130	76.66	1.00	0
STIMSON-NAIL W17T 20H	P-DP	332.07	385.07	150.03	159.16	0.0000000	0.0000000	0.0000130	0.0000130	76.66	1.00	0
STONE-GIST W45A 1H	P-DP	527.21	815.90	377.44	404.73	0.0000000	0.0000000	0.0031120	0.0031120	76.00	1.19	0
STONE-GIST W45B 2H	P-DP	453.11	489.14	338.12	405.77	0.0000000	0.0000000	0.0031560	0.0031560	76.00	1.19	0
STONE-GIST W45C 3H	P-DP	560.28	837.25	436.45	560.08	0.0000000	0.0000000	0.0031140	0.0031140	76.00	1.19	0
STONE-GIST W45I 9H	P-DP	253.61	380.46	201.33	257.07	0.0000000	0.0000000	0.0031130	0.0031130	76.00	1.19	0
STONE-GIST W45J 10H	P-DP	328.91	528.75	269.65	379.66	0.0000000	0.0000000	0.0031510	0.0031510	76.00	1.19	0
SUCCUBUS UNIT B 25-24 5AH	P-DP	203.49	167.73	64.25	32.43	0.0000000	0.0000000	0.0106540	0.0106540	73.67	3.34	0
SUCCUBUS UNIT B 25-24 8AH	P-DP	293.84	481.87	212.75	212.66	0.0000000	0.0000000	0.0106540	0.0106540	73.67	3.34	0
SUCCUBUS-ROUGAROU 24-37 7AH	P-DP	355.73	384.36	111.79	78.73	0.0000000	0.0000000	0.0106540	0.0106540	73.67	3.34	0
SUGARLOAF 74 1H	P-DP	518.03	1,252.44	415.77	1,224.12	0.0000000	0.0000000	0.0021900	0.0021900	75.81	1.34	0
SUGARLOAF 7475 10U C 10H	P-DP	319.77	1,996.16	126.54	681.43	0.0000000	0.0000000	0.0010540	0.0010540	75.81	1.34	0
SUGARLOAF 7475 1U B 1H	P-DP	384.83	2,090.50	243.38	1,006.85	0.0000000	0.0000000	0.0017860	0.0017860	75.81	1.34	0
SUGARLOAF 7475 2U B 2H	P-DP	330.71	1,481.02	258.05	1,104.84	0.0000000	0.0000000	0.0015460	0.0015460	75.81	1.34	0
SUGARLOAF 7475 3U A 3H	P-DP	784.24	2,965.01	640.64	2,239.52	0.0000000	0.0000000	0.0016110	0.0016110	75.81	1.34	0
SUGARLOAF 7475 4U A 4H	P-DP	460.46	1,967.91	175.55	583.73	0.0000000	0.0000000	0.0015440	0.0015440	75.81	1.34	0
SUGARLOAF 7475 5U B 5H	P-DP	377.82	2,347.80	153.00	699.62	0.0000000	0.0000000	0.0015340	0.0015340	75.81	1.34	0
SUGARLOAF 7475 6U A 6H	P-DP	499.20	2,392.27	198.94	756.05	0.0000000	0.0000000	0.0015450	0.0015450	75.81	1.34	0
SUGARLOAF 7475 7U A 7H	P-DP	378.05	2,048.67	166.00	588.52	0.0000000	0.0000000	0.0015370	0.0015370	75.81	1.34	0
SUGARLOAF 7475 8U A 8H	P-DP	473.05	1,839.02	194.61	841.07	0.0000000	0.0000000	0.0015120	0.0015120	75.81	1.34	0
SUGARLOAF 7475 9U B 9H	P-DP	406.16	2,631.05	162.94	786.75	0.0000000	0.0000000	0.0015500	0.0015500	75.81	1.34	0
SUGG A 141-140 (ALLOC-A) 1SM	P-DP	265.90	4,362.90	218.97	2,345.82	0.0000000	0.0000000	0.0121100	0.0121100	75.14	2.00	0
SUGG A 141-140 (ALLOC-B) 2SU	P-DP	171.20	2,906.50	141.80	1,718.65	0.0000000	0.0000000	0.0128240	0.0128240	75.14	2.00	0
SUGG A 141-140 (ALLOC-C) 3SM	P-DP	230.20	4,704.40	184.48	2,234.99	0.0000000	0.0000000	0.0124860	0.0124860	75.14	2.00	0

TABLE 8

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LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
SUGG A 141-140 (ALLOC-D) 4SU	P-DP	170.47	3,097.92	143.60	1,465.46	0.0000000	0.0000000	0.0122150	0.0122150	75.14	2.00	0
SUGG A 141-140 (ALLOC-E) 5RM	P-DP	178.84	4,741.30	153.28	2,477.10	0.0000000	0.0000000	0.0121540	0.0121540	75.14	2.00	0
SUGG A 141-140 (ALLOC-F) 6SM	P-DP	73.08	2,357.19	69.25	1,748.34	0.0000000	0.0000000	0.0121300	0.0121300	75.14	2.00	0
SUGG A 141-140 (ALLOC-F) 6SU	P-DP	125.07	2,458.36	116.63	1,469.99	0.0000000	0.0000000	0.0122160	0.0122160	75.14	2.00	0
SUGG A 141-140 (ALLOC-G) 7SM	P-DP	116.50	4,246.16	103.65	2,321.48	0.0000000	0.0000000	0.0122500	0.0122500	75.14	2.00	0
SUGG A 141-140 (ALLOC-G) 7SU	P-DP	120.82	4,319.99	108.79	2,192.03	0.0000000	0.0000000	0.0123400	0.0123400	75.14	2.00	0
SUGG A 141-140 (ALLOC-H) 8SM	P-DP	127.94	6,748.69	114.70	3,074.18	0.0000000	0.0000000	0.0121650	0.0121650	75.14	2.00	0
SUGG A 141-140 (ALLOC-H) 8SU	P-DP	130.20	2,827.52	116.94	1,870.64	0.0000000	0.0000000	0.0123360	0.0123360	75.14	2.00	0
SUNDOG A1 1LA	P-DP	228.62	611.87	228.62	611.87	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
SUNDOG A2 2LA	P-DP	278.49	559.61	237.09	469.08	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
SUNDOWN 4524LS	P-DP	410.83	955.79	327.89	510.49	0.0000000	0.0000000	0.0078090	0.0078090	76.19	1.96	0
SUNDOWN 4541WA	P-DP	964.74	1,542.51	649.68	647.38	0.0000000	0.0000000	0.0078090	0.0078090	76.19	1.96	0
SUNDOWN 4566WB	P-DP	591.51	1,340.72	491.42	741.38	0.0000000	0.0000000	0.0078090	0.0078090	76.19	1.96	0
SUSTR UNIT 1H	P-DP	202.76	1,446.92	179.21	702.52	0.0000000	0.0000000	0.0107180	0.0107180	73.55	1.70	0
TAMSULA 015-2	P-DP	0.00	146.92	0.00	146.16	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
TAMSULA 016-3	P-DP	0.00	228.07	0.00	227.00	0.0000000	0.0000000	0.1003470	0.1003470	73.94	1.41	0
TAMSULA 017-4	P-DP	0.00	193.94	0.00	186.25	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
TAMSULA 5	P-DP	0.00	28.72	0.00	28.18	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
TANNER WYN JF 2H	P-DP	0.00	13,461.65	0.00	11,596.38	0.0000000	0.0000000	0.1162520	0.1162520	73.94	1.98	0
TANNER WYN JF 4H	P-DP	0.00	17,234.06	0.00	13,573.30	0.0000000	0.0000000	0.1162520	0.1162520	73.94	1.98	0
TARGAC UNIT 1H	P-DP	177.67	780.44	164.02	648.05	0.0000000	0.0000000	0.0235040	0.0235040	73.55	1.70	0
TCB 39-34 1AH	P-DP	199.00	335.00	156.01	169.71	0.0000000	0.0000000	0.0000480	0.0000480	76.19	1.96	0
TCB 39-34 4AH	P-DP	581.90	535.35	392.67	272.46	0.0000000	0.0000000	0.0000480	0.0000480	76.19	1.96	0
TCB 39-34 4SH	P-DP	289.64	373.51	208.64	197.54	0.0000000	0.0000000	0.0000480	0.0000480	76.19	1.96	0
TCB A 1LS	P-DP	322.70	1,362.09	117.81	181.26	0.0000000	0.0000000	0.0000880	0.0000880	76.19	1.96	0
TCB B 2A	P-DP	439.64	1,075.74	165.73	202.33	0.0000000	0.0000000	0.0000880	0.0000880	76.19	1.96	0
TCM 3	P-DP	54.50	58.08	42.96	47.41	0.0000000	0.0000000	0.0070000	0.0070000	75.89	1.34	0
TCM 48L	P-DP	91.45	395.86	60.99	311.45	0.0000000	0.0000000	0.0070000	0.0070000	75.89	1.34	0
TEEWINOT A1 3LA	P-DP	279.55	567.59	68.08	95.90	0.0000000	0.0000000	0.0001670	0.0001670	75.15	0.68	0
TEEWINOT NORTH UNIT 4LA	P-DP	414.87	511.57	371.39	445.82	0.0000000	0.0000000	0.0004880	0.0004880	75.15	0.68	0
TEEWINOT SOUTH UNIT 5LA	P-DP	675.80	745.65	555.93	645.99	0.0000000	0.0000000	0.0004880	0.0004880	75.15	0.68	0
TESTA 5	P-DP	0.00	94.12	0.00	93.82	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
THE KING 45-04 1AH	P-DP	342.80	327.30	324.25	320.19	0.0000000	0.0000000	0.0022420	0.0022420	76.19	1.96	0
THE KING 45-04 1MS	P-DP	557.79	2,051.18	273.32	491.54	0.0000000	0.0000000	0.0022640	0.0022640	76.19	1.96	0
THE KING 45-04 1SH	P-DP	248.45	329.10	241.71	312.24	0.0000000	0.0000000	0.0022420	0.0022420	76.19	1.96	0
THE KING 45-04 C 3SA	P-DP	350.64	1,508.24	190.03	421.61	0.0000000	0.0000000	0.0022660	0.0022660	76.19	1.96	0
THE KING 45-04 C 3SS	P-DP	350.00	1,508.83	206.13	419.51	0.0000000	0.0000000	0.0022630	0.0022630	76.19	1.96	0

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THE KING 45-04 D 4MS	P-DP	354.35	2,110.43	205.91	520.19	0.0000000	0.0000000	0.0022720	0.0022720	76.19	1.96	0
THE KING 45-04 D 4SA	P-DP	367.52	973.62	222.01	352.65	0.0000000	0.0000000	0.0022640	0.0022640	76.19	1.96	0
THE KING 45-04 D 4SS	P-DP	348.56	2,089.42	205.01	512.40	0.0000000	0.0000000	0.0022710	0.0022710	76.19	1.96	0
THOMPSON E SMF JF 5H	P-DP	0.00	14,669.53	0.00	10,958.52	0.0000000	0.0000000	0.0014510	0.0014510	73.94	1.98	0
THOMPSON W SMF JF 1H	P-DP	0.00	14,156.72	0.00	11,562.00	0.0000000	0.0000000	0.0075890	0.0075890	73.94	1.98	0
THOMPSON W SMF JF 3H	P-DP	0.00	13,842.71	0.00	11,338.00	0.0000000	0.0000000	0.0075890	0.0075890	73.94	1.98	0
THORPE 1-74 LOV 2H	P-DP	54.67	391.30	49.52	372.90	0.0000000	0.0000000	0.0000800	0.0000800	76.15	-0.83	0
THORPE 1-74 LOV 3H	P-DP	448.29	1,100.40	341.64	782.98	0.0000000	0.0000000	0.0000800	0.0000800	76.15	-0.83	0
THORPE 1-74 LOV 4H	P-DP	275.16	431.02	249.31	372.61	0.0000000	0.0000000	0.0001590	0.0001590	76.15	-0.83	0
THUNDERBIRD UNIT 07-10 1AH	P-DP	414.37	415.93	364.75	344.70	0.0000000	0.0000000	0.0037450	0.0037450	73.67	3.34	0
THURMOND A137 ALLOC. A 10H	P-DP	370.01	2,819.77	284.28	1,753.80	0.0000000	0.0000000	0.0014490	0.0014490	75.81	1.34	0
TIGER 210187 2A	P-DP	0.00	11,370.44	0.00	9,477.97	0.0000000	0.0000000	0.0028920	0.0028920	67.06	2.04	0
TIGER 210187 3C	P-DP	0.00	10,114.20	0.00	8,750.67	0.0000000	0.0000000	0.0028920	0.0028920	67.06	2.04	0
TIGER 210187 5B	P-DP	0.00	8,385.48	0.00	7,424.05	0.0000000	0.0000000	0.0028920	0.0028920	67.06	2.04	0
TIGER 210475 4C	P-DP	0.00	8,904.86	0.00	7,823.41	0.0000000	0.0000000	0.0000080	0.0000080	67.06	2.04	0
TIGER 210476 1A	P-DP	0.00	10,921.60	0.00	9,302.28	0.0000000	0.0000000	0.0028520	0.0028520	67.06	2.04	0
TIGIWON 2627-C23 E 433H	P-DP	797.53	3,465.01	546.74	2,235.06	0.0000000	0.0000000	0.0004920	0.0004920	75.22	1.21	0
TIMMERMAN 14 1	P-DP	148.48	701.49	119.70	438.41	0.0000000	0.0000000	0.0000400	0.0000400	76.66	1.00	0
TIMMERMAN A1 403BH	P-DP	496.14	1,646.10	66.19	108.73	0.0000000	0.0000000	0.0006901	0.0006901	76.66	1.00	0
TIMMERMAN A10 411JH	P-DP	476.45	1,617.60	46.50	80.22	0.0000000	0.0000000	0.0006901	0.0006901	76.66	1.00	0
TIMMERMAN A2 413JH	P-DP	397.80	1,278.87	69.25	86.55	0.0000000	0.0000000	0.0006901	0.0006901	76.66	1.00	0
TIMMERMAN A3 402MH	P-DP	375.35	1,198.76	55.20	56.40	0.0000000	0.0000000	0.0006901	0.0006901	76.66	1.00	0
TIMMERMAN A4 402LH	P-DP	363.01	1,322.31	61.17	61.14	0.0000000	0.0000000	0.0006901	0.0006901	76.66	1.00	0
TIMMERMAN A5 402BH	P-DP	478.64	1,619.32	48.69	81.94	0.0000000	0.0000000	0.0006901	0.0006901	76.66	1.00	0
TIMMERMAN A6 412JH	P-DP	391.25	1,257.80	68.11	85.13	0.0000000	0.0000000	0.0006901	0.0006901	76.66	1.00	0
TIMMERMAN A7 401MH	P-DP	496.14	1,646.10	66.19	108.73	0.0000000	0.0000000	0.0006901	0.0006901	76.66	1.00	0
TIMMERMAN A8 401LH	P-DP	642.06	1,646.10	66.87	108.73	0.0000000	0.0000000	0.0006901	0.0006901	76.66	1.00	0
TIMMERMAN A9 401BH	P-DP	423.01	1,683.85	61.54	73.09	0.0000000	0.0000000	0.0006901	0.0006901	76.66	1.00	0
TIMMERMAN J1 2208MH	P-DP	513.71	1,332.73	398.52	695.49	0.0000000	0.0000000	0.0001190	0.0001190	76.66	1.00	0
TIMMERMAN J10 2206LH	P-DP	732.46	1,412.35	534.18	837.39	0.0000000	0.0000000	0.0001300	0.0001300	76.66	1.00	0
TIMMERMAN J11 2206BH	P-DP	489.99	2,144.26	374.03	1,434.26	0.0000000	0.0000000	0.0001300	0.0001300	76.66	1.00	0
TIMMERMAN J2 2208LH	P-DP	590.11	1,766.96	410.04	820.53	0.0000000	0.0000000	0.0001190	0.0001190	76.66	1.00	0
TIMMERMAN J3 2208BH	P-DP	392.08	2,473.22	307.72	1,401.51	0.0000000	0.0000000	0.0001190	0.0001190	76.66	1.00	0
TIMMERMAN J4 2207MH	P-DP	521.99	1,021.93	449.85	928.01	0.0000000	0.0000000	0.0001300	0.0001300	76.66	1.00	0
TIMMERMAN J5 2207LH	P-DP	455.44	1,114.61	371.47	820.55	0.0000000	0.0000000	0.0001300	0.0001300	76.66	1.00	0
TIMMERMAN J6 2207BH	P-DP	365.64	3,006.30	289.48	1,531.22	0.0000000	0.0000000	0.0001290	0.0001290	76.66	1.00	0
TIMMERMAN J7 2217LH	P-DP	465.50	1,544.86	354.00	972.38	0.0000000	0.0000000	0.0001280	0.0001280	76.66	1.00	0

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TIMMERMAN J8 2207CH	P-DP	162.29	854.95	156.82	833.21	0.0000000	0.0000000	0.0001290	0.0001290	76.66	1.00	0
TIMMERMAN J9 2206MH	P-DP	917.54	1,857.47	648.49	1,013.08	0.0000000	0.0000000	0.0001300	0.0001300	76.66	1.00	0
TIN STAR A L 33H	P-DP	710.46	5,130.73	487.06	3,103.44	0.0000000	0.0000000	0.0008000	0.0008000	75.81	1.34	0
TIN STAR B L 42H	P-DP	387.36	2,868.03	310.43	2,181.78	0.0000000	0.0000000	0.0006610	0.0006610	75.81	1.34	0
TIN STAR D U 46H	P-DP	580.87	5,610.89	433.09	3,844.67	0.0000000	0.0000000	0.0007870	0.0007870	75.81	1.34	0
TIPI CHAPMAN 34-163 1H	P-DP	283.16	827.76	253.47	763.29	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
TIPI CHAPMAN 34-163 2H	P-DP	357.86	699.17	299.82	635.31	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
TIPI CHAPMAN 34-163 3H	P-DP	168.68	843.54	151.28	750.10	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
TIPI CHAPMAN 34-163 4H	P-DP	542.30	383.42	478.57	350.68	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
TISH 46-03 1AH	P-DP	475.63	454.06	406.23	357.64	0.0000000	0.0000000	0.0251410	0.0251410	76.19	1.96	0
TISH 46-03 1SS	P-DP	195.81	1,062.10	132.44	336.30	0.0000000	0.0000000	0.0251410	0.0251410	76.19	1.96	0
TISH 46-03 3SA	P-DP	431.20	1,801.61	260.31	545.55	0.0000000	0.0000000	0.0251410	0.0251410	76.19	1.96	0
TISH 46-03 3SS	P-DP	410.30	1,109.35	252.16	408.37	0.0000000	0.0000000	0.0251410	0.0251410	76.19	1.96	0
TITO'S 31-42 1LS	P-DP	416.60	233.41	353.60	187.17	0.0000000	0.0000000	0.0008170	0.0008170	75.89	1.34	0
TITO'S 31-42 1WA	P-DP	440.79	258.19	369.67	203.55	0.0000000	0.0000000	0.0008170	0.0008170	75.89	1.34	0
TITO'S 31-42 1WB	P-DP	355.14	200.92	296.32	156.89	0.0000000	0.0000000	0.0008170	0.0008170	75.89	1.34	0
TITO'S 31-42 2LS	P-DP	477.04	634.77	360.48	361.34	0.0000000	0.0000000	0.0009100	0.0009100	75.89	1.34	0
TITO'S 31-42 2WA	P-DP	240.31	2,714.70	201.22	1,467.41	0.0000000	0.0000000	0.0008170	0.0008170	75.89	1.34	0
TITO'S 31-42 2WB	P-DP	221.79	887.60	179.58	501.79	0.0000000	0.0000000	0.0009100	0.0009100	75.89	1.34	0
TITO'S 31-42 3WA	P-DP	298.87	230.03	262.65	136.87	0.0000000	0.0000000	0.0009100	0.0009100	75.89	1.34	0
TODD 2-21A3	P-DP	518.45	1,497.94	436.14	814.34	0.0000000	0.0000000	0.0017360	0.0017360	60.48	1.70	0
TOMCAT 23-24 A 1LS	P-DP	206.75	428.39	76.31	114.62	0.0000000	0.0000000	0.0022320	0.0022320	75.89	1.34	0
TOMCAT 23-24 B 2LS	P-DP	177.05	268.73	69.04	88.91	0.0000000	0.0000000	0.0022320	0.0022320	75.89	1.34	0
TOMCAT 23-24 C 1DN	P-DP	762.13	2,589.00	261.13	312.28	0.0000000	0.0000000	0.0022320	0.0022320	75.89	1.34	0
TOMCAT 23-24 D 2DN	P-DP	520.26	1,286.04	210.38	222.52	0.0000000	0.0000000	0.0022320	0.0022320	75.89	1.34	0
TOMCAT 23-24 E 1AB	P-DP	144.77	263.05	75.68	104.57	0.0000000	0.0000000	0.0022320	0.0022320	75.89	1.34	0
TOMCAT 23-24 F 2AB	P-DP	155.98	382.62	83.95	112.94	0.0000000	0.0000000	0.0022320	0.0022320	75.89	1.34	0
TOMCAT 23-24 G 3AB	P-DP	254.70	702.14	93.31	98.90	0.0000000	0.0000000	0.0022320	0.0022320	75.89	1.34	0
TOMCAT 4448WA	P-DP	559.43	1,035.52	395.67	487.00	0.0000000	0.0000000	0.0090220	0.0090220	76.19	1.96	0
TORO 22 001	P-DP	43.93	109.16	41.43	107.84	0.0000000	0.0000000	0.0000000	0.0000000	76.17	1.13	0
TOWNSEN 24265 ALLOC. A 10H	P-DP	743.07	8,451.55	500.30	4,079.95	0.0000000	0.0000000	0.0007200	0.0007200	75.81	1.34	0
TRAUBE 1-11 WRD 1H	P-DP	618.87	715.95	541.74	687.98	0.0000000	0.0000000	0.0002120	0.0002120	75.15	0.68	0
TRAUBE 1-11 WRD 2H	P-DP	370.51	913.53	287.75	639.34	0.0000000	0.0000000	0.0002120	0.0002120	75.15	0.68	0
TREBLE STATE COM 601H	P-DP	196.01	167.41	60.03	38.43	0.0000000	0.0000000	0.0010880	0.0010880	76.17	1.13	0
TREBLE STATE COM 701H	P-DP	185.63	180.99	80.91	59.78	0.0000000	0.0000000	0.0010880	0.0010880	76.17	1.13	0
TREBLE STATE COM 801H	P-DP	263.87	217.09	87.55	74.00	0.0000000	0.0000000	0.0010880	0.0010880	76.17	1.13	0
TREE FROG 47 EAST A 1LS	P-DP	389.95	1,188.69	335.07	746.03	0.0000000	0.0000000	0.0010000	0.0010000	76.19	1.96	0

TABLE 8

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LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
TREE FROG 47 EAST A 1WA	P-DP	640.10	1,263.41	549.84	764.25	0.0000000	0.0000000	0.0010050	0.0010050	76.19	1.96	0
TREE FROG 47 EAST C 3LS	P-DP	385.45	1,750.51	300.12	769.46	0.0000000	0.0000000	0.0009950	0.0009950	76.19	1.96	0
TREE FROG 47 EAST C 3WA	P-DP	414.66	4,077.13	324.19	1,458.53	0.0000000	0.0000000	0.0009950	0.0009950	76.19	1.96	0
TREE FROG 47 EAST C 3WB	P-DP	313.01	2,349.83	241.82	882.91	0.0000000	0.0000000	0.0009960	0.0009960	76.19	1.96	0
TREE FROG 47 WEST UNIT 5LS	P-DP	426.35	953.77	379.59	518.43	0.0000000	0.0000000	0.0010400	0.0010400	76.19	1.96	0
TREE FROG 47 WEST UNIT 5WA	P-DP	606.08	1,850.62	476.35	888.74	0.0000000	0.0000000	0.0010400	0.0010400	76.19	1.96	0
TREE FROG 47 WEST UNIT 5WB	P-DP	436.49	1,341.62	339.27	619.63	0.0000000	0.0000000	0.0010400	0.0010400	76.19	1.96	0
TREE FROG 47 WEST UNIT 7LS	P-DP	273.76	1,587.16	178.86	629.65	0.0000000	0.0000000	0.0010400	0.0010400	76.19	1.96	0
TREE FROG 47 WEST UNIT 7WA	P-DP	328.88	2,909.99	219.95	1,205.49	0.0000000	0.0000000	0.0010400	0.0010400	76.19	1.96	0
TRENTINO 1	P-DP	272.53	564.25	168.33	386.93	0.0000000	0.0000000	0.0029140	0.0029140	76.19	1.96	0
TRENTINO 2	P-DP	69.17	41.86	37.96	38.74	0.0000000	0.0000000	0.0029140	0.0029140	76.19	1.96	0
TRENTINO 36 3	P-DP	17.83	119.67	13.47	111.03	0.0000000	0.0000000	0.0042380	0.0042380	76.19	1.96	0
TRENTINO 36-37 (ALLOC-C) 3SA	P-DP	327.69	964.71	250.76	442.06	0.0000000	0.0000000	0.0008450	0.0008450	76.19	1.96	0
TRENTINO 36-37 (ALLOC-C) 3SB	P-DP	480.86	3,243.01	356.18	1,228.93	0.0000000	0.0000000	0.0014090	0.0014090	76.19	1.96	0
TRENTINO 36-37 (ALLOC-C) 3SS	P-DP	187.45	488.87	131.22	230.89	0.0000000	0.0000000	0.0008820	0.0008820	76.19	1.96	0
TRENTINO 36-37 (ALLOC-D) 4SB	P-DP	337.26	941.29	230.19	514.52	0.0000000	0.0000000	0.0015010	0.0015010	76.19	1.96	0
TRENTINO 36-37 (ALLOC-D) 4SS	P-DP	162.56	1,383.70	105.80	443.51	0.0000000	0.0000000	0.0014560	0.0014560	76.19	1.96	0
TRENTINO 36-37 (ALLOC-DA) 4SA	P-DP	178.33	1,046.14	142.18	566.49	0.0000000	0.0000000	0.0014630	0.0014630	76.19	1.96	0
TRIANGLE 75 2H	P-DP	194.15	825.78	175.10	720.81	0.0000000	0.0000000	0.0008990	0.0008990	75.81	1.34	0
TRIDACNA 34-208 WRD UNIT 1H	P-DP	335.35	2,228.71	272.35	1,610.86	0.0000000	0.0000000	0.0001060	0.0001060	75.15	0.68	0
TRIDACNA 34-208 WRD UNIT 2H	P-DP	333.28	2,309.20	265.79	1,549.78	0.0000000	0.0000000	0.0001060	0.0001060	75.15	0.68	0
TRIDACNA 34-208 WRD UNIT 3H	P-DP	372.24	2,227.24	293.46	1,672.68	0.0000000	0.0000000	0.0001060	0.0001060	75.15	0.68	0
TROTT 34-183 1H	P-DP	168.67	1,429.23	143.69	1,128.45	0.0000000	0.0000000	0.0000980	0.0000980	75.15	0.68	0
UNFORGIVEN 34 113-114 A 605H	P-DP	474.06	915.13	246.82	444.87	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
UNFORGIVEN 34 113-114 B 706H	P-DP	430.23	940.59	249.05	463.90	0.0000000	0.0000000	0.0000060	0.0000060	75.15	0.68	0
UNFORGIVEN 34 113-114 C 606H	P-DP	414.00	765.66	316.08	587.04	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
UNFORGIVEN 34 113-114 D 604H	P-DP	764.06	1,055.32	374.26	580.71	0.0000000	0.0000000	0.0000060	0.0000060	75.15	0.68	0
UNICORN UNIT A 04-37 1AH	P-DP	225.60	235.53	173.44	155.60	0.0000000	0.0000000	0.0001940	0.0001940	73.67	3.34	0
UNICORN UNIT B 37-04 7AH	P-DP	159.06	235.07	121.68	115.19	0.0000000	0.0000000	0.0001910	0.0001910	73.67	3.34	0
UNICORN UNIT B 37-04 8MH	P-DP	138.71	54.23	85.72	27.29	0.0000000	0.0000000	0.0001910	0.0001910	73.67	3.34	0
URSULA 0848WA	P-DP	479.11	130.47	391.63	129.62	0.0000000	0.0000000	0.0047990	0.0047990	76.19	1.96	0
URSULA 1546WA	P-DP	327.01	1,620.79	264.54	826.39	0.0000000	0.0000000	0.0047990	0.0047990	76.19	1.96	0
URSULA BIG DADDY B 1527LS	P-DP	514.61	1,094.71	381.06	681.62	0.0000000	0.0000000	0.0015210	0.0015210	76.19	1.96	0
URSULA BIG DADDY B 1547WA	P-DP	471.93	948.97	350.37	577.53	0.0000000	0.0000000	0.0015870	0.0015870	76.19	1.96	0
URSULA BIG DADDY C 1528LS	P-DP	543.26	1,688.65	424.08	864.59	0.0000000	0.0000000	0.0018030	0.0018030	76.19	1.96	0
URSULA TOMCAT A 4446WA	P-DP	767.09	1,160.48	595.27	713.77	0.0000000	0.0000000	0.0076150	0.0076150	76.19	1.96	0
URSULA TOMCAT B 4421LS	P-DP	518.49	845.15	396.63	510.31	0.0000000	0.0000000	0.0076150	0.0076150	76.19	1.96	0

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URSULA TOMCAT C 4447WA	P-DP	727.94	1,215.60	507.97	563.21	0.0000000	0.0000000	0.0076150	0.0076150	76.19	1.96	0
UTE 3-12B3	P-DP	256.40	845.12	247.17	824.14	0.0000000	0.0000000	0.0026040	0.0026040	60.48	1.70	0
VALENCIA 10-8 A UNIT A 2H	P-DP	189.12	986.32	75.24	118.22	0.0000000	0.0000000	0.0002820	0.0002820	76.19	1.96	0
VALENCIA 10-8 A UNIT A 3H	P-DP	366.49	281.35	153.29	109.33	0.0000000	0.0000000	0.0002820	0.0002820	76.19	1.96	0
VALENCIA 10-8 A UNIT L 2H	P-DP	149.90	390.24	58.27	76.20	0.0000000	0.0000000	0.0002820	0.0002820	76.19	1.96	0
VALENCIA 10-8 A UNIT L 3H	P-DP	306.91	173.42	145.97	63.64	0.0000000	0.0000000	0.0002820	0.0002820	76.19	1.96	0
VALERIE 210473 1A	P-DP	0.00	10,648.78	0.00	9,654.20	0.0000000	0.0000000	0.0083560	0.0083560	67.06	2.04	0
VALERIE 210473 2B	P-DP	0.00	10,913.13	0.00	10,040.39	0.0000000	0.0000000	0.0083560	0.0083560	67.06	2.04	0
VALERIE 210473 4C	P-DP	0.00	12,478.10	0.00	11,196.57	0.0000000	0.0000000	0.0083560	0.0083560	67.06	2.04	0
VANNELLE SW WHL BL 2H	P-DP	0.00	20,472.16	0.00	12,404.27	0.0000000	0.0000000	0.0121790	0.0121790	67.06	2.04	0
VICKERS '34-127' 1H	P-DP	207.72	450.58	196.45	393.68	0.0000000	0.0000000	0.0004390	0.0004390	75.15	0.68	0
VICKERS '34-127' 2H	P-DP	165.99	265.28	140.21	221.55	0.0000000	0.0000000	0.0004390	0.0004390	75.15	0.68	0
VINTAGE A U 06H	P-DP	296.36	2,333.20	202.07	1,301.96	0.0000000	0.0000000	0.0003570	0.0003570	75.81	1.34	0
VINTAGE B T 13H	P-DP	388.59	5,618.22	240.47	3,208.79	0.0000000	0.0000000	0.0004020	0.0004020	75.81	1.34	0
VINTAGE C C 03H	P-DP	605.38	6,797.96	203.56	1,730.18	0.0000000	0.0000000	0.0002550	0.0002550	75.81	1.34	0
VINTAGE D T 26H	P-DP	399.88	5,967.40	242.68	3,158.28	0.0000000	0.0000000	0.0001610	0.0001610	75.81	1.34	0
VINTAGE E C 04H	P-DP	699.89	5,419.55	245.55	1,513.65	0.0000000	0.0000000	0.0002770	0.0002770	75.81	1.34	0
VINTAGE UNIT A U 19H	P-DP	290.36	2,275.68	166.09	989.83	0.0000000	0.0000000	0.0001530	0.0001530	75.81	1.34	0
VIPER FOSTER B 4545WA	P-DP	589.87	661.52	430.74	421.01	0.0000000	0.0000000	0.0050520	0.0050520	76.19	1.96	0
VIPER FOSTER C 4525LS	P-DP	653.48	1,771.38	458.96	690.97	0.0000000	0.0000000	0.0050420	0.0050420	76.19	1.96	0
VIPER FOSTER D 4546WA	P-DP	728.71	1,860.77	486.14	831.42	0.0000000	0.0000000	0.0050450	0.0050450	76.19	1.96	0
WALKER 32-48 B UNIT A 5H	P-DP	713.56	148.07	373.73	67.70	0.0000000	0.0000000	0.0038830	0.0038830	76.19	1.96	0
WALKER 32-48 B UNIT L 6H	P-DP	452.24	415.97	258.09	192.05	0.0000000	0.0000000	0.0044380	0.0044380	76.19	1.96	0
WALKER 48-32 A UNIT A 1H	P-DP	592.53	205.73	353.82	104.22	0.0000000	0.0000000	0.0083610	0.0083610	76.19	1.96	0
WALKER 48-32 A UNIT L 1H	P-DP	5.02	6.37	4.29	6.03	0.0000000	0.0000000	0.0126880	0.0126880	76.19	1.96	0
WALKER-DRRC 30-56 EAST UNIT 6SH	P-DP	823.94	1,310.18	491.90	449.81	0.0000000	0.0000000	0.0003230	0.0003230	76.19	1.96	0
WALKER-DRRC 30-56 EAST UNIT 7AH	P-DP	190.68	1,062.93	139.05	355.04	0.0000000	0.0000000	0.0003230	0.0003230	76.19	1.96	0
WALKER-DRRC 30-56 EAST UNIT 7SH	P-DP	200.73	1,218.88	156.28	405.75	0.0000000	0.0000000	0.0003230	0.0003230	76.19	1.96	0
WALKER-DRRC 30-56 WEST UNIT 5LS	P-DP	636.53	1,634.01	485.60	781.29	0.0000000	0.0000000	0.0003140	0.0003140	76.19	1.96	0
WALKER-DRRC 30-56 WEST UNIT 5WA	P-DP	282.96	803.66	225.03	351.99	0.0000000	0.0000000	0.0003140	0.0003140	76.19	1.96	0
WALKER-DRRC 30-56 WEST UNIT 6AH	P-DP	297.76	766.81	215.51	348.66	0.0000000	0.0000000	0.0003140	0.0003140	76.19	1.96	0
WALLACE, T. L. 1	P-DP	475.57	149.40	464.54	149.40	0.0000000	0.0000000	0.0002340	0.0002340	77.02	1.02	0
WALLACE, T. L. 3	P-DP	113.54	39.39	109.19	39.39	0.0000000	0.0000000	0.0002340	0.0002340	77.02	1.02	0
WALLY A1 15UA	P-DP	877.82	1,122.33	765.16	1,038.44	0.0000696	0.0000696	0.0000696	0.0000696	75.15	0.68	1,200
WALLY A1 21H	P-DP	206.27	322.19	191.82	284.70	0.0000000	0.0000000	0.0000460	0.0000460	75.15	0.68	0
WALLY A1 8LA	P-DP	466.95	754.64	393.64	692.40	0.0000810	0.0000810	0.0000810	0.0000810	75.15	0.68	1,200
WALLY A2 7LA	P-DP	552.02	732.17	456.87	668.80	0.0000648	0.0000648	0.0000648	0.0000648	75.15	0.68	1,200

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WALLY A3 20H	P-DP	179.36	621.01	139.92	366.68	0.0000000	0.0000000	0.0000140	0.0000140	75.15	0.68	0
WALLY A4 14UA	P-DP	732.44	986.13	321.06	494.05	0.0000461	0.0000461	0.0000461	0.0000461	75.15	0.68	1,200
WALLY A5 6LA	P-DP	402.77	589.12	170.21	259.94	0.0000365	0.0000365	0.0000365	0.0000365	75.15	0.68	1,200
WARD 18CC 1803D	P-DP	262.02	294.08	204.44	178.16	0.0000000	0.0000000	0.0015890	0.0015890	76.19	1.96	0
WARD 18CC 1804D	P-DP	392.59	507.22	248.44	376.04	0.0000000	0.0000000	0.0015890	0.0015890	76.19	1.96	0
WASHINGTON EAST I 23-14 4409H	P-DP	323.47	1,653.48	197.49	814.86	0.0000000	0.0000000	0.0004160	0.0004160	75.14	2.00	0
WASHINGTON WEST A 23-14 4201H	P-DP	469.45	671.78	294.62	322.47	0.0000000	0.0000000	0.0004810	0.0004810	75.14	2.00	0
WASHINGTON WEST A 23-14 4401H	P-DP	325.44	2,156.17	226.91	872.40	0.0000000	0.0000000	0.0004810	0.0004810	75.14	2.00	0
WASHINGTON WEST B 23-14 4302H	P-DP	586.12	5,777.03	424.07	2,062.14	0.0000000	0.0000000	0.0004810	0.0004810	75.14	2.00	0
WASHINGTON WEST B 23-14 4602H	P-DP	166.82	3,115.53	119.06	1,253.32	0.0000000	0.0000000	0.0005230	0.0005230	75.14	2.00	0
WASHINGTON WEST D 23-14 4404H	P-DP	129.36	3,049.11	102.48	1,111.88	0.0000000	0.0000000	0.0004270	0.0004270	75.14	2.00	0
WASHINGTON WEST E 23-14 4305H	P-DP	207.97	4,249.63	150.81	1,657.10	0.0000000	0.0000000	0.0004120	0.0004120	75.14	2.00	0
WASHINGTON WEST F 23-14 4406H	P-DP	126.59	1,498.10	95.28	686.22	0.0000000	0.0000000	0.0004300	0.0004300	75.14	2.00	0
WASHINGTON WEST G 23-14 4307H	P-DP	400.77	5,506.60	257.95	1,791.15	0.0000000	0.0000000	0.0004220	0.0004220	75.14	2.00	0
WATKINS 7 1	P-DP	87.27	141.18	69.87	112.04	0.0000000	0.0000000	0.0333330	0.0333330	75.89	1.34	0
WELCH 39 1	P-DP	285.30	573.39	207.15	397.97	0.0000000	0.0000000	0.0023440	0.0023440	75.89	1.34	0
WELCH 39 2	P-DP	24.03	58.73	19.68	44.66	0.0000000	0.0000000	0.0023440	0.0023440	75.89	1.34	0
WELCH 39 3	P-DP	38.82	266.95	31.80	213.96	0.0000000	0.0000000	0.0023440	0.0023440	75.89	1.34	0
WELCH 39 4	P-DP	73.45	389.11	55.67	323.67	0.0000000	0.0000000	0.0023440	0.0023440	75.89	1.34	0
WELCH-COX E39A 301H	P-DP	219.87	193.98	104.67	105.28	0.0000000	0.0000000	0.0011500	0.0011500	75.89	1.34	0
WELCH-COX E39B 302H	P-DP	949.25	2,433.57	257.99	359.58	0.0000000	0.0000000	0.0011750	0.0011750	75.89	1.34	0
WELCH-COX E39C 303H	P-DP	258.69	377.09	129.10	152.15	0.0000000	0.0000000	0.0011730	0.0011730	75.89	1.34	0
WELCH-COX E39D 304H	P-DP	692.88	1,077.81	210.47	241.37	0.0000000	0.0000000	0.0011410	0.0011410	75.89	1.34	0
WELCH-COX E39S 319H	P-DP	437.04	1,006.14	177.66	410.43	0.0000000	0.0000000	0.0011730	0.0011730	75.89	1.34	0
WELCH-COX E39T 320H	P-DP	532.59	715.51	258.14	310.88	0.0000000	0.0000000	0.0011710	0.0011710	75.89	1.34	0
WELCH-COX E39U 321H	P-DP	548.68	2,204.19	198.88	493.71	0.0000000	0.0000000	0.0011780	0.0011780	75.89	1.34	0
WELCH-COX E39V 322H	P-DP	596.71	1,209.77	251.24	308.75	0.0000000	0.0000000	0.0011730	0.0011730	75.89	1.34	0
WELCH-COX E39W 323H	P-DP	366.93	944.90	146.02	235.07	0.0000000	0.0000000	0.0001150	0.0001150	75.89	1.34	0
WELCH-COX W39F 206H	P-DP	452.33	1,960.02	260.32	683.15	0.0000000	0.0000000	0.0011310	0.0011310	75.89	1.34	0
WELCH-COX W39G 207H	P-DP	773.86	1,187.39	399.26	491.72	0.0000000	0.0000000	0.0011410	0.0011410	75.89	1.34	0
WELCH-COX W39H 208H	P-DP	380.76	1,548.50	225.55	602.95	0.0000000	0.0000000	0.0011530	0.0011530	75.89	1.34	0
WELCH-COX W39I 209H	P-DP	491.79	820.83	314.11	368.59	0.0000000	0.0000000	0.0011410	0.0011410	75.89	1.34	0
WELCH-COX W39J 210H	P-DP	549.41	1,829.53	270.76	594.32	0.0000000	0.0000000	0.0011400	0.0011400	75.89	1.34	0
WELCH-COX W39K 211H	P-DP	506.73	1,215.47	264.67	462.63	0.0000000	0.0000000	0.0011160	0.0011160	75.89	1.34	0
WELCH-COX W39L 212H	P-DP	415.18	985.13	223.06	354.10	0.0000000	0.0000000	0.0011410	0.0011410	75.89	1.34	0
WELCH-COX W39M 213H	P-DP	409.46	1,346.92	266.58	479.19	0.0000000	0.0000000	0.0011270	0.0011270	75.89	1.34	0
WELCH-COX W39N 214H	P-DP	408.40	1,167.01	239.82	426.81	0.0000000	0.0000000	0.0011170	0.0011170	75.89	1.34	0

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WELCH-COX W39O 215H	P-DP	416.12	1,092.59	205.95	321.47	0.0000000	0.0000000	0.0011170	0.0011170	75.89	1.34	0
WELCH-COX W39P 216H	P-DP	646.15	1,559.40	297.80	386.12	0.0000000	0.0000000	0.0011300	0.0011300	75.89	1.34	0
WEREWOLF UNIT A 12-05 1AH	P-DP	489.21	441.54	213.19	160.93	0.0000000	0.0000000	0.0001220	0.0001220	73.67	3.34	0
WEREWOLF UNIT A 12-05 2AH	P-DP	441.03	346.49	241.31	139.70	0.0000000	0.0000000	0.0001220	0.0001220	73.67	3.34	0
WEREWOLF UNIT A 12-05 3AH	P-DP	488.19	1,277.88	202.51	234.06	0.0000000	0.0000000	0.0001220	0.0001220	73.67	3.34	0
WEREWOLF UNIT B 12-05 4AH	P-DP	470.17	603.26	196.91	171.01	0.0000000	0.0000000	0.0001240	0.0001240	73.67	3.34	0
WEREWOLF UNIT B 12-05 5AH	P-DP	375.72	466.51	183.92	148.65	0.0000000	0.0000000	0.0001240	0.0001240	73.67	3.34	0
WEREWOLF UNIT B 12-05 6AH	P-DP	519.95	611.90	208.27	164.40	0.0000000	0.0000000	0.0001240	0.0001240	73.67	3.34	0
WHIRLAWAY 99 1HA	P-DP	363.70	462.82	291.19	251.78	0.0000000	0.0000000	0.0002250	0.0002250	75.15	0.68	0
WHISKEY RIVER 9596A-34 11H	P-DP	1,302.33	1,578.10	865.00	931.84	0.0000000	0.0000000	0.0000060	0.0000060	75.15	0.68	0
WHISKEY RIVER 9596A-34 12H	P-DP	431.50	1,452.40	289.07	719.12	0.0000000	0.0000000	0.0000060	0.0000060	75.15	0.68	0
WHISKEY RIVER 9596A-34 13H	P-DP	567.65	781.96	385.00	384.50	0.0000000	0.0000000	0.0000060	0.0000060	75.15	0.68	0
WHISKEY RIVER 9596B-34 1H	P-DP	428.87	376.78	307.23	307.43	0.0000000	0.0000000	0.0000060	0.0000060	75.15	0.68	0
WHISKEY RIVER 9596B-34 31H	P-DP	519.43	917.16	318.42	542.88	0.0000000	0.0000000	0.0000060	0.0000060	75.15	0.68	0
WHISKEY RIVER 9596B-34 32H	P-DP	692.72	1,814.20	402.80	1,008.48	0.0000000	0.0000000	0.0000060	0.0000060	75.15	0.68	0
WHISKEY RIVER 9596C-34 1H	P-DP	634.36	826.31	384.62	466.01	0.0000000	0.0000000	0.0000060	0.0000060	75.15	0.68	0
WHISKEY RIVER 9596D-34 81H	P-DP	537.99	781.86	438.03	592.52	0.0000000	0.0000000	0.0000060	0.0000060	75.15	0.68	0
WHITE 1-23C5	P-DP	130.49	273.33	121.54	258.54	0.0000000	0.0000000	0.0005650	0.0005650	60.48	1.70	0
WHITE 19	P-DP	56.70	119.64	48.80	119.64	0.0000000	0.0000000	0.0006510	0.0006510	77.02	1.02	0
WHITE 2-23C5	P-DP	196.60	525.75	162.42	386.99	0.0000000	0.0000000	0.0005650	0.0005650	60.48	1.70	0
WHITE 3-14C5	P-DP	180.06	427.15	147.22	322.01	0.0000000	0.0000000	0.0055190	0.0055190	60.48	1.70	0
WHITE TRUST 3-23C5	P-DP	206.60	556.69	163.88	454.79	0.0000000	0.0000000	0.0005650	0.0005650	60.48	1.70	0
WHITMIRE 36-37 (ALLOC-F) 6SA	P-DP	182.13	493.11	137.04	323.79	0.0000000	0.0000000	0.0001670	0.0001670	76.19	1.96	0
WHITMIRE 36-37 (ALLOC-F) 6SB	P-DP	156.36	734.06	115.83	405.85	0.0000000	0.0000000	0.0001606	0.0001606	76.19	1.96	0
WHITMIRE 36-37 (ALLOC-G) 7SA	P-DP	201.50	1,058.80	143.75	401.24	0.0000000	0.0000000	0.0001623	0.0001623	76.19	1.96	0
WHITMIRE 36-37 (ALLOC-G) 7SB	P-DP	257.32	930.27	173.96	355.74	0.0000000	0.0000000	0.0008810	0.0008810	76.19	1.96	0
WHITMIRE 36-37 (ALLOC-H) 8SA	P-DP	308.57	861.51	201.17	516.07	0.0000000	0.0000000	0.0008800	0.0008800	76.19	1.96	0
WHITMIRE 36-37 (ALLOC-H) 8SB	P-DP	271.13	390.84	194.70	256.50	0.0000000	0.0000000	0.0008728	0.0008728	76.19	1.96	0
WILEY 4 1	P-DP	147.64	505.82	126.66	410.40	0.0000000	0.0000000	0.0050220	0.0050220	75.89	1.34	0
WILEY 4 2	P-DP	16.05	49.39	16.05	49.39	0.0000000	0.0000000	0.0050220	0.0050220	75.89	1.34	0
WILLETT POT STILL 5-2C UNIT 1H	P-DP	272.76	2,574.78	220.90	1,904.96	0.0000000	0.0000000	0.0033420	0.0033420	75.81	1.34	0
WILLIE THE WILDCAT 3-15 A 1JC	P-DP	211.11	1,305.42	158.70	605.49	0.0000000	0.0000000	0.0003770	0.0003770	75.89	1.34	0
WILLIE THE WILDCAT 3-15 A 1LS	P-DP	311.08	1,175.29	242.48	754.80	0.0000000	0.0000000	0.0003800	0.0003800	75.89	1.34	0
WILLIE THE WILDCAT 3-15 A 1WA	P-DP	653.38	4,600.40	479.95	1,624.60	0.0000000	0.0000000	0.0003830	0.0003830	75.89	1.34	0
WILLIE THE WILDCAT 3-15 B 2DN	P-DP	402.73	1,452.37	340.07	947.18	0.0000000	0.0000000	0.0003840	0.0003840	75.89	1.34	0
WILLIE THE WILDCAT 3-15 B 2LS	P-DP	394.50	1,514.68	281.21	785.91	0.0000000	0.0000000	0.0003840	0.0003840	75.89	1.34	0
WILLIE THE WILDCAT 3-15 B 2WB	P-DP	220.50	2,979.52	177.77	1,583.50	0.0000000	0.0000000	0.0003840	0.0003840	75.89	1.34	0

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LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
WILLIE THE WILDCAT 3-15 B 3JD	P-DP	314.78	1,280.92	252.30	763.57	0.0000000	0.0000000	0.0003840	0.0003840	75.89	1.34	0
WILLIE THE WILDCAT 3-15 C 4LS	P-DP	258.44	749.52	219.37	581.40	0.0000000	0.0000000	0.0003840	0.0003840	75.89	1.34	0
WILLIE THE WILDCAT 3-15 C 4WA	P-DP	330.54	1,556.72	249.72	1,221.43	0.0000000	0.0000000	0.0003820	0.0003820	75.89	1.34	0
WILLIE THE WILDCAT 3-15 D 5JD	P-DP	243.43	762.03	176.31	417.06	0.0000000	0.0000000	0.0003810	0.0003810	75.89	1.34	0
WILLIE THE WILDCAT 3-15 D 6DN	P-DP	520.89	3,413.29	376.76	1,712.22	0.0000000	0.0000000	0.0003820	0.0003820	75.89	1.34	0
WILLIE THE WILDCAT 3-15 D 6LS	P-DP	432.13	1,139.79	340.10	701.75	0.0000000	0.0000000	0.0003850	0.0003850	75.89	1.34	0
WILLIE THE WILDCAT 3-15 D 6WB	P-DP	336.75	3,287.09	244.48	1,645.99	0.0000000	0.0000000	0.0003850	0.0003850	75.89	1.34	0
WILLIE THE WILDCAT 3-15 E 7JC	P-DP	385.56	146.57	237.98	74.69	0.0000000	0.0000000	0.0003750	0.0003750	75.89	1.34	0
WILLIE THE WILDCAT 3-15 E 7LS	P-DP	757.88	1,670.88	493.17	765.70	0.0000000	0.0000000	0.0003860	0.0003860	75.89	1.34	0
WILLIE THE WILDCAT 3-15 E 7WA	P-DP	320.52	3,640.96	276.94	1,781.96	0.0000000	0.0000000	0.0003860	0.0003860	75.89	1.34	0
WILSON 184-185 UNIT 131H	P-DP	407.79	3,968.17	188.15	1,913.39	0.0000000	0.0000000	0.0003420	0.0003420	75.15	0.68	0
WILSON 184-185 UNIT 132H	P-DP	317.24	3,182.84	161.06	1,575.97	0.0000000	0.0000000	0.0003420	0.0003420	75.15	0.68	0
WILSON 184-185 UNIT 232H	P-DP	272.45	3,257.96	143.21	1,379.28	0.0000000	0.0000000	0.0003420	0.0003420	75.15	0.68	0
WILSON 184-185 UNIT 2H	P-DP	695.90	8,471.83	461.36	4,945.34	0.0000000	0.0000000	0.0001870	0.0001870	75.15	0.68	0
WILSON 184-185 UNIT 332H	P-DP	430.11	6,456.24	194.68	1,847.52	0.0000000	0.0000000	0.0003420	0.0003420	75.15	0.68	0
WINDY MOUNTAIN 7879 1U B 1H	P-DP	401.88	2,893.89	288.19	2,103.34	0.0000000	0.0000000	0.0001810	0.0001810	75.81	1.34	0
WINDY MOUNTAIN 7879 2U B 2H	P-DP	468.26	2,988.77	341.49	2,004.83	0.0000000	0.0000000	0.0001800	0.0001800	75.81	1.34	0
WINTERS BB 2	P-DP	203.21	306.34	200.52	304.62	0.0000000	0.0000000	0.0099450	0.0099450	76.19	1.96	0
WINTERS,FERN D 2	P-DP	325.67	398.46	323.86	398.46	0.0000000	0.0000000	0.0212490	0.0212490	76.19	1.96	0
WORTHY 13-12 (ALLOC-A) 1NA	P-DP	660.06	1,565.84	345.97	562.72	0.0000000	0.0000000	0.0015040	0.0015040	76.19	1.96	0
WORTHY 13-12 (ALLOC-A) 1NS	P-DP	348.84	628.29	178.04	254.79	0.0000000	0.0000000	0.0015040	0.0015040	76.19	1.96	0
WORTHY 13-12 (ALLOC-B) 2NB	P-DP	436.78	1,715.04	250.73	498.10	0.0000000	0.0000000	0.0015040	0.0015040	76.19	1.96	0
WORTHY 13-12 (ALLOC-C) 3NA	P-DP	505.42	1,743.50	282.90	572.65	0.0000000	0.0000000	0.0015040	0.0015040	76.19	1.96	0
WORTHY 13-12 (ALLOC-D) 4NB	P-DP	465.42	2,508.40	277.36	735.48	0.0000000	0.0000000	0.0015040	0.0015040	76.19	1.96	0
WORTHY 13-12 (ALLOC-D) 4NS	P-DP	306.82	1,663.98	182.70	451.11	0.0000000	0.0000000	0.0015040	0.0015040	76.19	1.96	0
WRAITH UNIT A 12-16 1AH	P-DP	613.17	994.91	318.50	343.32	0.0000000	0.0000000	0.0053000	0.0053000	73.67	3.34	0
WRAITH UNIT A 12-16 2AH	P-DP	700.91	807.43	350.38	250.70	0.0000000	0.0000000	0.0053000	0.0053000	73.67	3.34	0
WRAITH UNIT A 12-16 3AH	P-DP	593.44	777.50	296.98	245.08	0.0000000	0.0000000	0.0053000	0.0053000	73.67	3.34	0
WRAITH UNIT B 12-16 4AH	P-DP	746.44	607.16	378.53	268.55	0.0000000	0.0000000	0.0052860	0.0052860	73.67	3.34	0
WRAITH UNIT B 12-16 5AH	P-DP	456.95	745.70	171.58	115.96	0.0000000	0.0000000	0.0052860	0.0052860	73.67	3.34	0
WRAITH UNIT B 12-16 6AH	P-DP	503.77	383.77	195.14	100.50	0.0000000	0.0000000	0.0052860	0.0052860	73.67	3.34	0
WRANGLER A UNIT 1H	P-DP	725.67	2,562.99	493.46	1,516.23	0.0000000	0.0000000	0.0004690	0.0004690	76.15	-0.83	0
WRANGLER A UNIT 2H	P-DP	971.12	672.03	671.38	591.16	0.0000000	0.0000000	0.0004690	0.0004690	76.15	-0.83	0
WRANGLER B UNIT 1H	P-DP	532.69	1,254.05	437.48	939.29	0.0000000	0.0000000	0.0004690	0.0004690	76.15	-0.83	0
WRANGLER B UNIT 2H	P-DP	812.44	1,655.45	623.44	1,114.96	0.0000000	0.0000000	0.0004690	0.0004690	76.15	-0.83	0
WRANGLER C UNIT 1H	P-DP	807.83	1,622.45	534.29	929.83	0.0000000	0.0000000	0.0004690	0.0004690	76.15	-0.83	0
WRANGLER C UNIT 2H	P-DP	1,001.62	1,987.79	690.38	1,284.21	0.0000000	0.0000000	0.0004690	0.0004690	76.15	-0.83	0

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WRANGLER C UNIT 752H	P-DP	400.15	1,557.98	157.90	499.54	0.0000000	0.0000000	0.0004690	0.0004690	76.15	-0.83	0
WRANGLER C UNIT 753H	P-DP	996.87	2,178.26	229.72	634.05	0.0000000	0.0000000	0.0004690	0.0004690	76.15	-0.83	0
WRANGLER D UNIT 1H	P-DP	743.02	1,617.51	561.64	1,143.44	0.0000000	0.0000000	0.0004690	0.0004690	76.15	-0.83	0
WRANGLER D UNIT 2H	P-DP	1,135.55	2,658.24	848.09	1,865.04	0.0000000	0.0000000	0.0004690	0.0004690	76.15	-0.83	0
WRANGLER D UNIT 751H	P-DP	553.12	1,772.62	188.41	568.57	0.0000000	0.0000000	0.0004690	0.0004690	76.15	-0.83	0
WRIGHT 1-22 E WRD UNIT 2H	P-DP	156.38	278.45	143.74	250.19	0.0000000	0.0000000	0.0001410	0.0001410	75.15	0.68	0
WRIGHT 1-22 W WRD UNIT 2H	P-DP	201.34	342.73	158.44	268.44	0.0000000	0.0000000	0.0001410	0.0001410	75.15	0.68	0
WRIGHT 1-22E WRD 1H	P-DP	223.60	389.88	197.12	335.36	0.0000000	0.0000000	0.0000710	0.0000710	75.15	0.68	0
WRIGHT 1-22W WRD 1H	P-DP	161.01	210.84	158.19	207.46	0.0000000	0.0000000	0.0000710	0.0000710	76.15	-0.83	0
WYNN 29 1	P-DP	32.93	169.35	22.12	103.25	0.0000000	0.0000000	0.0015890	0.0015890	76.19	1.96	0
WYNN FARMS 28 1	P-DP	16.08	57.80	15.40	55.25	0.0000000	0.0000000	0.0015800	0.0015800	76.19	1.96	0
XBC-CAROLINE 3B 302H	P-DP	546.23	2,639.60	424.20	1,333.38	0.0000000	0.0000000	0.0006270	0.0006270	75.75	1.47	0
XBC-CAROLINE 3C 303H	P-DP	506.73	2,592.50	373.45	1,299.64	0.0000000	0.0000000	0.0006280	0.0006280	75.75	1.47	0
XBC-CAROLINE 3K 311H	P-DP	464.73	2,610.12	369.40	1,357.17	0.0000000	0.0000000	0.0006350	0.0006350	75.75	1.47	0
XBC-CAROLINE 3L 312H	P-DP	479.73	2,583.80	367.60	1,307.88	0.0000000	0.0000000	0.0006470	0.0006470	75.75	1.47	0
XBC-CAROLINE 3M 313H	P-DP	550.45	2,610.28	388.11	1,187.90	0.0000000	0.0000000	0.0006440	0.0006440	75.75	1.47	0
XBC-UNRUH 3A 16H	P-DP	705.13	2,095.66	486.73	1,216.14	0.0000000	0.0000000	0.0006520	0.0006520	75.75	1.47	0
XBC-UNRUH 3B 17H	P-DP	564.64	2,568.22	425.45	1,443.45	0.0000000	0.0000000	0.0006610	0.0006610	75.75	1.47	0
YANKEE 210475 5A	P-DP	0.00	10,675.68	0.00	8,986.83	0.0000000	0.0000000	0.0000080	0.0000080	67.06	2.04	0
YELLOW ROSE A UNIT 1H	P-DP	776.28	539.96	587.09	506.83	0.0000000	0.0000000	0.0001590	0.0001590	76.15	-0.83	0
YELLOW ROSE A UNIT 2H	P-DP	768.62	606.59	597.42	561.21	0.0000000	0.0000000	0.0001590	0.0001590	76.15	-0.83	0
YELLOW ROSE A UNIT 3H	P-DP	508.72	3,157.46	403.14	1,996.53	0.0000000	0.0000000	0.0001590	0.0001590	76.15	-0.83	0
YELLOW ROSE B UNIT 1H	P-DP	1,135.43	633.30	601.67	502.40	0.0000000	0.0000000	0.0001590	0.0001590	76.15	-0.83	0
YELLOW ROSE B UNIT 2H	P-DP	525.41	286.83	345.14	247.47	0.0000000	0.0000000	0.0001590	0.0001590	76.15	-0.83	0
YELLOW ROSE B UNIT 3H	P-DP	1,001.50	5,602.43	585.90	2,807.21	0.0000000	0.0000000	0.0001590	0.0001590	76.15	-0.83	0
YORK-LAW 139A 101H	P-DP	614.61	2,362.28	322.06	637.07	0.0000000	0.0000000	0.0038670	0.0038670	75.89	1.34	0
YORK-LAW 139B 102H	P-DP	699.33	1,273.04	396.81	519.52	0.0000000	0.0000000	0.0038860	0.0038860	75.89	1.34	0
YORK-LAW 139C 103H	P-DP	434.34	849.25	303.75	317.95	0.0000000	0.0000000	0.0039180	0.0039180	75.89	1.34	0
YORK-LAW 139D 104H	P-DP	665.49	1,224.64	402.03	550.98	0.0000000	0.0000000	0.0038400	0.0038400	75.89	1.34	0
YORK-LAW 139E 105H	P-DP	577.34	1,194.46	318.33	430.03	0.0000000	0.0000000	0.0038570	0.0038570	75.89	1.34	0
YORK-LAW 139F 106H	P-DP	526.18	1,512.61	306.20	492.56	0.0000000	0.0000000	0.0039030	0.0039030	75.89	1.34	0
YORK-LAW 139G 107H	P-DP	598.35	1,182.76	316.92	368.88	0.0000000	0.0000000	0.0039520	0.0039520	75.89	1.34	0
YORK-LAW 139H 108H	P-DP	615.39	1,317.14	351.13	528.38	0.0000000	0.0000000	0.0030750	0.0030750	75.89	1.34	0
ZPZ 34-196 WRD UNIT 1H	P-DP	506.14	2,058.32	408.14	1,625.66	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
ZPZ 34-196 WRD UNIT 2H	P-DP	192.31	1,172.48	136.29	701.68	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
ZPZ 34-196 WRD UNIT 3H	P-DP	240.34	836.23	169.92	651.48	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
ZPZ 34-196 WRD UNIT 4H	P-DP	256.29	962.76	172.91	705.98	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0

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		677,319.08	4,947,815.62	417,502.26	3,018,822.20							
Proved Behind Pipe Rsv Class & Category												
44 MAGNUM 9-4 H 2LS	P-BP	285.24	1,414.37	0.00	0.00	0.0000000	0.0000000	0.0019390	0.0019390	76.19	1.96	0
ATOMIC 55-1-18-6 A 12HR	P-BP	733.63	13,084.46	0.00	0.00	0.0000000	0.0000000	0.0001410	0.0001410	76.15	-0.83	0
ATOMIC 55-1-18-6 B 13H	P-BP	733.57	13,090.98	0.00	0.00	0.0000000	0.0000000	0.0001410	0.0001410	76.15	-0.83	0
ATOMIC 55-1-18-6 C 14H	P-BP	733.15	13,082.38	0.00	0.00	0.0000000	0.0000000	0.0001410	0.0001410	76.15	-0.83	0
ATOMIC 55-1-18-6 D 15H	P-BP	421.74	7,525.47	0.00	0.00	0.0000000	0.0000000	0.0001410	0.0001410	76.15	-0.83	0
BATES S CRC JF 7H	P-BP	0.00	11,785.33	0.00	0.00	0.0000000	0.0000000	0.1284780	0.1284780	73.94	1.98	0
BILLY BOBS STATE A 3472H	P-BP	453.11	5,687.35	0.00	0.00	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
BOW TIE E 7MS	P-BP	206.37	687.58	0.00	0.00	0.0000000	0.0000000	0.0004923	0.0004923	76.19	1.96	0
BOW TIE F 8MS	P-BP	202.86	675.58	0.00	0.00	0.0000000	0.0000000	0.0004923	0.0004923	76.19	1.96	0
BROKEN ARROW 55-54-1-12 H 1WA	P-BP	193.43	643.37	0.00	0.00	0.0000000	0.0000000	0.0013180	0.0013180	76.19	1.96	0
BROKEN ARROW 55-54-1-12 H 1WB	P-BP	193.95	645.17	0.00	0.00	0.0000000	0.0000000	0.0013180	0.0013180	76.19	1.96	0
BROKEN ARROW 55-54-1-12 H 2WA	P-BP	185.71	617.03	0.00	0.00	0.0000000	0.0000000	0.0013180	0.0013180	76.19	1.96	0
BROKEN ARROW 55-54-1-12 H 2WB	P-BP	355.42	948.99	0.00	0.00	0.0000000	0.0000000	0.0013180	0.0013180	76.19	1.96	0
CHEST THUMPER 1-5 UNIT 1 143	P-BP	609.54	1,471.06	0.00	0.00	0.0000000	0.0000000	0.0003100	0.0003100	75.89	1.34	0
CHEVRON UNIT 03-38 3MH	P-BP	222.69	1,810.72	0.00	0.00	0.0000000	0.0000000	0.0004375	0.0004375	76.19	1.96	0
CHEVRON UNIT 03-38 3SH	P-BP	312.75	1,547.66	0.00	0.00	0.0000000	0.0000000	0.0004375	0.0004375	76.19	1.96	0
CHEVRON UNIT 03-38 4AH	P-BP	427.68	1,929.05	0.00	0.00	0.0000000	0.0000000	0.0004375	0.0004375	76.19	1.96	0
CHEVRON UNIT 03-38 4MH	P-BP	222.89	1,812.42	0.00	0.00	0.0000000	0.0000000	0.0004375	0.0004375	76.19	1.96	0
CHEVRON UNIT 03-56 4SH	P-BP	314.23	1,557.12	0.00	0.00	0.0000000	0.0000000	0.0004375	0.0004375	76.19	1.96	0
CHEVRON UNIT 03-56 5AH	P-BP	429.06	1,937.37	0.00	0.00	0.0000000	0.0000000	0.0004375	0.0004375	76.19	1.96	0
CHEVRON UNIT 03-56 5MH	P-BP	223.52	1,817.89	0.00	0.00	0.0000000	0.0000000	0.0004375	0.0004375	76.19	1.96	0
CHEVRON UNIT 03-56 5SH	P-BP	314.51	1,558.47	0.00	0.00	0.0000000	0.0000000	0.0004375	0.0004375	76.19	1.96	0
CHEVRON UNIT 03-56 6AH	P-BP	430.14	1,940.15	0.00	0.00	0.0000000	0.0000000	0.0004375	0.0004375	76.19	1.96	0
CHUMCHAL-GERGES 1H	P-BP	407.36	2,151.90	0.00	0.00	0.0000000	0.0000000	0.0102000	0.0102000	74.40	1.94	0
COWLEY C 3H	P-BP	367.08	1,939.61	0.00	0.00	0.0000000	0.0000000	0.0199160	0.0199160	74.40	1.94	0
COWLEY D 4H	P-BP	384.90	2,034.01	0.00	0.00	0.0000000	0.0000000	0.0199160	0.0199160	74.40	1.94	0
CROSS CREEK A S CRC JF	P-BP	0.00	23,448.55	0.00	0.00	0.0000000	0.0000000	0.0218471	0.0218471	73.94	1.98	0
CROSS CREEK A SE CRC JF 6H	P-BP	0.00	23,571.84	0.00	0.00	0.0000000	0.0000000	0.0206087	0.0206087	73.94	1.98	0
CROSS CREEK A SW CRC JF	P-BP	0.00	16,154.86	0.00	0.00	0.0000000	0.0000000	0.0411115	0.0411115	73.94	1.98	0
DIRE WOLF B 5A	P-BP	446.12	4,758.61	0.00	0.00	0.0000000	0.0000000	0.0013020	0.0013020	75.15	0.68	0
DIRE WOLF C 6TB	P-BP	446.48	4,762.20	0.00	0.00	0.0000000	0.0000000	0.0013020	0.0013020	75.15	0.68	0
DIRE WOLF D 7B	P-BP	446.83	4,765.84	0.00	0.00	0.0000000	0.0000000	0.0013020	0.0013020	75.15	0.68	0
ELIAS 16-9 UNIT 1 223	P-BP	430.48	1,944.54	0.00	0.00	0.0000000	0.0000000	0.0001858	0.0001858	75.89	1.34	0
ELIAS 16-9 UNIT 2 173	P-BP	317.26	2,055.70	0.00	0.00	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELIAS 16-9 UNIT 2 252	P-BP	420.15	1,896.79	0.00	0.00	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0

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LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
ELIAS 16-9 UNIT 2 262	P-BP	429.33	1,938.34	0.00	0.00	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELIAS 16-9 UNIT 2 271	P-BP	431.79	1,950.51	0.00	0.00	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELIAS 16-9 UNIT 2 281	P-BP	436.41	1,971.53	0.00	0.00	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
ELIAS 16-9 UNIT 2 282	P-BP	438.51	1,981.14	0.00	0.00	0.0000000	0.0000000	0.0001859	0.0001859	75.89	1.34	0
FLASH WEST A 29-20 4201H	P-BP	388.81	1,753.25	0.00	0.00	0.0000000	0.0000000	0.0004004	0.0004004	76.19	1.96	0
FLASH WEST B 29-20 4102H	P-BP	393.70	1,774.93	0.00	0.00	0.0000000	0.0000000	0.0004144	0.0004144	76.19	1.96	0
FLASH WEST D 29-20 4204H	P-BP	394.00	1,776.02	0.00	0.00	0.0000000	0.0000000	0.0041464	0.0041464	76.19	1.96	0
FLASH WEST F 29-20 4106H	P-BP	394.35	1,777.44	0.00	0.00	0.0000000	0.0000000	0.0004160	0.0004160	76.19	1.96	0
FLASH WEST G 29-20 4207H	P-BP	405.00	1,825.21	0.00	0.00	0.0000000	0.0000000	0.0004117	0.0004117	76.19	1.96	0
FRANCIS UNIT 1H	P-BP	512.15	2,699.04	0.00	0.00	0.0000000	0.0000000	0.0073981	0.0073981	73.55	1.70	0
GRAYSTONE UNIT 39-26 4AH	P-BP	390.78	1,041.75	0.00	0.00	0.0000000	0.0000000	0.0000790	0.0000790	76.19	1.96	0
GRAYSTONE UNIT 39-26 4SH	P-BP	270.45	933.86	0.00	0.00	0.0000000	0.0000000	0.0000790	0.0000790	76.19	1.96	0
GRAYSTONE UNIT 39-26 5AH	P-BP	392.39	1,046.07	0.00	0.00	0.0000000	0.0000000	0.0000790	0.0000790	76.19	1.96	0
GRAYSTONE UNIT 39-26 5SH	P-BP	272.61	941.14	0.00	0.00	0.0000000	0.0000000	0.0000790	0.0000790	76.19	1.96	0
GRAYSTONE UNIT 39-26 6AH	P-BP	393.50	1,049.15	0.00	0.00	0.0000000	0.0000000	0.0000790	0.0000790	76.19	1.96	0
GRAYSTONE UNIT 39-26 6SH	P-BP	272.26	938.78	0.00	0.00	0.0000000	0.0000000	0.0000790	0.0000790	76.19	1.96	0
HA RA SUD;RISN 17&20-11-10HC 001	P-BP	0.00	13,498.19	0.00	0.00	0.0000000	0.0000000	0.0548286	0.0548286	73.94	2.15	0
HA RA SUD;RISN 17&20-11-10HC 002-ALT	P-BP	0.00	11,325.18	0.00	0.00	0.0000000	0.0000000	0.0659245	0.0659245	73.94	2.15	0
HA RB SUKK;BAYOU5&8&17-11-10HC 001-PA-LBTP		0.00	13,719.13	0.00	0.00	0.0000000	0.0000000	0.0375770	0.0375770	73.94	2.15	0
HA RB SUKK;BAYOU5&8&17-11-10HC 002-PA-LBTP		0.00	12,870.13	0.00	0.00	0.0000000	0.0000000	0.0375770	0.0375770	73.94	2.15	0
KOLM-CHUMCHAL 1H	P-BP	229.47	1,209.26	0.00	0.00	0.0000000	0.0000000	0.0102000	0.0102000	74.40	1.94	0
LEAVITT FED 2-9-4MH	P-BP	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0080600	0.0000000	74.04	4.41	0
LEAVITT FED 4-9-4 MH	P-BP	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0080600	0.0000000	74.04	4.41	0
MADELEINE FAYE 133-137 A 1LS	P-BP	632.31	1,525.80	0.00	0.00	0.0000000	0.0000000	0.0013560	0.0013560	75.89	1.34	0
MADELEINE FAYE 133-137 B 2JM	P-BP	629.21	1,518.49	0.00	0.00	0.0000000	0.0000000	0.0013560	0.0013560	75.89	1.34	0
MADELEINE FAYE 133-137 C 2LS	P-BP	628.16	1,515.63	0.00	0.00	0.0000000	0.0000000	0.0013560	0.0013560	75.89	1.34	0
MADELEINE FAYE 133-137 D 1WB	P-BP	414.58	1,659.83	0.00	0.00	0.0000000	0.0000000	0.0012510	0.0012510	75.89	1.34	0
MADELEINE FAYE 133-137 E 3LS	P-BP	625.39	1,508.07	0.00	0.00	0.0000000	0.0000000	0.0013560	0.0013560	75.89	1.34	0
MADELEINE FAYE 133-137 F 1MS	P-BP	625.74	1,508.94	0.00	0.00	0.0000000	0.0000000	0.0013560	0.0013560	75.89	1.34	0
MADELEINE FAYE 133-137 G 2WB	P-BP	413.19	1,654.18	0.00	0.00	0.0000000	0.0000000	0.0012510	0.0012510	75.89	1.34	0
MADELEINE FAYE 133-137 H 1US	P-BP	629.08	1,518.18	0.00	0.00	0.0000000	0.0000000	0.0013560	0.0013560	75.89	1.34	0
MANCHESTER WELL	P-BP	0.00	51,367.68	0.00	0.00	0.0000000	0.0000000	0.0000000	0.0000000	75.48	2.13	0
MANGER UNIT 1H	P-BP	442.50	2,338.18	0.00	0.00	0.0000000	0.0000000	0.0003030	0.0003030	74.40	1.94	0
MCLINTOCK 15-27 B 2JM	P-BP	665.05	2,577.84	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200
MCLINTOCK 15-27 C 3JM	P-BP	578.42	1,634.62	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200
MCLINTOCK 15-27 G 7LS	P-BP	570.52	1,611.93	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200
MCLINTOCK 15-27 H 8LS	P-BP	579.26	1,637.03	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200

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MCLINTOCK 15-27 L 12WA	P-BP	590.80	1,425.85	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200
MCLINTOCK 15-27 L 18WB	P-BP	556.60	2,537.18	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200
MCLINTOCK 15-27 L 23JM	P-BP	566.60	1,600.78	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200
MCLINTOCK 15-27 L 6LS	P-BP	571.27	1,614.08	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200
MCLINTOCK 15-27 N 14WA	P-BP	593.11	1,431.22	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200
MCLINTOCK 15-27 S 19WB	P-BP	557.31	2,540.98	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200
MCLINTOCK 15-27H 20WB	P-BP	543.99	2,480.78	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200
MCLINTOCK 15-27M 13WA	P-BP	592.89	1,430.65	0.00	0.00	0.0022930	0.0022930	0.0017200	0.0017200	75.89	1.34	1,200
MIRANDA 202H	P-BP	518.20	2,736.04	0.00	0.00	0.0000000	0.0000000	0.0000000	0.0000000	73.55	1.70	0
MIRANDA A 1H	P-BP	510.20	2,694.05	0.00	0.00	0.0000000	0.0000000	0.0000000	0.0000000	73.55	1.70	0
MIRANDA B 201H	P-BP	468.55	2,475.16	0.00	0.00	0.0000000	0.0000000	0.0000000	0.0000000	73.55	1.70	0
MORGAN-NEAL 39-26 3SH	P-BP	270.33	933.50	0.00	0.00	0.0000000	0.0000000	0.0000790	0.0000790	76.19	1.96	0
MR. DYNAMITE A 3MS	P-BP	207.69	692.10	0.00	0.00	0.0000000	0.0000000	0.0041740	0.0041740	76.19	1.96	0
MR. DYNAMITE C 5MS	P-BP	206.43	687.79	0.00	0.00	0.0000000	0.0000000	0.0041740	0.0041740	76.19	1.96	0
PARKS, ROY 301LH	P-BP	357.60	1,300.82	0.00	0.00	0.0000000	0.0000000	0.0002680	0.0002680	76.66	1.00	0
PELLETIER JN SAL 1H	P-BP	0.00	21,395.86	0.00	0.00	0.0000000	0.0000000	0.0000000	0.0000000	73.94	1.98	0
PELLETIER JN SAL 3H	P-BP	0.00	8,257.69	0.00	0.00	0.0000000	0.0000000	0.0000000	0.0000000	73.94	1.98	0
RATHKAMP UNIT 202H	P-BP	536.34	2,829.44	0.00	0.00	0.0000000	0.0000000	0.0097130	0.0097130	74.40	1.94	0
RATHKAMP UNIT 5H	P-BP	500.06	2,638.82	0.00	0.00	0.0000000	0.0000000	0.0097130	0.0097130	74.40	1.94	0
RENDEZVOUS NORTH POOLED UNIT	10UAP-BP	393.81	986.25	0.00	0.00	0.0000000	0.0000000	0.0002750	0.0002750	75.15	0.68	0
RENDEZVOUS NORTH POOLED UNIT	18H P-BP	320.87	3,426.60	0.00	0.00	0.0000000	0.0000000	0.0002750	0.0002750	75.15	0.68	0
RENDEZVOUS NORTH POOLED UNIT	28SBP-BP	393.81	986.25	0.00	0.00	0.0000000	0.0000000	0.0002750	0.0002750	75.15	0.68	0
REV CON STATE T8-50-17 I 0045WA	P-BP	328.69	703.68	0.00	0.00	0.0000000	0.0000000	0.0011336	0.0011336	75.81	1.34	0
REV CON STATE T8-50-21 A 0091WA	P-BP	337.03	3,591.17	0.00	0.00	0.0000000	0.0000000	0.0011336	0.0011336	75.81	1.34	0
REV CON STATE T8-50-21 B 0092WA	P-BP	371.90	3,962.72	0.00	0.00	0.0000000	0.0000000	0.0011336	0.0011336	75.81	1.34	0
RIO GRANDE 12-24-A 32LS	P-BP	547.18	1,545.85	0.00	0.00	0.0000000	0.0000000	0.0005190	0.0005190	75.89	1.34	0
RIO GRANDE 12-24-B 32WA	P-BP	557.16	1,344.50	0.00	0.00	0.0000000	0.0000000	0.0005130	0.0005130	75.89	1.34	0
SHENANDOAH 11-2-58 H 1WB	P-BP	180.35	598.73	0.00	0.00	0.0000000	0.0000000	0.0003770	0.0003770	76.19	1.96	0
SHENANDOAH 11-2-58 XL H 3WA	P-BP	180.99	600.93	0.00	0.00	0.0000000	0.0000000	0.0003770	0.0003770	76.19	1.96	0
STOCKYARDS C 3551H	P-BP	537.37	6,744.15	0.00	0.00	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
STOCKYARDS STATE A 3401H	P-BP	524.71	6,585.21	0.00	0.00	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
STOCKYARDS STATE B 3471H	P-BP	536.66	6,734.99	0.00	0.00	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
SUNDANCE A 3501H	P-BP	569.51	7,145.92	0.00	0.00	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
SUNDANCE B 3571H	P-BP	587.78	7,372.47	0.00	0.00	0.0000000	0.0000000	0.0000020	0.0000020	75.15	0.68	0
TROLL UNIT A 08-04 2AH	P-BP	625.73	1,670.55	0.00	0.00	0.0000000	0.0000000	0.0134561	0.0134561	73.67	3.34	0
TROLL UNIT A 08-04 3AH	P-BP	627.15	1,674.29	0.00	0.00	0.0000000	0.0000000	0.0134561	0.0134561	73.67	3.34	0
WALKER 32-48 B UNIT A 6H	P-BP	486.76	1,300.45	0.00	0.00	0.0000000	0.0000000	0.0044780	0.0044780	76.19	1.96	0

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WALKER 32-48 B UNIT A 7H	P-BP	475.31	1,269.92	0.00	0.00	0.0000000	0.0000000	0.0151660	0.0151660	76.19	1.96	0
WALKER 32-48 B UNIT L 5H	P-BP	343.37	1,188.85	0.00	0.00	0.0000000	0.0000000	0.0034780	0.0034780	76.19	1.96	0
WALKER 32-48 B UNIT L 7H	P-BP	325.43	1,126.76	0.00	0.00	0.0000000	0.0000000	0.0034780	0.0034780	76.19	1.96	0
WALKER 48-32 A UNIT A 2H	P-BP	511.69	1,366.73	0.00	0.00	0.0000000	0.0000000	0.0023270	0.0023270	76.19	1.96	0
WALKER 48-32 A UNIT A 3H	P-BP	501.44	1,339.36	0.00	0.00	0.0000000	0.0000000	0.0034780	0.0034780	76.19	1.96	0
WALKER 48-32 A UNIT L 2H	P-BP	357.29	1,237.01	0.00	0.00	0.0000000	0.0000000	0.0051810	0.0051810	76.19	1.96	0
WALKER 48-32 A UNIT L 3H	P-BP	501.69	1,340.10	0.00	0.00	0.0000000	0.0000000	0.0075080	0.0075080	76.19	1.96	0
WHIRLAWAY 101-99 A 1WA	P-BP	641.48	1,607.67	0.00	0.00	0.0000000	0.0000000	0.0000760	0.0000760	75.15	0.68	0
WHIRLAWAY 101-99 B 2TS	P-BP	804.18	1,723.02	0.00	0.00	0.0000000	0.0000000	0.0000760	0.0000760	75.15	0.68	0
WHIRLAWAY 101-99 C 3WA	P-BP	642.16	1,609.35	0.00	0.00	0.0000000	0.0000000	0.0000760	0.0000760	75.15	0.68	0
WHIRLAWAY 101-99 D 4TS	P-BP	640.75	1,605.99	0.00	0.00	0.0000000	0.0000000	0.0000760	0.0000760	75.15	0.68	0
WHIRLAWAY 101-99 E 5WA	P-BP	704.79	2,910.98	0.00	0.00	0.0000000	0.0000000	0.0000760	0.0000760	75.15	0.68	0
WHIRLAWAY 101-99 F 6TS	P-BP	805.93	1,726.87	0.00	0.00	0.0000000	0.0000000	0.0000760	0.0000760	75.15	0.68	0
WHITE HORSE 1	P-BP	631.23	793.13	0.00	0.00	0.0000000	0.0000000	0.0000560	0.0000560	75.15	0.68	0
		49,892.97	**467,874.12**	**0.00**	**0.00**							
Proved Shut-In Rsv Class & Category												
ADAMEK UNIT 1H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0105380	0.0000000	74.40	1.94	0
ALEX TAMSULA 3	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.1003470	0.0000000	73.94	1.41	0
ALICO -A- 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0077290	0.0000000	75.89	1.34	0
ALICO 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0077290	0.0000000	75.89	1.34	0
ALLMAN 24 6H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0043020	0.0000000	75.81	1.34	0
BAKER TRUST 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0030210	0.0000000	76.19	1.96	0
BAYES 16 2	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0003350	0.0000000	75.89	1.34	0
BIZZELL 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0138640	0.0000000	76.66	1.00	0
BLACK STONE 34-216 1H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0009150	0.0000000	75.15	0.68	0
BLACK STONE 34-216 2H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0009150	0.0000000	75.15	0.68	0
BLACK, S.E. -42- 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0117190	0.0000000	76.00	1.19	0
BLACK, S.E. 42 9	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0058590	0.0000000	76.00	1.19	0
BROWN, A. D. 2	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0026040	0.0000000	77.02	1.02	0
CAMPBELL 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
CHILDRESS 140 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0500000	0.0000000	75.14	2.00	0
CHILDRESS 140 2	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0500000	0.0000000	75.14	2.00	0
CHILDRESS 140 5	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0500000	0.0000000	75.14	2.00	0
CHUMCHAL UNIT 2H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0101900	0.0000000	74.40	1.94	0
CHUMCHAL UNIT 3H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0101900	0.0000000	74.40	1.94	0
CLAWSON 6	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.1250000	0.1250000	73.94	1.41	0
COFFIELD -A- 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0077290	0.0000000	75.89	1.34	0

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LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
COURAGE 41-2827-23N	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0015630	0.0000000	60.48	1.70	0
DAVIS 1_2	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.1158070	0.0000000	73.94	1.41	0
DYER 3302	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0183330	0.0000000	75.89	1.34	0
FIREBIRD 52 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0001180	0.0000000	75.15	0.68	0
FISHERMAN -A- 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0052080	0.0000000	75.89	1.34	0
GUITAR 11 2	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0031250	0.0000000	76.19	1.96	0
HA RA SUA;NAC 36 H 001-ALT	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0986160	0.0000000	66.78	2.04	0
HA RA SUA;WIGGINS 36-25 HC 002-ALT	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0503550	0.0000000	66.78	2.34	0
HA RA SUB;SHELBY INTERESTS 31H 001	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0157350	0.0000000	66.78	2.04	0
HA RA SUL;MADDEN 18 H 001	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0156400	0.0000000	66.78	2.34	0
HA RA SUL;MADDEN 18 H 002-ALT	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0156400	0.0000000	66.78	2.34	0
HA RA SUL;MADDEN 18-19 HC 001-ALT	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0019050	0.0000000	66.78	2.34	0
HA RB SU74;NAC ROYALTY 28 H 001	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.1313610	0.0000000	66.78	2.34	0
HA RB SU90;NRG 29-12-10 H 002-ALT	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0375770	0.0000000	66.78	2.34	0
HOLMES LIMESTONE 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0765500	0.0000000	73.94	1.98	0
JANAK UNIT 1H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0251620	0.0000000	74.40	1.94	0
JERSEY 35-23-H 2815H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0004860	0.0000000	76.00	1.19	0
JIM TOM 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0077290	0.0000000	75.89	1.34	0
JOHN F. FERGUSON 3	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0736450	0.0736450	73.94	1.41	0
LARRY CARLSON 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.1100000	0.1100000	73.94	1.41	0
LOBLEY, G. D. 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0218750	0.0000000	76.66	1.00	0
LONG UNIT 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0662440	0.0662440	73.94	1.41	0
MARY GRACE 201-202 UNIT 2H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0001950	0.0000000	75.15	0.68	0
MEADOR, J. J. 3	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0003120	0.0000000	76.19	1.96	0
MERCHANT UNIT 6704A	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0014580	0.0000000	75.14	2.00	0
MORAN A2 2LA	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0000000	0.0000000	75.15	0.68	0
NAC GAS UNIT B 3H-3	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.1157930	0.0000000	73.94	1.98	0
NORTH AMERICAN COAL 1_1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0560430	0.0000000	73.94	1.98	0
NUNN, J. F. -A- 20	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0014580	0.0000000	75.14	2.00	0
NUNN, J. F. -A- 9	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0014580	0.0000000	75.14	2.00	0
O'NEAL -D- 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0117180	0.0000000	76.66	1.00	0
PHILLIPS 7 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0031010	0.0000000	76.19	1.96	0
RHOADES MOON 1-36B5	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0006770	0.0000000	60.48	1.70	0
RINGNECK DOVE 3	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0031010	0.0000000	76.19	1.96	0
RIPLEY UNIT 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0152740	0.0000000	73.94	1.98	0
RIPLEY UNIT 3	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0152740	0.0000000	73.94	1.98	0
SCHWALBE UNIT 01	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0000427	0.0000000	75.15	0.68	0

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SCHWALBE UNIT 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0002250	0.0000000	75.81	1.34	0
SHERROD UNIT 3904	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0014590	0.0000000	75.14	2.00	0
SHERROD UNIT 904	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0014590	0.0000000	75.14	2.00	0
SHIPPER GAS UNIT 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0115110	0.0000000	73.94	1.75	0
SOUTH HILIGHT UNIT 1-41	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0050000	0.0000000	74.04	4.41	0
SOUTH HILIGHT UNIT 13-39	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0100010	0.0000000	74.04	4.41	0
SPRABERRY DRIVER UNIT 343	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0167720	0.0000000	76.00	1.19	0
STELLA STATE 34-208 WRD UNIT 1H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0002120	0.0000000	75.15	0.68	0
TCM 1	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0070000	0.0000000	75.89	1.34	0
THORPE 1-74 LOV 1H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0000400	0.0000000	76.15	-0.83	0
THURMOND 132 ALLOC C 11H	P-SI	180.06	1,656.88	180.06	1,656.88	0.0000000	0.0000000	0.0015190	0.0000000	75.81	1.34	0
TIGIWON 2627-C23 E 1H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0004920	0.0000000	75.22	1.21	0
WHITLEY 34-231 1H	P-SI	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0007280	0.0000000	75.15	0.68	0
		180.06	**1,656.88**	**180.06**	**1,656.88**							
Proved Undeveloped Rsv Class & Category												
BARZONA STATE COM 303H	P-UD	548.30	2,276.73	0.00	0.00	0.0000000	0.0000000	0.0027470	0.0027470	76.17	1.13	0
BARZONA STATE COM 503H	P-UD	542.09	2,250.92	0.00	0.00	0.0000000	0.0000000	0.0027470	0.0027470	76.17	1.13	0
BARZONA STATE COM 603H	P-UD	237.16	415.69	0.00	0.00	0.0000000	0.0000000	0.0027470	0.0027470	76.17	1.13	0
BARZONA STATE COM 703H	P-UD	112.07	192.18	0.00	0.00	0.0000000	0.0000000	0.0027470	0.0027470	76.17	1.13	0
BARZONA STATE COM 803H	P-UD	266.34	1,096.32	0.00	0.00	0.0000000	0.0000000	0.0027470	0.0027470	76.17	1.13	0
BTR 11E-35W-H5UB	P-UD	175.19	445.49	0.00	0.00	0.0000000	0.0000000	0.0009430	0.0009430	60.48	1.70	0
BTR 11E-35W-H6UB	P-UD	170.85	434.24	0.00	0.00	0.0000000	0.0000000	0.0009430	0.0009430	60.48	1.70	0
BTR 11E-35W-H7UB	P-UD	441.14	2,198.65	0.00	0.00	0.0000000	0.0000000	0.0009430	0.0009430	60.48	1.70	0
CHEVRON UNIT 03-38 3AH	P-UD	427.12	1,926.55	0.00	0.00	0.0000000	0.0000000	0.0004375	0.0004375	76.19	1.96	0
CLEMENTS ALLOCATION B 26-35 2HA	P-UD	287.28	765.40	0.00	0.00	0.0000000	0.0000000	0.0004050	0.0004050	73.67	3.34	0
CLEMENTS ALLOCATION C 26-35 3HA	P-UD	285.21	759.71	0.00	0.00	0.0000000	0.0000000	0.0004050	0.0004050	73.67	3.34	0
CLEMENTS ALLOCATION D 26-35 7LS	P-UD	197.03	677.16	0.00	0.00	0.0000000	0.0000000	0.0004050	0.0004050	73.67	3.34	0
DANIELLE 183 UNIT 221H	P-UD	314.29	2,559.45	0.00	0.00	0.0000000	0.0000000	0.0001309	0.0001309	75.15	0.68	0
DIRE WOLF 10 1BS A 1H	P-UD	449.08	4,819.15	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
DIRE WOLF 10 1BS B 2H	P-UD	445.72	4,752.07	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
DIRE WOLF 10 1BS C 3H	P-UD	497.10	5,295.92	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
DIRE WOLF 10 1BS D 4H	P-UD	499.21	5,314.75	0.00	0.00	0.0000000	0.0000000	0.0004700	0.0004700	75.15	0.68	0
DIRE WOLF 30 3BS B 2H	P-UD	444.92	4,750.90	0.00	0.00	0.0000000	0.0000000	0.0013020	0.0013020	75.15	0.68	0
DIRE WOLF 30 3BS C 3H	P-UD	449.37	4,822.24	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
DIRE WOLF 30 3BS D 4H	P-UD	500.77	5,331.25	0.00	0.00	0.0000000	0.0000000	0.0004700	0.0004700	75.15	0.68	0
DIRE WOLF 50 WA B 2H	P-UD	450.75	4,812.74	0.00	0.00	0.0000000	0.0000000	0.0013020	0.0013020	75.15	0.68	0
DIRE WOLF 50 WA C 3H	P-UD	448.91	4,785.81	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0

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DIRE WOLF 50 WA D 4H	P-UD	449.99	4,794.24	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
DIRE WOLF 50 WA E 5H	P-UD	501.05	5,334.42	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
DIRE WOLF 50 WA F 6H	P-UD	500.77	5,331.36	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
DIRE WOLF 60 WB B 2H	P-UD	448.77	4,791.80	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
DIRE WOLF 60 WB C 3H	P-UD	449.03	4,787.12	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
DIRE WOLF 60 WB D 4H	P-UD	449.48	4,788.86	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
DIRE WOLF 60 WB E 5H	P-UD	500.71	5,330.70	0.00	0.00	0.0000000	0.0000000	0.0000010	0.0000010	75.15	0.68	0
DIRE WOLF 70 WC B 2H	P-UD	447.86	4,781.97	0.00	0.00	0.0000000	0.0000000	0.0013020	0.0013020	75.15	0.68	0
DRIVER N5A 1H	P-UD	448.22	2,440.23	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
DRIVER N5B 2H	P-UD	445.96	2,427.90	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
DRIVER N5C 3H	P-UD	443.79	2,416.02	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
DRIVER N5D 4H	P-UD	441.88	2,405.71	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
DRIVER N5E 5H	P-UD	440.89	2,400.25	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
DRIVER N5F 6H	P-UD	441.30	2,402.46	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
DRIVER SE5S 119H	P-UD	452.17	2,461.64	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
DRIVER SE5T 120H	P-UD	450.90	2,454.76	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
DRIVER SE5U 121H	P-UD	454.11	2,472.28	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
DRIVER SE5V 122H	P-UD	456.60	2,485.85	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
DRIVER SE5W 123H	P-UD	459.81	2,503.37	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
DRIVER SE5X 124H	P-UD	462.90	2,520.11	0.00	0.00	0.0000000	0.0000000	0.0005630	0.0005630	76.00	1.19	0
HAWKS 55-1-33-28 A 13H	P-UD	457.50	6,585.20	0.00	0.00	0.0000000	0.0000000	0.0002500	0.0002500	76.15	-0.83	0
HAWKS 55-1-33-28 B 14H	P-UD	455.43	6,552.58	0.00	0.00	0.0000000	0.0000000	0.0002500	0.0002500	76.15	-0.83	0
HAWKS 55-1-33-28 C 21H	P-UD	455.39	6,554.85	0.00	0.00	0.0000000	0.0000000	0.0002500	0.0002500	76.15	-0.83	0
HAWKS 55-1-33-28 D 15H	P-UD	455.35	6,554.26	0.00	0.00	0.0000000	0.0000000	0.0002500	0.0002500	76.15	-0.83	0
HAWKS 55-1-33-28 E 22H	P-UD	455.31	6,553.66	0.00	0.00	0.0000000	0.0000000	0.0002500	0.0002500	76.15	-0.83	0
HAWKS 55-1-33-28 F 16H	P-UD	455.97	6,563.19	0.00	0.00	0.0000000	0.0000000	0.0002500	0.0002500	76.15	-0.83	0
HORNSILVER 2H	P-UD	373.93	2,288.37	0.00	0.00	0.0000000	0.0000000	0.0001610	0.0001610	75.15	0.68	0
MADELEINE FAYE 133-137 I 2US	P-UD	624.28	1,505.43	0.00	0.00	0.0000000	0.0000000	0.0011100	0.0011100	75.89	1.34	0
MADELEINE FAYE 133-137 J 1WD	P-UD	415.15	1,660.62	0.00	0.00	0.0000000	0.0000000	0.0012510	0.0012510	75.89	1.34	0
MADELEINE FAYE 133-137 K 2WD	P-UD	413.32	1,653.37	0.00	0.00	0.0000000	0.0000000	0.0012510	0.0012510	75.89	1.34	0
MARY GRACE 201-202 UNIT 225H	P-UD	0.00	0.00	0.00	0.00	0.0000000	0.0000000	0.0001950	0.0001950	75.15	0.68	0
RAMBO FEE COM 302H	P-UD	252.44	443.06	0.00	0.00	0.0000000	0.0000000	0.0004830	0.0004830	76.17	1.13	0
RAMBO FEE COM 802H	P-UD	594.06	882.59	0.00	0.00	0.0000000	0.0000000	0.0004830	0.0004830	76.17	1.13	0
RAMBO STATE COM 303H	P-UD	253.90	445.67	0.00	0.00	0.0000000	0.0000000	0.0004830	0.0004830	76.17	1.13	0
RAMBO STATE COM 503H	P-UD	575.48	2,389.54	0.00	0.00	0.0000000	0.0000000	0.0004830	0.0004830	76.17	1.13	0
RAMBO STATE COM 803H	P-UD	597.68	887.95	0.00	0.00	0.0000000	0.0000000	0.0004830	0.0004830	76.17	1.13	0
RANCH WATER UNIT 2 1904BH	P-UD	578.22	2,633.14	0.00	0.00	0.0000000	0.0000000	0.0082140	0.0082140	75.89	1.34	0

TABLE 8

As of: 01/01/2025

GROSS ULTIMATE RESERVES, CUMULATIVE PRODUCTION AND BASIC ECONOMIC DATA

LEASE NAME	RES CAT	GROSS ULTIMATE Mbbl	GROSS ULTIMATE MMcf	CUM OIL Mbbl	CUM GAS MMcf	EXPENSE INITIAL DECIMAL	INTEREST FINAL DECIMAL	REVENUE INITIAL DECIMAL	INTEREST FINAL DECIMAL	OIL PRC INITIAL $/bbl	GAS PRC INITIAL $/Mcf	FIXED COST $/MO
RANCH WATER UNIT 2 1905BH	P-UD	577.73	2,630.88	0.00	0.00	0.0000000	0.0000000	0.0082140	0.0082140	75.89	1.34	0
RANCH WATER UNIT 2 1964DH	P-UD	616.43	1,486.36	0.00	0.00	0.0000000	0.0000000	0.0082140	0.0082140	75.89	1.34	0
RANCH WATER UNIT 2 1965DH	P-UD	615.33	1,483.72	0.00	0.00	0.0000000	0.0000000	0.0082140	0.0082140	75.89	1.34	0
RANCH WATER UNIT 2 1966DH	P-UD	615.37	1,483.79	0.00	0.00	0.0000000	0.0000000	0.0082140	0.0082140	75.89	1.34	0
RANCH WATER UNIT 2 1974JH	P-UD	705.65	2,731.77	0.00	0.00	0.0000000	0.0000000	0.0082140	0.0082140	75.89	1.34	0
RANCH WATER UNIT 2 1975JH	P-UD	705.20	2,730.04	0.00	0.00	0.0000000	0.0000000	0.0082140	0.0082140	75.89	1.34	0
RANCH WATER UNIT 2 1976JH	P-UD	705.51	2,731.22	0.00	0.00	0.0000000	0.0000000	0.0082140	0.0082140	75.89	1.34	0
RANCH WATER UNIT 2 1984NH	P-UD	407.72	1,629.36	0.00	0.00	0.0000000	0.0000000	0.0082140	0.0082140	75.89	1.34	0
RANCH WATER UNIT 2 1986NH	P-UD	407.92	1,630.18	0.00	0.00	0.0000000	0.0000000	0.0082140	0.0082140	75.89	1.34	0
RENDEZVOUS NORTH POOLED UNIT	2LAP-UD	319.58	3,411.52	0.00	0.00	0.0000000	0.0000000	0.0002748	0.0002748	75.15	0.68	0
SILVER FOX 16-1-2-C5-4H	P-UD	313.53	817.78	0.00	0.00	0.0000000	0.0000000	0.0002410	0.0002410	60.48	1.70	0
SILVER FOX 16-1-2-C5-5H	P-UD	313.53	817.78	0.00	0.00	0.0000000	0.0000000	0.0002410	0.0002410	60.48	1.70	0
SILVER FOX 9-1-2-C5-1H	P-UD	316.29	825.20	0.00	0.00	0.0000000	0.0000000	0.0002410	0.0002410	60.48	1.70	0
SILVER FOX 9-1-2-C5-2H	P-UD	314.91	821.49	0.00	0.00	0.0000000	0.0000000	0.0002410	0.0002410	60.48	1.70	0
SILVER FOX 9-1-2-C5-3H	P-UD	313.91	818.79	0.00	0.00	0.0000000	0.0000000	0.0002410	0.0002410	60.48	1.70	0
SNOWBIRD 13-16-15-C5-7H	P-UD	193.93	494.00	0.00	0.00	0.0000000	0.0000000	0.0035830	0.0035830	60.48	1.70	0
STEVENSON-STOKES 26A 1H	P-UD	449.37	2,443.97	0.00	0.00	0.0000000	0.0000000	0.0004840	0.0004840	75.14	2.00	0
STEVENSON-STOKES 26B 2H	P-UD	560.62	6,897.64	0.00	0.00	0.0000000	0.0000000	0.0004840	0.0004840	75.14	2.00	0
STEVENSON-STOKES 26C 3H	P-UD	563.81	3,419.38	0.00	0.00	0.0000000	0.0000000	0.0004840	0.0004840	75.14	2.00	0
STEVENSON-STOKES 26D 4H	P-UD	563.73	3,418.93	0.00	0.00	0.0000000	0.0000000	0.0004860	0.0004860	75.14	2.00	0
STICKLINE 2H	P-UD	373.28	2,284.56	0.00	0.00	0.0000000	0.0000000	0.0000280	0.0000280	75.15	0.68	0
STONE-WINSLOW E40F 6H	P-UD	812.11	1,958.63	0.00	0.00	0.0000000	0.0000000	0.0031300	0.0031300	76.00	1.19	0
STONE-WINSLOW E40G 7H	P-UD	810.47	1,954.68	0.00	0.00	0.0000000	0.0000000	0.0031300	0.0031300	76.00	1.19	0
STONE-WINSLOW E40H 8H	P-UD	811.71	1,957.68	0.00	0.00	0.0000000	0.0000000	0.0031300	0.0031300	76.00	1.19	0
TREBLE STATE COM 301H	P-UD	237.54	416.12	0.00	0.00	0.0000000	0.0000000	0.0007330	0.0007330	76.17	1.13	0
TREBLE STATE COM 501H	P-UD	534.83	2,225.14	0.00	0.00	0.0000000	0.0000000	0.0007330	0.0007330	76.17	1.13	0
VALENCIA 10-8 A UNIT A 1H	P-UD	398.22	1,062.92	0.00	0.00	0.0000000	0.0000000	0.0003220	0.0003220	76.19	1.96	0
VALENCIA 10-8 A UNIT L 1H	P-UD	396.75	1,059.15	0.00	0.00	0.0000000	0.0000000	0.0003220	0.0003220	76.19	1.96	0
WINDY MOUNTAIN 7978 7U A 7H	P-UD	367.27	2,248.18	0.00	0.00	0.0000000	0.0000000	0.0001800	0.0001800	75.81	1.34	0
WINDY MOUNTAIN 7978 8U A 8H	P-UD	365.56	2,237.70	0.00	0.00	0.0000000	0.0000000	0.0001800	0.0001800	75.81	1.34	0
WINDY MOUNTAIN 7978 9U A 9H	P-UD	366.92	2,245.90	0.00	0.00	0.0000000	0.0000000	0.0001800	0.0001800	75.81	1.34	0
		39,804.23	**246,542.34**	**0.00**	**0.00**							
Grand Total		**767,196.33**	**5,663,888.96**	**417,682.32**	**3,020,479.08**							