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

FORM 8-K/A
(Amendment No. 1)

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

Date of report (Date of earliest event reported): November 7, 2023

VIPER ENERGY, INC.
(Exact Name of Registrant as Specified in Charter)

DE	**001-36505**	**46-5001985**
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification Number)

500 West Texas Ave. **Suite 100** **Midland, TX**	**79701**
(Address of principal executive offices)	(Zip code)

(432) 221-7400
(Registrant's telephone number, including area code)

Viper Energy Partners LP
(Former name or former address, if changed since last report)

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

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class	**Trading Symbol(s)**	**Name of each exchange on which registered**
Class A Common Stock, $0.000001 Par Value	VNOM	The Nasdaq Stock Market LLC (NASDAQ Global Select Market)

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

Emerging growth company ☐

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

Explanatory Note

As previously disclosed in its Current Report on Form 8-K filed with the Securities and Exchange Commission (the “SEC”) on November 7, 2023 (the “Closing 8-K”), on November 1, 2023 (the "Closing Date"), Viper Energy Partners LP (“Viper”) and its operating subsidiary, Viper Energy Partners LLC (“Viper OpCo” and, together with Viper, the “Buyer Parties”) completed the acquisition (the “Acquisition”) of certain mineral interests, overriding royalty interests, royalty interests and non-participating royalty interests in oil, gas, and other hydrocarbons (the “Assets”) from Royalty Asset Holdings, LP, Royalty Asset Holdings II, LP and Saxum Asset Holdings, LP (collectively, “Sellers,” and affiliates of Warwick Capital Partners and GRP Energy Capital) under the previously reported Purchase and Sale Agreement, dated as of September 4, 2023, by and among the Buyer Parties and the Sellers (the “Purchase and Sale Agreement”). The total consideration for the Acquisition consisted of 9,018,760 common units representing limited partnership interests in Viper (the “Common Units”) (the “Common Unit Consideration”) and $750 million in cash (the “Cash Consideration”). The Cash Consideration for the Acquisition was funded through a combination of (i) cash on hand, (ii) proceeds from Viper’s offering of $400 million in aggregate principal amount of 7.375% Senior Notes due 2031, (iii) $200 million in net proceeds from the issuance of 7,215,007 Common Units to Viper’s parent, Diamondback Energy, Inc. (“Diamondback”), under that certain Common Unit Purchase and Sale Agreement (the “Common Unit Purchase Agreement”) described in Item 1.01 of Viper’s Current Report on Form 8-K filed with the Securities and Exchange Commission (the “SEC”) on September 7, 2023 (the “Initial 8-K”) at the same implied valuation per Common Unit as the Common Unit Consideration, and (iv) borrowings under Viper OpCo’s revolving credit facility. The Acquisition has an effective date of October 1, 2023.

This Amendment to Current Report on Form 8-K is being filed to amend and supplement the Initial 8-K, the sole purpose of which is to provide the financial statements and pro forma financial information required by Item 9.01, which were excluded from the Initial 8-K and are filed as exhibits hereto and are incorporated herein by reference. All other items in the Initial remain the same.

Further, as previously disclosed in its Current Report on Form 8-K filed with the SEC on November 2, 2023, Viper filed a Certificate of Conversion with the Secretary of the State of Delaware to convert its legal status from a Delaware limited partnership into a Delaware corporation (the “Conversion”). The Conversion became effective at 12:01 a.m. (Eastern Time) on November 13, 2023 at which time Viper Energy Partners LP converted its legal status from a Delaware limited partnership into a Delaware corporation and changed its name to Viper Energy, Inc.

References in this 8-K/A and the exhibits to this 8-K/A to the “Partnership” refer to Viper Energy Partners LP, the predecessor of Viper Energy, Inc., prior to the Conversion. Additionally, references to “Viper Energy,” “Viper,” “the Company,” “we,” “our,” “us” or like terms refer to (A) following the conversion, Viper Energy, Inc. individually and collectively with Viper OpCo, as the context requires, and (B) before the conversion, the Partnership individually and collectively with Viper OpCo, as the context requires.

Item 9.01. Financial Statements and Exhibits.

(a) Financial Statements of Business or Funds Acquired.

The combined financial statements of the Sellers, which comprise the combined balance sheets, the related combined statements of operations, combined statement of partners' capital, and combined statements of cash flows, the related notes to the combined financial statements, and the unaudited supplemental information on oil and natural gas operations for the years ended December 31, 2022 and 2021, are filed as Exhibit 99.1 hereto and incorporated by reference herein.

The unaudited interim combined financial statements of the Sellers, which comprise the combined balance sheets, the related combined statements of operations, combined statement of partners' capital, and combined statements of cash flows, and the related notes to the combined financial statements for the nine months ended September 30, 2023 and 2022, are filed as Exhibit 99.2 hereto and incorporated by reference herein.

(b) Pro Forma Financial Information.

The unaudited pro forma condensed combined financial information of Viper, which comprises the balance sheet as of September 30, 2023, the statements of operations for the nine months ended September 30, 2023 and year ended December 31, 2022, and the related notes thereto, is filed as Exhibit 99.3 hereto and incorporated by reference herein.

(d) Exhibits

Number	Description
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of DeGolyer and MacNaughton.
23.3*	Consent of Ryder Scott Company, LP.
99.1*	Audited combined statements of revenues and direct operating expenses of the mineral and royalty interests owned by Royalty Asset Holdings, LP, Royalty Asset Holdings II, LP and Saxum Asset Holdings LP for the years ended December 31, 2022 and 2021.
99.2*	Unaudited combined statements of revenues and direct operating expenses of the mineral and royalty interests owned by Royalty Asset Holdings, LP, Royalty Asset Holdings II, LP and Saxum Asset Holdings LP for the nine months ended September 30, 2023 and 2022.
99.3*	Unaudited pro forma condensed combined financial information of Viper Energy, Inc. as of September 31, 2023 and for the nine months ended September 31, 2023 and year ended December 31, 2022.
99.4*	Report on estimates of reserves with respect to mineral and royalty interests prepared by DeGolyer and MacNaughton Corp, an independent petroleum engineering firm, as of December 30, 2022.
99.5*	Report on estimates of reserves with respect to mineral and royalty interests prepared by DeGolyer and MacNaughton Corp, an independent petroleum engineering firm, as of December 30, 2021.
104	Cover Page Interactive Data File - the cover page XBRL tags are embedded within the Inline XBRL document.

* Filed herewith.

SIGNATURE

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

VIPER ENERGY, INC.

Date: November 13, 2023

By:	/s/ Teresa L. Dick
Name:	Teresa L. Dick
Title:	Chief Financial Officer, Executive Vice President and Assistant Secretary

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated November 13, 2023, with respect to the combined financial statements of Royalty Asset Holdings, LP, Royalty Asset Holdings II, LP, and Saxum Asset Holdings, LP included in this current report of Viper Energy, Inc. on Form 8-K/A. We consent to the incorporation by reference of said report in the Registration Statement of Viper Energy Partners LP (now known as Viper Energy, Inc.) on Form S-8 (File No. 333-196971).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
November 13, 2023

Exhibit 23.2

CONSENT OF DEGLOYER AND MACNAUGHTON

We have issued our reports, each dated October 25, 2023, on estimates of proved reserves, future production and income attributable to certain royalty interests acquired by Viper Energy Partners LP (now known as Viper Energy, Inc.) (“Viper”) from Royalty Asset Holdings, LP, Royalty Asset Holdings II, LP and Saxum Asset Holdings, LP, prepared as of December 31, 2022 and December 31, 2021 (the “Reserve Reports”), included as Exhibit 99.4 and 99.5, respectively, in this Current Report on Form 8-K/A of Viper. As independent petroleum engineers, we hereby consent to (i) the inclusion of the Reserve Reports and the information contained therein and information from our prior reserve reports referenced in this Current Report on Form 8-K/A of Viper (this “Form 8-K/A”) and to all references to our firm in this Form 8-K/A and (ii) the incorporation by reference of the Reserve Reports in the Registration Statement on Form S-8 (File No. 333-196971) (the “S-8 Registration Statement”) and (ii) the use in the S-8 Registration Statement of the information contained in the Reserve Reports.

DeGloyer and MacNaughton

/s/ DeGloyer and MacNaughton

DEGLOYER AND MACNAUGHTON

Houston, Texas

November 13, 2023

Exhibit 23.3

CONSENT OF RYDER SCOTT COMPANY, L.P.

We have issued our report dated January 5, 2023 on estimates of proved reserves, future production and income attributable to certain royalty interests of Viper Energy Partners LP (now known as Viper Energy, Inc.) (“Viper”), prepared as of December 31, 2022 (the “Reserve Report”), included in Viper’s Annual Report on Form 10-K for the year ended December 31, 2022 (the “Annual Report”). As independent oil and gas consultants, we hereby consent to (i) the inclusion or incorporation by reference of the Reserve Report and the information contained therein and information from our prior reserve reports referenced in this Current Report on Form 8-K/A (this “Form 8-K/A”) and (ii) all references to our firm in this Form 8-K/A.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Houston, Texas

November 13, 2023

ROYALTY ASSET HOLDINGS, LP
ROYALTY ASSET HOLDINGS II, LP
SAXUM ASSET HOLDINGS, LP

COMBINED FINANCIAL STATEMENTS

Years Ended December 31, 2022 and 2021
with Report of Independent Auditors

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REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

Board of Directors and Stockholders
Viper Energy, Inc.

Opinion
We have audited the combined financial statements of Royalty Asset Holdings, LP, Royalty Asset Holdings II, LP and Saxum Asset Holdings, LP (collectively, the "Businesses"), which comprise the combined balance sheets as of December 31, 2022 and 2021, and the related combined statements of operations, changes in partners' equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying combined financial statements present fairly, in all material respects, the financial position of the Businesses as of December 31, 2022 and 2021, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for opinion
We conducted our audits of the combined financial statements in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Businesses and to meet our other ethical responsibilities in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of management for the financial statements
Management is responsible for the preparation and fair presentation of the combined financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of combined financial statements that are free from material misstatement, whether due to fraud or error.
In preparing the combined financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Businesses' ability to continue as a going concern for one year after the date the financial statements are available to be issued.

Auditor's responsibilities for the audit of the financial statements
Our objectives are to obtain reasonable assurance about whether the combined financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the combined financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the combined financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Businesses' internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the combined financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Businesses' ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
November 13, 2023

ROYALTY ASSET HOLDINGS, LP
ROYALTY ASSET HOLDINGS II, LP
SAXUM ASSET HOLDINGS, LP

COMBINED BALANCE SHEETS

	December 31,	
	2022	2021
Assets		
Current assets:		
Cash and cash equivalents	$ 26,523,350	$ 25,625,173
Accounts receivable-oil and gas sales and other	30,393,393	23,085,831
Prepaid expenses and other current assets	765,488	593,431
Total current assets	57,682,231	49,304,435
Property:		
Oil and gas properties	660,404,232	612,856,556
Accumulated depletion	(101,043,279)	(70,916,751)
Impairment	(164,532,161)	(164,532,161)
Total oil and gas properties, net	394,828,792	377,407,644
Total assets	$ 452,511,023	$ 426,712,079
Liabilities and Partner's equity		
Current liabilities:		
Accounts payable and accrued expenses	$ 1,620,000	$ —
Commitments and contingencies (Note 3)		
Partners' equity	450,891,023	426,712,079
Total liabilities and Partner's equity	$ 452,511,023	$ 426,712,079

The accompanying notes form an integral part of these combined financial statements.

ROYALTY ASSET HOLDINGS, LP
ROYALTY ASSET HOLDINGS II, LP
SAXUM ASSET HOLDINGS, LP

COMBINED STATEMENTS OF OPERATIONS

	Year Ended December 31,	
	2022	2021
Revenues		
Oil and gas sales	$ 156,930,913	$ 96,271,733
Lease bonuses	3,615,406	510,152
Total revenues	160,546,319	96,781,885
Operating expenses		
Production and ad valorem taxes	10,059,617	6,380,218
Depletion	30,126,528	23,353,101
General and administrative	12,947,795	8,254,093
Total operating expenses	53,133,940	37,987,412
Income from operations	107,412,379	58,794,473
Other income (expense)		
Other income, net	645,449	998,936
Total other income	645,449	998,936
Net income	$ 108,057,828	$ 59,793,409

The accompanying notes form an integral part of these combined financial statements.

ROYALTY ASSET HOLDINGS, LP
ROYALTY ASSET HOLDINGS II, LP
SAXUM ASSET HOLDINGS, LP

COMBINED STATEMENTS OF PARTNERS' CAPITAL

	Limited Partners
Balance at December 31, 2020	$ 360,865,786
Net income	59,793,409
Contributions	59,834,243
Distributions	(53,781,359)
Balance at December 31, 2021	426,712,079
Net income	108,057,828
Contributions	45,927,676
Distributions	(129,806,560)
Balance at December 31, 2022	$ 450,891,023

The accompanying notes form an integral part of these combined financial statements.

ROYALTY ASSET HOLDINGS, LP
ROYALTY ASSET HOLDINGS II, LP
SAXUM ASSET HOLDINGS, LP

COMBINED STATEMENTS OF CASH FLOWS

	Year Ended December 31,	
	2022	**2021**
Cash flows from operating activities:		
Net income	$ 108,057,828	$ 59,793,409
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion	30,126,528	23,353,101
Effect of changes in current assets and liabilities:		
Accounts receivable-oil and gas sales and other	(7,307,562)	(9,870,133)
Prepaid expenses and other current assets	(172,057)	75,233
Accounts payable and accrued expenses	1,620,000	—
Net cash provided by operating activities	132,324,737	73,351,610
Cash flows from investing activities:		
Acquisition of oil and gas properties	(47,547,676)	(84,027,425)
Net cash used in investing activities	(47,547,676)	(84,027,425)
Cash flows from financing activities:		
Contributions	45,927,676	59,834,243
Distributions	(129,806,560)	(53,781,359)
Net cash provided by (used in) financing activities	(83,878,884)	6,052,884
Net increase (decrease) in cash and cash equivalents	898,177	(4,622,931)
Cash, cash equivalents and restricted cash at beginning of period	25,625,173	30,248,104
Cash, cash equivalents and restricted cash at end of period	$ 26,523,350	$ 25,625,173

The accompanying notes form an integral part of these combined financial statements.

NOTES TO THE COMBINED FINANCIAL STATEMENTS

1. BUSINESS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business - Royalty Asset Holdings, LLC ("RAH LLC") was formed as a Texas limited liability company on September 22, 2016. On March 7, 2017, RAH LLC was converted into Royalty Asset Holdings, LP ("RAH LP"), a Texas limited partnership pursuant to the filing of a certificate of conversion with the Secretary of State of the State of Texas and in accordance with the provisions of the Texas Limited Partnership Law.

Prior to the filing of the certificate of conversion, Royalty Asset Holdings GP, LLC ("RAH GP"), a Texas limited liability company and Brigadier Royalty Warehouse, LLC ("BRW"), a Texas limited liability company owned 0.1% and 99.9% equity interest in RAH LLC respectively. On March 7, 2017, RAH GP was appointed as the sole general partner and BRW was appointed as the sole limited partner of RAH LP. Effective as of April 1, 2017, BRW assigned to Warwick Royalty and Mineral Master Fund LP ("WRMF") a Delaware limited partnership, all of BRW's equity interests in and to each of RAH GP and RAH LP.

Royalty Asset Holdings II, LP ("RAH II LP"), a Delaware limited partnership was formed on February 11, 2019, by Warwick Royalty and Mineral Fund II GP Limited ("WRMF II GP"), a Cayman Islands exempted limited company, as the sole general partner, and Brigadier Royalty Warehouse II, LLC ("BRW II"), a Delaware limited liability company, as the sole limited partner. Effective as of April 18, 2019, BRW II assigned to Warwick Royalty and Mineral Master Fund II LP ("WRMF II"), a Delaware limited partnership, all BRW II's equity interests in RAH II LP.

Saxum Asset Holdings, LP ("Saxum LP") was formed on April 15, 2020, by Warwick Royalty and Mineral Fund III GP Limited, a Cayman Islands exempted company as the sole general partner ("WRMF III GP") and Warwick Royalty and Mineral Master Fund III LP ("WRMF III"), a Delaware limited partnership, as the sole limited partner to Saxum LP.

RAH LP, RAH II LP and Saxum LP together are known as the Limited Partners.

RAH LP, RAH II LP and Saxum LP (together the "Businesses") were formed to seek and acquire both producing and nonproducing mineral interests, royalty interests, overriding royalty interests, net profit interests, and production payments, in each case, in the United States.

The General Partners and the Businesses have delegated, subject to its responsibility and supervision, day-to-day investment management of the Partnership's assets to GRP Royalty Holdings LLC, a Texas limited liability company and their affiliates, GRP RAH I Holdings LLC, GRP RAH II Holdings LLC and GRP Saxum Holdings, LLC, all of which are Delaware limited liability company (together the "Manager").

Basis of Presentation - The accompanying combined financial statements and related notes thereto were prepared in conformity with accounting principles generally accepted in the United States of America. All intercompany balances and transactions have been eliminated in combination.

Use of Estimates in the Preparation of Financial Statements - Management is required to make certain estimates and assumptions in the preparation of the combined financial statements that affect the reported amounts of assets, liabilities, and the disclosure of contingent assets and liabilities at the date of the combined financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

The impact of oil and gas prices has a significant impact on estimates made by management. Changes in the value of these commodities has a direct impact on the economic limits of estimated oil and gas reserves. These economic limits have significant effects upon predicted reserve values. These estimates are the basis for the calculation of depletion for the oil and gas properties and the assessment as to whether an impairment of such properties is required.

Further, these estimates and other factors, including those outside of the Businesses' control, such as the impact of sustained lower commodity prices, can potentially impact operators' current and future development plans (including the impact to undeveloped oil & gas properties), which could have a significant adverse impact to the Businesses' financial condition, results of operations and cash flows.

The Businesses' oil, natural gas, and natural gas liquid reserves represent estimated quantities of oil and gas which, using geological and engineering data, are estimated with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. There are numerous uncertainties inherent in estimating oil and gas reserves and their values including many factors beyond the Businesses' control. Accordingly, reserve estimates are different from the future quantities of oil and gas that are ultimately recovered.

Cash - Cash includes cash on hand.

Accrued Revenue Recognized on Production Income Basis - Production estimates are made based upon internal estimated ultimate recovery curves in the routine course of business if publicly available data does not exist for new Proved Developed Producing (PDP) wells.

Revenue from Contracts with Customers

Oil and Gas Sales

Revenues from oil, natural gas and natural gas liquids are generally recognized when control of the product is transferred to the purchaser, which is the point where performance obligations are satisfied based on the Businesses' percentage ownership share of the revenue, net of any deductions for gathering and transportation. All the Businesses' oil and gas sales are made under contracts between the operators of the properties in which the Businesses hold interest and their respective customers. The Businesses' contract is with the operator of the oil and gas properties; however, we have concluded that the substance of the transactions between the Businesses and the end customer results in the Businesses being the principal within the context of Accounting Standards Codification 606, Revenue from Contracts with Customers, "ASC 606". The Businesses' performance obligations are satisfied at the point in time the product is delivered by the operator to the purchaser of the hydrocarbons. Accordingly, the Businesses' contracts do not give rise to contract assets or liabilities.

The Businesses typically receive payment for oil and gas sales within 60 days, unless the product being sold is related to a newly drilled well, in which case, payment may be received up to six months beyond the date of first production. Contracts for the sale of oil, natural gas and natural gas liquids are industry standard contracts that include variable consideration based upon a monthly index and may include provisions related to gravity, price differentials, discounts and other adjustments and deductions. As each unit of production represents a separate performance obligation, the consideration is variable as it relates to oil and gas prices, and the variability is resolved as each unit of production is delivered to the purchaser, variable consideration does not need to be estimated. Additionally, the Businesses' right to royalties does not originate until production occurs and, therefore, is not considered to exist beyond each day's production. Therefore, there are no unsatisfied performance obligations at the end of the period.

Lease Bonus Revenue

The Businesses earn revenue from lease bonuses. Lease bonus revenue is generated by leasing the Businesses' mineral interests to exploration and production companies. A lease agreement represents a contract with a customer (in this case the operator of oil and gas properties) and generally transfers the rights to any oil, natural gas and natural gas liquids discovered, grants the Businesses a right to a specified royalty interest and requires that drilling and completion operations commence within a specified time frame. The Businesses recognize lease bonus revenue when the lease agreement has been executed, payment has been received, and the Businesses have no obligation to refund the payment. At the time the Businesses execute the lease agreement, the Businesses expect to receive payment of the lease bonus within a short time frame, but in no case more than one year. As such, the

Businesses have not adjusted the expected amount of revenue for the effects of any significant financing component per the practical expedient in ASC 606.

Prior-Period Performance Obligations

The Businesses derive revenue from the sale of oil, natural gas and natural gas liquids produced from properties in which they own a royalty or overriding royalty interest, which is recognized based on the Businesses' pro-rata interest. Revenue is recorded and receivables are accrued in the month production is delivered to the purchaser, at which time ownership of the oil and gas is transferred to the purchaser. The Businesses accrue revenue based on estimated production dates of the wells associated with the Businesses' mineral and overriding royalty interests, along with estimates of pricing for the production. In certain instances, statements are received from operators which provide information with respect to actual revenues to be received after year end, which are incorporated into the accrued revenue analysis.

The difference between the Businesses' estimates and the actual amounts received for oil and gas sales is recorded in the month that payment is received. For the years ended December 31, 2022 and 2021, revenues recognized relating to performance obligations satisfied in prior periods were immaterial.

The Businesses' oil, natural gas and natural gas liquids receivables are related to revenues due from operators of properties in which the Businesses owns mineral or overriding royalty interests. Although diversified amongst several producers, collectability of receivables is largely dependent upon the general economic conditions of the industry. All receivables are reviewed periodically, and balances are written off when, in the judgement of management, the receivable becomes uncollectible. Historically, the Businesses have not experienced significant issues with collectability and have determined no allowance for uncollectible accounts is necessary at December 31, 2022 and 2021.

Disaggregation of Revenue

The following table disaggregates the Businesses' total oil and gas sales by product type net of any deductions for gathering and transportation.

	For the Years Ended December 31,	
	2022	2021
Oil sales	$ 121,133,976	$ 73,051,880
Gas sales	18,626,238	11,620,247
Natural gas liquids sales	17,170,699	11,599,606
Oil and gas sales	$ 156,930,913	$ 96,271,733

Concentrations of Credit Risk - The Businesses regularly have cash in a single financial institution which exceeds federal depository insurance limits. The Businesses place such deposits with high credit quality institutions and have not experienced any credit losses. The Businesses are also subject to credit risk related to oil and gas receivables due from operators related to the sale of hydrocarbons produced from properties in which the Businesses own a mineral or overriding royalty interest. For the years ended December 31, 2022 and 2021, one purchaser accounted for more than 10% of royalty income each year.

Fair Value of Financial Instruments - The Businesses' financial instruments consist of cash, accounts receivable, prepayments, other current assets, accounts payables and accrued expenses. The carrying values of these financial instruments are considered to be representative of their fair market values, due to the short-term maturity of these instruments.

Accounting for Oil and Gas Operations - The Businesses use the full cost method of accounting for oil and gas properties. Under this method, all costs related to the acquisition, exploration and development of oil and gas properties are capitalized to the full cost pool. The Businesses' oil and gas properties are comprised of only mineral and overriding royalty interests. As such, the Businesses have not incurred any exploration or development costs.

All acquisitions of mineral and royalty interests are considered asset acquisitions in accordance with the guidance in Accounting Standards Codification 805 – Business Combinations. For asset acquisitions, the purchase price (which includes costs incurred for the acquisition) is allocated to the individual assets acquired and liabilities assumed based on their relative fair values. In substantially all of the acquisitions completed by the Businesses during the years ended December 31, 2022 and 2021, the fair value of the proved properties acquired exceeded the purchase price. As such, the purchase price for each acquisition was fully allocated to proved properties. Proceeds from the disposition of oil and gas properties are accounted for as adjustments to the full cost pool, with no gain or loss recognized unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Proved reserves are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations. Fair values of acquired proved properties were estimated using associated future net cash flows prepared by the Businesses' internal reservoir engineers, which include significant inputs such as anticipated production of proved reserves and other relevant data.

Depletion of capitalized costs of oil and gas properties is provided for using the units of production method based upon estimates of proved oil and gas reserves. In calculating depletion, the volume of proved oil and gas reserves and production is converted into a common unit of measure at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of oil. Depletion expense for the years ended December 31, 2022 and 2021 was $30,126,528 or $12.80 per barrel of oil equivalent and $23,353,101 or $11.65 per barrel of oil equivalent, respectively.

In accordance with the full cost method of accounting, the net capitalized costs of oil and gas properties are subject to a ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues from proved reserves, discounted at 10% per annum based on the trailing 12-month unweighted arithmetic average of the commodity prices posted on the first day of each month in the respective year, adjusted for existing contract provisions; (b) the cost of properties not being amortized, if any; and (c) the lower of cost or fair market value of unproved properties included in the cost being amortized.

If the net book value exceeds the ceiling, the book balance of the properties is written down to the ceiling via an impairment charge. No ceiling test impairment was recorded for the year ended December 31, 2022 and 2021. The businesses recorded an impairment expense of $164,532,161 as a result of the decline in commodity prices for the year ended December 31, 2020.

Income Taxes - All the Businesses are disregarded for U.S. income tax purposes. As such, they are neither subject to taxation nor required to submit tax returns. All the assets and liabilities of the Businesses are treated as owned directly by the respective limited partners. Further, the Businesses are passive entities for Texas franchise tax purposes, so they are not subject to tax in the state.

Recently Issued Accounting Standards

Adoption of ASU 2016-02

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, Leases. The FASB issued the guidance to increase the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. This is required for all leases that have a term longer than one year. ASU 2016-02 does not apply to leases of mineral rights to explore for or use crude oil and natural gas. For non-public entities, ASU 2016-02 is effective for financial statements issued for fiscal years beginning after December 15, 2021. Adoption of the accounting standard did not have a material impact on the combined financial statements or related disclosures.

Accounting Standards Not Yet Adopted

In June 2016, the FASB issued ASU 2016-13, Financial Instruments-Credit Losses. In May 2019, ASU 2016-13 was subsequently amended by ASU 2019-04, Codification Improvements to Topic 326, Financial Instruments-Credit Losses and ASU 2019-05, Financial Instruments-Credit Losses (Topic 326): Targeted Transition Relief. ASU 2016-13, as amended, applies to trade receivables, financial assets and certain other instruments that are not measured at fair value through net income. This ASU will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost and is effective for financial statements issued for fiscal years beginning after December 15, 2022, including interim periods in those fiscal years. Adoption of this accounting standard is not expected to have a material impact on the combined financial statements or related disclosures.

There are no other accounting standards applicable to the Businesses that would have a material effect on the Businesses' combined financial statements and disclosures that have been issued but not yet adopted by the Businesses as of December 31, 2022, and through the filing date of this report.

2. ACQUISITIONS OF ASSETS

2022 Acquisitions

During the year ended December 31, 2022, in individually insignificant transactions, the Businesses acquired, from unrelated third party sellers, mineral and royalty interests representing 1,920 net royalty acres in the Permian Basin for an aggregate net purchase price of approximately $47.5 million, including certain customary post-closing adjustments. The Businesses funded the acquisitions through capital contributions from Partners.

2021 Acquisitions

During the year ended December 31, 2021, in individually insignificant transactions, the Businesses acquired, from unrelated third party sellers, mineral and royalty interests representing 5,430 net royalty acres in the Permian Basin for an aggregate net purchase price of approximately $84.0 million, including certain customary post-closing adjustments. The Businesses funded the acquisitions through capital contributions from Partners.

3. COMMITMENTS AND CONTINGENCIES

The Businesses may from time to time be involved in various legal actions arising in the normal course of business or from activities associated with properties prior to their acquisition by the Businesses. In the opinion of management, the Businesses’ liability, if any, in these pending actions would not have a material adverse effect on the financial position, results of operations or cash flows of the Businesses.

4. PARTNERS' CAPITAL

Capitalization and Distributions - The General Partners of the Businesses may from time to time call capital, and the limited partners will contribute capital to the Businesses in accordance with their respective Partnership Interests.

During the years ended December 31, 2022 and 2021, the Businesses made aggregate distributions to their limited partners of $129,806,560 and $53,781,359, respectively.

The limited partners shall not be entitled to (a) withdraw from the Businesses except upon the assignment by the limited partner of all of the limited partner's interest in the Businesses, or (b) the return of the limited partner's capital contributions except to the extent, if any, that distributions made pursuant to the express terms of the limited partnership agreement may be considered as such by law or upon dissolution and liquidation of the Businesses, and then only to the extent expressly provided for in the limited partnership agreement and as permitted by applicable law.

Except upon liquidation, all distributions of cash or property of the Businesses to the Partners is made in accordance with their Partnership Interests. The timing of all distributions of the Businesses' income and capital is at the sole discretion of the General Partner. No Partner is entitled to withdraw any part of its capital contributions or its capital account or to receive any distribution from the Businesses, except as provided in the limited partnership agreement.

Dissolution, Liquidation, and Terminations - The Businesses shall dissolve upon the happening of one of the following events: (a) any event which, in the opinion of the General Partner, would make it in the best interests of the Businesses to be dissolved; (b) the bankruptcy of the General Partner; or (c) the occurrence of any other event under the agreement that causes the dissolution of a limited partnership (unless the Partners elect to continue the Businesses within 90 days of such event in accordance with the agreement, if permissible under the circumstances).

Upon dissolution, the General Partner shall proceed diligently to wind up the business and affairs of the Businesses, allocate income and loss among the limited partners and distribute its properties and assets, if any. Distributions to limited partners upon the liquidation of the Businesses will be made pro rata in accordance with the Partners' Partnership Interests. Subject to the preceding sentence, the manner in which the Businesses is liquidated will be within the sole and absolute discretion of the General Partner.

5. RELATED PARTY TRANSACTIONS

Parties are considered to be related if one party has the ability to control the other party or exercise significant influence over the other party in making financial and operational decisions or if two entities are under common control. Related party transactions in the Partnership are discussed below.

Service Fee

The Manager is entitled to a monthly service fee of $135,000 from each of the Businesses. In addition, the Businesses pay the Manager a quarterly incentive payment ("MIP") which is calculated by the General Partner as of the end of each calendar quarter during the year in an amount equal to 5% of the net cash flows realized by each Business during the calendar quarter.

The services fee and MIP paid out for the years ended December 31, 2022 and 2021 were $11,378,480 and $7,719,570, respectively.

6. SUBSEQUENT EVENTS

Subsequent events have been evaluated through November 13, 2023, the date the combined financial statements were issued. Subsequent to December 31, 2022 and up to November 13, 2023, the Businesses made distributions of $116,949,510. No additional subsequent events of a material nature have been identified that require recognition or disclosure.

7. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS OPERATIONS (UNAUDITED)

Proved Oil and Gas Reserve Quantities

Proved oil and natural gas reserve estimates and their associated future net cash flows for the Businesses were estimated by independent reserve engineers, DeGolyer and MacNaughton Corp, as of December 31, 2022 and 2021. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted arithmetic average of the first-day-of-the-month prices for the 12-month period prior to the end of the reporting period.

The SEC has defined proved reserves as the estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

The following table presents changes in the estimated quantities of proved reserves for the years ended December 31, 2022 and 2021.

	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total (MBOE)
		(In thousands)		
Proved Developed and Undeveloped Reserves:				
As of December 31, 2020	13,136	56,735	8,351	30,943
Purchase of reserves in place	1,350	4,124	688	2,725
Extensions and discoveries	235	1,166	153	582
Revisions of previous estimates	(32)	598	69	137
Production	(1,123)	(2,997)	(381)	(2,004)
As of December 31, 2021	13,566	59,626	8,880	32,383
Purchase of reserves in place	263	1,785	303	864
Extensions and discoveries	56	273	34	136
Revisions of previous estimates	52	(776)	(102)	(179)
Production	(1,316)	(3,266)	(494)	(2,354)
As of December 31, 2022	12,621	57,642	8,621	30,850
Proved Developed Reserves:				
December 31, 2021	6,146	32,774	4,559	16,167
December 31, 2022	7,126	35,007	4,961	17,922
Proved Undeveloped Reserves:				
December 31, 2021	7,420	26,852	4,321	16,216
December 31, 2022	5,495	22,635	3,660	12,928

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

For the year ending December 31, 2021, the Businesses' positive revisions of 137 MBoe of previously estimated quantities consisted of price and performance revisions of proved developed producing wells. Extensions and discoveries of 582 MBoe resulted primarily from the addition of 67 new wells and from 105 new proved undeveloped locations added.

For the year ending December 31, 2022, the Businesses' negative revisions of 179 MBoe of previously estimated quantities consisted of performance revisions of proved developed producing wells. Extensions and discoveries of 136 MBoe resulted primarily from the addition of 40 new wells and from 46 new proved undeveloped locations added.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value of proved reserves to the Businesses. 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 sets forth the standardized measure of discounted future net cash flows attributable to the Business' proved oil and natural gas reserves as of December 31, 2022, 2021.

	December 31,	
	2022	2021
	(In thousands)	
Future cash inflows	$ 1,739,907	$ 1,228,960
Future production taxes	(97,469)	(70,750)
Future income tax expense	(7,691)	(5,491)
Future net cash flows	1,634,747	1,152,719
10% discount to reflect timing of cash flows	(779,108)	(550,980)
Standardized measure of discounted future net cash flows	$ 855,639	$ 601,739

The following table presents the unweighted arithmetic average first-day-of–the-month prices within the 12-month period prior to the end of the reporting period as adjusted by differentials and other contractual terms for oil, natural gas and natural gas liquids utilized in the computation of future cash inflows.

	December 31,	
	2022	2021
Oil (per Bbl)	$ 94.02	$ 66.92
Natural gas (per Mcf)	$ 5.63	$ 2.88
Natural gas liquids (per Bbl)	$ 33.24	$ 23.62

Principal changes in the standardized measure of discounted future net cash flows attributable to the Partnership's proved reserves are as follows.

	December 31,	
	2022	2021
	(In thousands)	
Standardized measure of discounted future net cash flows at the beginning of the period	$ 601,739	$ 315,230
Purchase of minerals in place	20,346	60,230
Sales of oil and natural gas, net of production costs	(146,871)	(89,892)
Extensions and discoveries	3,573	10,820
Net changes in prices and production costs	336,617	278,475
Revisions of previous quantity estimates	(2,882)	2,810
Net changes in income taxes	(1,174)	(1,345)
Accretion of discount	60,462	31,677
Net changes in timing of production and other	(16,171)	(6,266)
Standardized measure of discounted future net cash flows at the end of the period	$ 855,639	$ 601,739

Exhibit 99.2

ROYALTY ASSET HOLDINGS, LP
ROYALTY ASSET HOLDINGS II, LP
SAXUM ASSET HOLDINGS, LP

COMBINED FINANCIAL STATEMENTS

For the Nine Months Ended September 30, 2023 and 2022

TABLE OF CONTENTS

ROYALTY ASSET HOLDINGS, LP
ROYALTY ASSET HOLDINGS II, LP
SAXUM ASSET HOLDINGS, LP

COMBINED BALANCE SHEETS (UNAUDITED)

	September 30 2023	December 31 2022
Assets		
Current assets:		
Cash and cash equivalents	$ 30,633,190	$ 26,523,350
Accounts receivable-oil and gas sales and other	16,859,511	30,393,393
Prepaid expenses and other current assets	1,033,141	765,488
Total current assets	48,525,842	57,682,231
Property:		
Oil and gas properties	666,463,108	660,404,232
Accumulated depletion	(125,032,364)	(101,043,279)
Impairment	(164,532,161)	(164,532,161)
Total oil and gas properties, net	376,898,583	394,828,792
Total assets	$ 425,424,425	$ 452,511,023
Liabilities and Partner's equity		
Current liabilities:		
Accounts payable and accrued expenses	$ —	$ 1,620,000
Commitments and contingencies (Note 3)		
Partners' equity	425,424,425	450,891,023
Total liabilities and Partner's equity	$ 425,424,425	$ 452,511,023

The accompanying notes form an integral part of these combined financial statements.

ROYALTY ASSET HOLDINGS, LP
ROYALTY ASSET HOLDINGS II, LP
SAXUM ASSET HOLDINGS, LP

COMBINED STATEMENTS OF OPERATIONS (UNAUDITED)

	For the period from January 1, 2023 to September 30, 2023	For the period from January 1, 2022 to September 30, 2022
Revenues		
Oil and gas sales	$ 91,098,931	$ 120,024,757
Lease bonuses	1,788,093	2,731,987
Total revenues	92,887,024	122,756,744
Operating expenses		
Production and ad valorem taxes	6,180,425	7,764,671
Depletion	23,989,085	22,670,734
General and administrative	10,533,600	9,313,685
Total operating expenses	40,703,110	39,749,090
Income from operations	52,183,914	83,007,654
Other income (expense)		
Other income, net	1,818,911	522,323
Total other income	1,818,911	522,323
Net income	$ 54,002,825	$ 83,529,977

The accompanying notes form an integral part of these combined financial statements.

ROYALTY ASSET HOLDINGS, LP
ROYALTY ASSET HOLDINGS II, LP
SAXUM ASSET HOLDINGS, LP

COMBINED STATEMENTS OF PARTNERS' CAPITAL (UNAUDITED)

	Limited Partners
	For the period from January 1, 2023 to September 30, 2023
Balance at January 1, 2023	$ 450,891,023
Net income	54,002,825
Contributions	7,678,876
Distributions	(87,148,299)
Balance at September 30, 2023	$ 425,424,425

	Limited Partners
	For the period from January 1, 2022 to September 30, 2022
Balance at January 1, 2022	$ 426,712,079
Net income	83,529,977
Contributions	42,892,074
Distributions	(85,818,073)
Balance at September 30, 2022	$ 467,316,057

The accompanying notes form an integral part of these combined financial statements.

ROYALTY ASSET HOLDINGS, LP
ROYALTY ASSET HOLDINGS II, LP
SAXUM ASSET HOLDINGS, LP

COMBINED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the period from January 1, 2023 to September 30, 2023	For the period from January 1, 2022 to September 30, 2022
Cash flows from operating activities:		
Net income	$ 54,002,825	$ 83,529,977
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion	23,989,085	22,670,734
Effect of changes in current assets and liabilities:		
Accounts receivable-oil and gas sales and other	13,533,882	(4,706,828)
Prepaid expenses and other current assets	(267,653)	293,598
Accounts payable and accrued expenses	(1,620,000)	—
Net cash provided by operating activities	89,638,139	101,787,481
Cash flows from investing activities:		
Acquisition of oil and gas properties	(6,058,876)	(42,892,076)
Net cash used in investing activities	(6,058,876)	(42,892,076)
Cash flows from financing activities:		
Contributions	7,678,876	42,892,074
Distributions	(87,148,299)	(85,818,073)
Net cash used in financing activities	(79,469,423)	(42,925,999)
Net increase (decrease) in cash and cash equivalents	4,109,840	15,969,406
Cash, cash equivalents and restricted cash at beginning of period	26,523,350	25,625,173
Cash, cash equivalents and restricted cash at end of period	$ 30,633,190	$ 41,594,579

The accompanying notes form an integral part of these combined financial statements.

NOTES TO THE COMBINED FINANCIAL STATEMENTS (UNAUDITED)

1. BUSINESS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business - Royalty Asset Holdings, LLC ("RAH LLC") was formed as a Texas limited liability company on September 22, 2016. On March 7, 2017, RAH LLC was converted into Royalty Asset Holdings, LP ("RAH LP"), a Texas limited partnership pursuant to the filing of a certificate of conversion with the Secretary of State of the State of Texas and in accordance with the provisions of the Texas Limited Partnership Law.

Prior to the filing of the certificate of conversion, Royalty Asset Holdings GP, LLC ("RAH GP"), a Texas limited liability company and Brigadier Royalty Warehouse, LLC ("BRW"), a Texas limited liability company owned 0.1% and 99.9% equity interest in RAH LLC respectively. On March 7, 2017, RAH GP was appointed as the sole general partner and BRW was appointed as the sole limited partner of RAH LP. Effective as of April 1, 2017, BRW assigned to Warwick Royalty and Mineral Master Fund LP ("WRMF") a Delaware limited partnership, all of BRW's equity interests in and to each of RAH GP and RAH LP.

Royalty Asset Holdings II, LP ("RAH II LP"), a Delaware limited partnership was formed on February 11, 2019, by Warwick Royalty and Mineral Fund II GP Limited ("WRMF II GP"), a Cayman Islands exempted limited company, as the sole general partner, and Brigadier Royalty Warehouse II, LLC ("BRW II"), a Delaware limited liability company, as the sole limited partner. Effective as of April 18, 2019, BRW II assigned to Warwick Royalty and Mineral Master Fund II LP ("WRMF II"), a Delaware limited partnership, all BRW II's equity interests in RAH II LP.

Saxum Asset Holdings, LP ("Saxum LP") was formed on April 15, 2020, by Warwick Royalty and Mineral Fund III GP Limited, a Cayman Islands exempted company as the sole general partner ("WRMF III GP") and Warwick Royalty and Mineral Master Fund III LP ("WRMF III"), a Delaware limited partnership, as the sole limited partner to Saxum LP.

RAH LP, RAH II LP and Saxum LP together are known as the Limited Partners.

RAH LP, RAH II LP and Saxum LP (together the "Businesses") were formed to seek and acquire both producing and nonproducing mineral interests, royalty interests, overriding royalty interests, net profit interests, and production payments, in each case, in the United States.

The general partners of the Businesses (the "General Partners") and the Businesses have delegated, subject to its responsibility and supervision, day-to-day investment management of the Partnership's assets to GRP Royalty Holdings LLC, a Texas limited liability company and their affiliates, GRP RAH I Holdings LLC, GRP RAH II Holdings LLC and GRP Saxum Holdings, LLC, all of which are Delaware limited liability companies (together the "Manager").

Basis of Presentation - The accompanying combined financial statements and related notes thereto were prepared in conformity with accounting principles generally accepted in the United States of America. All intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates in the Preparation of Financial Statements - Management is required to make certain estimates and assumptions in the preparation of the combined financial statements that affect the reported amounts of assets, liabilities, and the disclosure of contingent assets and liabilities at the date of the combined financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

The impact of oil and gas prices has a significant impact on estimates made by management. Changes in the value of these commodities has a direct impact on the economic limits of estimated oil and gas reserves. These economic limits have significant effects upon predicted reserve values. These estimates are the basis for the calculation of depletion for the oil and gas properties and the assessment as to whether an impairment of such properties is required. Further, these estimates and other factors, including those outside of the Businesses' control, such as the impact of sustained lower commodity prices, can potentially impact operators' current and future development plans (including the impact to undeveloped oil & gas properties), which could have a significant adverse impact to the Businesses' financial condition, results of operations and cash flows.

The Businesses' oil, natural gas, and natural gas liquid reserves represent estimated quantities of oil and gas which, using geological and engineering data are estimated with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. There are numerous uncertainties inherent in estimating oil and gas reserves and their values including many factors beyond the Businesses' control. Accordingly, reserve estimates are different from the future quantities of oil and gas that are ultimately recovered.

Cash - Cash includes cash on hand.

Accrued Revenue Recognized on Production Income Basis

Production estimates are made based upon internal estimated ultimate recovery curves in the routine course of business if publicly available data does not exist for new Proved Developed Producing (PDP) wells.

Revenue from Contracts with Customers

Oil and Gas Sales

Revenues from oil, natural gas and natural gas liquids are generally recognized when control of the product is transferred to the purchaser, which is the point where performance obligations are satisfied based on the Businesses' percentage ownership share of the revenue, net of any deductions for gathering and transportation. All the Businesses' oil and gas sales are made under contracts between the operators of the properties in which the Businesses hold interest and their respective customers. The Businesses' contract is with the operator of the oil and gas properties; however, we have concluded that the substance of the transactions between the Businesses and the end customer results in the Businesses being the principal within the context of Accounting Standards Codification 606, Revenue from Contracts with Customers, "ASC 606". The Businesses' performance obligations are satisfied at the point in time the product is delivered by the operator to the purchaser of the hydrocarbons. Accordingly, the Businesses' contracts do not give rise to contract assets or liabilities.

The Businesses typically receive payment for oil and gas sales within 60 days, unless the product being sold is related to a newly drilled well, in which case payment may be received up to six months beyond the date of first production. Contracts for the sale of oil, natural gas and natural gas liquids are industry standard contracts that include variable consideration based upon a monthly index and may include provisions related to gravity, price differentials, discounts and other adjustments and deductions. As each unit of production represents a separate performance obligation, the consideration is variable as it relates to oil and gas prices, and the variability is resolved as each unit of production is delivered to the purchaser, variable consideration does not need to be estimated. Additionally, the Businesses' right to royalties does not originate until production occurs and, therefore, is not considered to exist beyond each day's production. Therefore, there are no unsatisfied performance obligations at the end of the period.

Lease Bonus Revenue

The Businesses earn revenue from lease bonuses. Lease bonus revenue is generated by leasing the Businesses' mineral interests to exploration and production companies. A lease agreement represents a contract with a customer (in this case the operator of oil and gas properties) and generally transfers the rights to any oil, natural gas and natural gas liquids discovered, grants the Businesses a right to a specified royalty interest and requires that drilling and completion operations commence within a specified time frame. The Businesses recognize lease bonus revenue when the lease agreement has been executed, payment has been received, and the Businesses have no obligation to refund the payment. At the time the Businesses execute the lease agreement, the Businesses expect to receive payment of the lease bonus within a short time frame, but in no case more than one year. As such, the Businesses have not adjusted the expected amount of revenue for the effects of any significant financing component per the practical expedient in ASC 606.

Prior-Period Performance Obligations

The Businesses derive revenue from the sale of oil, natural gas and natural gas liquids produced from properties in which they own a royalty or overriding royalty interest, which is recognized based on the Businesses’ pro-rata interest. Revenue is recorded and receivables are accrued in the month production is delivered to the purchaser, at which time ownership of the oil and gas is transferred to the purchaser. The Businesses accrue revenue based on estimated production dates of the wells associated with the Businesses’ mineral and overriding royalty interests, along with estimates of pricing for the production. In certain instances, statements are received from operators which provide information with respect to actual revenues to be received after period end, which are incorporated into the accrued revenue analysis.

The difference between the Businesses' estimates and the actual amounts received for oil and gas sales is recorded in the month that payment is received. For the nine month periods ended September 30, 2023 and 2022, revenues recognized relating to performance obligations satisfied in prior periods were immaterial.

The Businesses' oil, natural gas and natural gas liquids receivables are related to revenues due from operators of properties in which the Businesses owns mineral or overriding royalty interests. Although diversified amongst several producers, collectability of receivables is largely dependent upon the general economic conditions of the industry. All receivables are reviewed periodically, and balances are written off when, in the judgement of management, the receivable becomes uncollectible. Historically, the Businesses have not experienced significant issues with collectability and have determined no allowance for uncollectible accounts is necessary at September 30, 2023 and 2022.

Disaggregation of Revenue

The following table disaggregates the Businesses' total oil and gas sales by product type net of any deductions for gathering and transportation.

	For the Periods Ended September 30,	
	2023	**2022**
Oil sales	$ 76,171,584	$ 91,531,048
Gas sales	5,301,974	14,753,029
Natural gas liquids sales	9,625,373	13,740,680
Oil and gas sales	$ 91,098,931	$ 120,024,757

Concentrations of Credit Risk - The Businesses regularly have cash in a single financial institution which exceeds federal depository insurance limits. The Businesses place such deposits with high credit quality institutions and have not experienced any credit losses. The Businesses are also subject to credit risk related to oil and gas receivables due from operators related to the sale of hydrocarbons produced from properties in which the Businesses own a mineral or overriding royalty interest. For the periods ended September 30, 2023 and 2022, one purchaser accounted for more than 10% of royalty income each period.

Fair Value of Financial Instruments - The Businesses' financial instruments consist of cash, accounts receivables, prepayments, other current assets, account payables and accrued expenses. The carrying values of these financial instruments are considered to be representative of their fair market value, due to the short-term maturity of these instruments.

Accounting for Oil and Gas Operations - The Businesses use the full cost method of accounting for oil and gas properties. Under this method, all costs related to the acquisition, exploration and development of oil and gas properties are capitalized to the full cost pool. The Businesses' oil and gas properties are comprised of only mineral and overriding royalty interests. As such, the Businesses have not incurred any exploration or development costs.

All acquisitions of mineral and royalty interests are considered asset acquisitions in accordance with the guidance in Accounting Standards Codification 805 – Business Combinations. For asset acquisitions, the purchase price (which includes costs incurred for the acquisition) is allocated to the individual assets acquired and liabilities assumed based on their relative fair values. In substantially all of the acquisitions completed by the Businesses during the periods ended September 30, 2023 and September 30, 2022, the fair value of the proved properties acquired exceeded the purchase price. As such, the purchase price for each acquisition was fully allocated to proved properties. Proceeds from the disposition of oil and gas properties are accounted for as adjustments to the full cost pool, with no gain or loss recognized unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Proved reserves are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations. Fair values of acquired proved properties were estimated using associated future net cash flows prepared by the Businesses' internal reservoir engineers, which include significant inputs such as anticipated production of proved reserves and other relevant data.

Depletion of capitalized costs of oil and gas properties is provided for using the units of production method based upon estimates of proved oil and gas reserves. In calculating depletion, the volume of proved oil and gas reserves and production is converted into a common unit of measure at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of oil. Depletion expense for the periods ended September 30, 2023 and 2022 was $23,989,085 or $13.09 per barrel of oil equivalent and $22,670,734 or $13.00 per barrel of oil equivalent, respectively.

In accordance with the full cost method of accounting, the net capitalized costs of oil and gas properties are subject to a ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues from proved reserves, discounted at 10% per annum based on the trailing 12-month unweighted arithmetic average of the commodity prices posted on the first day of each month in the respective year, adjusted for existing contract provisions; (b) the cost of properties not being amortized, if any; and (c) the lower of cost or fair market value of unproved properties included in the cost being amortized.

If the net book value exceeds the ceiling, the book balance of the properties is written down to the ceiling via an impairment charge. No ceiling test impairment was recorded for the nine-month periods ended September 30, 2023 and 2022.

Income Taxes - All the Businesses are disregarded for U.S. income tax purposes. As such, they are neither subject to taxation nor required to submit tax returns. All the assets and liabilities of the Businesses are treated as owned directly by the respective limited partners. Further, the Businesses are passive entities for Texas franchise tax purposes, so they are not subject to tax in the state.

Recently Issued Accounting Standards

Adoption of ASU 2016-13

In June 2016, the FASB issued ASU 2016-13, Financial Instruments-Credit Losses. In May 2019, ASU 2016-13 was subsequently amended by ASU 2019-04, Codification Improvements to Topic 326, Financial Instruments-Credit Losses and ASU 2019-05, Financial Instruments-Credit Losses (Topic 326): Targeted

Transition Relief. ASU 2016-13, as amended, applies to trade receivables, financial assets and certain other instruments that are not measured at fair value through net income. This ASU replaces the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost and is effective for financial statements issued for fiscal years beginning after December 15, 2022, including interim periods in those fiscal years. Adoption of the accounting standard did not have a material impact on the combined financial statements or related disclosures.

There are no other accounting standards applicable to the Businesses that would have a material effect on the Businesses' combined financial statements and disclosures that have been issued but not yet adopted by the Businesses as of September 30, 2023, and through the filing date of this report.

2. ACQUISITIONS OF ASSETS

2023 Acquisitions

During the nine months ended September 30, 2023, in individually insignificant transactions, the Businesses acquired, from unrelated third party sellers, mineral and royalty interests representing 580 net royalty acres in the Permian Basin for an aggregate net purchase price of approximately $6.1 million, including certain customary post-closing adjustments. The Businesses funded the acquisitions through capital contributions from Partners.

2022 Acquisitions

During the nine months ended September 30, 2022, in individually insignificant transactions, the Businesses acquired, from unrelated third party sellers, mineral and royalty interests representing 1,674 net royalty acres in the Permian Basin for an aggregate net purchase price of approximately $42.9 million, including certain customary post-closing adjustments. The Businesses funded the acquisitions through capital contributions from Partners.

3. COMMITMENTS AND CONTINGENCIES

The Businesses may from time to time be involved in various legal actions arising in the normal course of business or from activities associated with properties prior to their acquisition by the Businesses. In the opinion of management, the Businesses’ liability, if any, in these pending actions would not have a material adverse effect on the financial position, results of operations or cash flows of the Businesses.

4. PARTNERS’ CAPITAL

Capitalization and Distributions – The General Partners of the Businesses may from time to time call capital, and the limited partners will contribute capital to the Businesses in accordance with their respective Partnership Interests.

During the periods ended September 30, 2023 and 2022, the Businesses made aggregate distributions to their limited partners of $87,148,299 and $85,818,073, respectively.

The limited partners shall not be entitled to (a) withdraw from the Businesses except upon the assignment by the limited partner of all of the limited partner’s interest in the Businesses, or (b) the return of the limited partner’s capital contributions except to the extent, if any, that distributions made pursuant to the express terms of the limited partnership agreement may be considered as such by law or upon dissolution and liquidation of the Businesses, and then only to the extent expressly provided for in the limited partnership agreement and as permitted by applicable law.

Except upon liquidation, all distributions of cash or property of the Businesses to the Partners is made in accordance with their Partnership Interests. The timing of all distributions of the Businesses’ income and capital is at the sole discretion of the General Partner. No Partner is entitled to withdraw any part of its capital contributions or its capital account or to receive any distribution from the Businesses, except as provided in the limited partnership agreement.

Dissolution, Liquidation, and Terminations - The Businesses shall dissolve upon the happening of one of the following events: (a) any event which, in the opinion of the General Partner, would make it in the best interests of the Businesses to be dissolved; (b) the bankruptcy of the General Partner; or (c) the occurrence of any other event under the agreement that causes the dissolution of a limited partnership (unless the Partners elect to continue the Businesses within 90 days of such event in accordance with the agreement, if permissible under the circumstances).

Upon dissolution, the General Partner shall proceed diligently to wind up the business and affairs of the Businesses, allocate income and loss among the limited partners and distribute its properties and assets, if any. Distributions to limited partners upon the liquidation of the Businesses will be made pro rata in accordance with the Partners' Partnership Interests. Subject to the preceding sentence, the manner in which the Businesses is liquidated will be within the sole and absolute discretion of the General Partner.

5. RELATED PARTY TRANSACTIONS

Parties are considered to be related if one party has the ability to control the other party or exercise significant influence over the other party in making financial and operational decisions or if two entities are under common control. Related party transactions in the Partnership are discussed below.

Service Fee

The Manager is entitled to a monthly service fee of $135,000 from each of the Businesses. In addition, the Businesses pay the Manager a quarterly incentive payment ("MIP") which is calculated by the General Partner as of the end of each calendar quarter during the period in an amount equal to 5% of the net cash flows realized by each Business during the calendar quarter.

The services fee and MIP paid out for the periods ended September 30, 2023 and 2022 were $8,382,028 and $8,122,195, respectively.

6. SUBSEQUENT EVENTS

Subsequent events have been evaluated through November 13, 2023, the date the combined financial statements were issued. Subsequent to September 30, 2023 and up to November 13, 2023, the Businesses made distributions of $29,801,211. No additional subsequent events of a material nature have been identified that require recognition or disclosure.

Exhibit 99.3

Viper Energy Partners LP
Unaudited Pro Forma Condensed Combined Financial Statements

On November 1, 2023, (the "Closing Date") Viper Energy Partners LP ("Viper" or the "Partnership") and its subsidiary Viper Energy Partners LLC ("Viper OpCo") acquired certain mineral and royalty interests (the "Assets") from Royalty Asset Holdings, LP, Royalty Asset Holdings II, LP and Saxum Asset Holdings, LP (collectively, "the Sellers," and affiliates of Warwick Capital Partners and GRP Energy Capital) pursuant to a definitive purchase and sale agreement for approximately 9.02 million common units (the "Common Unit Consideration") and $750.0 million in cash (the "Cash Consideration"), subject to customary post-closing adjustments (the "Acquisition"). The mineral and royalty interests acquired in the Acquisition represent approximately 4,600 net royalty acres in the Permian Basin, plus approximately 2,700 additional net royalty acres in other major basins. The cash consideration for the Acquisition was funded through a combination of cash on hand and held in escrow, borrowings under Viper OpCo's revolving credit facility, proceeds from the offering of $400.0 million in aggregate principal amount of 7.375% Senior Notes maturing on November 1, 2031 (the "2031 Notes") and proceeds from a $200.0 million common unit issuance to Diamondback Energy, Inc and its subsidiary, Diamondback E&P LLC (collectively, "Diamondback") on October 31, 2023.

The Acquisition was accounted for as an asset acquisition in accordance with Accounting Standards Codification Topic 805, Business Combinations ("ASC 805"). The fair value of the consideration paid by the Partnership and the allocation of that amount to the underlying assets acquired is recorded on a relative fair value basis. Additionally, transaction costs directly related to the Acquisition are capitalized as a component of the purchase price.

The following unaudited pro forma condensed combined financial statements (the "pro forma financial statements") are based on the Partnership's historical consolidated financial statements, adjusted to give effect to transaction adjustments for (i) the Acquisition of the Assets by the Partnership from the Sellers, and (ii) the funding of the purchase price for the Acquisition.

The following pro forma financial statements present (i) our unaudited pro forma balance sheet as of September 30, 2023, (ii) our unaudited pro forma statement of operations for the nine months ended September 30, 2023 and (iii) our unaudited pro forma statement of operations for the year ended December 31, 2022. The pro forma balance sheet assumes that the Acquisition as well as the debt and equity transactions executed to finance the Acquisition all occurred on September 30, 2023. The pro forma statements of operations for the nine months ended September 30, 2023 and the year ended December 31, 2022 give pro forma effect to the Acquisition and related financing transactions as if they had occurred on January 1, 2022, the beginning of the earliest period presented.

The pro forma adjustments related to the Acquisition and related financing for the transaction are based on available information and certain assumptions that management believes are factually supportable, as further described below in Note 3—Pro Forma Adjustments and Assumptions. In the opinion of management, all adjustments necessary to present fairly the pro forma financial statements have been made.

These pro forma financial statements are for information purposes only and do not purport to represent what the Partnership's financial position and results of operations would have been had the Acquisition occurred on the dates indicated. These pro forma financial statements should not be used to project the Partnership's financial performance for any future period. A number of factors may affect the results.

The pro forma financial statements have been developed from and should be read in conjunction with:

a. the accompanying notes to the pro forma financial statements;
b. the historical combined financial statements of the Sellers and related notes for the year ended December 31, 2022 and for the nine months ended September 30, 2023; and
c. the separate historical consolidated financial statements and related notes thereto in the Partnership's filings with the Securities and Exchange Commission.

Viper Energy Partners LP
Unaudited Pro Forma Condensed Combined Balance Sheet

	As of September 30, 2023		
	Viper (Historical)	**Transaction Accounting Adjustments**	**Viper Pro Forma Combined**
		(In thousands)	
Assets			
Current assets:			
Cash and cash equivalents	$ 146,814	$ (95,836) *(e)*	$ 50,978
Royalty income receivable (net of allowance for credit losses)	103,804	—	103,804
Royalty income receivable—related party	7,431	—	7,431
Other current assets	4,081	—	4,081
Total current assets	262,130	(95,836)	166,294
Property:			
Oil and natural gas interests, full cost method of accounting	3,592,768	1,013,427 *(a)*	4,606,195
Land	5,688	—	5,688
Accumulated depletion and impairment	(821,565)	—	(821,565)
Property, net	2,776,891	1,013,427	3,790,318
Funds held in escrow	50,000	(50,000) *(f)*	—
Deferred income taxes (net of allowances)	48,768	—	48,768
Other assets	5,577	—	5,577
Total assets	$ 3,143,366	$ 867,591	$ 4,010,957
Liabilities and Unitholders' Equity			
Current liabilities:			
Accounts payable	$ 197	$ —	$ 197
Accrued liabilities	24,688	—	24,688
Derivative instruments	9,284	—	9,284
Income taxes payable	13,322	—	13,322
Total current liabilities	47,491	—	47,491
Long-term debt, net	675,681	412,991 *(b)*	1,088,672
Derivative instruments	1,619	—	1,619
Total liabilities	724,791	412,991	1,137,782
Commitments and contingencies			
Unitholders' equity:			
General Partner	589	—	589
Common units	712,728	254,600 *(c)*	1,014,976
		200,000 *(d)*	
		(152,352) *(g)*	
Class B units	757	—	757
Total Viper Energy Partners LP unitholders' equity	714,074	302,248	1,016,322
Non-controlling interest	1,704,501	152,352 *(g)*	1,856,853
Total equity	2,418,575	454,600	2,873,175
Total liabilities and unitholders' equity	$ 3,143,366	$ 867,591	$ 4,010,957

See accompanying notes to unaudited pro forma condensed consolidated combined financial statements.

Viper Energy Partners LP and Subsidiary
Unaudited Pro Forma Condensed Combined Statement of Operations

	Nine Months Ended September 30, 2023			
	Viper (Historical)	Sellers (Historical)	Transaction Accounting Adjustments	Viper Pro Forma Combined
	(In thousands, except per unit amounts)			
Operating income:				
Royalty income	$ 514,896	$ 91,099	$ —	$ 605,995
Lease bonus income—related party	105,585	—	—	105,585
Lease bonus income	1,730	1,788	—	3,518
Other operating income	774	—	—	774
Total operating income	622,985	92,887	—	715,872
Costs and expenses:				
Production and ad valorem taxes	37,794	6,180	—	43,974
Depletion	101,331	23,989	(23,291) *(a)*	102,029
General and administrative expenses	6,652	10,534	—	17,186
Total costs and expenses	145,777	40,703	(23,291)	163,189
Income (loss) from operations	477,208	52,184	23,291	552,683
Other income (expense):				
Interest expense, net	(32,180)	—	(23,151) *(b)*	(55,331)
Gain (loss) on derivative instruments, net	(30,685)	—	—	(30,685)
Other income, net	802	1,819	—	2,621
Total other expense, net	(62,063)	1,819	(23,151)	(83,395)
Income (loss) before income taxes	415,145	54,003	140	469,288
Provision for (benefit from) income taxes	39,735	—	10,391 *(c)*	50,126
Net income (loss)	375,410	54,003	(10,251)	419,162
Net income (loss) attributable to non-controlling interest	232,294	—	6,477 *(d)*	238,771
Net income (loss) attributable to Viper Energy Partners LP	$ 143,116	$ 54,003	$ (16,728)	$ 180,391
Net income (loss) attributable to common limited partner units:				
Basic	$ 1.99			$ 2.05
Diluted	$ 1.99			$ 2.05
Weighted average number of common limited partner units outstanding:				
Basic	71,803		16,234 *(e)*	88,037
Diluted	71,803		16,234 *(e)*	88,037

See accompanying notes to unaudited pro forma condensed consolidated combined financial statements.

Viper Energy Partners LP and Subsidiary
Unaudited Pro Forma Condensed Combined Statement of Operations

	Year Ended December 31, 2022			
	Viper (Historical)	Sellers (Historical)	Acquisition Transaction Adjustments	Viper Pro Forma Combined
	(In thousands, except per unit amounts)			
Operating income:				
Royalty income	$ 837,976	$ 156,931	$ —	$ 994,907
Lease bonus income—related party	4,424	—	203 *(f)*	4,627
Lease bonus income	23,367	3,615	(203) *(f)*	26,779
Other operating income	700	—	—	700
Total operating income	866,467	160,546	—	1,027,013
Costs and expenses:				
Production and ad valorem taxes	56,372	10,060	—	66,432
Depletion	121,071	30,126	(30,441) *(a)*	120,756
General and administrative expenses	8,542	12,948	—	21,490
Total costs and expenses	185,985	53,134	(30,441)	208,678
Income (loss) from operations	680,482	107,412	30,441	818,335
Other income (expense):				
Interest expense, net	(40,409)	—	(30,284) *(b)*	(70,693)
Gain (loss) on derivative instruments, net	(18,138)	—	—	(18,138)
Other income, net	416	646	—	1,062
Total other expense, net	(58,131)	646	(30,284)	(87,769)
Income (loss) before income taxes	622,351	108,058	157	730,566
Provision for (benefit from) income taxes	(32,653)	—	14,505 *(c)*	(18,148)
Net income (loss)	655,004	108,058	(14,348)	748,714
Net income (loss) attributable to non-controlling interest	503,331	—	41,678 *(d)*	545,009
Net income (loss) attributable to Viper Energy Partners LP	$ 151,673	$ 108,058	$ (56,026)	$ 203,705
Net income (loss) attributable to common limited partner units:				
Basic	$ 2.00			$ 2.21
Diluted	$ 2.00			$ 2.21
Weighted average number of common limited partner units outstanding:				
Basic	75,612		16,234 *(e)*	91,846
Diluted	75,679		16,234 *(e)*	91,913

See accompanying notes to unaudited pro forma condensed combined financial statements.

NOTES TO UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

The Partnership's historical financial information has been derived from its Quarterly Report on Form 10-Q for the quarter ended September 30, 2023 and its Annual Report on Form 10-K for the year ended December 31, 2022. Pro forma adjustments have been made to reflect the Acquisition and certain transaction accounting adjustments, as discussed further in Notes 2 and 3. The pro forma balance sheet gives effect to the Acquisition as if it had been completed on September 30, 2023. The pro forma statements of operations for the nine months ended September 30, 2023 and the year ended December 31, 2022 give pro forma effect to the Acquisition as if it had occurred on January 1, 2022, the beginning of the earliest period presented.

The Acquisition was accounted for as an acquisition of assets under ASC 805-50. The Partnership therefore recognized the assets acquired in the transaction based on their cost to the Partnership, which includes the total consideration paid as well as capitalization of all transaction costs incurred relating to the Acquisition.

In the opinion of management, all material adjustments have been made that are necessary to present fairly, in accordance with Article 11 of Regulation S-X, the pro forma financial statements. The pro forma financial statements are provided for illustrative purposes only and do not purport to be indicative of what the Partnership's actual results of operations and financial position would have been on a consolidated basis if the Acquisition had occurred on the dates indicated, nor are they indicative of the future results of operations or financial position.

The pro forma basic and diluted earnings per share amounts presented in the unaudited pro forma statements of operations are based on the weighted average number of the Partnership's common units outstanding, assuming the Acquisition occurred at the beginning of the earliest period presented.

2. CONSIDERATION AND PURCHASE PRICE ALLOCATION

The Partnership has performed a preliminary analysis of the total consideration paid for the assets acquired. The total consideration for the Acquisition, including all associated transaction costs, has been allocated to the assets acquired. Due to the fact that the pro forma financial statements have been prepared based on these preliminary estimates, the final purchase price allocation and the resulting effect on the Partnership's financial position and results of operations may differ significantly from the pro forma amounts included herein.

The following table summarizes the preliminary purchase price as of the Closing Date and the allocation of the total accumulated transaction costs to the assets acquired (in thousands except common units and per unit amount):

Consideration:		
Partnership common units issued at closing		9,018,760
Closing price per common unit of the Partnership	$	28.23
Common unit consideration	$	254,600
Cash consideration		750,000
Transaction costs		8,827
Total consideration (including fair value of Viper common stock issued)	$	1,013,427
Purchase price allocation:		
Oil and natural gas interests	$	1,013,427
Net assets acquired	$	1,013,427

The total consideration has been used to prepare the transaction accounting adjustments in the pro forma balance sheet and statements of operations. The total value of consideration, including transaction costs, is subject to change due to customary purchase price adjustments including post-close adjustments and actual transaction costs incurred. The final amount and allocation of the total consideration is expected to be completed when the Partnership files its report on Form 10-K for the year ended December 31, 2023 and could differ materially from the preliminary allocation used in the transaction accounting adjustment.

3. PRO FORMA ADJUSTMENTS AND ASSUMPTIONS

The pro forma financial statements have been prepared to illustrate the effect of the Acquisition and have been prepared for informational purposes only.

Balance Sheet

The adjustments included in the pro forma balance sheet as of September 30, 2023 are as follows:

(a) Reflects the total purchase price allocated to the oil and natural gas properties acquired, which consists of $296.3 million allocated to proved properties, $708.3 million allocated to unproved properties and $8.8 million in transaction costs. See Note 2—Consideration and Purchase Price Allocation.

(b) Represents the total increase in long-term debt borrowed by Viper to fund the Acquisition, consisting of:
- net proceeds of approximately $394.4 million, including estimated transactions costs, from the issuance of the 2031 Notes; and
- an increase of $18.6 million in borrowings under Viper OpCo's revolving credit facility.

(c) Represents the 9.02 million common units issued to the Sellers as part of the total consideration for the Acquisition. See Note 2—Consideration and Estimated Cost Allocation.

(d) Represents proceeds of approximately $200.0 million from Viper's issuance of approximately 7.22 million common units to Diamondback at a price of $27.72 per unit on October 31, 2023, which were used to fund a portion of the Cash Consideration for the Acquisition.

(e) Reflects the use of $95.8 million in cash held as of September 30, 2023 which was obtained from lease bonus proceeds and effectively used to partially fund the Cash Consideration for the Acquisition.

(f) Reflects the application of the $50.0 million of funds held in escrow as of September 30, 2023 towards the Cash Consideration for the Acquisition.

(g) Reflects the change in ownership interest attributable to Viper's noncontrolling interest which resulted from the issuance of 7.22 million common units to Diamondback and 9.02 million common units issued to the Sellers as part of the total consideration for the Acquisition.

Statements of Operations

The adjustments included in the pro forma statements of operations for the nine months ended September 30, 2023 and for the year ended December 31, 2022 are as follows:

(a) Reflects the change in depletion expense computed on a unit of production basis under the full cost method of accounting following the preliminary purchase price allocation to oil and natural gas properties, as if the Acquisition was consummated on January 1, 2022. Of the $1.0 billion of oil and natural gas properties acquired, $296.3 million was subject to depletion in the periods presented.

(b) Reflects the estimated interest expense that would have been recorded in the periods presented with respect to the incremental borrowings used to finance the cash consideration for the Acquisition.
- The $400 million in new debt bears interest at 7.375%, resulting in pro forma interest expense of $22.1 million and $29.5 million for the nine months ended September 30, 2023 and for the year ended December 31, 2022, respectively.
- The pro forma statements of operations for the nine months ended September 30, 2023 and for the year ended December 31, 2022 used the weighted average interest rates prevailing during the periods of 7.37% and 4.22% respectively on the pro forma incremental outstanding borrowings on Viper's revolving credit facility of $18.6 million, resulting in pro forma interest expense of $1.0 million and $0.8 million, respectively.

(c) Reflects the estimated incremental income tax provision associated with the incremental pro forma income before taxes attributable to Viper Energy Partners LP, using a blended federal plus state statutory tax rate, net of federal benefit, of 21.8%.

(d) Reflects the non-controlling interest portion of incremental pro forma earnings as well as the estimated incremental impact on Viper's historical net income attributable to the non-controlling interests as a result of the Partnership's sale of common units to Diamondback and the issuance of common units as part of the purchase consideration for the Acquisition, as if the additional common units had been outstanding since the beginning of the periods presented.

(e) Reflects the issuance of approximately 9.02 million common units to the Sellers and 7.22 million common units to Diamondback to partially finance the Acquisition. The additional common units were assumed to have been outstanding since the beginning of the periods presented. The following table reconciles historical and pro forma basic and diluted earnings per share utilizing the two-class method for the periods indicated:

	Nine Months Ended September 30, 2023		Year Ended December 31, 2022	
	Historical	Pro Forma	Historical	Pro Forma
	(in thousands, except per share amounts)			
Net income (loss) attributable to the period	$ 143,116	$ 180,391	$ 151,673	$ 203,705
Less: distributed and undistributed earnings allocated to participating securities	263	296	365	391
Net income (loss) attributable to common unitholders	$ 142,853	$ 180,095	$ 151,308	$ 203,314
Weighted average common units outstanding:				
Basic weighted average common units outstanding	71,803	88,037	75,612	91,846
Effect of dilutive securities:				
Potential common units issuable	—	—	67	67
Diluted weighted average common units outstanding	71,803	88,037	75,679	91,913
Net income (loss) per common unit, basic	$ 1.99	$ 2.05	$ 2.00	$ 2.21
Net income (loss) per common unit, diluted	$ 1.99	$ 2.05	$ 2.00	$ 2.21

(f) Reflects the reclassification of lease bonus income of the Sellers during the year ended December 31, 2022 which was paid by Diamondback to Sellers.

4. SUPPLEMENTAL PRO FORMA OIL AND NATURAL GAS RESERVES INFORMATION

The following unaudited supplemental pro forma oil and natural gas reserve tables present how the combined oil and natural gas reserves and standardized measure information of the Company and the Acquisition may have appeared had the Acquisition occurred on January 1, 2022. The supplemental pro forma combined oil and natural gas reserves and standardized measure information are for illustrative purposes only. Numerous uncertainties are inherent in estimating quantities and values of proved reserves including future rates of production, exploration and development expenditures, commodity prices, and service costs which may affect the reserve volumes attributable to the Properties and the standardized measure of discounted future net cash flows.

The following tables provide a summary of the changes in estimated proved reserves for the year ended December 31, 2022, as well as pro forma proved developed and proved undeveloped reserves as of the beginning and end of the year, giving effect to the Acquisition as if it had occurred on January 1, 2022.

Estimated Pro Forma Combined Quantities of Proved Reserves

	Oil (MBbls)		
	Viper (Historical)	Sellers (Historical)	Viper Pro Forma Combined
Proved Developed and Undeveloped Reserves:			
As of December 31, 2021	69,240	13,566	82,806
Purchase of reserves in place	599	263	862
Extensions and discoveries	15,714	56	15,770
Revisions of previous estimates	1,453	52	1,505
Divestitures	(905)	—	(905)
Production	(7,097)	(1,316)	(8,413)
As of December 31, 2022	79,004	12,621	91,625
Proved Developed Reserves:			
December 31, 2021	49,280	6,146	55,426
December 31, 2022	54,817	7,126	61,943
Proved Undeveloped Reserves:			
December 31, 2021	19,960	7,420	27,380
December 31, 2022	24,187	5,495	29,682

	Natural Gas (MMcf)		
	Viper (Historical)	Sellers (Historical)	Viper Pro Forma Combined
Proved Developed and Undeveloped Reserves:			
As of December 31, 2021	183,690	59,626	243,316
Purchase of reserves in place	1,186	1,785	2,971
Extensions and discoveries	29,177	273	29,450
Revisions of previous estimates	15,248	(776)	14,472
Divestitures	(3,469)	—	(3,469)
Production	(15,868)	(3,266)	(19,134)
As of December 31, 2022	209,964	57,642	267,606
Proved Developed Reserves:			
December 31, 2021	134,485	32,774	167,259
December 31, 2022	161,119	35,007	196,126
Proved Undeveloped Reserves:			
December 31, 2021	49,205	26,852	76,057
December 31, 2022	48,845	22,635	71,480

	Natural Gas Liquids (MBbls)		
	Viper (Historical)	Sellers (Historical)	Viper Pro Forma Combined
Proved Developed and Undeveloped Reserves:			
As of December 31, 2021	28,033	8,880	36,913
Purchase of reserves in place	209	303	512
Extensions and discoveries	5,281	34	5,315
Revisions of previous estimates	4,483	(102)	4,381
Divestitures	(564)	—	(564)
Production	(2,540)	(494)	(3,034)
As of December 31, 2022	34,902	8,621	43,523
Proved Developed Reserves:			
December 31, 2021	19,476	4,559	24,035
December 31, 2022	25,621	4,961	30,582
Proved Undeveloped Reserves:			
December 31, 2021	8,557	4,321	12,878
December 31, 2022	9,281	3,660	12,941

	Total (MBOE)		
	Viper (Historical)	Sellers (Historical)	Viper Pro Forma Combined
Proved Developed and Undeveloped Reserves:			
As of December 31, 2021	127,888	32,383	160,271
Purchase of reserves in place	1,006	864	1,870
Extensions and discoveries	25,858	136	25,994
Revisions of previous estimates	8,477	(179)	8,298
Divestitures	(2,047)	—	(2,047)
Production	(12,282)	(2,354)	(14,636)
As of December 31, 2022	148,900	30,850	179,750
Proved Developed Reserves:			
December 31, 2021	91,170	16,167	107,337
December 31, 2022	107,291	17,922	125,213
Proved Undeveloped Reserves:			
December 31, 2021	36,718	16,216	52,934
December 31, 2022	41,609	12,928	54,537

Pro Forma Combined Standardized Measure of Discounted Future Net Cash Flows

	December 31, 2022		
	Viper (Historical)	Sellers (Historical)	Viper Pro Forma Combined
	(In thousands)		
Future cash inflows	$ 10,072,969	$ 1,739,907	$ 11,812,876
Future production taxes	(729,256)	(97,469)	(826,725)
Future income tax expense	(1,465,160)	(7,691)	(1,472,851)
Future net cash flows	7,878,553	1,634,747	9,513,300
10% discount to reflect timing of cash flows	(4,424,457)	(779,108)	(5,203,565)
Standardized measure of discounted future net cash flows	$ 3,454,096	$ 855,639	$ 4,309,735

Pro Forma Combined Changes in the Standardized Measure of Discounted Future Net Cash Flows

	December 31, 2022		
	Viper (Historical)	Sellers (Historical)	Viper Pro Forma Combined
	(In thousands)		
Standardized measure of discounted future net cash flows at the beginning of the period	$ 2,093,117	$ 601,739	$ 2,694,856
Purchase of minerals in place	30,331	20,346	50,677
Divestiture of reserves	(30,076)	—	(30,076)
Sales of oil and natural gas, net of production costs	(781,604)	(146,871)	(928,475)
Extensions and discoveries	844,010	3,573	847,583
Net changes in prices and production costs	1,131,202	336,617	1,467,819
Revisions of previous quantity estimates	309,338	(2,882)	306,456
Net changes in income taxes	(393,652)	(1,174)	(394,826)
Accretion of discount	234,717	60,462	295,179
Net changes in timing of production and other	16,713	(16,171)	542
Standardized measure of discounted future net cash flows at the end of the period	$ 3,454,096	$ 855,639	$ 4,309,735

SIGNATURES

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

VIPER ENERGY, INC.

Date:	November 13, 2023	By:	/s/ Travis D. Stice
			Travis D. Stice
			Chief Executive Officer
Date:	November 13, 2023	By:	/s/ Teresa L. Dick
			Teresa L. Dick
			Chief Financial Officer

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

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Each file contained herein is intended to be a manifestation of certain data in the subject report and as such is subject to the definitions, qualifications, explanations, conclusions, and other conditions thereof. The information and data contained in each file may be subject to misinterpretation; therefore, the signed and bound copy of this report should be considered the only authoritative source of such information.

DeGolyer and MacNaughton
5001 Spring Valley Road
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REPORT
as of
DECEMBER 31, 2022
on
RESERVES and REVENUE
of
CERTAIN PROPERTIES
with interests attributable to
GRP ENERGY CAPITAL
prepared for
VIPER ENERGY PARTNERS LP

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FOREWORD

Scope of Investigation

This report presents estimates, as of December 31, 2022, of the extent and value of the proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Viper Energy Partners LP (Viper) has represented that GRP Energy Capital (GRP) holds an interest. The properties evaluated herein consist of royalty interests located in Colorado, Montana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, and Wyoming. A list of the properties evaluated in this report is shown in the appendix to this report under the Lease Totals – Reserves and Revenue tab.

Estimates of reserves presented in this report have been prepared in compliance with the regulations promulgated by the United States Securities and Exchange Commission (SEC). These reserves definitions are discussed in detail in the Definition of Reserves section of this report.

Reserves estimated in this report are expressed as gross reserves and net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2022. Net reserves are defined as that portion of the gross reserves attributable to the interests held by GRP after deducting all interests held by others.

This report presents values for proved reserves that were estimated using prices, expenses, and costs provided by Viper. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). A detailed explanation of the future price, expense, and cost assumptions is included in the Valuation of Reserves section of this report.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, and gathering, processing, and transportation (GP&T) expenses from future gross revenue. At the request of Viper, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold. In this report, present worth values using a discount rate of 10 percent are reported in detail and values using discount rates of 5, 8, 12, 15, 17.5, 20, and 25 percent are reported as totals in the appendix to this report.

Estimates of reserves and revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

This report was prepared in October 2023; therefore, certain events that may have occurred before the preparation of this report but after the “as-of” date of December 31, 2022, which might have affected the reserves, prices, costs, and values used in the estimates presented herein, were not taken into account.

Authority

This report was authorized by Mr. Matthew Kaes Van’t Hof, President, Viper Energy Partners LP.

Source of Information

Information used in the preparation of this report was obtained from Viper and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Viper with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

DEFINITION of RESERVES

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

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.

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 (iv) and (vi) of the definition of possible reserves.

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 (iii) of the proved oil and gas reserves definition, 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.

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.

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 [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

The extent to which probable and possible reserves ultimately may be reclassified as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. No probable or possible reserves have been evaluated for this report.

ESTIMATION of RESERVES

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019" and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Viper, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

Viper was unable to provide actual plans for the future development of the properties evaluated herein. Therefore, for the purposes of this report, the timing for the development of undeveloped reserves estimates presented herein was derived based on data provided by Viper. Proved undeveloped reserves were estimated for locations that have been permitted, are currently drilling, are drilled but not yet completed, or locations where the operator has identified to Viper its intention to drill.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In the evaluation of developed undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Viper from wells drilled through December 31, 2022, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available through December 31, 2022. Cumulative production, as of December 31, 2022, was deducted from the estimated gross ultimate recovery to estimate gross reserves.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in the appendix to this report are expressed in barrels (bbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base of the state in which the quantities are located. Gas quantities included in the appendix to this report are expressed in thousands of cubic feet (Mcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

All proved developed reserves included herein are considered to be proved developed producing.

The estimated gross and net proved reserves, as of December 31, 2022, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Gross Reserves			**Net Reserves**		
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil and Condensate (Mbbl)**	**NGL (Mbbl)**	**Sales Gas (MMcf)**
Proved						
Developed Producing	1,074,894	778,278	5,578,336	7,126	4,961	35,007
Developed Non-Producing	0	0	0	0	0	0
Total Proved Developed	**1,074,894**	**778,278**	**5,578,336**	**7,126**	**4,961**	**35,007**
Undeveloped	747,214	431,343	2,788,132	5,495	3,660	22,635
Total Proved	**1,822,108**	**1,209,621**	**8,366,468**	**12,621**	**8,621**	**57,642**

VALUATION of RESERVES

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Viper. Future prices were estimated using guidelines established by the SEC and the FASB.

The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and NGL Prices

Viper has represented that the oil, condensate, and NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Viper supplied differentials to a West Texas Intermediate (WTI) reference price of $93.67 per barrel and these prices were held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $94.02 per barrel of oil and condensate and $33.24 per barrel of NGL.

Gas Prices

Viper has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Viper supplied differentials to a Henry Hub reference price of $6.36 per million Btu and the prices were held constant thereafter. Btu factors provided by Viper were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $5.634 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for each state in which the reserves are located, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Viper based on recent payments.

GP&T Expenses

GP&T expenses, provided by Viper, were used in estimating future expenses associated with the operation of the properties evaluated herein and were not adjusted for inflation.

Operating Expenses, Capital Costs, and Abandonment Costs

The properties evaluated are royalties. Therefore, no operating expenses, capital costs, or abandonment costs are incurred. Estimates of operating expenses, provided by Viper and based on current expenses, were used to determine the economic life of each property. Viper was unable to provide actual capital costs or abandonment costs for the properties evaluated herein. Therefore, for the purposes of this report, typical capital costs and abandonment costs were estimated based on our knowledge of the areas and/or field operations. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the undeveloped reserves estimated herein.

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of December 31, 2022, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed Producing (M$)	Proved Developed Non-Producing (M$)	Total Proved Developed (M$)	Proved Undeveloped (M$)	Total Proved (M$)
Future Gross Revenue	1,035,370	0	1,035,370	762,551	1,797,921
Production and Ad Valorem Taxes	60,469	0	60,469	37,000	97,469
GP&T Expenses	38,787	0	38,787	19,227	58,014
Future Net Revenue	936,114	0	936,114	706,324	1,642,438
Present Worth at 10 Percent	470,511	0	470,511	389,182	859,693

Note: Future income taxes have not been taken into account in the preparation of these estimates.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8)(i), (ii), and (v)–(x), and 1203(a) of Regulation S–K of the SEC; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year. This report does not include certain disclosures required by Item 1202 (a)(8) of Regulation S–K and is thus not to be used for inclusion in certain SEC filings.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

The appendix bound with this report includes (i) summary projections of proved reserves and revenue sorted by reserves category, (ii) summary projections of proved reserves and revenue sorted by basin and reserves category, and (iii) tabulations of proved reserves and revenue sorted by basin, reserves category, and lease.

SUMMARY and CONCLUSIONS

Viper has represented that GRP holds an interest in certain properties located in Colorado, Montana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, and Wyoming evaluated herein. The estimated net proved reserves, as of December 31, 2022, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Net Reserves		
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**
Proved			
Developed Producing	7,126	4,961	35,007
Developed Non-Producing	0	0	0
Total Proved Developed	**7,126**	**4,961**	**35,007**
Undeveloped	5,495	3,660	22,635
Total Proved	**12,621**	**8,621**	**57,642**

The estimated future revenue attributable to GRP's interest in the proved reserves, as of December 31, 2022, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed Producing (M$)	**Proved Developed Non-Producing (M$)**	**Total Proved Developed (M$)**	**Proved Undeveloped (M$)**	**Total Proved (M$)**
Future Gross Revenue	1,035,370	0	1,035,370	762,511	1,797,921
Future Net Revenue	936,114	0	936,114	706,324	1,642,438
Present Worth at 10 Percent	470,511	0	470,511	389,182	859,693

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2022, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Viper. DeGolyer and MacNaughton has used all assumptions, procedures, data, and methods that it considers necessary to prepare this report.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

SIGNED: October 25, 2023

STATE OF TEXAS
DILHAN ILK
139334
LICENSED
PROFESSIONAL ENGINEER

Dilhan

Dilhan Ilk, P.E.
Executive Vice President
DeGolyer and MacNaughton

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DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

DEGOLYER AND MACNAUGHTON
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REPORT
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FOREWORD

Scope of Investigation

This report presents estimates, as of December 31, 2021, of the extent and value of the proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Viper Energy Partners LP (Viper) has represented that GRP Energy Capital (GRP) holds an interest. The properties evaluated herein consist of royalty interests located in Colorado, Montana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, and Wyoming. A list of the properties evaluated in this report is shown in the appendix to this report under the Lease Totals – Reserves and Revenue tab.

Estimates of reserves presented in this report have been prepared in compliance with the regulations promulgated by the United States Securities and Exchange Commission (SEC). These reserves definitions are discussed in detail in the Definition of Reserves section of this report.

Reserves estimated in this report are expressed as gross reserves and net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2021. Net reserves are defined as that portion of the gross reserves attributable to the interests held by GRP after deducting all interests held by others.

is report presents values for proved reserves that were estimated using prices, expenses, and costs provided by Viper. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). A detailed explanation of the future price, expense, and cost assumptions is included in the Valuation of Reserves section of this report.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, and gathering, processing, and transportation (GP&T) expenses from future gross revenue. At the request of Viper, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold. In this report, present worth values using a discount rate of 10 percent are reported in detail and values using discount rates of 5, 8, 12, 15, 17.5, 20, and 25 percent are reported as totals in the appendix to this report.

Estimates of reserves and revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

This report was prepared in October 2023; therefore, certain events that may have occurred before the preparation of this report but after the “as-of” date of December 31, 2021, which might have affected the reserves, prices, costs, and values used in the estimates presented herein, were not taken into account.

Authority

This report was authorized by Mr. Matthew Kaes Van’t Hof, President, Viper Energy Partners LP.

Source of Information

Information used in the preparation of this report was obtained from Viper and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Viper with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

DEFINITION of RESERVES

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

> *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.

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 (iv) and (vi) of the definition of possible reserves.

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 (iii) of the proved oil and gas reserves definition, 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.

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.

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 [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

The extent to which probable and possible reserves ultimately may be reclassified as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. No probable or possible reserves have been evaluated for this report.

ESTIMATION of RESERVES

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019” and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Viper, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

Viper was unable to provide actual plans for the future development of the properties evaluated herein. Therefore, for the purposes of this report, the timing for the development of undeveloped reserves estimates presented herein was derived based on data provided by Viper. Proved undeveloped reserves were estimated for locations that have been permitted, are currently drilling, are drilled but not yet completed, or locations where the operator has identified to Viper its intention to drill.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Viper from wells drilled through December 31, 2021, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available through December 31, 2021. Cumulative production, as of December 31, 2021, was deducted from the estimated gross ultimate recovery to estimate gross reserves.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in the appendix to this report are expressed in barrels (bbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base of the state in which the quantities are located. Gas quantities included in the appendix to this report are expressed in thousands of cubic feet (Mcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

All proved developed reserves included herein are considered to be proved developed producing.

The estimated gross and net proved reserves, as of December 31, 2021, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Gross Reserves			Net Reserves		
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil and Condensate (Mbbl)**	**NGL (Mbbl)**	**Sales Gas (MMcf)**
Proved						
Developed Producing	874,978	700,482	5,050,129	6,146	4,559	32,774
Developed Non-Producing	0	0	0	0	0	0
Total Proved Developed	**874,978**	**700,482**	**5,050,129**	**6,146**	**4,559**	**32,774**
Undeveloped	1,109,262	565,554	3,714,647	7,420	4,321	26,852
Total Proved	**1,984,240**	**1,266,036**	**8,764,776**	**13,566**	**8,880**	**59,626**

VALUATION of RESERVES

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Viper. Future prices were estimated using guidelines established by the SEC and the FASB.

The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and NGL Prices

Viper has represented that the oil, condensate, and NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Viper supplied differentials to a West Texas Intermediate (WTI) reference price of $66.56 per barrel and these prices were held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $66.92 per barrel of oil and condensate and $23.62 per barrel of NGL.

Gas Prices

Viper has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Viper supplied differentials to a Henry Hub reference price of $3.60 per million Btu and the prices were held constant thereafter. Btu factors provided by Viper were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $2.882 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for each state in which the reserves are located, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Viper based on recent payments.

GP&T Expenses

GP&T expenses, provided by Viper, were used in estimating future expenses associated with the operation of the properties evaluated herein and were not adjusted for inflation.

Operating Expenses, Capital Costs, and Abandonment Costs

The properties evaluated are royalties. Therefore, no operating expenses, capital costs, or abandonment costs are incurred. Estimates of operating expenses, provided by Viper and based on current expenses, were used to determine the economic life of each property. Viper was unable to provide actual capital costs or abandonment costs for the properties evaluated herein. Therefore, for the purposes of this report, typical capital costs and abandonment costs were estimated based on our knowledge of the areas and/or field operations. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the undeveloped reserves estimated herein.

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of December 31, 2021, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed Producing (M$)	**Proved Developed Non-Producing (M$)**	**Total Proved Developed (M$)**	**Proved Undeveloped (M$)**	**Total Proved (M$)**
Future Gross Revenue	616,965	0	616,965	672,442	1,289,407
Production and Ad Valorem Taxes	38,326	0	38,326	32,424	70,750
GP&T Expenses	37,220	0	37,220	23,227	60,447
Future Net Revenue	541,419	0	541,419	616,791	1,158,210
Present Worth at 10 Percent	281,318	0	281,318	323,302	604,620

Note: Future income taxes have not been taken into account in the preparation of these estimates.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8)(i), (ii), and (v)–(x), and 1203(a) of Regulation S–K of the SEC; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year. This report does not include certain disclosures required by Item 1202 (a)(8) of Regulation S–K and is thus not to be used for inclusion in certain SEC filings.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

The appendix bound with this report includes (i) summary projections of proved reserves and revenue sorted by reserves category, (ii) summary projections of proved reserves and revenue sorted by basin and reserves category, and (iii) tabulations of proved reserves and revenue sorted by basin, reserves category, and lease.

SUMMARY and CONCLUSIONS

Viper has represented that GRP holds an interest in certain properties located in Colorado, Montana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, and Wyoming evaluated herein. The estimated net proved reserves, as of December 31, 2021, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Net Reserves		
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**
Proved			
Developed Producing	6,146	4,559	32,774
Developed Non-Producing	0	0	0
Total Proved Developed	**6,149**	**4,559**	**32,774**
Undeveloped	7,420	4,321	26,852
Total Proved	**13,569**	**8,880**	**59,626**

The estimated future revenue attributable to GRP's interest in the proved reserves, as of December 31, 2021, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed Producing (M$)	**Proved Developed Non-Producing (M$)**	**Total Proved Developed (M$)**	**Proved Undeveloped (M$)**	**Total Proved (M$)**
Future Gross Revenue	616,965	0	616,965	672,442	1,289,407
Future Net Revenue	541,419	0	541,419	616,791	1,158,210
Present Worth at 10 Percent	281,318	0	281,318	323,302	604,620

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2021, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Viper. DeGolyer and MacNaughton has used all assumptions, procedures, data, and methods that it considers necessary to prepare this report.

Submitted,

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

SIGNED: October 25, 2023

Dilhan Ilk, P.E.
Executive Vice President
DeGolyer and MacNaughton