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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 OR 15(d)
of the Securities Exchange Act of 1934

April 8, 2024
Date of Report (Date of Earliest Event Reported)

DIAMONDBACK ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**001-35700**	**45-4502447**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

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

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

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

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

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

Title of each class	**Trading Symbol(s)**	**Name of each exchange on which registered**
Common stock, par value $0.01 per share	FANG	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.

Item 8.01 Other Events.

Diamondback Energy, Inc., a Delaware corporation (the "Company") is filing this current report on Form 8-K to provide certain historical financial information with respect to Endeavor Parent, LLC, a Texas limited liability company ("Endeavor").

The Company is filing the following exhibits to this Current Report on Form 8-K: (i) Endeavor's consolidated financial statements and supplemental schedules as Exhibit 99.1, which contain (a) its audited consolidated financial statements as of December 31, 2023 and 2022 and for each of the fiscal years ended December 31, 2023, 2022 and 2021 and (b) unaudited supplemental information on oil and natural gas producing activities; and (ii) Endeavor management's discussion and analysis of financial condition and results of operations of Endeavor as Exhibit 99.2.

Item 9.01 Financial Statements and Exhibits.

(d) *Exhibits*

Exhibit Number	Description
23.1	Consent of Grant Thornton LLP, independent certified public accountants of Endeavor.
23.2	Consent of Netherland, Sewell & Associates, Inc., independent petroleum engineers of Endeavor.
99.1	Consolidated Financial Statements and Supplemental Schedules of Endeavor.
99.2	Endeavor Management's Discussion and Analysis of Financial Condition and Results of Operations of Endeavor.
104	Cover Page Interactive Data File (embedded within the Inline XBRL document).

Forward-Looking Statements

Certain of the documents included in this Current Report on Form 8-K contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act of 1934, as amended, which involve risks, uncertainties, and assumptions. All statements, other than statements of historical fact, including statements regarding future performance; business strategy; future operations (including drilling plans and capital plans); estimates and projections of revenues, losses, costs, expenses, returns, cash flow, and financial position; reserve estimates and its ability to replace or increase reserves; anticipated benefits of strategic transactions (including acquisitions and divestitures), and plans and objectives of Endeavor management (including plans for future cash flow from operations and for executing environmental strategies) are forward-looking statements. When used in such documents, the words "aim," "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "future," "guidance," "intend," "may," "model," "outlook," "plan," "positioned," "potential," "predict," "project," "seek," "should," "target," "will," "would," and similar expressions (including the negative of such terms) are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Forward-looking statements involve risks and uncertainties that are difficult to predict and, in many cases, beyond Endeavor's control. Accordingly, forward-looking statements are not guarantees of future performance and actual outcomes could differ materially from what Endeavor has expressed in any forward-looking statements in the documents included in this Current Report on Form 8-K.

Factors that could cause the outcomes to differ materially include (but are not limited to) the following: changes in supply and demand levels for oil, natural gas, and natural gas liquids, and the resulting impact on the price for those commodities; the impact of public health crises, including epidemic or pandemic diseases and any related company or government policies or actions; actions taken by the members of OPEC and Russia affecting the production and pricing of oil, as well as other domestic and global political, economic, or diplomatic developments, including any impact of the ongoing war in Ukraine and the Israel-Hamas war on the global energy markets and geopolitical stability; instability in the financial markets; concerns over a potential economic slowdown or recession; inflationary pressures; rising interest rates and their impact on the cost of capital; regional supply and demand factors, including delays, curtailment delays or interruptions of production, or governmental orders, rules or regulations that impose production limits; federal and state legislative and regulatory initiatives relating to hydraulic fracturing, including the effect of existing and future laws and governmental regulations; physical and transition risks relating to climate change; those risks described in Item 1A of Diamondback's Annual Report on Form 10-K, filed with the SEC on February 22, 2024 (which are also applicable to Endeavor as Diamondback and Endeavor operate similar businesses in similar industries), and risks relating to the proposed transaction between Diamondback and Endeavor.

In light of these factors, the events anticipated by such forward-looking statements may not occur at the time anticipated or at all. Moreover, Endeavor operates in a very competitive and rapidly changing environment and new risks emerge from time to time. Diamondback and Endeavor cannot predict all risks, nor can they assess the impact of all factors on Endeavor's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those anticipated by any forward-looking statements it may make. Accordingly, you should not place undue reliance on any forward-looking statements. All forward-looking statements in the documents included as exhibits in this Current Report on Form 8-K speak only as of the date of such documents or, if earlier, as of the date they were made. Diamondback and Endeavor do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by applicable law.

SIGNATURES

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

DIAMONDBACK ENERGY, INC.

Date: April 8, 2024

By:	/s/ Kaes Van't Hof
Name:	Kaes Van't Hof
Title:	President and Chief Financial Officer

Exhibit 23.1

CONSENT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

We have issued our report dated March 13, 2024, with respect to the consolidated financial statements of Endeavor Parent, LLC included in the Current Report of Diamondback Energy, Inc. on Form 8-K filed on April 8, 2024. We consent to the incorporation by reference of said report in the Registration Statements of Diamondback Energy, Inc. on Forms S-3ASR (File No. 333-255731; File No. 333-268495; File No. 333-268614; and File No. 333-269476), and on Forms S-8 (File No. 333-188552; File No. 333-215798; File No. 333-228637; File No 333-235671; and File No. 333-257561).

/s/ GRANT THORNTON LLP

Dallas, Texas
April 8, 2024

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion in the Form 8-K (including any amendments or supplements thereto, related appendices, and financial statements) of Diamondback Energy, Inc., to be filed with the Securities and Exchange Commission on or around April 8, 2024, of our report dated March 11, 2024, with respect to our estimates of proved reserves and future net revenue to the Endeavor Energy Resources, L.P. interest, as of December 31, 2023, in certain oil and gas properties located in the United States. We also hereby consent to the incorporation by reference of said report in the Registration Statements of Diamondback Energy, Inc. on Forms S-3ASR (File No. 333-255731; File No. 333-268495; File No. 333-268614; and File No. 333-269476), and on Forms S-8 (File No. 333- 188552; File No. 333-215798; File No. 333-228637; File No 333-235671; and File No. 333-257561).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Eric J. Stevens
Eric J. Stevens, P.E.
President and Chief Operating Officer

Dallas, Texas
April 8, 2024

Exhibit 99.1

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTAL SCHEDULES OF ENDEAVOR PARENT, LLC

GRANT THORNTON LLP
500 North Akard Street, Suite 1200
Dallas, TX 75201

D +1 214 561 2300
F +1 214 561 2370

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

To the Members of
Endeavor Parent, LLC

Opinion
We have audited the consolidated financial statements of Endeavor Parent, LLC, a Texas limited liability company, and subsidiaries (including its predecessor Endeavor Energy Resources, LP and its subsidiaries prior to November 13, 2023) (collectively, the “Company”), which comprise the consolidated balance sheets as of December 31, 2023 and 2022, and the related consolidated statements of operations and comprehensive income, members’ equity, and cash flows for each of the three years in the period ended December 31, 2023, and the related notes to the financial statements.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in accordance with accounting principles generally accepted in the United States of America.

Basis for opinion
We conducted our audits of the consolidated 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 Company 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 consolidated 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 consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company’s 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 consolidated 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 consolidated 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 consolidated 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 Company’s 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 consolidated financial statements.

- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company’s 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.

Other information included in the annual report
Management is responsible for the other information included in the annual report. The other information comprises the Description of Endeavor Business (not presented herein) and Management's Discussion and Analysis of Financial Condition and Results of Operations of Endeavor but does not include the consolidated financial statements and our auditor's report thereon. Our opinion on the consolidated financial statements does not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information and consider whether material inconsistency exists between the other information and the consolidated financial statements, or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

Grant Thornton LLP

Dallas, Texas
March 13, 2024

ENDEAVOR PARENT, LLC
CONSOLIDATED BALANCE SHEETS
(dollars in millions)

	December 31, 2023	December 31, 2022
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 690	$ 1,585
Receivables:		
Accrued oil and natural gas revenues	727	524
Joint interest billings, net of allowance for doubtful accounts of $12 million and $12 million, respectively	29	20
Related parties (Note C), net of allowance for doubtful accounts of $1 million and $0 million, respectively	32	6
Accounts receivable - other	9	5
Total receivables	797	555
Inventories, net	83	91
Derivative contracts - short-term (Note H)	46	—
Prepaid expenses	17	12
Total current assets	1,633	2,243
PROPERTY AND EQUIPMENT:		
Oil and natural gas property and equipment, full cost method, net ($176 million and $144 million excluded from amortization, respectively) (Note D)	8,917	6,763
Other property and equipment, net (Note D)	571	429
OTHER NON-CURRENT ASSETS:		
Related parties (Note C)	8	10
Operating lease right -of-use assets	37	—
Derivative contracts (Note H)	9	4
Other	25	10
	$ 11,200	$ 9,459
LIABILITIES AND MEMBERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	459	401
Oil and gas revenue	704	505
Accrued expenses	231	246
Taxes payable	2	23
Derivative contracts (Note H)	9	—
Asset retirement obligations (Note G)	15	15
Current operating lease liabilities	20	—
Total current liabilities	1,440	1,190
OTHER LONG-TERM LIABILITIES (Note L)	19	—
LONG-TERM DEBT (Note E)	913	985
OPERATING LEASE LIABILITIES	18	—
DEFERRED TAXES (Note N)	57	40
DERIVATIVE CONTRACTS (Note H)	1	5
ASSET RETIREMENT OBLIGATIONS (Note G)	245	208
COMMITMENTS AND CONTINGENCIES (Note I)	—	—
MEMBERS' EQUITY (Note M)		
Members' equity	8,494	7,032
Accumulated other comprehensive (loss) income	13	(1)
Total members' equity	8,507	7,031
	$ 11,200	$ 9,459

The accompanying notes are an integral part of these consolidated financial statements.

ENDEAVOR PARENT, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(dollars in millions)

	Years Ended December 31,		
	2023	2022	2021
Operating revenues:			
Oil sales	$ 5,452	$ 5,814	$ 3,034
Natural gas and NGL sales	713	1,171	655
Sales of purchased oil	—	2	361
Service company division revenue	22	22	14
Total operating revenues	6,187	7,009	4,064
Operating expenses:			
Lease operating expense	688	569	421
Production taxes	301	351	187
Purchased oil	—	—	361
Service company division operating expenses	21	19	12
Depletion, depreciation, amortization and accretion	1,117	789	575
Impairment of other property and equipment	—	3	—
Loss from inventory write down	1	1	—
General and administrative expense	116	114	85
(Gain) loss on sale of other assets, net	(10)	(109)	(1)
Total operating expenses	2,234	1,737	1,640
Income from operations	3,953	5,272	2,424
Other income (expense):			
Gain (loss) from derivative transactions, net	26	(399)	(625)
Loss on redemption of debt	—	(24)	(25)
Interest income (expense), net	28	(55)	(126)
Other expenses	(11)	(3)	—
Total other income (expense)	43	(481)	(776)
Income before taxes	3,996	4,791	1,648
Taxes:			
Current expense (benefit)	(5)	22	—
Deferred expense (benefit)	17	14	6
Net income	$ 3,984	$ 4,755	$ 1,642
Other comprehensive income (loss)			
Commodity cash flow hedging derivative instruments (Note H):			
Change in fair value of cash flow hedges	$ 14	$ (1)	$ —
Total other comprehensive net income (loss)	$ 14	$ (1)	$ —
Total comprehensive income	$ 3,998	$ 4,754	$ 1,642

The accompanying notes are an integral part of these consolidated financial statements.

ENDEAVOR PARENT, LLC
CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY
(dollars in millions)

	Members' Equity	Accumulated Other Comprehensive Income (loss)	Total
Balance at December 31, 2020	$ 1,850	$ —	1,850
Net income	1,642	—	1,642
Balance at December 31, 2021	$ 3,492	$ —	$ 3,492
Net income	4,755	—	4,755
Distributions	(1,215)	—	(1,215)
Cash flow hedges	—	(1)	(1)
Balance at December 31, 2022	$ 7,032	$ (1)	$ 7,031
Net income	3,984	—	3,984
Distributions	(2,522)	—	(2,522)
Cash flow hedges	—	14	14
Balance at December 31, 2023	$ 8,494	$ 13	$ 8,507

The accompanying notes are an integral part of these consolidated financial statements.

ENDEAVOR PARENT, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in millions)

	Years Ended December 31, 2023	2022	2021
Cash flows from operating activities:			
Net income	$ 3,984	$ 4,755	$ 1,642
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	1,117	789	575
Amortization of debt costs	1	2	3
Deferred taxes	17	14	6
Net (gain) loss on derivative instruments	(26)	399	625
Net cash (payment) receipts from settled derivatives	(6)	(575)	(557)
Impairment of other property and equipment	—	3	—
Loss from inventory write down	1	1	—
(Gain) loss on sale of other assets	(10)	(109)	(1)
Cash paid to satisfy asset retirement obligations	(40)	(30)	(21)
Loss on redemption of debt	—	24	25
Loss from equity method investment	1	—	—
Change in assets and liabilities:			
Accounts receivables	(246)	(121)	(258)
Prepaid expenses and other	(12)	(31)	(33)
Accounts payable and accrued liabilities	230	115	285
(Decrease) increase in taxes payable	(21)	16	(1)
Net cash provided by operating activities	4,989	5,252	2,290
Cash flows from investing activities:			
Oil and gas properties additions	(3,035)	(2,522)	(1,335)
Acquisition of oil and natural gas properties	(75)	(60)	(5)
Proceeds from sales of oil and gas properties	7	4	6
Other property and equipment additions	(205)	(135)	(103)
Proceeds from sales of other assets	18	118	2
Contribution to equity method investment	(1)	(3)	—
Net cash used in investing activities	(3,291)	(2,598)	(1,435)
Cash flows from financing activities:			
Payment on senior notes	(71)	(622)	(500)
Deferred debt costs	—	(6)	—
Cash distributions to members	(2,522)	(1,200)	—
Debt extinguishment costs	—	(19)	(21)
Net cash used in financing activities	(2,593)	(1,847)	(521)
Net (decrease) increase in cash and cash equivalents	(895)	807	334
Cash, cash equivalents and restricted cash at beginning of period	1,585	778	444
Cash, cash equivalents and restricted cash at end of period	$ 690	$ 1,585	$ 778
Supplemental disclosures of cash flow information:			
Cash paid during the year for interest	$ 63	$ 104	$ 140
Cash paid during the year for taxes	$ 16	$ 7	$ —
Supplemental disclosures of noncash investing and financing:			
Additions (reductions) to oil and gas properties resulting from change in future abandonment costs	$ 61	$ (16)	$ 14
Increase (decrease) in accrued capital expenditures	$ 31	$ 114	$ 155
Net settlement of related party note receivable	$ —	$ 15	$ —

The accompanying notes are an integral part of these consolidated financial statements.

NOTE A – ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

1. NATURE OF OPERATIONS

For purposes of the accompanying consolidated financial statements, for periods (i) prior to November 13, 2023, references to “Endeavor,” the “Partnership” or the “Company” refer to Endeavor Energy Resources, L.P., and, as applicable, its consolidated subsidiaries, and (ii) on and after November 13, 2023, references to “Endeavor” or the “Company” refer to Endeavor Parent, LLC and, as applicable, its consolidated subsidiaries. Furthermore, for periods (i) prior to November 13, 2023, these financial statements reflect the balances and accounts of Endeavor Energy Resources, L.P. and, as applicable, its consolidated subsidiaries, and (ii) on and after November 13, 2023, these financial statements reflect the balances and accounts of Endeavor Parent, LLC and, as applicable, its consolidated subsidiaries.

Founded in 2000 as the successor to the sole proprietorship of Autry C. Stephens, the Company is an independent oil and natural gas producer with oilfield service operations, pipeline subsidiaries and a finance subsidiary based in Midland, Texas. The Company’s focus is on the acquisition, exploration, development and exploitation of long-lived oil, natural gas and NGL reserves. The Company’s business activities are currently carried out primarily in the Permian Basin of West Texas.

On November 13, 2023, we underwent a reorganization, wherein Autry C. Stephens contributed all the issued and outstanding membership interests in Endeavor GP to Endeavor Manager. Immediately thereafter, in a transaction treated as a reorganization described in Section 368(a)(1)(F) of the Internal Revenue Code of 1986, as amended, (i) Endeavor Manager contributed its entire membership interest in Endeavor GP, and all limited partners in the Partnership contributed their entire limited partnership interests in the Partnership, to Endeavor Parent, in exchange for membership interests in Endeavor Parent, and (ii) on the same date, Endeavor Parent filed an election to treat the Partnership as a qualified subchapter S subsidiary of Endeavor Parent effective as of the same date. This reorganization did not alter the ownership of the Partnership’s properties or assets or impact the nature or scope of the Partnership’s operations. As part of this reorganization, the Board of Managers of Endeavor GP was dissolved and a Board of Managers of Endeavor Manager was put in place. The members of the Board of Managers of Endeavor Manager are the same individuals that served on the Board of Managers of Endeavor GP, immediately prior to the date of the reorganization. Following the reorganization, the Partnership continues to operate its properties and assets. See Item 1. Our Business for a summary of the Company's organizational structure. Effective January 1, 2024, the Company's tax status for U.S. federal income tax purposes, was converted from an S-Corporation to a C-Corporation.

Endeavor Parent, LLC was formed in connection with the reorganization described above. Endeavor Parent, LLC is managed by its sole manager, Endeavor Manager, LLC. Endeavor Manager, LLC is managed by the Board of Managers and is owned and controlled by the Autry Stephens Management Trust, the sole trustee of which is Autry C. Stephens.

The oilfield service functions of the Company are comprised of various Energy Services divisions, Bryant Ranch, Electrical Maintenance and Construction, ACS Pump & Supply and a wholly owned subsidiary, Environmental Disposal Systems, LLC.

The pipeline subsidiaries of the Company are comprised of Natural Gas Gatherers, Ltd., its wholly owned subsidiary, NGG Gathering Company, LLC, Barnett Gathering Company, LLC, Barnett Field Services, LLC and LCX Pipeline Company, LLC. The pipeline subsidiaries were formed or acquired to operate natural gas gathering systems.

DG Royalty, LLC, Wyatt Energy Partners, 1979 Royalties, LP and DRE Energy, LLC (the “Royalty Subsidiaries”) were formed to hold mineral interests, royalty interests, overriding royalty interests, and non-working interests in oil and natural gas properties.

EER Finance, Inc., a Delaware corporation ("EER Finance") is a wholly owned subsidiary of the Company and was organized to serve as a co-issuer of the Senior Notes (see Note E - Long-Term Debt). EER Finance does not have any operations, assets or liabilities other than with respect to the Senior Notes and other debt securities that may be issued in the future.

Sprouts Energy, LLC is a subsidiary of the Company and was formed in June 2022 for the purpose of jointly owning and operating a daycare facility with Diamondback E&P LLC. The Company and Diamondback E&P LLC each own fifty percent (50%) of the issued and outstanding limited liability membership interests of Sprouts Energy LLC. Employees of the Company and Diamondback E&P LLC are eligible to apply for their children to attend the daycare.

2. BASIS OF CONSOLIDATION

The accompanying consolidated financial statements of the Company as of December 31, 2023 and for each of the three years ended December 31, 2023, present the accounts of the Company, the oilfield service divisions and subsidiaries, the pipeline subsidiaries, the Royalty Subsidiaries and EER Finance. All significant inter-company balances and transactions have been eliminated. The Company accounts for its interests in oil and natural gas ventures and working interests using the proportionate consolidation method. Under this method, the Company records its proportionate share of assets, liabilities, revenues and expenses.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current period financial statement presentation. These reclassifications had an immaterial effect on the previously reported total assets, total liabilities, members' equity, results of operations and comprehensive income and cash flows.

3. USE OF ESTIMATES

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses resulting in normal recurring entries. Areas of significance requiring the use of management's judgments include the estimation of proved oil, natural gas and NGL reserves used in calculating depletion, the estimation of future net revenues used in computing ceiling test limitations and the estimation of future abandonment obligations used in recording asset retirement obligations. Estimates and judgments also are required in determining revenue accruals, allowances for doubtful accounts, impairments of unproved properties and other assets, fair value measurements and contingencies. We analyze our estimates and base them on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions.

The process of estimating quantities of oil, natural gas and NGL reserves is complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures.

4. CASH AND CASH EQUIVALENTS AND SHORT-TERM INVESTMENTS

The Company considers cash on hand, cash on deposit in banks, money market mutual funds and highly liquid debt instruments purchased with a maturity of three months or less to be cash and cash equivalents. The Company maintains its cash and cash equivalents at financial institutions that are insured by the Federal Deposit Insurance Corporation. At December 31, 2023 and 2022, our cash and cash equivalents exceeded what is federally insured. The Company has not experienced any losses from such accounts.

Periodically, the Company invests in commercial paper with investment grade rated entities. The Company also periodically enters into time deposits with financial institutions. Income related to these investments is recorded in interest and other income in the Company's consolidated statements of operations. As of December 31, 2023 and 2022, the Company had $266 million and $53 million, respectively, in short-term money market funds, which was included in the Company's cash and cash equivalents. Income related to these investments is recorded in interest and other income in the Company's consolidated statements of operations. The following table summarizes the Company's cash and cash equivalents for the periods presented (dollars in millions):

	December 31, 2023	December 31, 2022
Cash and cash equivalents:		
Cash	$ 424	$ 1,532
Money market funds	266	53
Total cash and cash equivalents	$ 690	$ 1,585

5. ACCOUNTS RECEIVABLE

Substantially all of the Company's accounts receivable result from oil, natural gas and NGL sales and other joint activity with other companies in the oil and natural gas industry. This concentration of customers may impact the Company's overall credit risk, either positively or negatively, in that these entities may be similarly affected by industry-wide changes in economic or other conditions. Receivables are generally not collateralized. However, an allowance for doubtful accounts is established based on reviews of individual customer accounts over one year past due, recent loss experience, current economic conditions and other pertinent factors. As of December 31, 2023 and 2022, the Company has recorded an allowance of $13 million and $12 million, respectively.

6. INVENTORIES

Inventories consist of pipe and other production equipment. Inventories are stated at the lower of average cost or net realizable value. For the years ended December 31, 2023, 2022 and 2021, the Company recorded lower of cost or market adjustment to inventories of $1 million, $1 million and $0 million, respectively.

7. OIL AND NATURAL GAS PROPERTIES

The Company follows the full cost method of accounting for oil and natural gas properties. Under this method of accounting all costs associated with the acquisition, exploration and development, including certain internal costs of oil, natural gas and NGL reserves are capitalized. Internal costs that are capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. Internal costs, including employee costs, related to production and operation of the properties are charged to expense as incurred. Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, natural and NGL. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to amortization of capitalized costs. Depletion of proved oil and natural gas properties is calculated using the unit-of-production method, whereby capitalized costs of oil and natural gas properties including the estimated future costs to develop proved reserves, are amortized over the total proved reserves.

In addition, the capitalized costs are subject to a "ceiling test," which limits such capitalized costs to the aggregate of the "estimated present value," discounted at a 10 percent interest rate of future net revenues from proved reserves, based on current economic and operating conditions, plus the lower of cost or fair market value of unproved properties. Unproved oil and natural gas properties are periodically assessed for impairment on a project-by-project basis. These impairment assessments are affected by the results of exploration activities, commodity price outlook, planned future sales or expirations of all or a portion of such projects. If the estimated future net cash flows attributable to such projects are not expected to be sufficient to fully recover the costs invested in each project, the Company will transfer all or a portion of the leasehold costs to the full cost pool and such costs are then subject to amortization.

8. OTHER PROPERTY AND EQUIPMENT

Property and equipment are carried at their cost basis. The cost of maintenance and repairs is charged to expense as paid; significant renewals and improvements are capitalized.

Upon retirement or disposition of other property and equipment, the cost and related accumulated depreciation are removed from the accounts with the resulting gains or losses, if any, recognized in income. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the property and equipment.

The useful lives of the properties are as follows:

	Lives
Buildings and land improvements	10 - 30 years
Automobiles and light trucks	3 - 5 years
Heavy trucks and trailers	3 - 10 years
Service company equipment, pipeline and other equipment	3 - 15 years

Periodically, the Company evaluates other property and equipment for impairment when indicators of possible impairment are present. If the related asset exceeds the undiscounted cash flows, the carrying value is reduced to the asset's fair value, and an impairment loss is recorded against other property and equipment. For the year ended December 31, 2023, the Company did not recognize a provision for impairment on other property and equipment for the year ended December 31, 2022, the Company recognized $3 million for impairment on other property and equipment. For the year ended December 31, 2021, the Company did not record a provision for impairment on other property and equipment.

Gain on sale of other assets

During the year ended December 31, 2023, the Company recognized a gain on sale of other assets of $10 million, primarily attributable to the Company divesting a service company division to an unrelated third party. In addition, during the year ended December 31, 2023, the Company received $8 million of additional proceeds from the sale of its investment in a midstream entity that occurred during the year ended December 31, 2022.

During the year ended December 31, 2022, the Company recognized a gain on the sale of other assets of $109 million. This was primarily related to the Company divesting its investment in a midstream entity, which was accounted for as a cost basis investment. Under the terms of the agreement to sell its investment in the midstream entity, the Company received $112 million in proceeds and had $5 million accrued as a receivable from the sale of its investment. As a result, the Company recognized a gain on sale of assets related to its investment in the midstream entity of $107 million.

Leases

The Company enters into leases for drilling rigs and buildings and recognizes lease expenses on a straight-line basis over the lease term. Lease right-of-use assets and liabilities are initially recorded on the lease commencement date based on the present value of lease payments over the lease term. As most of the Company's lease contracts do not provide an implicit discount rate, the Company uses its incremental borrowing rate, which is determined based on information available at the commencement date of a lease. Leases may include renewal, purchase or termination options that can extend or shorten the term of the lease. The exercise of those options is at the Company's sole discretion and is evaluated at inception and throughout the contract to determine if a modification of the lease term is required. Leases with an initial term of 12 months or less are not recorded as a lease right- of-use asset and liability. See Note D - Oil and Natural Gas Properties, Other Property and Equipment and Lease Information for additional information.

9. ENVIRONMENTAL COSTS

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental costs that relate to current operations are expensed or capitalized as appropriate. Costs are expensed when they relate to an existing condition caused by past operations and will not contribute to current or future revenue generation. Liabilities related to environmental assessments and/or remedial efforts are accrued when property or services are provided or can reasonably be estimated.

10. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The Company follows the provisions of the Derivatives and Hedging topic of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC 815") to account for its derivative financial instruments. Under this topic, all derivative instruments, whether designated as hedging relationships or not, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in the fair value of the derivative are recorded in other comprehensive income (loss) and are recognized in the statement of operations when the hedged item affects earnings. If the derivative is not designated as a hedge, changes in the fair value are recognized in earnings.

11. REVENUE RECOGNITION

Oil, natural gas and NGL sales under the Company's contracts are generally considered performed when the Company sells oil, natural gas and NGL production at the wellhead and receives an agreed-upon index price, net of any price differentials and costs to gather or transport the product, in some cases. The Company recognizes revenue when control transfers to the purchaser, generally at the wellhead, based on the net price received.

Oil sales. Upon review of current contracts with crude oil purchasers, it was determined that oil production is sold at the outlet of the wellhead, and purchasers typically take custody, title and risk of loss of the product and, therefore, control as defined under ASC 606 typically passes at the delivery point.

Natural gas and NGL sales. The Company reviewed natural gas contracts with natural gas purchasers. Based on the terms of the contracts, the majority of the natural gas production is sold at the wellhead, and the purchaser typically takes custody, title and risk of loss of the product and, therefore, control as defined under ASC 606 typically passes at the delivery point.

Sales of purchased oil. The Company entered into purchases and resales of oil during the years ended December 31, 2022 and 2021. Revenues and expenses from these transactions are presented on a gross basis as the Company acts as a principal in the transaction by assuming both the risk and rewards of ownership, including credit risk, of the commodities purchased and the responsibility to deliver the commodities sold. Transportation costs associated with these transactions are presented on a net basis in purchased oil expense. Firm transportation payments on excess pipeline capacity are recorded as a component of purchased oil in the consolidated statements of operations.

Service company division revenues. The Company recognizes revenue during the normal course of business and performance obligations are generally considered satisfied when the Company sells products or completes services for customers.

Disaggregation of revenues. The Company recognizes revenues from the sale of oil, natural gas, NGL and sales of purchased oil to customers and presents them disaggregated on the Company's consolidated statements of operations and comprehensive income. Substantially all of the Company's revenues are earned in the geographical region of the Permian Basin.

12. ASSET RETIREMENT OBLIGATIONS (ARO)

In accordance with the Asset Retirement and Environmental Obligation topic of the FASB ASC 410 and in connection with the properties recognized at December 31, 2023 and 2022, respectively, the Company recorded the present value of estimated future abandonment cost, represented by the summation additional of liabilities incurred and revisions of estimates. See Note G - Asset Retirement Obligations. The Company will adjust the abandonment liability associated with its oil and natural gas wells and related facilities as projects are completed or abandoned, or as estimates of future abandonment costs fluctuate.

We measure the future cost to retire our tangible long-lived assets and recognize such cost as a liability for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction or normal operation of a long- lived asset. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred if a reasonable estimate of fair value can be made and the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, the difference is recorded in oil and natural gas properties. The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. The Company estimates the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk-adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and natural gas property balance.

13. INCOME TAXES

The Company accounts for income taxes under the asset and liability method. Deferred tax liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to be applied to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred income tax expense represents the change during the period in the deferred tax assets and deferred tax liabilities. The financial statements of the Company account for deferred tax assets and liabilities in accordance with Accounting Standards Codification ("ASC") 740, Income taxes.

For all periods prior to January 1, 2024, the Company was a limited partnership classified as an S-corporation for U.S. federal income tax purposes and certain applicable state laws. S-Corporations are not subject to federal income tax at the entity level. Instead, federal income taxes are assessed at the owner level and are not reflected in these financial statements. Texas margin tax is assessed at the entity level and deferred margin tax liabilities of $57 million and $40 million have been recorded as of December 31, 2023 and 2022, respectively, resulting from a book to tax difference in asset carrying amounts. As of December 31, 2023, we had uncertain tax positions that would require disclosure. Uncertain tax positions may change in the next twelve months; however, we do not expect any possible changes to have a significant impact on our results of operations and comprehensive income or financial position. See Note N - Income Taxes for additional information.

On January 1, 2024, Endeavor Parent revoked its classification as an S-Corporation for U.S. federal income tax purposes, thus becoming a C-Corporation for U.S. federal income purposes. See Note N - Income Taxes for addition information related to this conversion and other income tax information.

14. LONG-TERM DEBT PREMIUM AND DEFERRED DEBT COSTS

The Company records premiums associated with the Senior Notes as a component of long-term debt which are amortized over the term of the respective notes.

The Company's deferred debt costs related to its Senior Notes are reported as a direct reduction from the carrying amount of the long-term debt liability, are amortized on a straight-line basis over the life of the respective long-term debt, and amortization is a component of interest expense.

The Company's deferred debt cost related to its revolving credit facility are reported as other noncurrent assets, is amortized on a straight-line basis over the life of the revolving credit facility and amortization is a component of interest expense.

15. RECENTLY ISSUED ACCOUNTING STANDARDS

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses*. This update affects entities holding financial assets and net investment in leases that are not accounted for at fair value through net income. The amendments affect loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables and any other financial assets not excluded from the scope that have the contractual right to receive cash. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. This update will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The Company adopted this during the year ended December 31, 2022 and this ASU had an immaterial impact on the Company's consolidated financial statements since the Company does not have a history of credit losses.

16. **FAIR VALUE**

The Company values financial instruments as required by GAAP ("ASC 820"). The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value because of the short maturity of these instruments. The carrying amount, if any, under our revolving credit facility approximates fair value because the interest rate on this instrument is variable. The fair value of derivative financial instruments is the amount at which they could be settled, based on quoted market prices.

Certain of the Company's financial and nonfinancial assets and liabilities are reported at fair value on the accompanying consolidated balance sheets. ASC 820 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. To increase consistency and comparability in fair value measurements and related disclosures, ASC 820 establishes a fair value hierarchy that prioritizes the relative reliability of inputs used in fair value measurements. The hierarchy gives highest priority to Level 1 inputs that represent unadjusted quoted market prices in active markets for identical assets and liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are directly or indirectly observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs and have the lowest priority in the hierarchy. ASC 820 requires that an entity give consideration to the credit risk of its counterparties, as well as its own credit risk, when measuring financial assets and liabilities at fair value. See Note J - Fair Value for additional information.

NOTE B – CONCENTRATION OF CREDIT RISK

The Company's accounts receivable consists principally of uncollateralized sales to customers in the oil and natural gas industry and joint interest billings to working interest owners. The concentration of credit risk in a single industry affects its overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions.

In addition, the Company maintains its cash and cash equivalents at a limited number of financial institutions that are insured by the Federal Deposit Insurance Corporation. At December 31, 2023 and 2022, our cash and cash equivalents exceeded what is federally insured. The Company has not experienced any losses from such accounts.

NOTE C – RELATED PARTY TRANSACTIONS

The Company either receives revenues or is billed for services provided by entities wholly or partially owned Autry C. Stephens, the sole member of Endeavor Manager, the sole manager of Endeavor Parent. Related party revenues and expenses for the years ended December 31, 2023, 2022 and 2021 are summarized below (dollars in millions).

	2023	2022	2021
Relationship with affiliates to purchase oil and natural gas (revenue)			
Oasis Transportation and Marketing Corporation	$ 729	$ 336	$ 263
ACME Energy Services, Inc.	$ 1	$ 2	$ 1
Relationships with affiliates to provide services (cost)			
Advanced Stimulation Technologies, Inc.	$ 323	$ 293	$ 203
Blue Streak Transportation, Inc.	1	1	9
ACME Energy Services, Inc. - Other	1	1	—
Exxcel Weed Control, LLC	—	1	1
Oasis Transportation and Marketing Corporation	—	1	1
	$ 325	$ 297	$ 214

We have certain shared services of insurance, management, accounting, payroll and other administration that benefit companies that Mr. Stephens wholly and partially owns. The direct costs of these shared services are allocated to each respective entity based on their proportional beneficial usage.

We have filed consolidated Texas margin tax return with entities partially or wholly owned by Mr. Stephens during the years ended December 31, 2022 and 2021. The Company will not be required file a consolidated tax with certain entities partially or wholly owned by Mr. Stephens for the year ended December 2023. The amount of tax due, to the extent there is a liability in a given year, is allocated among the entities based on their incurrence of the tax due.

The following tables summarize the current and non-current related party receivables and payables as of December 31, 2023 and 2022 (dollars in millions).

	Current			
	December 31, 2023		December 31, 2022	
Related Party	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
Oasis Transportation and Marketing Corporation - Oil and natural gas sales receivable	$ 28	$ —	$ —	$ —
Employee Joint Interest Billings, net of allowance of $1 million and $0 million, respectively	2	—	3	—
ACME Energy Service, Inc.	1	—	2	—
Other	1	—	1	—
	$ 32	$ —	$ 6	$ —

	Non-Current	
	December 31, 2023	December 31, 2022
Related Party	Accounts Receivable and Notes Receivable	
ACME Energy Services	$ 3	$ 2
Autry C. Stephens	1	1
Other	1	—
Blue Streak Transportation, Inc.	—	4
Total related party receivables	$ 5	$ 7

Related party investments	Investments	
Sprouts Energy, LLC	$ 2	$ 2
Saltwater Partners #1 SWD, LLC	1	1
Total related party investments	$ 3	$ 3
Total other non-current related party assets	$ 8	$ 10

Contracts with Related Parties

Oasis Transportation and Marketing Corporation ("Oasis"), an entity in which Mr. Stephens is a majority owner, purchases some of our crude oil. The contract may be terminated by either party without penalty upon 30 days' notice. Under the terms of this contract Oasis purchases and transports crude oil produced from some of our Midland Basin operated wells at Oasis's resale price less a transportation rate that is equal to or less than the rate that would be charged by unaffiliated parties.

Advanced Stimulation Technologies, Inc., ("AST") an entity wholly owned and controlled by Mr. Stephens, provides well fracturing, stimulation and cementing services to us at prices agreed upon by the parties from time to time, all in accordance with the terms of a written contract. In December 2023, the Company entered into an 18-month contract with AST for hydraulic fracturing and related services. This contract may be terminated by Endeavor upon 90 days' notice.

As a result of the related party relationship, the Company obtained a fairness opinion from an independent financial advisor prior to executing this contract. The independent financial advisor conducted an assessment of general economic, market and financial conditions, as well market research and benchmarking related to similar transactions. The independent financial advisor concluded that the aggregate economic terms of this contract were fair from a financial point of view to the Company.

ACME Energy Services, Inc. (“ACME”), an entity wholly owned by Mr. Stephens, has provided or provides oilfield services to us. The services provided include natural gas pipeline services in Texas, Oklahoma and Kansas, at market rates and terms. The oilfield services contract that we have with ACME may be terminated by either party without penalty upon 30 days’ notice. ACME also purchases natural gas from us in Oklahoma and Texas. The Company, through its oilfield service company divisions and subsidiaries, also bills for services provided to ACME.

Agreements and Relationships with Employees
Since our inception in 2000 until 2016, we granted certain of our employees working interests in virtually all of our new oil and natural gas leases by allowing them to participate in our drilling activities. This practice was discontinued in 2016, and employees no longer participate in new leases. However, employees that were participants in the program prior to its discontinuance are able to participate in new wells drilled on leases in which they own working interests, but only to the extent of such working interests. The total employee participation in any well does not exceed 15%. We are reimbursed for costs associated with the employee joint working interest owners through the joint interest billing. Employees may defer payment of their joint interest billings beyond normal terms from time to time based on their individual financial circumstances. Ultimately, joint interest billing payment is made through the combination of application of oil and natural gas sales revenues or employee payments. The amount due from employees on open joint interest billing account was $2 million and $3 million at December 31, 2023 and 2022, respectively, and is included in current receivables-related parties in the accompanying financial statements.

We have made loans to certain related parties. The notes receivable outstanding were $0 million and $4 million at December 31, 2023 and 2022, respectively. In addition, we have paid costs subject to reimbursement on behalf of Autry C. Stephens. As of December 31, 2023 and 2022, the Company had approximately $1 million and $1 million, respectively, in receivables due from Autry C. Stephens. These notes receivable and payments made on behalf of Autry C. Stephens are recorded in related parties of other non-current assets on the consolidated balance sheet.

The Company is permitted to make distributions to members under certain conditions. For the years ended December 31, 2023, 2022 and 2021, the Company made $2,522 million, $1,215 million and $0 million, respectively, in distributions to its members. See Note M - Members' Equity for additional discussion.

NOTE D – OIL AND NATURAL GAS PROPERTIES, OTHER PROPERTY AND EQUIPMENT AND LEASE INFORMATION

The following is a summary of oil and natural gas properties and other property and equipment and the related accumulated depletion and depreciation for the years ended December 31, 2023 and 2022, respectively (dollars in millions):

	As of December 31, 2023			
	Oil and Gas Operations	**Oilfield Service Companies**	**Pipeline Subsidiaries**	**Total**
Oil and natural gas property and equipment				
Proved properties	$ 15,314	$ —	$ —	$ 15,314
Unproved properties	176	—	—	176
Accumulated depletion and impairment	(6,573)	—	—	(6,573)
Oil and natural gas property and equipment, net	$ 8,917	$ —	$ —	$ 8,917
Buildings and land	$ 97	$ 46	$ —	$ 143
Automobiles and light trucks	35	12	—	47
Service company, pipeline and other equipment	40	595	6	641
	172	653	6	831
Accumulated depreciation	(46)	(208)	(6)	(260)
Other property and equipment, net	$ 126	$ 445	$ —	$ 571

	As of December 31, 2022			
	Oil and Gas Operations	Oilfield Service Companies	Pipeline Subsidiaries	Total
Oil and natural gas property and equipment				
Proved properties	$ 13,681	$ —	$ —	$ 13,681
Unproved properties	144	—	—	144
Accumulated depletion and impairment	(7,062)	—	—	(7,062)
Oil and natural gas property and equipment, net	$ 6,763	$ —	$ —	$ 6,763
Buildings and land	$ 85	$ 39	$ —	$ 124
Automobiles and light trucks	27	12	—	39
Service company, pipeline and other equipment	27	439	6	472
	139	490	6	635
Accumulated depreciation	(39)	(161)	(6)	(206)
Other property and equipment, net	$ 100	$ 329	$ —	$ 429

The Company received $7 million and $4 million from sale of oil and natural gas properties for the years ended December 31, 2023 and 2022, respectively. Under the full cost method of accounting, sales of proved and unproved properties are accounted for as an adjustment of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas, in which case the gain or loss is recognized in income. Generally, a significant alteration is not expected to occur for sales of less than 25% of total proved reserves.

The following table provides the components of our depletion, depreciation, amortization and accretion expense for the years ended December 31, 2023, 2022 and 2021, respectively (figures in millions, except per BOE amounts):

	Years Ended December 31,					
	2023		2022		2021	
	Amount	Per BOE	Amount	Per BOE	Amount	Per BOE
Depletion of proved oil and natural gas properties	$ 1,036	$ 8.40	$ 719	$ 7.06	$ 515	$ 6.89
Depreciation of other property and equipment	65		54		46	
Accretion of asset retirement obligations	16		16		14	
Total depletion, depreciation, amortization and accretion expense	$ 1,117		$ 789		$ 575	

Leases

A lease provides the lessee the right to control the use of an identified asset for a period of time in exchange for consideration. Operating lease right-of-use assets and finance lease right-of-use assets (collectively “ROU Assets”) represent the Company’s right to use an underlying asset for the lease term. Operating lease liabilities and finance lease liabilities (collectively, “Lease Liabilities”) represent the Company’s obligation to make lease payments arising from the lease. The Company determines if an arrangement is a lease at inception. ROU Assets and Lease Liabilities are recognized at the lease commencement date based on the present value of lease payments over the lease term. The Company excludes short-term leases having initial terms of 12-months or less from ROU Assets and Lease Liabilities and recognizes rent expense on a straight-line basis over the lease term. In addition, the Company has leases, primarily related to drilling rig commitments, that extend for approximately two years beginning in December of 2023. As a result, the Company has recorded ROU Asset and ROU Liabilities associated with the long-term contracts.

The Company has leases for its office spaces and certain equipment. Most operating leases contain renewal options that provide for rent increases based on prevailing market conditions. The Company has lease extension terms for our office spaces that have either been extended or are likely to be extended. The terms used to calculate the ROU Assets and Lease Liabilities for these properties include the renewal options that the Company is reasonably certain to exercise.

The discount rate used to determine the commencement date present value of lease payments is the interest rate implicit in the lease, or when that is not readily determinable, the Company utilizes its secured borrowing rate. ROU Assets include any lease payments required to be made prior to commencement and exclude lease incentives. Both ROU Assets and Lease Liabilities exclude variable payments not based on an index or rate, which are treated as period costs. The Company's lease agreements do not contain significant residual value guarantees, restrictions or covenants.

Total short-term operating lease costs with terms of less than 12-months were approximately $168 million and $118 million for the year ended December 31, 2023 and 2022, respectively. Maturities of Lease Liabilities as of December 31, 2023 are as follows (dollars in millions):

	Operating Leases
2024	$ 20
2025	18
2026	—
2027	—
2028	—
Thereafter	$ 38

The component of lease costs related to short-term drilling costs, including amounts recoverable from joint operating partners, are as follows (dollars in millions):

	Years ended December 31,	
	2023	2022
Short-term lease cost[(a)]	$ 167	$ 118

(a) Represents costs associated with short-term leases (those with a contractual term of 12-months or less) that are not included in the consolidated balance sheet.

Cash flow information related to lease is as follows (dollars in millions):

	Year Ended December 31,	
	2023	2022
Operating cash flows:		
Cash payments for operating, short-term leases	$ 1	$ —
Investing cash flows:		
Cash payments for operating, short-term leases[(a)]	$ 167	$ 118

(a) Represents costs associated with drilling operations that are capitalized as additions to oil and natural gas properties.

NOTE E – LONG-TERM DEBT

The following table provides the carrying value and fair value of the Company's financial debt instruments for the years ended December 31, 2023 and 2022, respectively (dollars in millions):

	December 31, 2023		December 31, 2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
5.750% Senior Notes due 2028	$ 907	$ 911	$ 978	$ 936
Premium on 5.750% Senior Notes due 2028	10	—	13	—
Total debt	917	911	991	936
Deferred debt costs	(4)	—	(6)	—
Long-term debt, net of deferred debt costs	$ 913	$ 911	$ 985	$ 936

The fair value of the Company's consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

Revolving Credit Facility

As of December 31, 2023 and 2022, the Company had no advances outstanding under its revolving credit facility. As of December 31, 2023, the borrowing base under our revolving credit facility was $5,000 million, and we had elected commitments of $1,500 million, with no advances outstanding and $2 million of letters of credit issued and outstanding, resulting in $1,498 million in available borrowing capacity.

In October 2023, as part of the Company's semi-annual borrowing base redetermination, the Company's lenders reaffirmed the borrowing base at $5,000 million and the Company elected to keep commitments unchanged at $1,500 million. Additionally, the Company entered into an amendment under its revolving credit facility to allow for the reorganization described in Note A - Organization and Summary of Significant Accounting Policies. In May 2023, the Company entered into an amendment under its revolving credit facility to update the definition of EBITDA for qualified acquisitions and divestitures, increase the amount governing Events of Default related to Cross Default, Judgment and ERISA to $125 million and made other minor amendments.

On February 16, 2022, the Company entered into a new senior secured revolving credit facility that matures on March 12, 2025. PNC Bank, N.A. is the new administrative agent and availability under the revolving credit facility is currently subject to a borrowing base of $5,000 million, and elected commitments remain unchanged at $1,500 million. In addition to extending the maturity date from March 12, 2023 to March 12, 2025, the new senior secured revolving credit facility (1) increased the limitations on excess cash balances, if amounts drawn on the revolving credit facility are outstanding, to the greater of (i) $150 million and (ii) 10% of elected commitments, and (2) provides for the release of collateral, as well as adjustment to utilization pricing margins if the Company is rated as investment grade by two out of the three major rating agencies (Moody’s, S&P or Fitch), referred to as an “Investment Grade Period.”

The revolving credit facility bears interest, at our option, based on Adjusted Term SOFR or the Base Rate, plus a margin. The following margins for advances are only applicable during any time other than the Investment Grade Period. SOFR advances bear interest at the SOFR for the applicable period plus a margin of 175 basis points to 275 basis points based on utilizations. Base Rate advances bear an interest rate at the prime rate (8.50 percent as of December 31, 2023) plus a margin of 75 basis points to 175 basis points based on our utilization of the facility.

During the Investment Grade Period, SOFR advances bear an interest rate at the SOFR for the applicable period plus a margin of 125 basis points to 187.5 basis points determined by reference to the Credit Rating applicable on such day. Base Rate advances bear an interest rate at the prime rate plus a margin of 25 basis points to 87.5 basis points determined by reference to the Credit Rating applicable on such day. We pay commitment fees ranging from 37.5 basis points to 50 basis points dependent on utilization and ranging from 15 basis points to 27.5 basis points during an Investment Grade Period.

Distributions may be made by the borrower to purchase its equity interests from its members and to its members for any purposes and fund loans to Autry C. Stephens or other members evidenced by a note containing current market provisions if the following conditions are met: no default exists, there is at least 20% of availability under the senior credit facility, and the ratio of Net Funded Debt to Adjusted EBITDA calculated on a pro forma basis is less than 3.0 to 1.0. The revolving credit facility also allows cash distributions to the members in (a) an aggregate amount of $5.5 million per year, plus (b) an amount to cover the actual income tax liabilities of the members up to 35% (or such higher percentage if the combined U.S. federal and applicable state tax rate is higher) of the quarterly taxable income of the borrower; provided, however, that immediately before and after giving effect thereto no (i) default or event of default or (ii) borrowing base deficiency or requirement to make any mandatory prepayment of principal shall exist.

Our revolving credit facility has numerous affirmative covenants. The revolving credit facility required covenants are as follows, (i) Minimum Current Ratio of 1.00 to 1.00 calculated as a ratio of Current Assets to Current Liabilities on a quarterly basis. This ratio stood at 2.16 to 1.00 at December 31, 2023, and (ii) Maximum Net Funded Debt to Adjusted EBITDA ratio of 3.50 to 1.00 determined quarterly based on the ending net funded debt of that quarter divided by the previous four quarters’ Adjusted EBITDA. This ratio stood at 0.04 to 1.00 at December 31, 2023, and we were in compliance with all financial covenants under our revolving credit facility as of December 31, 2023. The lenders may accelerate all of the indebtedness under our revolving credit facility upon the occurrence and during the continuance of any event of default. The revolving credit facility governing our revolving credit facility contains customary events of default, including non-payment and breach of covenants. With certain specified exceptions, the terms and provisions of our revolving credit facility generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Senior Notes

At December 31, 2023 and 2022, the Company had $907 million and $978 million, respectively, in outstanding 2028 Senior Notes. During 2023, the Company entered into open market repurchases of its outstanding 2028 Senior Notes. As a result, the Company paid $71 million that included principal, accrued interest payable and discount amounts due as of the respective repurchase dates. In addition, the Company recorded a net gain on repurchases of $0.4 million comprised of discounts paid to repurchase the 2028 Senior Notes, unamortized deferred loan cost and unamortized premiums.

In December 2022, the Company entered into open market repurchases of its outstanding 2028 Senior Notes. As a result, the Company paid $22 million that included principal, accrued interest payable and discount amounts due as of the respective repurchase dates. In addition, the Company recorded a net gain on repurchases of $1 million comprised of discounts paid to repurchase the 2028 Senior Notes, unamortized deferred loan costs and unamortized premiums.

On July 5, 2022, the Partnership and its wholly owned subsidiary, EER Finance, Inc., announced the redemption of $600 million in aggregate principal amount, representing all of the aggregate principal amount then outstanding, of the 2025 Senior Notes on July 15, 2022, the redemption dates for the Senior Notes. The redemption price for the 2025 Senior Notes was equal to 103.313% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date in accordance with the terms of the 2025 Senior Notes and the indenture under which the 2025 Senior Notes were issued. Interest on the 2025 Senior Notes ceased to accrue on and after the redemption date. On July 15, 2022, the Company paid $640 million to redeem all of the 2025 Senior Notes then outstanding, which included $600 million in aggregate principal amount, $20 million in redemption premiums and $20 million in accrued and unpaid interest. In connection with the redemption of the 2025 Senior Notes, the Company recognized a loss on redemption of debt of $25 million during the year ended December 31, 2022. The indenture governing the 2025 Senior Notes was formally discharged on October 13, 2022.

On October 14, 2021, the redemption date of the 2026 Senior Notes, we redeemed $500 million in aggregate principal amount, representing all of the aggregate principal amount then outstanding, of the 2026 Senior Notes. The redemption price for the 2026 Senior Notes was equal to 104.125% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date in accordance with the terms of the 2026 Senior Notes and the indenture under which the 2026 Senior Notes were issued. Interest on the 2026 Senior Notes ceased to accrue on and after the redemption date. The redemption of the entire aggregate principal amount then outstanding, of the 2026 Senior Notes closed on October 14, 2021, and the Company paid a redemption price of $526 million which included $500 million in aggregate principal amount, $5 million in accrued interest payable and $21 million in premiums. In connection with such redemption, the Company recognized a loss on redemption of debt of $25 million which includes $21 million in redemption premiums and $4 million unamortized deferred loan costs.

On or after January 30, 2023 we may on any one or more occasion redeem all or part of the 2028 Senior Notes, upon notice as provided in the indenture, at the redemption prices (expressed as a percentage of principal amount) set forth below, plus accrued and unpaid interest, if any, on the notes redeemed, to the applicable date of redemption, if redeemed during the twelve-month period beginning January 30 of the years indicated below, subject to the rights of holders of the notes on the relevant record date to receive interest on the relevant interest payment date:

Year	2028 Senior Notes Redemption Prices
2024	101.916%
2025	101.437%
2026	100.000%
2027	100.000%
2028	100.000%

Maturities of debt at December 31, 2023 were as follows (dollars in millions):

Period Ending December 31,	
2024	$ —
2025	—
2026	—
2027	—
2028	907
	$ 907

Interest Income (Expense), net

The following amounts have been incurred and charged to interest income (expense), net for the years ended December 31, 2023, 2022 and 2021 (dollars in millions):

	2023	2022	2021
Cash payments for interest	$ (63)	$ (104)	$ (140)
Amortization of issuance premium	2	2	2
Amortization of debt issuance costs	(3)	(4)	(5)
Net change in accruals	2	18	16
Total	(62)	(88)	(127)
Less: Interest income	90	33	1
Total interest income (expense), net	$ 28	$ (55)	$ (126)

NOTE F – SIGNIFICANT CUSTOMERS

Oil, natural gas and NGL sales to purchasers that accounted for more than ten percent of the Company’s revenue for the years ended December 31, 2023, 2022 and 2021, were as follows:

Purchaser	2023	2022	2021
Enterprise Crude Oil, LLC	16%	26%	*
Oasis Transportation and Marketing Corporation, a related party	11%	*	*
Trafigura PTE	*	13%	20%
Lion Oil Trading & Transportation, LLC	*	*	10%
Navitas Midstream Partners, LLC(1)	*	*	10%

* Purchaser did not represent 10% or more of the Company's revenues during the applicable period.
(1) Navitas Midstream Partners, LLC was acquired by Enterprise Crude Oil, LLC in February of 2022, as such, amounts applicable to Navitas have been included with Enterprise Crude Oil, LLC.

Because there are numerous other parties available to purchase the Company’s production, the Company believes that the loss of these purchasers would not materially affect its ability to sell crude oil, natural gas or NGL.

NOTE G – ASSET RETIREMENT OBLIGATIONS (“ARO”)

The changes to the ARO during the periods ended December 31, 2023, 2022 and 2021 are as follows (dollars in millions):

	December 31, 2023	December 31, 2022	December 31, 2021
ARO, beginning of year	$ 223	$ 253	$ 246
ARO additions and dispositions, net	29	(26)	5
Asset retirement costs incurred	(40)	(30)	(21)
Accretion expense	16	16	14
Revisions of estimates	32	10	9
ARO, end of year	$ 260	$ 223	$ 253

NOTE H – DERIVATIVE CONTRACTS

The Company has entered into derivative instruments to mitigate a portion of its exposure to adverse market changes of hydrocarbon prices and electricity prices. Swap instruments require a sale or buy of the hedged commodity at a fixed price and a purchase at a floating market price, as defined in each instrument, to a counterparty.

Collar instruments are the simultaneous purchase of a put option or “floor” and sale of a call option or “ceiling” for the hedged commodity at different fixed prices. Under the terms of these collar instruments, the Company generally does not pay or receive cash at inception of the instruments. Derivative instruments not designated as hedges are “marked to market” at each period end and the increases or decreases in fair values are recorded to earnings.

The following table summarizes our outstanding swaps and collars for crude oil WTI price, oil basis, natural gas Henry Hub price, Waha basis and Electric Reliability Council of Texas (“ERCOT”) - ERCOT West 345 kV hub derivative contracts as of December 31, 2023:

Derivative Contracts - Oil	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	Accounting Treatment
Derivatives not designated as hedging instruments						
Oil Price Swaps - NYMEX WTI						Mark-to-market
2024:						
Volumes (MBbl)	91	—	—	—	91	
Weighted average price per Bbl	$ 86.20	$ —	$ —	$ —	$ 86.20	
Oil Collars - NYMEX WTI						
2024:						
Volumes (MBbl)	3,640	3,185	1,104	276	8,205	
Weighted average floor price per Bbl	$ 62.25	$ 63.29	$ 66.25	$ 70.00	$ 63.45	
Weighted average ceiling price per Bbl	$ 92.76	$ 91.57	$ 88.77	$ 90.75	$ 91.69	
Oil Basis Swaps - NYMEX WTI Midland - Argus						
2024:						
Volumes (MBbl)	3,731	3,276	1,104	368	8,479	
Weighted average price per Bbl	$ 1.18	$ 1.18	$ 1.20	$ 1.21	$ 1.18	

Derivative Contracts - Natural Gas	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	Accounting Treatment
Derivatives not designated as hedging instruments						
Natural Gas Price Swaps - NYMEX Henry Hub						Mark-to-market
2024:						
Volumes (MMBtu)	910	4,550	920	920	7,300	
Weighted average price per MMBtu	$ 3.51	$ 3.26	$ 3.51	$ 3.51	$ 3.35	
Natural Gas Collars - NYMEX Henry Hub						
2024:						
Volumes (MMBtu)	10,465	4,095	2,300	2,300	19,160	
Weighted average floor price per MMBtu	$ 2.89	$ 2.94	$ 2.90	$ 2.90	$ 2.90	
Weighted average ceiling price per MMBtu	$ 4.69	$ 4.05	$ 3.93	$ 3.93	$ 4.37	
Natural Gas Basis Swaps - Waha						
2024:						
Volumes (MMBtu)	11,375	8,645	3,220	3,220	26,460	
Weighted average price per MMBtu	$ (0.67)	$ (0.83)	$ (0.70)	$ (0.70)	$ (0.73)	

Derivative Contracts - Electricity	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	Accounting Treatment
Derivatives designated as hedging instruments						
Electricity - Electric Reliability Council of Texas (“ERCOT”) - ERCOT West 345 kV Hub						Cash flow hedges
2024:						
Volumes (MWh)	—	152,880	154,560	154,560	462,000	
Weighted average price per MWh	$ —	$ 40.85	$ 40.85	$ 40.85	$ 40.85	
2025:						
Volumes (MWh)	151,200	131,040	132,480	132,480	547,200	
Weighted average price per MWh	$ 40.85	$ 40.30	$ 40.30	$ 40.30	$ 40.45	
2026:						
Volumes (MWh)	129,600	—	—	—	129,600	
Weighted average price per MWh	$ 40.30	$ —	$ —	$ —	$ 40.30	

Derivative Gains and Losses

Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity index prices as compared to the contracted prices and the monthly settlements (if any) of the instruments. Certain of our hedge contracts have been designated as cash flow hedging instruments and as a result, the change in the fair value is reported in other comprehensive income (loss) and is reclassified to earnings when the forecasted transaction affects earnings. In addition, we have elected to not designate certain of our derivatives as hedging instruments for accounting purposes and, therefore, we do not apply hedge accounting treatment to those derivatives instruments. Consequently, changes in the fair value of our derivative instruments not designated as hedges and cash settlements on the instruments are included as a component of operating costs and expenses as either a net gain or loss on derivative instruments. Cash settlements of our contracts are included in cash flows from operating activities in our statement of cash flows.

The following table sets forth the gain (loss) on derivatives for the periods presented (dollars in millions):

	Years End December 31,		
	2023	2022	2021
Gain (loss) on derivative instruments, net			
Oil contracts	$ 24	$ (350)	$ (629)
Natural gas contracts	2	(49)	4
Total	26	(399)	(625)

The following tables represents our net cash receipts from (payments on) derivatives for the periods presented (dollars in millions):

	Years End December 31,		
	2023	2022	2021
Cash receipts (payments) on derivative instruments, net:			
Oil contracts	10	(530)	(557)
Natural gas contracts	(16)	(45)	—
	(6)	(575)	(557)

The following table presents the effect of our derivative instruments designated as cash flow hedges on our Consolidated Statements of Operations and Comprehensive Income for the periods presented.

	Change in Value Recognized in Other Comprehensive Gain (Loss) on Derivatives		
	For the Years Ended December 31,		
Derivative in Cash Flow Hedging Relationships	2023	2022	2021
Commodity derivatives - Electricity	$ 14	$ (1)	$ —
Total	$ 14	$ (1)	$ —

Derivative Fair Value

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs and are subject to enforceable master netting arrangements, which allow us to offset recognized asset and liability fair value amounts on contracts with the same counterparty. Our accounting policy is to not offset asset and liability positions in our balance sheets. The following tables present the amounts and classifications of our derivative assets and liabilities as of December 31, 2023 and 2022, as well as the effect of netting arrangements on our recognized derivative asset and liability amounts (dollars in millions):

	As of December 31, 2023			
	Current		Noncurrent	
	Assets	Liabilities	Assets	Liabilities
Crude oil contracts	$ 20	$ 6	$ —	$ —
Natural gas contracts	20	2	—	—
Electricity price swaps	6	1	9	1
Total gross amount presented in the balance sheet	$ 46	$ 9	$ 9	$ 1
Less: gross amount offset in the balance sheet	—	—	—	—
Net amounts	$ 46	$ 9	$ 9	$ 1

	December 31, 2022	
	Noncurrent	
	Assets	Liabilities
Electricity price swaps	4	5
Total gross amount presented in the balance sheet	$ 4	$ 5
Less: gross amount offset in the balance sheet	—	—
Net amounts	$ 4	$ 5

Accumulated Other Comprehensive Income (loss)

Accumulated other comprehensive income (loss) reflects cumulative gain or loss on derivative instruments designated and qualified as a cash flow hedges from inception less gains or losses previously reclassified from accumulated other comprehensive income (loss) into earnings. Gain or loss amounts related to cash flow hedges recorded in accumulated other comprehensive income (loss) are reclassified to earnings in the same period(s) in which the underlying hedge forecasted transactions affect earnings. If it becomes probable that a forecasted transaction will not occur, the related net gain or loss in accumulated other comprehensive income (loss) is immediately reclassified into earnings. The following tables present the components of accumulated other comprehensive income (loss) as reported on the Consolidated Balance Sheet at the dates indicated:

Cash Flow Hedges	Commodity Derivatives
Accumulated other comprehensive income (loss), December 31, 2022	$ (1)
Other comprehensive income (loss) for period, before reclassifications	14
Reclassification of losses (gains) to net income during period	—
Accumulated Other Comprehensive Income (loss), December 31, 2023	$ 13

NOTE I – COMMITMENTS AND CONTINGENCIES

We are a party to various routine legal proceedings, disputes and claims arising in the ordinary course of our business, including those that arise from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry, personal injury claims, title disputes, royalty disputes, contract claims, employment claims, contamination claims relating to oil and natural gas exploration and development and environmental claims, including claims involving assets previously sold to third parties and no longer part of our current operations. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on us, cannot be predicted with certainty, we believe that none of these matters, if ultimately decided adversely, will have a material adverse effect on our financial condition, results of operations and comprehensive income or cash flows. We will continue to evaluate proceedings and claims involving us on a regular basis and will establish and adjust any reserve as appropriate to reflect our assessment of the current status of the matters.

The Company's contractual obligations include long-term debt, derivative liabilities, asset retirement obligations, firm transportation commitments, purchase commitments and drilling commitments. At December 31, 2023, we had the following contractual obligations and material commitments (dollars in millions):

	Payments Due by Period				
Contractual obligations	**Total**	**1 Year or Less**	**2-3 Years**	**4-5 Years**	**More than 5 Years**
Long-term debt - principal(1)	$ 907	$ —	$ —	$ 907	$ —
Long-term debt - interest(1)	220	58	105	57	—
Derivative liabilities	10	9	1	—	—
Asset retirement obligations(2)	260	15	13	13	219
Transportation service agreement(3)	33	12	19	2	—
Purchase commitments(4)	189	189	—	—	—
Drilling and completion commitments(5)	50	38	12	—	—
Compressor commitment(6)	37	5	27	5	—
Incentive Plan Commitments(7)	74	44	30	—	—
Other commitments(8)	1	1	—	—	—
	$ 1,781	$ 371	$ 207	$ 984	$ 219

(1) The interest payment presented above includes the accrued interest payable on our long-term debt as of December 31, 2023 as well as future payments calculated using the long-term debt's fixed rates, stated maturity dates and principal amounts outstanding as of December 31, 2023. See Note E - Long-Term Debt to the consolidated financial statements for additional information regarding debt.

(2) Amounts represent costs related to expected oil and natural gas property abandonments related to proved reserves by period.

(3) The Company has a firm transportation agreement for dedicated capacity on a pipeline that connects with regional gathering systems and transports oil to the Gulf Coast. We have a long-term 22,000 Bbl per day average commitment.

(4) The Company entered into purchase agreements for Oil Country Tubular Goods ("OCTG") materials that are expected to be used for the development of the Company's oil and natural gas properties. These agreements are at fixed prices and quantities of such materials during 2024.

(5) The Company as of December 31, 2023, has entered into drilling rig and completion contracts with various third party parties in the ordinary course of business to ensure rig and frac crew availability to complete the Company's drilling and completions projects. As a result, certain of the Company's rig commitment being long-term, the Company has recognized a right-of-use assets and liabilities under ASC 842. See Note D - Oil and Natural Gas Properties, Other Property and Equipment and Lease Information for additional information related to lease. In addition, certain of these commitments are not recorded on the Company's consolidated balance sheets as a result of contracts having an initial term of 12-months or less. Future minimum commitments as of December 31, 2023 total approximately $50 million.

(6) The Company has entered into commitments for compressor rentals in the normal course of business for operating oil and natural gas properties. As a result, the Company's compressor rental commitments total $37 million. The Company's compressor rentals are subject to long-term contracts which are subject to substantive substitution rights and thus not considered a lease under Accounting Standard Codification Topic 842 ("ASC 842").

(7) The Company has awarded long-term incentives which vest over a three-year period. Accordingly, the Company has accrued amounts as discussed in Note L - Employee Incentive Plans. As of December 31, 2023, the Company has $74 million employee incentive plan commitments.

(8) Other commitments related to a two year lease of office space in Midland, Texas.

NOTE J – FAIR VALUE

The following table provides fair value measurement information for the Company's financial assets and liabilities carried at fair value as of December 31, 2023 (dollars in millions):

	Total	Fair value measurements		
	Carrying Value	**Level 1**	**Level 2**	**Level 3**
Derivative:				
Crude oil contract assets	$ 20	$ —	$ 20	$ —
Crude oil contract liabilities	$ 6	$ —	$ 6	$ —
Natural gas contract assets	$ 20	$ —	$ 20	$ —
Natural gas contract liabilities	$ 2	$ —	$ 2	$ —
Electricity price swap assets	$ 15	$ —	$ 15	$ —
Electricity price swap liabilities	$ 2	$ —	$ 2	$ —
Rabbi Trust:				
Marketable securities held in trust(1)	$ 19	$ 19	$ —	$ —

(1) The Company has selected investments held in a trust related to certain Non-Qualified Deferred Compensation Plan. These securities are classified as other noncurrent assets and other noncurrent liabilities in the consolidated balance sheets because the funds are restricted and are not available for the Company to use in its operations. See Note L - Employee Incentive Plan for additional discussion.

‘The following table provides fair value measurement information within the hierarchy for the Company’s financial assets and liabilities carried at fair value as of December 31, 2022 (dollars in millions):

	Total carrying value	Fair value measurements		
		Level 1	Level 2	Level 3
Derivatives:				
Electricity price swap assets	$ 4	$ —	$ 4	$ —
Electricity price swap liabilities	$ 5	$ —	$ 5	$ —

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and natural gas properties. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. Financial instruments which potentially subject the Company to concentrations of credit risk consist principally of cash and cash equivalents, accounts receivable and derivative financial instruments. The Company places its cash and cash equivalents with creditworthy institutions. With respect to accounts receivable, these financial instruments primarily pertain to oil, natural gas and NGL sales and joint interest billings. These receivables are due from small to large companies engaged principally in oil and natural gas activities. Ongoing credit evaluations are performed. Payment terms are on a short-term basis and in accordance with industry practices.

NOTE K – EMPLOYEE BENEFIT PLANS

The Company’s qualified 401(k) profit sharing plan is the Endeavor Parent, LLC 401(k) Plan, which is open to employees of the Company. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) Plan accounts, subject to plan limits and those set by the Internal Revenue Service. The Company matches employee contributions 100% for each dollar (subject to a maximum) contributed up to 8% of an employee’s base salary. Total contributions made by the Company were $8 million and $7 million for the years ended December 31, 2023 and 2022, respectively.

NOTE L – EMPLOYEE INCENTIVE PLANS

The Company maintains a short-term incentive plan for eligible employees. The bonuses are payable under the plan through cash awards based on the financial achievements of the Company coupled with individual performance objectives each calendar year. As of December 31, 2023 and 2022, the Company had accrued $32 million and $22 million, respectively, for the short-term incentive plan.

The Company maintains a long-term incentive plan which provides for cash awards to eligible employees which vest over a three-year period and are payable on an annual basis, contingent on continued employment. As of December 31, 2023 and 2022, the Company accrued $6 million and $5 million, respectively, for the long-term incentive.

The Company maintains a Phantom Unit Plan which provides for grants of phantom unit awards to certain eligible employees. The awards vest over a three-year period, contingent on continued employment, and provide for a cash payment equal to the unit value (calculated based upon the annual value of the Company's proved reserves) multiplied by the number of phantom units subject to each award upon vesting, or under a change of control, in certain cases. At December 31, 2023 and 2022, 26,969 units and 39,344 units remain outstanding and unvested, respectively. As of December 31, 2023 and 2022, the Company had accrued $33 million and $55 million, respectively, related to these agreements.

The Company offers a Non-Qualified Deferred Compensation Plan (“NQDC Plan”) to a select group of our management and highly compensated employees. The NQDC Plan provides participants the opportunity to defer payment of certain compensation as defined in the NQDC Plan. As of December 31, 2023, the NQDC Plan obligations were $19 million and were included in other long-term liabilities in the consolidated balance sheets. The assets held by the plan's Trust (as defined below) are included in other noncurrent assets in the consolidated balance sheets. The NQDC Plan is managed by a third-party institution, and the deferred compensation and investment earnings are held as Company assets in a trust (the “Trust”). The assets in the Trust are restricted unless the Company becomes insolvent, in which case the Trust assets are subject to the claims of the Company's creditors.

NOTE M – MEMEBERS' EQUITY

During the year ended December 31, 2023, the Company made distributions to the members of $2,522 million. The distribution were partially a result of the Company contemplating its conversion from a S-Corporation to a C-Corporation, as more fully described in Note N - Income Taxes.

December 31, 2022 and 2021, the Company made distributions to the members of $1,215 million and $0 million, respectively. Contemporaneously with the distributions made during 2022, the Company and Stephens Family Trust entered into an agreement to settle the Stephens Family Trust Note receivable. As a result, the Company retained $15 million, in lieu of distributions, to fully satisfy any and all amounts due to the Company for the Stephen Family Trust Note.

NOTE N – INCOME TAXES

As an S-corporation, the Company is not subject to U.S. federal income taxes and most state taxes. However, the Company does conduct certain activities through a corporate subsidiary which is subject to a minimal amount of U.S. federal and state income taxes. The Company's components of the U.S. federal and state income tax expense (benefit) are summarized below for the periods indicated (dollars in millions):

	Years Ended December 31,		
	2023	2022	2021
Current:			
Federal	$ —	$ —	$ —
State	(5)	22	—
	$ (5)	$ 22	$ —
Deferred:			
Federal	$ —	$ —	$ —
State	17	14	6
	$ 17	$ 14	$ 6
Income tax expense (benefit)	$ 12	$ 36	$ 6

Historically, our effective tax rate has differed from the statutory rate primarily due to Company earnings that are not subject to U.S. federal income taxes and most state income taxes. During the year ended December 31, 2023, the Company made payments of approximately $16 million in settlement of state taxes due for 2022.

As of December 31, 2023, the Company amended certain Texas returns to assert the tax position on certain drilling and experimental expenditures related to horizontal drilling and completion innovations, which reduced the Company's effective tax rate as a result of the Company recognizing $12 million, net of allowance of $3 million, in research and development tax credit during 2023. The Company anticipates that all research and development tax credits will be used on the 2023 Texas Franchise tax return, as such, no amounts have been included as deferred tax assets. We have recorded the amounts related to the Texas state credits noting that uncertainty exists with the total amount of recovery and time of such recovery. As of December 31, 2023 and 2022, the Company had $2 million and $23 million, respectively, in taxes payable, net of research and development tax credits. A reconciliation of income tax expense at the U.S. statutory rate to the income tax expense attributable to continuing operations for the periods indicated (dollars in millions):

	Years Ended December 31,		
	2023	2022	2021
Income before income taxes	$ 3,996	$ 4,791	$ 1,648
Member income not subject to U.S. federal income taxes	3,996	4,791	1,648
Income before income tax subject to U.S. federal income taxes	$ —	$ —	$ —
Federal statutory income tax rate	21%	21%	21%
Provision for U.S. federal income taxes at the statutory rate	$ —	$ —	$ —
Current state income tax provision	7	22	—
Current research and development tax credits	(15)	—	—
Change in valuation allowance	3	—	—

	Years Ended December 31,		
	2023	2022	2021
Deferred state income tax provision	17	14	6
Income tax provision	$ 12	$ 36	$ 6
Effective income tax rate	0%	1%	0%

Deferred Texas franchise taxes result from the temporary difference between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal component of the deferred tax assets (liabilities) as follows (dollars in millions):

	As of December 31,	
	2023	2022
Deferred income tax liabilities:		
Oil and natural gas properties	$ (55)	$ (39)
Unrealized gain (loss) on derivatives	(2)	(1)
Total deferred income tax liabilities	$ (57)	$ (40)
Net deferred income taxes	$ (57)	$ (40)

Endeavor's Board of Managers elected to convert the Company from an S-Corporation to a C-Corporation effective January 1, 2024. The owners of the issued and outstanding equity interests of Endeavor Parent, LLC consented to the tax conversion. See Item 1. Our Business for a summary of the Company's organizational restructure including tax structure following the conversion.

Endeavor revoked its S-Corporation tax status effective January 1, 2024. The Company will be taxed for federal income tax purposes as a C-Corporation after this date.

As an S-Corporation, the Company's income and deductions were passed through to its owners and taxed on their individual returns. The Company paid no federal income tax and did not maintain federal income tax asset and liability accounts. As a C-Corporation, the Company will be subject to federal corporate income tax rules and GAAP requirements for income tax accounting. Federal income tax assets, liabilities and expenses will now be recorded on the Company's financial statements. In accordance with GAAP, the Company will set up a deferred tax liability for the difference between the book basis of its assets and the tax basis as determined as of January 1, 2024. This deferred liability has not been finalized but is estimated to be between $1.5 billion and $1.7 billion dollars. The offset to this liability will be recognized on the income statement.

NOTE O – SUBSEQUENT EVENTS

As a result of the conversion from an S-Corporation to a C-Corporation for U.S. federal income tax purposes, as discussed in Note N - Income Taxes, the Company anticipates that it will recognize a deferred tax liability and corresponding deferred tax expense in the range of $1.5 billion – $1.7 billion on January 1, 2024. The tax conversion is expected to materially impact the Company's future results of operations and comprehensive income and accrued tax liabilities.

During January 2024, the Company entered into an agreement to acquire deep rights in approximately 10,980 net acres in the Midland County, Texas for approximately $71 million. In addition, the Company, through its wholly owned subsidiary 1979 Royalties, LP, entered into an agreement to acquire 7,182 net royalty acres in the Midland and Delaware Basins from an unrelated third party for an aggregate purchase price of $62 million (subject to customary closing and post-closing adjustments).

On February 11, 2024, we entered into the Diamondback Merger an Agreement and Plan of Merger (the "Merger Agreement") with Diamondback pursuant to which, among other things, the Company will merge with and into a wholly owned subsidiary of Diamondback (the "Diamondback Merger"). As a result of the Diamondback Merger, Diamondback will acquire 100% of the issued and outstanding equity interests of the Endeavor Parent, being the entity that owns all the issued and outstanding equity interests of the Endeavor Energy Resources, L.P. Subject to the terms and conditions of the Merger Agreement, all the Company's equity interests will be converted into the right to receive, in the aggregate, (i) cash consideration consisting of a base cash amount of $8.0 billion, subject to adjustments and (ii) approximately 117.3 million shares of Diamondback common stock.

The transaction was unanimously approved by the board of directors of Diamondback and the Company has all necessary approvals. The Merger Agreement requires that the Company use commercially reasonable efforts to conduct the Company's business in the ordinary course and consistent with past practices. Accordingly, the Merger Agreement contains certain interim operating covenants which limit the Company's ability to take certain material actions without Diamondback's written consent (which consent shall not be unreasonably withheld, conditioned or delayed), including, without limitation, making capital expenditures in excess of 115% of the Company's approved capital budget, selling a material portion of the Company's assets, amending or changing the organizational documents of the Company, or entering into certain material contracts. The Diamondback Merger is expected to close in the fourth quarter of 2024, subject to the satisfaction of customary closing conditions, including the requisite Diamondback shareholder vote and customary regulatory approvals.

Management has evaluated subsequent events through March 13, 2024, the date the consolidated financial statements were available to be issued.

SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES (UNAUDITED)

Oil, Natural Gas and NGL Reserve Information

The Company's reserve information presented herein was prepared by independent petroleum engineering consultants as of December 31, 2023, 2022 and 2021. The reserve information is subject to many inherent uncertainties in estimating proved reserve quantities, projecting future production rates and timing of development expenditures. Accordingly, reserve estimates are subject to change as future information becomes available.

The following information represents estimates of the Company's proved reserves as of December 31, 2023, 2022 and 2021, which have been prepared under SEC rules. These rules require companies to prepare their reserve estimates consistent with generally accepted reserve definitions and pricing.

	2023				2022				2021			
	Oil (MBbl)	Natural Gas (MMcf)	NGL (MBbl)	MBOE(a)	Oil (MBbl)	Natural Gas (MMcf)	NGL (MBbl)	MBOE(a)	Oil (MBbl)	Natural Gas (MMcf)	NGL (MBbl)	MBOE(a)
Proved developed	379,329	1,573,030	312,386	953,887	369,003	1,365,437	276,068	872,644	321,053	941,717	183,064	661,070
Proved undeveloped	271,704	812,992	162,750	569,953	314,370	864,387	182,639	641,074	317,362	802,384	161,049	612,142
Total proved	651,033	2,386,022	475,136	1,523,840	683,373	2,229,824	458,707	1,513,718	638,415	1,744,101	344,113	1,273,212

(a) Mcf of natural gas has been converted to barrel of oil equivalents using a conversion factor of 6 Mcf to each barrel.

The average spot and wellhead prices for the periods reviewed were calculated using prices equal to the unweighted arithmetic average of oil and natural gas prices as of the first-day-of-the-month for the most recent 12-months as of the balance sheet date, which are provided below. The spot prices are provided for reference only and are not used to calculate our PV-10.

	As of December 31, 2023	2022	2021
WTI Spot Price (Oil)	$ 78.21	$ 94.14	$ 66.55
Henry Hub Spot Price (Natural gas)	$ 2.64	$ 6.36	$ 3.60
Effective Wellhead Pricing:			
Oil	$ 78.14	$ 96.18	$ 65.37
Natural gas	$ 1.31	$ 4.34	$ 2.90
Natural gas liquid	$ 17.88	$ 31.94	$ 24.31

Discounted Future Net Cash Flows

In accordance with the Securities and Exchange Commission guidelines, the 2023, 2022 and 2021 estimates of the standardized measure of discounted future cash flows were determined by applying the unweighted arithmetic average first-day-of the-months price for oil and natural gas for the 12-month period from January through December (adjusted for location and quality differentials) to the estimated future production of year-end proved reserves.

Future cash inflows were reduced by the estimated future production and development costs based on period end costs to determine cash inflows of the associated proved oil and natural gas properties. Future net cash inflows were discounted using a 10% annual discount rate to arrive at the standardized measure. Future income tax expenses have not been taken into account as of December 31, 2023 as a result of future taxable income or loss being taxed directly to the members and not to the Company. Estimates for future general and administrative and interest expense have also not been considered. The standardized measure of discounted future net cash flow amounts contained in the following tabulation does not purport to represent the fair market value of oil and natural gas properties. No value has been given to unproved acreage. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs.

Future realization of oil and natural gas prices over the remaining reserve lives may vary significantly from those used. In addition, the method of valuation utilized, based on year-end costs and the use of a 10% discount rate, is not necessarily appropriate for determining fair value.

The standardized measure of discounted future net cash flows relating to proved oil, natural gas and NGL reserves as of December 31, 2023, 2022 and 2021, respectively, is as follows (dollars in millions):

	December 31, 2023		
	Proved Developed	Proved Undeveloped	Total Proved
Future cash inflows	$ 37,355	$ 25,129	$ 62,484
Future production costs	13,683	6,386	20,069
Future development costs	36	4,289	4,325
Future net cash flows	23,636	14,454	38,090
Less 10% discount to reflect timing of cash flows	9,783	7,305	17,088
Standardized measure of discounted future net cash flows	$ 13,853	$ 7,149	$ 21,002

	December 31, 2022		
	Proved Developed	Proved Undeveloped	Total Proved
Future cash inflows	$ 50,151	$ 39,899	$ 90,050
Future production costs	13,685	7,191	20,876
Future development costs	38	4,831	4,869
Future net cash flows	36,428	27,877	64,305
Less 10% discount to reflect timing of cash flows	16,911	15,358	32,269
Standardized measure of discounted future net cash flows	$ 19,517	$ 12,519	$ 32,036

	December 31, 2021		
	Proved Developed	Proved Undeveloped	Total Proved
Future cash inflows	$ 28,093	$ 26,973	$ 55,066
Future production costs	8,417	5,622	14,039
Future development costs	65	2,888	2,953
Future net cash flows	19,611	18,463	38,074
Less 10% discount to reflect timing of cash flows	9,048	10,170	19,218
Standardized measure of discounted future net cash flows	$ 10,563	$ 8,293	$ 18,856

The following table provides information regarding changes in total estimated proved reserves for the periods presented:

Total Proved	2023 BOE (MBOE)	2022 BOE (MBOE)	2021 BOE (MBOE)
Beginning balance	1,513,718	1,273,212	837,199
Revisions	(207,332)	(171,241)	(50,107)
Extensions and discoveries	45,095	89,230	82,373
PUD additions	314,498	412,822	436,713
Property acquisitions	8,350	269	66
Divestitures	(1,222)	(4,051)	(412)
Production	(123,258)	(101,761)	(74,920)
Economic effect	(26,009)	15,238	42,300
Ending balance	1,523,840	1,513,718	1,273,212

The following table provides a roll-forward of the standardized measure of discounted future net cash flows for the years ended December 31, 2023, 2022 and 2021 (dollars in millions):

	Years Ended December 31,		
	2023	2022	2021
Beginning balance	$ 32,036	$ 18,856	$ 5,186
Revisions	(3,848)	(2,414)	2
Extensions and discoveries	934	2,694	1,720
PUD additions	3,931	7,957	5,852
Property acquisitions	129	6	1
Divestitures	(22)	(44)	(2)
Production	(2,228)	(2,939)	(1,102)
Economic effect	(9,930)	7,920	7,199
Ending balance	$ 21,002	$ 32,036	$ 18,856

Revisions

Revisions represent changes in previous reserve estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history. Total downward revisions of 207 MMBOE for 2023 are primarily comprised of 92 MMBOE downward revision of PUD reserves that are no longer on the Company's drill schedule for the next five years due to the continual refinement of our drilling programs and reallocation of capital to areas providing the greatest opportunities to improve efficiencies, recoveries, and rates of return. Revisions are also inclusive of 115 MMBOE downward as a result of technical revisions and well performance.

Extensions, discoveries and other additions

These are additions to our proved reserves that result from (i) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (ii) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. Extensions, discoveries and other additions for each of the three years reflected in the table above were primarily due to increases in proved reserves associated with our successful drilling and completion activities during the respective periods presented. Extensions and discoveries amount to 45 MMBOE additions and include 206 wells, 201 proved developed producing and 5 proved developed non-producing (“PDNP”). Of the 206 wells, 161 are non-operated wells and 45 of the wells are operated by the Company. This represents the reserves of exploratory wells drilled during 2023 and were not included as either PDNP or PUD reserves in the Company’s reserve report at December 31, 2022.

Proved undeveloped reserves

Annually, the Company reviews its PUD reserves to ensure appropriate plans exist for development of this reserve category. PUD reserves are recorded only if the Company has plans to convert these reserves into PDP reserves within five years of the date they are first recorded. Our development plans include the allocation of capital to projects included within our 2024 capital budget and, in subsequent years, the allocation of capital within our long-range business plan to convert PUD reserves to PDP reserves within this five- year period. In general, our 2024 capital budget and our long-range capital plans are primarily governed by our expectations of internally generated cash flow, borrowing availability under our revolving credit facility and corporate credit metrics. Reserve calculations at any end-of-year period are representative of our development plans at that time. Changes in commodity pricing, oilfield service costs and availability and other economic factors may lead to changes in development plans. PUD additions amount to 314 MMBOE and include 436 economic locations (168 drilled, but uncompleted) of which 291 economic locations (56 drilled, but uncompleted) were operated by Endeavor, all of which are horizontal and in the Midland Basin. At December 31, 2023, we had no reserves that remained undeveloped for more than five years.

Property acquisitions

These are additions to proved reserves resulting from the acquisition of properties during a period. We have had no significant acquisitions in the past three years.

Divestitures

These are reductions to proved reserves resulting from the disposition of properties during a period.

Economic effect

Economic effect refers to changes in reserve estimates resulting from a change in economic factors, such as hydrocarbon prices and differentials, operating costs or development costs. Given the significant volatility in commodity prices in recent years, and given the uncertainty regarding the timing, magnitude and duration of any price recovery, maintaining a strong balance sheet, ample liquidity and financial flexibility has become an increasingly important component of our long-term business strategy. In light of our strategy to preserve financial flexibility and minimize the incurrence of new debt, we maintained a disciplined spending approach in 2023 and continued to refine our capital program to focus on areas that provide the greatest opportunities to achieve operating efficiencies and cost reductions, to convert undeveloped acreage to acreage held by production and to improve hydrocarbon recoveries, cash flows and rates of return using optimized completions. Changes to prices and operating costs resulted in a net proved equivalent reserves change of 26 MMBOE. The year-end 2023 average effective prices were $78.14 per Bbl of oil, $1.31 per Mcf of natural gas and $17.88 per Bbl of NGL as compared to the year-end 2022 average effective prices of $96.18 per Bbl of oil, $4.34 per Mcf of natural gas and $31.94 per Bbl of NGL.

Qualifications of Responsible Technical Persons

The reserve estimates shown herein have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Randolph K. Green and William J. Knights. Mr. Green, a Licensed Professional Engineer in the State of Texas (No. 72951), has been practicing consulting petroleum engineering at NSAI since 1983 and has over 41 years of industry experience. He graduated from Texas Tech University with a Bachelor of Science Degree in Petroleum Engineering. Mr. Knights, a Licensed Professional Geoscientist in the State of Texas (No. 1532), has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 43 years of industry experience. He graduated from Texas Christian University with a Bachelor of Science Degree in Geology and with a Master of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

Proved Reserves Estimation Procedures

Proved oil, natural gas and NGL reserve quantities are based on estimates prepared in accordance with the SEC’s rules for reporting oil, natural gas and NGL reserves. Our reserve definitions conform with definitions of Rule 4-10(a) (1)-(32) of Regulation S-X of the SEC. All of our reserve estimates are maintained by our internal corporate reservoir engineering group, which is comprised of reservoir engineers and engineering technicians. The objectives and management of this group are separate from and independent of the exploration and production functions of the Company. The primary objective of our corporate reservoir engineering group is to maintain accurate forecasts on all properties of the Company through ongoing monitoring and timely updates of operating and economic parameters (production forecasts, prices and regional differentials, operating expenses, ownership, etc.) in accordance with guidelines established by the SEC.

Oil and Natural Gas Operations
(dollars in millions)
(unaudited)

The following table contains the direct revenues and costs information relating to our oil and natural gas exploration and production activities for the periods indicated.

	Years Ended December 31,		
	2023	2022	2021
Oil and natural gas revenues from production	$ 6,165	$ 6,985	$ 3,689
Less operating costs and income taxes			
Lease operating expense	688	569	421
Production taxes	301	351	187
Depletion	1,036	719	515
Accretion	16	16	14
Income tax expense	12	36	6
Total operating costs and income taxes	2,053	1,691	1,143
Results of operations from oil and natural gas producing activities	$ 4,112	$ 5,294	$ 2,546

March 11, 2024

Mr. Autry C. Stephens
Endeavor Energy Resources, L.P.
110 North Marienfeld Street, Suite 200
Midland, Texas 79701

Dear Mr. Stephens:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2023, to the Endeavor Energy Resources, L.P. (Endeavor) interest in certain oil and gas properties located in the United States. We completed our evaluation on or about January 29, 2024. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Endeavor. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities— Oil and Gas, except that future income taxes are excluded and, as requested, abandonment costs have not been included in our estimates of future net revenue. Definitions are presented immediately following this letter. This report has been prepared for inclusion in Endeavor's 2023 Annual Report.

We estimate the net reserves and future net revenue to the Endeavor interest in these properties, as of December 31, 2023, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	364,856.4	301,579.1	1,520,279.7	22,609,995.6	13,200,998.7
Proved Developed Non-Producing	14,473.0	10,807.5	52,749.9	1,025,353.4	652,008.3
Proved Undeveloped	271,704.1	162,750.3	812,991.6	14,454,273.5	7,148,649.5
Total Proved	651,033.5	475,136.9	2,386,021.2	38,089,622.6	21,001,656.5

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Endeavor's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Endeavor's share of production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2023. For oil and NGL volumes, the average West Texas Intermediate spot price of $78.21 per barrel is adjusted by lease for quality, transportation fees, and market differentials; for certain properties, NGL prices are negative after adjustments. For gas volumes, the average Henry Hub spot price of $2.637 per MMBTU is adjusted by lease for energy content, transportation fees, and market differentials; for certain properties, gas prices are negative after adjustments. When applicable, gas prices have been adjusted to include the value for NGL. For certain Midland Basin properties, the fees associated with Endeavor's Gray Oak Pipeline, LLC transportation contract, which is in place through March 31, 2027, are included as a deduction to oil prices. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $78.14 per barrel of oil, $17.88 per barrel of NGL, and $1.306 per MCF of gas.

Operating costs used in this report are based on operating expense records of Endeavor. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs, per-well workover costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Endeavor are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Endeavor and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Endeavor interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Endeavor receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Endeavor, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Endeavor, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Randolph K. Green, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1983 and has over 41 years of industry experience. William J. Knights, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 43 years of industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chief Executive Officer

By: /s/ Randolph K. Green
Randolph K. Green, P.E. 72951
Senior Vice President

Date Signed: March 11, 2024

By: /s/ William J. Knights
William J. Knights, P.G. 1532
Vice President

Date Signed: March 11, 2024

RKG:CLH

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an “analogous reservoir” refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *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.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory- type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or “G&G” costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (“oil and gas”) in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *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.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

- *a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
- *b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

- *a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
- *b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
- *c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
- *d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
- *e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
- *f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *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.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);
- The company's historical record at completing development of comparable long-term projects;
- The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;
- The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and
- The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS OF ENDEAVOR

Recent developments

Endeavor Parent, LLC's (together with its subsidiaries, "Endeavor") board of managers voted to convert Endeavor's U.S. federal income tax status from an S-Corporation to a C-Corporation effective January 1, 2024. The members of Endeavor also consented to the conversion.

Following Endeavor's conversion to a C-Corporation, Endeavor will be recording financial activity with regards to U.S. federal income taxes. As of January 1, 2024, as a result of this conversion, Endeavor will be responsible for U.S. federal income taxes and will record deferred tax liabilities for the tax effects of any temporary differences that exist as of that date. Due to the timing differences in the book basis and tax basis of Endeavor's assets on January 1, 2024, the date of conversion, Endeavor expects to record a noncash deferred tax charge on its income statement and associated deferred taxes on its balance sheet in the range of $1.5 billion to $1.7 billion. Endeavor will also begin recording a U.S. federal income tax provision in its results of operations and comprehensive income during the first quarter of 2024 in connection with 2024 taxable activity.

On February 11, 2024, Endeavor entered into an Agreement and Plan of Merger (the "Merger Agreement") with Diamondback Energy, Inc. ("Diamondback") pursuant to which, among other things, Endeavor will merge with and into a wholly owned subsidiary of Diamondback (the "Merger"). As a result of the Merger, Diamondback will acquire 100% of the issued and outstanding equity interests of Endeavor, being the entity that owns all the issued and outstanding equity interests of Endeavor Energy Resources, L.P. ("Endeavor LP"). Subject to the terms and conditions of the Merger Agreement, all of Endeavor's equity interests will be converted into the right to receive, in the aggregate, (i) cash consideration consisting of a base cash amount of $8.0 billion, subject to adjustments and (ii) approximately 117.3 million shares of Diamondback common stock. The transaction was unanimously approved by the board of directors of Diamondback, and Endeavor has all necessary approvals. The Merger Agreement requires that Endeavor uses commercially reasonable efforts to conduct Endeavor's business in the ordinary course and consistent with past practices. Accordingly, the Merger Agreement contains certain interim operating covenants which limit Endeavor's ability to take certain material actions without Diamondback's written consent (which consent shall not be unreasonably withheld, conditioned or delayed), including, without limitation, making capital expenditures in excess of 115% of Endeavor's approved capital budget, selling a material portion of Endeavor's assets, amending or changing the organizational documents of Endeavor, or entering into certain material contracts. The Merger is expected to close in the fourth quarter of 2024, subject to the satisfaction of customary closing conditions, including the requisite Diamondback shareholder vote and customary regulatory approvals.

Overview

Endeavor is a privately held independent oil and natural gas company engaged in oil and liquids-rich natural gas acquisition, development, exploitation and exploration in the Permian Basin. Endeavor seeks to develop and explore for reserves through development and exploratory drilling activities on its multi-decade, low cost, high return project inventory and through opportunistic acquisitions that meet its strategic and financial objectives.

The majority of Endeavor's acreage is located within the Spraberry Trend field of the Midland Basin in Texas covering six counties, or approximately 2,500 square miles, almost entirely on state and private lands. Based on the returns Endeavor has generated through its drilling plan to date, the number of undrilled locations in its drilling plan, its observation of the activity and results of other operators in this area, Endeavor believes the Spraberry Trend represents one of the premier oil, natural gas and NGL development opportunities in North America.

Most of Endeavor's leases are held by continuous production past the primary term and allow Endeavor to drill new horizontal wells as limited by regulatory policies. Typically, oil and natural gas lease agreements covering Endeavor's properties provide for the payment of royalties to the mineral owner for oil, natural gas and NGL produced from any wells drilled on the leased premises.

During 2023, 88% of Endeavor's revenues (excluding realized and unrealized gains on commodity hedging financial derivatives) were derived from the production of oil. As of December 31, 2023, Endeavor's total proved reserves had a PV-10 of approximately $21 billion, and its proved developed reserves had a PV-10 of approximately $14 billion. During 2023, Endeavor generated $6,187 million of total revenues, $3,984 million of net income and $5,044 million of Adjusted EBITDA on average daily production of 337.7 MBOE per day.

During the year ended December 31, 2023, Endeavor's capital expenditures totaled $3,315 million, and Endeavor exited the year with 12 horizontal operated drilling rigs and spudded 302 gross operated horizontal wells in the State of Texas. Endeavor anticipates that total capital expenditures, excluding unbudgeted acquisitions, for 2024 will range from $2,500 million to $2,600 million which includes operated and non-operated drilling and completion activities, leasehold costs, and other property and equipment, which primarily includes water disposal facilities, electrical facilities and other infrastructure. From time to time, Endeavor evaluates strategic property and mineral acquisitions, but none are included in Endeavor's capital budget. Endeavor currently believes that it will be able to fund its 2024 capital budget predominantly with cash flows from operations, cash on hand and, if needed, borrowings under its revolving credit facility.

The following is a summary of certain 2023 operating and financial results compared to 2022:

- total daily production volumes increased 21% to 337.7 MBOE per day;
- daily oil volumes increased 15% to 191.8 MBbl per day;
- daily natural gas volumes increased 33% to 406.0 MMcf per day;
- daily NGL volumes increased 28% to 78.2 MBbl per day;
- total revenues from production activities decreased 12% to $6,165 million;
- 2023 year-end proved developed reserves were 954 MMBOE, a 9% increase, as compared to 873 MMBOE for the year end 2022;
- oil and natural gas property additions including leasehold acquisitions were $3,110 million, as compared to $2,582 million; and
- cash flow provided by operating activities decreased 5% to $4,989 million.

For 2024, Endeavor's primary business strategy will focus on:

- efficiently deploying capital to exploit Endeavor's high value leasehold acreage and make strategic mineral and leasehold acquisitions;
- enhancing cash flows and return on capital employed through improvements in project management, operating efficiencies and service division integration;
- managing the uncertainty associated with changes to the current hydrocarbon price environment, inflationary pressures and world events;
- investing in infrastructure to build out water and electrical facilities;
- maintaining a flexible capital program; and
- maintaining a strong balance sheet and a robust liquidity profile.

How Endeavor evaluates its operations

Endeavor uses a variety of financial and operational metrics to assess performance of its oil, natural gas and NGL operations, including:

- production volumes;
- lease operating expenses;
- capital expenditures and associated capital efficiency;
- net income; and
- Adjusted EBITDA.

Adjusted EBITDA is a non-GAAP financial measure. For the definition of Adjusted EBITDA and reconciliation to the closest comparable GAAP measure, please see "—Non-GAAP Financial Measures."

Factors affecting comparability of Endeavor's results of operations and comprehensive income

Endeavor's historical results of operations and comprehensive income for the periods presented may not be comparable, either to each other or to Endeavor's future results of operations and comprehensive income, primarily for the reasons described below:

- **Supply, demand, market risk, geopolitical and macroeconomic factors and their impacts on oil, natural gas and NGL prices** affect many aspects of Endeavor's business including its results of operations and comprehensive income. The average oil realized price decreased 18% during 2023 as compared to 2022. In addition, natural gas and NGL realized prices decreased by 71% and 40%, respectively, in each case, during 2023 as compared to 2022.
- **Endeavor uses commodity derivatives** to reduce the volatility of the prices it receives for a portion of its production and to partially protect cash flow and returns on invested capital from a drop in hydrocarbon prices. For the years ended December 31, 2023 and 2022, Endeavor recognized $26 million net gain and $399 million net loss, respectively, on derivative instruments.
- **Repayments and Repurchases of Senior Notes.** During the year ended December 31, 2023, Endeavor repurchased $71 million of its 5.750% senior unsecured notes due 2028 in the aggregate principal amount of $1,000 million (the "2028 Senior Notes") outstanding in a series of open market transactions.

Endeavor redeemed $600 million in aggregate principal amount, representing all of the aggregate principal amount then outstanding, of its 6.625% senior unsecured notes due 2025 in the aggregate principal amount of $600 million (the "2025 Senior Notes") on July 15, 2022. Endeavor paid a redemption price of $640 million which included $20 million of accrued interest and $20 million of premiums on redemption. Endeavor recognized a loss on redemption of debt of $25 million during the third quarter of 2022. Endeavor also repurchased $22 million of the 2028 Senior Notes outstanding in a series of open market transactions in December 2022.

The 2025 Senior Notes, the 2026 Senior Notes (as defined below) and the 2028 Senior Notes are collectively referred to as the "Senior Notes".

- **Oil, natural gas and NGL development activities.** During 2023 Endeavor completed 269 gross (255 net) operated horizontal wells. During 2023, Endeavor spent $3,110 million for drilling and completing wells and on infrastructure costs, which included $153 million for leasehold and mineral acquisitions. This compares to $2,582 million that Endeavor spent in 2022 for drilling, completion and infrastructure costs and leasehold and mineral acquisitions. During 2022 Endeavor completed 292 gross (283 net) operated horizontal wells.

Endeavor's approved capital budget for 2024 will range from $2,500 million to $2,600 million which includes operated and non-operated drilling and completion activities, leasehold costs, and other property and equipment, which primarily includes water disposal facilities, infrastructure and electrical facilities. The ultimate amount of capital that Endeavor expends may fluctuate materially based on market conditions, including service costs, availability and/or attractiveness of acquisitions and Endeavor's drilling results. From time to time, Endeavor evaluates strategic property and mineral acquisitions, but none are included in Endeavor's capital budget. During the first quarter of 2024, Endeavor closed certain unbudgeted leasehold and mineral acquisitions for an aggregate purchase price of approximately $133 million.

Financial and operating performance

Net income was $3,984 million during the year ended December 31, 2023, a $771 million (16%) decrease from net income of $4,755 million during the year ended December 31, 2022. This decrease is primarily due to lower realized oil, natural gas and NGL prices, which was partially offset by higher production levels.

Endeavor's Adjusted EBITDA, an indicator of operating performance, for the year ended December 31, 2023 was $5,044 million, a decrease of $334 million (6%) from $5,378 million during the year ended December 31, 2022.

Adjusted EBITDA performance is affected by the level of oil, natural gas and NGL prices and production. Endeavor's average wellhead realized BOE price was $50.02 per BOE during the year ended December 31, 2023, a decrease of $18.64 per BOE (27%) from $68.66 per BOE for the year ended December 31, 2022.

Total BOE production was 123,258 MBOE during the year ended December 31, 2023, an increase of 21,497 MBOE (21%) from 101,761 MBOE during the year ended December 31, 2022. The increase in production level was due to an increase in the number of operated and non-operated horizontal wells completed during the year ended December 31, 2023. The following table summarizes Endeavor's average daily production for the periods presented:

	Years Ended December 31,		
	2023	2022	2021
Oil (Bbl/d)	191,792	166,906	122,838
Natural gas (Mcf/d)	405,960	304,890	234,617
Natural gas liquid (Bbl/d)	78,243	61,075	43,319
BOE/d	337,695	278,796	205,259
Percentage Oil	57%	60%	60%

Endeavor spudded 302 gross (288 net) operated horizontal wells and completed 269 gross (255 net) operated horizontal wells in the Midland Basin during the year ended December 31, 2023. During the year ended December 31, 2022, Endeavor spudded 333 gross (313 net) operated horizontal wells and completed 292 gross (283 net) operated horizontal wells.

Lease operating expenses also affected operating performance during the year ended December 31, 2023, with $688 million incurred, a $119 million (21%) increase from the $569 million incurred during the year ended December 31, 2022. Lease operating expenses on a per BOE basis was consistent during the years ended December 31, 2023 and 2022. The increase in aggregate lease operating expense during the year ended December 31, 2023, as compared to the year ended December 31, 2022, was due to additional wells being placed on production, additional workover jobs performed and higher ad valorem costs incurred.

Source of Endeavor's Revenues

Endeavor's main sources of revenues are the sale of oil, natural gas and NGL production. Endeavor's oil, natural gas and NGL revenues do not include the effects of derivatives. Endeavor's revenues may vary significantly from period to period as a result of changes in volumes of production sold, production mix or hydrocarbon prices. Endeavor also receive revenues from operating various service company divisions. The following table presents the breakdown of Endeavor's revenues for the following periods:

	Years Ended December 31,		
	2023	2022	2021
Revenues			
Oil sales	88%	83%	75%
Natural gas and NGL sales	12%	17%	16%
Sales of purchased oil	0%	0%	9%
	100%	100%	100%

During the years ended December 31, 2023, 2022 and 2021, Endeavor's production consisted primarily of 57%, 60% and 60% oil, respectively, however, 88%, 83% and 75%, respectively, of Endeavor's total revenues during such periods were generated from the sale of oil. As a result, Endeavor's revenues are more sensitive to fluctuations in oil prices and the Midland-Cushing differentials than they are to fluctuations in natural gas and NGL prices.

Lower hydrocarbon prices may not only decrease Endeavor's revenues but may also potentially negatively impact the amount of oil, natural gas and NGL that Endeavor can produce economically. Lower oil, natural gas and NGL prices may also result in a reduction in the borrowing base under Endeavor's credit agreement, which may be redetermined at the discretion of Endeavor's lenders. See "Note E - Long-Term Debt" to the consolidated financial statements of Endeavor, which is included in Exhibit 99.1 to Diamondback's Current Report on Form 8-K in which this discussion is being filed, for additional information regarding the revolving credit facility.

ENDEAVOR PARENT, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(dollars in million)

	Years Ended December 31,		
	2023	2022	2021
Operating revenues:			
Oil sales	$ 5,452	$ 5,814	$ 3,034
Natural gas and NGL sales	713	1,171	655
Sales of purchased oil	—	2	361
Service company division revenue	22	22	14
Total operating revenues	6,187	7,009	4,064
Operating expenses:			
Lease operating expense	688	569	421
Production taxes	301	351	187
Purchased oil	—	—	361
Service company division operating expenses	21	19	12
Depletion, depreciation, amortization and accretion	1,117	789	575
Impairment of other property and equipment	—	3	—
Loss from inventory write down	1	1	—
General and administrative expense	116	114	85
(Gain) loss on sale of other assets, net	(10)	(109)	(1)
Total operating expenses	2,234	1,737	1,640
Income from operations	3,953	5,272	2,424
Other income (expense):			
Gain (loss) from derivative transactions, net	26	(399)	(625)
Loss on redemption of debt	—	(24)	(25)
Interest income (expense), net	28	(55)	(126)
Other income	(11)	(3)	—
Total other income (expense)	43	(481)	(776)
Income before taxes	3,996	4,791	1,648
Taxes:			
Current expense (benefit)	(5)	22	—
Deferred expense (benefit)	17	14	6
Net income	$ 3,984	$ 4,755	$ 1,642
Other comprehensive income (loss)			
Commodity cash flow hedging derivative instruments:			
Change in fair value of cash flow hedges	$ 14	$ (1)	$ —
Total other comprehensive net income (loss)	$ 14	$ (1)	$ —
Total comprehensive income	$ 3,998	$ 4,754	$ 1,642

ENDEAVOR PARENT, LLC
SELECTED FINANCIAL DATA

	Years Ended December 31,		Change Between Years Ended 2023/2022	
	2023	2022	Value	Percentage
NYMEX prices:				
Oil ($/Bbl) – CMA	$ 77.62	$ 94.23	$ (16.61)	(18)%
Natural gas ($/MMBtu) – FOM	$ 2.74	$ 6.65	$ (3.91)	(59)%
Average wellhead realized prices:				
Oil ($/Bbl)(1)	$ 77.88	$ 95.47	$ (17.59)	(18)%
Natural Gas ($/Mcf)	$ 1.27	$ 4.40	$ (3.13)	(71)%
Natural gas liquid ($/Bbl)	$ 18.38	$ 30.55	$ (12.17)	(40)%
Total ($/BOE)	$ 50.02	$ 68.66	$ (18.64)	(27)%
Realized gain (loss) from derivative transactions:				
Oil ($/Bbl)	$ 0.14	$ (8.70)	$ 8.84	102%
Natural gas ($/Mcf)	$ (0.11)	$ (0.40)	$ 0.29	73%
Total ($/BOE)	$ (0.05)	$ (5.65)	$ 5.60	99%
Average wellhead realized prices including the effects of realized gain (loss) from derivative instruments:				
Oil ($/Bbl)	$ 78.02	$ 86.77	$ (8.75)	(10)%
Natural gas ($/Mcf)	$ 1.16	$ 4.00	$ (2.84)	(71)%
Natural gas liquid ($/Bbl)	$ 18.38	$ 30.55	$ (12.17)	(40)%
Total ($/BOE)	$ 49.97	$ 63.01	$ (13.04)	(21)%
Differentials to NYMEX prices:				
Oil ($/Bbl)	$ 0.26	$ 1.24	$ (0.98)	(79)%
Natural gas ($/Mcf)	$ (1.47)	$ (2.25)	$ 0.78	35%
Production Volumes:				
Oil (MBbl)	70,004	60,921	9,083	15%
Natural gas (MMcf)	148,175	111,285	36,890	33%
Natural gas liquid (MBbl)	28,558	22,292	6,266	28%
Total (MBOE)	123,258	101,761	21,497	21%
Daily Production Volumes:				
Oil (MBbl)	191.8	166.9	24.9	15%
Natural gas (MMcf)	406.0	304.9	101.1	33%
Natural gas liquid (MBbl)	78.2	61.1	17.1	28%
Total (MBOE)	337.7	278.8	58.9	21%
Average Costs per BOE:				
Lease operating expense	$ 5.58	$ 5.59	$ (0.01)	(0)%
Production taxes	2.44	3.45	(1.01)	(29)%
General and administrative expense	0.94	1.12	(0.18)	(16)%
Total cash costs	8.96	10.16	(1.20)	(12)%
Depletion, depreciation, amortization and accretion	9.06	7.75	1.31	17%
Total operating costs	18.02	17.91	0.11	1%
Interest (income) expense, net	(0.23)	0.54	(0.77)	(143)%
Total Costs per BOE	$ 17.79	$ 18.45	$ (0.66)	(4)%

(1) Includes the effects of purchases and resales of oil.

ENDEAVOR PARENT, LLC
SELECTED FINANCIAL DATA

	Years Ended December 31,		Change Between Years Ended 2022/2021	
	2022	2021	Value	Percentage
NYMEX prices:				
Oil ($/Bbl) – CMA	$ 94.23	$ 67.91	$ 26.32	39%
Natural gas ($/MMBtu) – FOM	$ 6.65	$ 3.85	$ 2.80	73%
Average wellhead realized prices:				
Oil ($/Bbl)(1)	$ 95.47	$ 67.67	$ 27.80	41%
Natural Gas ($/Mcf)	$ 4.40	$ 3.00	$ 1.40	47%
Natural gas liquid ($/Bbl)	$ 30.55	$ 25.20	$ 5.35	21%
Total ($/BOE)	$ 68.66	$ 49.24	$ 19.42	39%
Realized gain (loss) from derivative transactions:				
Oil ($/Bbl)	$ (8.70)	$ (12.46)	$ 3.76	30%
Natural gas ($/Mcf)	$ (0.40)	$ —	$ (0.40)	0%
Total ($/BOE)	$ (5.65)	$ (7.45)	$ 1.80	24%
Average wellhead realized prices including the effects of realized gain (loss) from derivative instruments:				
Oil ($/Bbl)	$ 86.77	$ 55.21	$ 31.56	57%
Natural gas ($/Mcf)	$ 4.00	$ 3.00	$ 1.00	33%
Natural gas liquid ($/Bbl)	$ 30.55	$ 25.20	$ 5.35	21%
Total ($/BOE)	$ 63.01	$ 41.79	$ 21.22	51%
Differentials to NYMEX prices:				
Oil ($/Bbl)	$ 1.24	$ (0.24)	$ 1.48	617%
Natural gas ($/Mcf)	$ (2.25)	$ (0.85)	$ (1.40)	(165)%
Production Volumes:				
Oil (MBbl)	60,921	44,836	16,085	36%
Natural gas (MMcf)	111,285	85,635	25,650	30%
Natural gas liquid (MBbl)	22,292	15,811	6,481	41%
Total (MBOE)	101,761	74,920	26,841	36%
Daily Production Volumes:				
Oil (MBbl)	166.9	122.8	44.1	36%
Natural gas (MMcf)	304.9	234.6	70.3	30%
Natural gas liquid (MBbl)	61.1	43.3	17.8	41%
Total (MBOE)	278.8	205.3	73.5	36%
Average Costs per BOE:				
Lease operating expense	$ 5.59	$ 5.62	$ (0.03)	(1)%
Production taxes	3.45	2.50	0.95	38%
General and administrative expense	1.12	1.13	(0.01)	(1)%
Total cash costs	10.16	9.25	0.91	10%
Depletion, depreciation, amortization and accretion	7.75	7.68	0.07	1%
Total operating costs	17.91	16.93	0.98	6%
Interest (income) expense, net	0.54	1.68	(1.14)	(68)%
Total Costs per BOE	$ 18.45	$ 18.61	$ (0.16)	(1)%

(1) Includes the effects of purchases and resales of oil.

ENDEAVOR PARENT, LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
(dollars in millions)

	As of December 31, 2023	As of December 31, 2022	Change	Percent Change
Cash and cash equivalents	$ 690	$ 1,585	$ (895)	(56)%
Other current assets	943	658	285	43%
Oil and natural gas property, net	8,917	6,763	2,154	32%
Other property and equipment, net	571	429	142	33%
Other assets	79	24	55	229%
Total assets	$ 11,200	$ 9,459	$ 1,741	18%
Current liabilities	$ 1,440	$ 1,190	$ 250	21%
Senior Notes	917	991	(74)	(7)%
Debt issuance costs	(4)	(6)	2	33%
Other long-term liabilities	340	253	87	34%
Members' equity	8,507	7,031	1,476	21%
Total liabilities and members' equity	$ 11,200	$ 9,459	$ 1,741	18%
Liquidity:				
Revolving credit facility commitments	$ 1,500	$ 1,500	$ —	0%
Letters of credit	(2)	(3)	1	33%
Revolving credit facility availability	1,498	1,497	1	0%
Cash and cash equivalents	690	1,585	(895)	(56)%
Cash on hand and revolving credit facility availability	$ 2,188	$ 3,082	$ (894)	(29)%
Ratio of net debt to Adjusted EBITDA[1]	0.04x	-0.11x		
Ratio of secured funded debt to Adjusted EBITDA[1]	0.00x	0.00x		
Net debt/average daily BOE production ($/BOE)[1]	$ 649	$ (2,120)		
Net debt/proved developed producing reserves ($/BOE)[1][2]	$ 0.24	$ (0.70)		

(1) Net debt is defined as the amount outstanding under the revolving credit facility, senior notes and other current and long-term debt less cash, restricted cash and short-term investments. Secured funded debt is the amount drawn on the revolving credit facility plus letters of credit.

(2) Based on December 31, 2023 and 2022 reserves, respectively.

RESULTS OF OPERATIONS

Year Ended December 31, 2023 Compared To Year Ended December 31, 2022

Operating revenues. Revenue from operations was $6,187 million for the year ended December 31, 2023, a decrease of $822 million from $7,009 million for the year ended December 31, 2022. The following table summarizes the changes in average sales realized prices (without derivatives) and sales volumes that caused changes to Endeavor's oil, natural gas and NGL revenues between the years ended December 31, 2023 and 2022, respectively (dollars in millions):

	Years Ended December 31,		Variance		Price/Volume Variance		
	2023	2022	Dollar	Percentage	Price	Volume	Total
Revenues							
Oil sales	$ 5,452	$ 5,814	$ (362)	(6)%	$ (1,229)	$ 867	$ (362)
Natural gas and NGL sales	713	1,171	(458)	(39)%	(811)	353	(458)
	$ 6,165	$ 6,985	$ (820)	(12)%	$ (2,040)	$ 1,220	$ (820)

Specifics include the following:

- the average oil wellhead realized price (excluding the effects of derivative activities) was $77.88 per Bbl during the year ended December 31, 2023, a decrease of 18% from $95.47 per Bbl during the year ended December 31, 2022. The decrease in the average oil wellhead realized price was due to a decrease in NYMEX oil prices;
- the average natural gas wellhead realized price (excluding the effects of derivative activities) was $1.27 per Mcf during the year ended December 31, 2023, a decrease of 71% from $4.40 per Mcf during the year ended December 31, 2022. The decrease in the average natural gas wellhead realized prices was due to a decrease in NYMEX natural gas prices;
- the average NGL wellhead realized price (excluding the effects of derivative activities) was $18.38 per Bbl during the year ended December 31, 2023, a decrease of 40% from $30.55 per Bbl during the year ended December 31, 2022. The decrease in the average NGL wellhead realized price was related to a decrease in the Mont Belvieu price index; and
- total BOE production was 123,258 MBOE for the year ended December 31, 2023, an increase of 21,497 MBOE (21%) from 101,761 MBOE for the year ended December 31, 2022. This increase was primarily due to an increase in the number of horizontal wells producing as a result of Endeavor's drilling program.

Service company division revenue. Endeavor's service company divisions generated revenue of $22 million during the year ended December 31, 2023 which was consistent with service company division revenues during the year ended December 31, 2022.

Lease operating expense. Aggregate lease operating expenses were $688 million ($5.58 per BOE) for the year ended December 31, 2023, which was an increase of $119 million (21%) from $569 million ($5.59 per BOE) for the year ended December 31, 2022. The increase in aggregate lease operating expenses was due to additional wells placed on production during the year ended December 31, 2023 and a larger number of workover jobs completed during 2023 compared to 2022. The following table summarizes Endeavor's components of lease operating expenses for the years presented (figures in million, except per BOE amounts):

	Years Ended December 31,					
	2023		2022		Variance	
	Amount	Per BOE	Amount	Per BOE	Dollar	Percentage
Direct lease operating expenses	$ 480	$ 3.89	$ 412	$ 4.04	$ 68	17%
Workover expenses	115	0.93	74	0.73	41	55%
Ad valorem expenses	93	0.76	83	0.82	10	12%
Total lease operating expenses	$ 688	$ 5.58	$ 569	$ 5.59	$ 119	21%

Production taxes. Production taxes were $301 million for the year ended December 31, 2023, a decrease of $50 million (14%) from $351 million for the year ended December 31, 2022. The decrease was directly related to a decrease in oil, natural gas and NGL revenues offset by an increase in production volumes.

Service company division operating expenses. The operating expenses of Endeavor's service company divisions were $21 million for the year ended December 31, 2023, an increase of $2 million (11%) from $19 million for the year ended December 31, 2022.

Depletion, depreciation, amortization and accretion expense. The following table provides the components of Endeavor's depletion, depreciation, amortization and accretion expense for the years ended December 31, 2023 and 2022, respectively (figures in millions, except per BOE amounts):

	Years Ended December 31,					
	2023		2022		Variance	
	Amount	Per BOE	Amount	Per BOE	Dollar	Percentage
Depletion of proved oil and natural gas properties	$ 1,036	$ 8.40	$ 719	$ 7.06	$ 317	44%
Depreciation of other property and equipment	65	0.53	54	0.53	11	20%
Accretion of asset retirement obligations	16	0.13	16	0.16	—	0%
Total depletion, depreciation, amortization and accretion expense	$ 1,117	$ 9.06	$ 789	$ 7.75	$ 328	42%

Depletion of proved oil and natural gas properties was $1,036 million ($8.40 per BOE) for the year ended December 31, 2023, an increase of $317 million (44%) from $719 million ($7.06 per BOE) for the year ended December 31, 2022. The increase in aggregate depletion expense was primarily due to an increase in production levels due to additional drilling efforts during 2023 coupled with a higher depletable full cost pool due to higher drilling and completion costs. Accretion of asset retirement obligations was $16 million ($0.13 per BOE) for the year ended December 31, 2023 consistent with accretion of expense of $16 million ($0.16 per BOE) for the year ended December 31, 2022.

Impairment of other property and equipment. Endeavor recognized no impairment expense on other property and equipment during the year ended December 31, 2023 and recognized impairment expense of $3 million on other property and equipment during the year ended December 31, 2022.

Loss from inventory write down. For 2023 and 2022, non-cash expense associated with inventory valuation totaled $1 million and $1 million, respectively, in each case, caused by a decline in demand for certain well related equipment inventory and well construction design changes.

General and administrative expense ("G&A"). G&A expense was $116 million for the year ended December 31, 2023, an increase of $2 million (2%) from $114 million for the year ended December 31, 2022. The table below presents Endeavor's G&A costs for the years ended December 31, 2023 and 2022, respectively (dollars in millions):

	Years Ended December 31,		Variance	
General and administrative expense	2023	2022	Dollar	Percentage
Gross G&A	$ 158	$ 158	$ —	0%
Less amounts capitalized to oil and natural gas properties	(42)	(44)	2	5%
G&A expense	$ 116	$ 114	$ 2	2%

Gain/loss on sale of assets. During the year ended December 31, 2023, Endeavor recognized a gain on sale of assets of $10 million, primarily related to the sale of a service company division. In addition, during 2023, Endeavor received additional proceeds as a result of the sale of its investment in a midstream entity that occurred in during 2022.

During the year ended December 31, 2022, Endeavor recognized a gain on sale of assets of $109 million, which was primarily attributable to its divestiture of its investment in a midstream entity and Endeavor's divesture of certain service company equipment.

Gain/loss on derivatives not designated as hedges. Endeavor is required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. As a result, Endeavor marks its derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in its consolidated statements of operations. During the year ended December 31, 2023, Endeavor recognized a $26 million net gain on derivative instruments. During the year ended December 31, 2022, Endeavor recognized a $399 million net loss on derivative instruments. The change in Endeavor's derivative instruments fair value position was a result of the change in the future commodity prices. The following table sets forth the net gain (loss) on derivatives for the periods presented (dollars in millions):

	Years Ended December 31,	
	2023	2022
Gain (loss) on derivative instruments, net		
Oil contracts	$ 24	$ (350)
Natural gas contracts	2	(49)
Total	$ 26	$ (399)

The following table represent Endeavor's net cash receipts from (payments on) derivatives for the periods presented (dollars in millions):

	Years Ended December 31,	
	2023	2022
Cash receipts (payments) on derivative instruments, net:		
Oil contracts	$ 10	$ (530)
Natural gas contracts	(16)	(45)
	$ (6)	$ (575)

Loss on redemption of debt. During 2023, Endeavor entered into open market repurchases of its outstanding 2028 Senior Notes. As a result, Endeavor paid $71 million that included principal, accrued interest payable and discount amounts due as of the respective repurchase dates. In addition, Endeavor recorded a net gain of $0.4 million on the repurchases of the 2028 Senior Notes, which gain was comprised of discounts paid to repurchase the 2028 Senior Notes, unamortized deferred loan cost and unamortized premiums.

On July 15, 2022, Endeavor paid $640 million to redeem all of the 2025 Senior Notes then outstanding at 103.313% of par value, which included $600 million in aggregate principal amount, $20 million in redemption premiums and $20 million in accrued and unpaid interest. In connection with the redemption of the 2025 Senior Notes, Endeavor recognized a loss on redemption of debt of $25 million during the year ended December 31, 2022.

In December 2022, Endeavor entered into open market repurchases of its outstanding 2028 Senior Notes. As a result, Endeavor paid $22 million that included principal, accrued interest payable and discount amounts due as of the respective repurchase dates. In addition, Endeavor recorded a net gain on repurchases of $1 million comprised of discounts paid to repurchase the 2028 Senior Notes, unamortized deferred loan costs and unamortized premiums.

Interest income (expense), net. Interest income (expense), net was $28 million in net interest income for the year ended December 31, 2023, as compared to $55 million in net interest expense for the year ended December 31, 2022. The increase in interest income, net, during 2023 is due to higher interest rates on a higher cash balance and lower outstanding debt, as compared to interest expense, net, in 2022. The weighted average debt balance for the years ended December 31, 2023 and 2022 was approximately $935 million and $1,321 million, respectively. The decrease in the weighted average debt balance was due to Endeavor retiring Senior Notes during the second half of 2022 and during the second quarter of 2023. Additionally, interest income increased due to an increase in Endeavor's total cash balance with higher interest rates. Endeavor's weighted average interest rate on its outstanding Senior Notes during the years ended December 31, 2023 and 2022, was 5.75% and 6.04%, respectively. The following table sets forth the components of interest expense, debt balances and average debt balance for the years ended December 31, 2023 and 2022, respectively (dollars in millions):

	Years Ended December 31,		Variance	
	2023	2022	Value	Percentage
Interest expense on Senior Notes	$ (54)	$ (79)	$ 25	32%
Interest expense on revolving credit facility	(4)	(6)	2	33%
Amortization of debt issuance costs and premiums	(1)	(2)	1	50%
Other interest expense	(3)	(1)	(2)	(200)%
Interest expense	$ (62)	$ (88)	$ 26	30%
Less: Interest income	90	33	57	173%
Interest income (expense), net	$ 28	$ (55)	$ 83	151%

Net income. Net income was $3,984 million for the year ended December 31, 2023, compared to net income of $4,755 million for the year ended December 31, 2022. The decrease in earnings is primarily due to:

- a $822 million decrease in net operating revenues;
- a $328 million increase in depletion, depreciation, amortization and accretion;
- a $119 million increase in lease operating expense; and
- a $99 million decrease in gain on sale of other assets.

Offset by:

- a $425 million decrease in loss from derivative transactions, net;
- a $83 million decrease in interest expense, net;
- a $50 million decrease in production taxes; and
- a $24 million decrease in loss on redemption of debt.

RESULTS OF OPERATIONS

Year Ended December 31, 2022 Compared To Year Ended December 31, 2021

Operating revenues. Revenue from operations was $7,009 million for the year ended December 31, 2022, an increase of $2,945 million from $4,064 million for the year ended December 31, 2021. The following table summarizes the changes in average sales realized prices (without derivatives) and sales volumes that caused changes to Endeavor's oil, natural gas and NGL revenues between the years ended December 31, 2022 and 2021, respectively (dollars in millions):

	Years Ended December 31,		Variance		Price/Volume Variance		
	2022	2021	Dollar	Percentage	Price	Volume	Total
Revenues							
Oil sales	$ 5,814	$ 3,034	$ 2,780	92%	$ 1,692	$ 1,088	$ 2,780
Natural gas and NGL sales	1,171	655	516	79%	276	240	516
	$ 6,985	$ 3,689	$ 3,296	89%	$ 1,968	$ 1,328	$ 3,296

Specifics include the following:

- the average oil wellhead realized price (excluding the effects of derivative activities) was $95.47 per Bbl during the year ended December 31, 2022, an increase of 41% from $67.67 per Bbl during the year ended December 31, 2021. The increase in average oil wellhead realized price was due to an increase in NYMEX oil price;
- the average natural gas wellhead realized price (excluding the effects of derivative activities) was $4.40 per Mcf during the year ended December 31, 2022, an increase of 47% from $3.00 per Mcf during the year ended December 31, 2021. The increase in average natural gas wellhead realized price was due to an increase in NYMEX natural gas prices;
- the average NGL wellhead realized price (excluding the effects of derivative activities) was $30.55 per Bbl during the year ended December 31, 2022, an increase of 21% from $25.20 per Bbl during the year ended December 31, 2021. The increase in average NGL wellhead realized price was related to an increase in other hydrocarbon prices; and
- total BOE production was 101,761 MBOE for the year ended December 31, 2022, an increase of 26,841 MBOE (36%) from 74,920 MBOE for the year ended December 31, 2021. This increase was primarily due to an increase in the number of horizontal wells producing as a result of Endeavor's drilling program.

Purchases and resales of oil. Endeavor entered into purchases and resales of oil during the years ended December 31, 2022 and 2021 that had no material effect on its results of operations and comprehensive income. Under contract rights, Endeavor purchased oil at the Midland Hub at matching formula prices to mitigate credit exposure on crude oil sales. The following table summarizes the net effect of third-party purchases and resales of oil for the periods presented (dollars in millions):

	Years Ended December 31, 2022	Years Ended December 31, 2021
Sales of purchased oil	$ 2	$ 361
Purchased oil	—	361
Net effect on results of operations	$ 2	$ —

Service company division revenue. The revenues generated by Endeavor's service company divisions was $22 million for the year ended December 31, 2022, as compared to $14 million for the year ended December 31, 2021, an increase of 57%. The increase was primarily due to an increase in services provided to third party customers.

Lease operating expense. Aggregate lease operating expenses were $569 million ($5.59 per BOE) for the year ended December 31, 2022, which was an increase of $148 million (35%) from $421 million ($5.62 per BOE) for the year ended December 31, 2021. On a per BOE basis lease operating expense decreased by 1%. The increase in aggregate lease operating expenses was due to an increase in costs related to wells placed on production during the year ended December 31, 2022. The increase in workover costs on an aggregate basis and a per BOE basis was primarily due to an increase in the number of workover jobs completed in 2022 compared to 2021. The following table summarizes Endeavor's components of lease operating expenses for the years presented (figures in millions, except per BOE amounts):

	Years Ended December 31,					
	2022		2021		Variance	
	Amount	Per BOE	Amount	Per BOE	Dollar	Percentage
Direct lease operating expenses	$ 412	$ 4.04	$ 326	$ 4.35	$ 86	26%
Workover expenses	74	0.73	45	0.60	29	64%
Ad valorem expenses	83	0.82	50	0.67	33	66%
Total lease operating expenses	$ 569	$ 5.59	$ 421	$ 5.62	$ 148	35%

Production taxes. Production taxes were $351 million for the year ended December 31, 2022, an increase of $164 million (88%) from $187 million for the year ended December 31, 2021. The increase was directly related to the increase in oil, natural gas and NGL revenues.

Service company division operating expenses. The operating expenses of Endeavor's service company divisions were $19 million for the year ended December 31, 2022, an increase of $7 million (58%) from $12 million for the year ended December 31, 2021. The increase in operating expense was due to an increase in services provided to third party customers.

Depletion, depreciation, amortization and accretion expense. The following table provides components of Endeavor's depletion, depreciation, amortization and accretion expense for the years ended December 31, 2022 and 2021, respectively (figures in millions, except per BOE amounts):

	Years Ended December 31,				Variance	
	2022		2021			
	Amount	Per BOE	Amount	Per BOE	Dollar	Percentage
Depletion of proved oil and natural gas properties	$ 719	$ 7.06	$ 515	$ 6.89	$ 204	40%
Depreciation of other property and equipment	54	0.53	46	0.61	8	17%
Accretion of asset retirement obligations	16	0.16	14	0.18	2	14%
Total depletion, depreciation, amortization and accretion expense	$ 789	$ 7.75	$ 575	$ 7.68	$ 214	37%

Depletion of proved oil and natural gas properties was $719 million ($7.06 per BOE) for the year ended December 31, 2022, an increase of $204 million (40%) from $515 million ($6.89 per BOE) for the year ended December 31, 2021. The increase in aggregate depletion expense was primarily due to an increase in production levels due to additional drilling efforts during 2022 coupled with a higher depletable full cost pool. Accretion of asset retirement obligations was $16 million ($0.16 per BOE) for the year ended December 31, 2022, an increase of $2 million (14%) from $14 million ($0.18 per BOE) for the year ended December 31, 2021.

Loss from inventory write down. For 2022 and 2021, non-cash expense associated with inventory valuation totaled $1 million and $0 million, respectively, caused by a decline in demand for certain well related equipment inventory and well construction design changes.

General and administrative expense. G&A expense was $114 million for the year ended December 31, 2022, an increase of $29 million (34%) from $85 million for the year ended December 31, 2021. The increase was due primarily to an overall increase in compensation expense under Endeavor's phantom unit plan and employee related expenses. The table below presents Endeavor's G&A cost for the years ended December 31, 2022 and 2021, respectively (dollars in millions):

	Years Ended December 31,		Variance	
General and Administrative Expense	2022	2021	Dollar	Percentage
Gross G&A	$ 158	$ 120	$ 38	32%
Less amounts capitalized to oil and natural gas properties	(44)	(35)	(9)	(26)%
G&A expense	$ 114	$ 85	$ 29	34%

Gain/loss on sale of assets. During the year ended December 31, 2022, Endeavor recognized a gain on sale of assets of $109 million, which was primarily attributable to its divestiture of its investment in a midstream entity and Endeavor's divestiture of certain service company equipment.

Gain/loss on derivatives not designated as hedges. Endeavor is required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. As a result, Endeavor marks its derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in its consolidated statements of operations. During the year ended December 31, 2022, Endeavor recognized a $399 million net loss on derivatives. During the year ended December 31, 2021, Endeavor recognized a $625 million net loss on derivatives. The following table sets forth the gain (loss) on derivatives for the periods presented (dollars in millions):

	Years Ended December 31,	
	2022	**2021**
Gain (loss) on derivative instruments, net		
Oil contracts	$ (350)	$ (629)
Natural gas contracts	(49)	4
Total	(399)	(625)

The following tables represents Endeavor's net cash receipts from (payments on) derivatives for the periods presented (dollars in millions):

	Years Ended December 31,	
	2022	**2021**
Cash receipts (payments) on derivative instruments, net:		
Oil contracts	$ (530)	$ (557)
Natural gas contracts	(45)	—
	(575)	(557)

Loss on redemption of debt. On July 15, 2022, Endeavor paid $640 million to redeem all of the 2025 Senior Notes then outstanding at 103.313% of par value, which included $600 million in aggregate principal amount, $20 million in redemption premiums and $20 million in accrued and unpaid interest. In connection with the redemption of the 2025 Senior Notes, Endeavor recognized a loss on redemption of debt of $25 million during the year ended December 31, 2022.

In December 2022, Endeavor entered into open market repurchases of its outstanding 2028 Senior Notes. As a result, Endeavor paid $22 million that included principal, accrued interest payable and discount amounts due as of the respective repurchase dates. In addition, Endeavor recorded a net gain on repurchases of $1 million comprised of discounts paid to repurchase the 2028 Senior Notes, unamortized deferred loan costs and unamortized premiums.

On October 14, 2021, Endeavor redeemed $500 million in aggregate principal amount, representing all of the aggregate principal amount then outstanding, of the 5.500% senior unsecured notes due 2026 in the aggregate principal amount of $500 million (the "2026 Senior Notes") at 104.125% of par value. As a result of the tender offer, Endeavor paid $526 million, which included $21 million in redemption premium and $6 million in interest payable. In addition, Endeavor recognized a loss on redemption of debt of $25 million which is composed of a $21 million redemption premium and $4 million in unamortized deferred loan costs.

Interest expense, net. Interest expense, net was $55 million and $126 million for the years ended December 31, 2022 and 2021, respectively. The decrease in interest expense, net, was due primarily to a decrease in Endeavor's weighted average debt balance and an increase in interest income. The weighted average debt balance as of December 31, 2022 was approximately $1,321 million as compared to $1,993 million as of December 31, 2021. The decrease in the weighted average debt balance was due to Endeavor retiring its 2025 Senior Notes, as well as Endeavor repurchasing a portion of its 2028 Senior Notes during the second half of 2022. Endeavor's weighted average interest rate on its outstanding Senior Notes during the years ended December 31, 2022 and 2021 was 6.04% and 5.98%, respectively. The following table sets forth the components of interest expense, debt balances and average debt balance for the years ended December 31, 2022 and 2021, respectively (dollars in millions):

	Years Ended December 31,		Variance	
	2022	2021	Value	Percentage
Interest expense on Senior Notes	$ (79)	$ (118)	39	(33)%
Interest expense on revolving credit facility	(6)	(6)	—	0%
Amortization of debt issuance costs and premiums	(2)	(3)	1	(33)%
Other interest expense	(1)	—	(1)	0%
Interest expense	$ (88)	$ (127)	39	(31)%
Less: Interest income	33	1	32	3200%
Interest expense, net	$ (55)	$ (126)	71	(56)%

Net Income. Net income was $4,755 million for the year ended December 31, 2022, compared to net income of $1,642 million for the year ended December 31, 2021. The increase in earnings is primarily due to:

- a $3,306 million increase in net operating revenues;
- a $108 million increase in gain on sale of other assets;
- a $226 million decrease in loss from derivative transactions, net; and
- $71 million decrease in interest expense, net.

Offset by:

- a $148 million increase in lease operating expense;
- a $164 million increase in production taxes; and
- a $214 million increase in depletion, depreciation, amortization and accretion.

Non-GAAP Financial Measures

Adjusted EBITDA

Endeavor defines Adjusted EBITDA as net income before interest expense, net, depletion, depreciation, amortization and accretion, impairment of other property and equipment, loss from inventory write down, current and deferred tax (benefit) expense, (gain) loss on sale of other assets, net, loss on redemption of debt, (gain) loss from derivative transactions and net cash receipt from (payments on) derivatives. Adjusted EBITDA is a supplemental measure of Endeavor's performance that is not required by or presented in accordance with GAAP. The GAAP measure most directly comparable to Adjusted EBITDA is net income. Endeavor believes that Adjusted EBITDA may provide additional information about Endeavor's ability to meet its future requirements for debt service, capital expenditures and working capital. Adjusted EBITDA is a financial measure commonly used in the oil and natural gas industry, but Endeavor's definition may not be comparable to similarly titled measures of other companies.

Adjusted EBITDA should not be considered in isolation or as a substitute for net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP, or as a measure of a company's profitability or liquidity. The table below presents a reconciliation of Adjusted EBITDA to net income for the periods indicated (dollars in millions).

	Years Ended December 31,		
	2023	2022	2021
Reconciliation of net income to Adjusted EBITDA:			
Net income	$ 3,984	$ 4,755	$ 1,642
Interest (income) expense, net	(28)	55	126
Depletion, depreciation, amortization and accretion	1,117	789	575
Impairment of other property and equipment	—	3	—
Loss from inventory write down	1	1	—
Current and deferred tax expense	12	36	6
Gain on sale of other assets, net	(10)	(109)	(1)
Loss on redemption of debt	—	24	25
(Gain) loss on derivative instruments	(26)	399	625
Net payments on derivatives	(6)	(575)	(557)
Adjusted EBITDA	$ 5,044	$ 5,378	$ 2,441

PV-10

Pre-tax present value discounted at ten percent ("PV-10") is considered a non-GAAP measure. The most directly comparable GAAP financial measure is the standardized measure of discounted future net cash flows. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future U.S. federal income taxes, discounted at ten percent. However, Endeavor's PV-10 is equal to its standardized measure of discounted future net cash flows because its standardized measure does not include the impact of future U.S. federal income taxes because before January 1, 2024, Endeavor was classified as an S-corporation for U.S. federal income tax purposes, and as such, Endeavor were not subject to U.S. federal income taxes. Endeavor believes that the presentation of PV-10 is relevant and useful to investors because it presents the relative monetary significance of its oil, natural gas and NGL properties regardless of tax structure. Further, investors may use the measure as a basis for comparison of the relative size and value of Endeavor's proved reserves to other companies. Endeavor uses this measure when assessing the potential return on investment related to its oil, natural gas and NGL properties. Generally, for other companies, PV-10 is not equal to, or a substitute for, the standardized measure of discounted future net cash flows. Endeavor's PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of its oil, natural gas and NGL reserves.

Market Conditions and Outlook

Endeavor's business success is affected by hydrocarbon price levels which are based on many factors beyond its control such as economic, political, and regulatory developments, as well as competition from other sources of energy. Hydrocarbon price volatility is a significant risk to Endeavor's business, cash flows and results of operations and comprehensive income. Hydrocarbon prices continue to remain volatile, and Endeavor expects them to remain volatile during 2024. Also, regional oil, natural gas and NGL price differentials may have an important effect on near term financial results due to potential constraints on Endeavor's delivery of oil, natural gas and NGL to consuming markets. Income is expected to be affected by changes to hydrocarbon prices and their differentials in 2024.

Endeavor continues to actively monitor hydrocarbon prices along with micro- and macroeconomic activity to ensure it is suited to adapt to changes within the oil and natural gas industry and minimize impacts that could adversely affect its financial condition and results of operations and comprehensive income. The general rate of inflation has increased in conjunction with overall imbalances in supply and demand, supply chain disruptions and shipping bottlenecks caused by the war in Ukraine and the Israel-Hamas war along with general labor market constraints. Concerns about a potential economic downturn or recession, and measures to combat persistent inflation and instability in the financial sector have contributed to recent economic and pricing volatility and may continue to impact pricing throughout 2024.

Endeavor's total capital expenditures budget for 2024 is expected to be lower than 2023 levels and will be in the range of $2,500 million to $2,600 million which includes operated and non-operated drilling and completion activities, leasehold costs, and other property and equipment, which primarily includes water disposal facilities, infrastructure, and electrical facilities. From time to time, Endeavor evaluates strategic property, leasehold and mineral acquisitions, but none are included in Endeavor's capital budget. During the first quarter of 2024, Endeavor closed certain unbudgeted leasehold and mineral acquisitions for approximately $133 million, in the aggregate.

Endeavor will endeavor to maintain a conservative financial position to allow the expansion of its drilling and development activities reflective of current hydrocarbon prices to maximize the present value of its resource potential. Endeavor intends to fund development with cash flow from operations, cash on hand and borrowings under its revolving credit facility. As of December 31, 2023, Endeavor had $2,188 million of liquidity, with $690 million of cash and cash equivalents and $1,498 million available borrowing capacity under its revolving credit facility, with no amount outstanding under its revolving credit facility. Endeavor intends to develop and explore its reserves through the drilling, development and exploitation of its multi-decade horizontal well inventory of identified drilling locations in the Midland Basin. Endeavor has focused its operations on its Midland Basin assets because of its extensive knowledge and lengthy experience in the basin, its multi-decade inventory of drilling locations, the liquids-rich content of the formations Endeavor targets, the established infrastructure, wells with long-lived reserves and multiple stacked pay zones with horizontal target intervals. Most of Endeavor's leases are held by continuous production pursuant to their terms. Endeavor's drilling program will be focused in the core of the Midland Basin where extensive historical vertical drilling has defined the geology providing more consistent horizontal results.

Capital Commitments and Analysis of Changes in Cash Flows

Endeavor's primary needs for cash are development, exploration, exploitation and acquisition of oil and natural gas assets, payment of contractual obligations including debt, distributions to members of Endeavor and working capital obligations. Funding for these cash needs may be provided by any combination of cash on hand, internally generated cash flow, borrowings under Endeavor's revolving credit facility or alternative financing sources, including sale of assets. The following presents Endeavor's cash flows for the periods presented (dollars in millions).

	Years Ended December 31,		
	2023	2022	2021
Net cash provided by operating activities	$ 4,989	$ 5,252	$ 2,290
Net cash used in investing activities	(3,291)	(2,598)	(1,435)
Net cash used in financing activities	(2,593)	(1,847)	(521)
Net (decrease) increase in cash	(895)	807	334
Cash and cash equivalent, beginning of period	1,585	778	444
Cash and cash equivalent, end of period	$ 690	$ 1,585	$ 778

Cash flows provided by operating activities. Net cash provided by operating activities was $4,989 million for the year ended December 31, 2023 as compared to $5,252 million for the year ended December 31, 2022. The decrease in operating cash flows is primarily the result of a decrease in Endeavor's oil, natural gas and NGL revenues due to a decrease in hydrocarbon prices offset partially by an increase in production for the year ended December 31, 2023, as compared to December 31, 2022. Net cash provided by operating activities was $2,290 million for the year ended December 31, 2021.

Cash flows used in investing activities. The purchase and development of oil and natural gas properties accounted for the majority of Endeavor's cash outlays for investing activities. Net cash used in investing activities was $3,291 million, $2,598 million and $1,435 million during the years ended December 31, 2023, 2022 and 2021, respectively. The increase in cash flow used in investing activities is primarily due to an increase in horizontal drilling and completion activity and higher costs. Investing activities during the years ended December 31, 2023, 2022 and 2021 were offset by $7 million, $4 million and $6 million, respectively, in proceeds from the sale of oil and natural gas properties. In addition, during the year ended December 31, 2022, Endeavor divested its investment in a midstream entity that resulted in $112 million in proceeds being received.

Cash flows used in financing activities. Below is a description of Endeavor's financing activities during the years ended December 31, 2023, 2022 and 2021.

- Net cash used in financing activities totaled $2,593 million for the year ended December 31, 2023, which was attributable primarily to $2,522 million in distributions made to the owners of Endeavor's equity interests and $71 million paid for repurchases of Endeavor's 2028 Senior Notes.
- Net cash used in financing activities totaled $1,847 million for the year ended December 31, 2022. On July 15, 2022, Endeavor paid approximately $640 million to redeem all of the 2025 Senior Notes then outstanding, which included $600 million in aggregate principal amount, $20 million in redemption premiums and $20 million in accrued and unpaid interest. In addition, Endeavor paid $6 million in deferred loan cost associated with the revolving credit facility.
- In December 2022, Endeavor entered into open market repurchases of its outstanding 2028 Senior Notes. As a result, Endeavor paid $22 million that included principal, accrued interest payable and discount amounts due as of the respective repurchase dates. In addition, Endeavor recorded a net gain on repurchases of $1 million comprised of discounts paid to repurchase the 2028 Senior Notes, unamortized deferred loan costs and unamortized premiums.
- During the year ended December 31, 2022, Endeavor made $1,215 million in distributions to Endeavor's equity interest owners primarily to satisfy tax obligations of such equity interest owners. Contemporaneously, Endeavor and Stephens Family Trust entered into an agreement to settle the Stephens Family Trust Note receivable (see "Note C - Related Party Transactions" to the consolidated financial statements of Endeavor for additional discussion, which is included in Exhibit 99.1 to Diamondback's Current Report on Form 8-K in which this discussion is being filed). As a result, Endeavor retained $15 million, in lieu of distributions, to fully satisfy any and all amounts due to Endeavor for the Stephen Family Trust Note.

- Net cash used in financing activities were $521 million for the year ended December 31, 2021. On October 14, 2021, Endeavor redeemed $500 million in aggregate principal amount, representing all of the aggregate principal amount then outstanding, of the 2026 Senior Notes. As a result of the redemption offer, Endeavor paid $526 million, which included a $21 million redemption premium and $6 million in interest payable.

Oil and natural gas properties. Endeavor's cash flows used by or invested in its oil and natural gas properties during the years ended December 31, 2023, 2022 and 2021 were as follows in the table below. These expenditures were funded by cash flows from operations, from borrowings under Endeavor's revolving credit facility and alternative financing sources (dollars in millions).

	Years Ended December 31,		
	2023	**2022**	**2021**
Cash flows used by or invested in oil and natural gas properties			
Acquisition of proved oil and natural gas properties, undeveloped leasehold acreage and mineral interests	$ 75	$ 60	$ 5
Other leasehold costs	78	93	55
Investment in drilling and development	2,957	2,429	1,280
Total cash flows used by investing in oil and natural gas properties	$ 3,110	$ 2,582	$ 1,340
Gross operated Permian Basin Wells spudded	302	333	259
Gross operated Permian Basin Wells completed	269	292	164

Endeavor's development and exploitation expenditures primarily relate to drilling and completing horizontal wells and field related facilities. Wells are drilled to exploit known resource geologic trends.

Endeavor's approved 2024 capital budget will range from $2,500 million to $2,600 million which includes operated and non-operated drilling and completion activities, leasehold costs, and other property and equipment, which primarily includes water disposal facilities, infrastructure and electrical facilities. From time to time, Endeavor evaluates strategic property, leasehold and mineral acquisitions, but none are included in Endeavor's capital budget. Endeavor currently believes that it will be able to fund its 2024 short-term working capital requirements and its current 2024 capital budget with cash and cash equivalents, cash flows from operations and borrowing under its revolving credit facility. During the first quarter of 2024, Endeavor closed certain unbudgeted leasehold and mineral acquisitions for an aggregate purchase price of approximately $133 million.

Endeavor generally seeks to fund its non-acquisition expenditures with available cash, operating cash flow and borrowings under its revolving credit facility. The actual amount and timing of Endeavor's expenditures may differ materially from its estimates because of, among other things, timing of lease expirations, actual drilling results, the availability of drilling rigs and other services and equipment, regulatory, technological and competitive developments and market conditions.

Acquisitions. Other than the purchase of leasehold acreage and an allocated budget for other acquisitions, Endeavor's 2024 plan does not contemplate any material acquisitions. Endeavor does not have a specific acquisition budget as the timing and size of acquisitions are often difficult to forecast. Endeavor evaluates opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. Endeavor seeks to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, exploitation and control of operations that will allow us to apply its operating expertise.

Debt repurchase. Endeavor may from time to time seek to retire or purchase its outstanding Senior Notes through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, Endeavor's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Distributions to Endeavor's equity interest owners. Prior to the revocation of Endeavor's election to be taxed as an S-Corporation for U.S. federal income tax purposes, Endeavor was permitted to make tax distributions to Endeavor's equity interest owners when such equity owners had cumulative taxable income passed through to them in excess of taxable losses previously passed through to them. Such tax distributions were calculated at the highest combined marginal U.S. federal, state and local tax rate applicable to equity owners who owned at least 10% of the issued and outstanding equity interests of Endeavor at the time of the distribution. Effective January 1, 2024, Endeavor elected to be a C-Corporation for U.S. federal income tax purposes and, as such, will be paying taxes at the Endeavor level rather than as a pass-through to Endeavor's equity interest owners. Additionally, Endeavor may make discretionary distributions as approved by its board of managers, as limited by the indentures governing its Senior Notes and the credit agreement governing its revolving credit facility.

Liquidity and Capital Resources

Endeavor's primary sources of liquidity have been cash flows generated from operating activities, borrowings under its revolving credit facility, the issuance of its Senior Notes and sales of assets. Should future borrowing base redetermination amounts be lower than the total advances at the time of their effectiveness, Endeavor would be required to repay the deficiency over a short time span after notice. Any future borrowing base reductions may require a reduction in drilling and completion operations and may affect Endeavor's ability to close alternative funding sources or other credit sources. Endeavor believes that its cash flows from operations, together with its other sources of liquidity, will meet both its short-term working capital requirements and its 2024 capital budget. As of December 31, 2023, Endeavor's working capital surplus (excluding the effects of derivative instruments) was $156 million.

Revolving Credit Facility

As of December 31, 2023 and 2022, Endeavor had no advances outstanding under its revolving credit facility. As of December 31, 2023, the borrowing base under Endeavor's revolving credit facility was $5,000 million, and Endeavor had elected commitments of $1,500 million, with no advances outstanding and $2 million of letters of credit issued and outstanding, resulting in $1,498 million in available borrowing capacity. Endeavor's revolving credit facility has a maturity date of March 12, 2025.

Senior Notes

At December 31, 2023 and 2022, Endeavor had $907 million and $978 million, respectively, in outstanding 2028 Senior Notes. The 2028 Senior Notes are guaranteed by certain of Endeavor's subsidiaries, and interest on the 2028 Senior Notes is payable semi-annually.

Joint Development Agreement Funding

In December 2016, Endeavor entered into a drill fund agreement which commits its financial working interest partner to fund the drilling and completion of 44 horizontal Wolfcamp wells on 2,560 gross acres in Midland and Martin Counties, Texas. The drill fund agreement provides for the financial working interest partner to fund 90% of its working interest subject to certain performance provisions for the 44 wells. The drill fund partner committed $260 million to drill, complete and equip the proposed wells. The terms of the agreement are structured as a reversionary working interest whereby Endeavor will receive an initial disproportionate share of cash flow with a further reversion to Endeavor occurring when certain financial hurdles are achieved.

Farmout Agreements

In 2014 and 2015, Endeavor entered into seven-year farmout agreements with XTO Energy Inc. ("XTO Energy"), a wholly owned subsidiary of ExxonMobil. The farmout agreements, as amended, support development of approximately 32,000 net acres in Southern Midland and Northern Upton Counties, Texas. Under the terms of the farmout agreements, XTO Energy earns a majority working interest in each horizontal well drilled and completed at its sole cost. In 2022, Endeavor amended the farmout agreements with XTO to provide for further development of the farmout acreage on or before July 2024. As of December 31, 2023, 362 horizontal wells had been drilled, completed and producing in the farmout area. As of December 31, 2023, XTO Energy had no horizontal rigs running in the farmout area.

Acquisition, Exchanges and Divestitures

During 2023, Endeavor, through its wholly owned subsidiary 1979 Royalties, LP, acquired certain mineral and royalty assets held by unrelated third-party, Peacemaker Royalties, LP (the "Peacemaker Acquisition"). The aggregate consideration for the Peacemaker Acquisition was approximately $59 million (subject to customary post-closing adjustments). The Peacemaker Acquisition was accounted for as an asset acquisition and the allocation of the purchase price, subject to customary post-closing adjustments, was approximately $30 million to proved properties and $29 million to unproved properties.

During the years ended December 31, 2023 and 2022, Endeavor entered into various oil and natural gas property exchanges that resulted in no monetary consideration exchanged between parties. In addition, during the years ended December 31, 2023, 2022 and 2021 Endeavor divested certain assets that have resulted in it recognizing total proceeds of $7 million, $4 million and $6 million, respectively. As a result of Endeavor accounting for its oil and natural gas properties under the full cost method of accounting, Endeavor has not recognized a gain or loss on sale or exchange of oil and natural gas properties.

Internally Generated Cash Flows

Endeavor's internally generated cash flows, results of operations and comprehensive income and financing for its operations are largely dependent on oil, natural gas and NGL prices. During the year ended December 31, 2023, Endeavor's average oil wellhead realized prices decreased 18% as compared to the year ended December 31, 2022. During the year ended December 31, 2023 Endeavor's average wellhead natural gas price decreased 71% and its average wellhead NGL price decreased 40%, in each case, as compared to the year ended December 31, 2022. Realized hydrocarbon prices fluctuate widely in response to changing market forces. Endeavor may experience significant detrimental fluctuations of the differentials between its realized wellhead prices and NYMEX oil and natural gas prices due to regional supply imbalances, which may materially impact its results of operation and comprehensive income. Prolonged periods of lower hydrocarbon prices or sustained wider differentials to NYMEX prices could cause Endeavor to not be in compliance with certain financial covenants under its revolving credit facility and thereby affect its financial condition and liquidity.

Contractual Obligations

Endeavor's contractual obligations include long-term debt, derivative liabilities, asset retirement obligations, firm transportation commitments, purchase commitments, drilling commitments and incentive plan commitments. For additional discussion, see "Note I - Commitments and Contingencies" to the consolidated financial statements of Endeavor, which is included in Exhibit 99.1 to Diamondback's Current Report on Form 8-K in which this discussion is being filed.

Off-Balance Sheet Arrangements

Endeavor does not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have material current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations and comprehensive income, liquidity, capital expenditures or capital resources which are not disclosed in the notes to its consolidated financial statements.

Critical Accounting Estimates

Endeavor's historical consolidated financial statements and related notes contain information that is pertinent to Management's Discussion and Analysis of Financial Condition and Results of Operations of Endeavor. Preparation of financial statements in conformity with GAAP requires that Endeavor's management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. For additional discussions of Endeavor's critical account policies, see "Note A - Organization and Summary Significant Accounting Policies" to the consolidated financial statements of Endeavor, which is included in Exhibit 99.1 to Diamondback's Current Report on Form 8-K in which this discussion is being filed.

In management's opinion, the more significant reporting areas affected by management's judgments and estimates are the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, impairment of long-lived assets, revenue accrual, and valuation of financial derivative instruments. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, landmen and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.