Berry Corporation (bry) Reports Fourth Quarter and Full Year 2022 Financial Results, Including 2022 Shareholder Returns of $189 Million; Doubles Fixed Dividend for 2023

February 22, 2023

DALLAS, Feb. 22, 2023 (GLOBE NEWSWIRE) -- Berry Corporation (bry) (NASDAQ: BRY) (“Berry” or the “Company”) today reported fourth quarter and full-year 2022 results. For the fourth quarter Berry’s net income was $72 million, or $0.90 per diluted share, and Adjusted Net Income (1) was $76 million, or $0.95 per diluted share. For the full year Berry's net income was $250 million, or $3.03 per diluted share, Adjusted Net Income(1) was $226 million, or $2.74 per diluted share, and cash flows from operating activities were $361 million.

2022 Highlights

- Delivered record $189 million of shareholder returns, consisting of:
  - $1.78 per share fixed and variable dividends (inclusive of dividends to be paid in March 2023) and
  - Five million shares repurchased, or 7% of current shares outstanding
- Produced net income of $250 million and Adjusted EBITDA(1) of $380 million
- Generated cash flows from operating activities of $361 million and Adjusted Free Cash Flow(1) of $200 million
- Increased proved reserves to 110 million boe, achieved reserve replacement of 236%, primarily through field extensions
- Announced doubling the fixed dividend to $0.48 per share annually beginning with the first quarter 2023
- Increased authorization of share repurchases to $200 million

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(1) Please see “Non-GAAP Financial Measures and Reconciliations” later in this press release for a reconciliation and more information on these Non-GAAP measures.

“2022 was a good year for Berry both financially and operationally. Once again, we showed the incredible quality of our assets and our ability to navigate the California regulatory environment by holding production flat in the state, net of prior year divestitures. We believe the quality of our assets gives us a competitive advantage over other energy companies. We have decline curves in the low teens, and we achieved 94% of our total annual production from our existing wells, or our base production, in 2022. We are proud to have returned $189 million to shareholders in the form of dividends and share repurchases, which is roughly 27% of our current market capitalization returned in just one year. Our unique assets and operating model generated strong free cash flow which, when allocated in accordance with our shareholder return model, delivered industry leading returns to our shareholders,” said Fernando Araujo, Berry CEO.

“Reflecting the confidence we have in our business plan and strategy, we are doubling our quarterly fixed dividend in 2023. Our goal is to continue to demonstrate our ability to consistently generate substantial free cash flow and return it to shareholders, further proving the quality of our assets and our ability to efficiently manage the business,” continued Araujo.

Fourth Quarter 2022 Results

Net income was $72 million and Adjusted EBITDA was $78 million in the fourth quarter 2022 compared to $192 million and $97 million, respectively, in the third quarter. This decrease is primarily due to lower commodity prices resulting in lower revenue, higher purchased fuel costs and higher greenhouse gas (“GHG”) costs.

The Company's average daily production in the fourth quarter 2022 of 25,800 boe/d was flat compared to third quarter volumes. Company-wide oil production in the fourth quarter 2022 increased 2% sequentially and California production, which consists solely of oil and comprises 82% of total company production, increased 1% to 21,100 mboe/d in the fourth quarter.

Company-wide realized oil price, including hedging effects, were $73.39 per bbl for the fourth quarter 2022 compared to $76.41 per bbl in the third quarter. Excluding hedging effects, California's average realized oil prices were $81.66 per bbl in the fourth quarter, 92% of Brent, and $91.67 per bbl in the third quarter, 94% of Brent.

Lease operating expenses, which includes fuel gas costs for our California steam operations, increased 11% in the fourth quarter 2022 from the third quarter due to higher natural gas purchase prices. Natural gas average purchase price increased 18% from the third quarter.

Taxes, other than income taxes increased 95% in the fourth quarter 2022 from the third quarter due to higher GHG mark-to-market prices and higher property taxes.

General and administrative expenses increased 15% in the fourth quarter 2022 compared to the third quarter, almost entirely due to executive transition costs. Adjusted General and Administrative Expenses(1), which excludes non-cash stock compensation costs and non-recurring costs, remained flat quarter over quarter.

The net income for the well servicing and abandonment business, C&J Well Services, improved 27% to $6.6 million in the fourth quarter 2022 compared to $5.2 million in the third quarter, due to improved margins.

For the fourth quarter 2022, capital expenditures were approximately $45 million, excluding acquisitions, asset retirement obligation spending and well servicing and abandonment capital of $5 million. This was an increase compared to $41 million for the third quarter reflecting California development activity late into the year. Additionally, Berry spent approximately $4 million for plugging and abandonment activities in the fourth quarter.

Full-Year 2022 Results

Net income was $250 million in 2022 compared to a net loss of $16 million in 2021. Adjusted EBITDA was $380 million in 2022 compared to $212 million in 2021. The increase was primarily driven by higher oil and gas realized prices and lower GHG costs, partially offset by higher purchased fuel costs, other non-fuel lease operating expenses, and general and administrative expenses.

The decrease in the Company's average daily production for the full year 2022 compared to 2021 was driven by the divestitures made in late 2021 (California) and early 2022 (Colorado), partially offset by the Utah Antelope Creek acquisition in early 2022. California production, net of the 2021 divestiture, production was flat year-over-year despite significant challenges in receiving new drill permits which forced a mid-year capital allocation pivot to increased sidetrack, workover and recompletion activity. Utah production in 2022 increased 12% compared to 2021 due to new drilling activity and the Antelope Creek acquisition, which more than offset natural decline.

Company-wide realized oil prices, including hedging effects, were $77.59 per bbl in 2022 compared to $50.12 per bbl in 2021. Excluding hedging effects, California average realized oil prices were $93.40 per bbl, 94% of Brent in 2022 and $67.27 per bbl in 2021, 95% of Brent.

Lease operating expenses, which includes fuel costs for our California steam operations, increased 28% due to higher prices associated with purchased fuel, well servicing and workover costs, outside services, chemicals, power, and other inflationary impacts. Natural gas average purchase price increased 39% from 2021. Natural gas prices also impact electricity generation expense.

The divestitures made in late 2021 (California) and early 2022 (Colorado) also decreased other expenses and revenues related to our field operations, including for electricity, marketing and transportation activities. In particular, the majority of our marketing expenses and revenues were related to our Colorado operations, which were sold in early 2022.

Taxes, other than income taxes, decreased 15% in 2022 compared to 2021, largely due to the California divestiture in the fourth quarter of 2021, which lowered GHG emissions, as well as lower GHG mark-to-market prices in 2022 on remaining operations.

General and administrative expenses increased 32% in 2022 compared to 2021, primarily due to a full year of expense for the well servicing and abandonment business, employee cost inflation, including non-cash stock compensation costs and higher professional services costs. Adjusted General and Administrative Expenses, which excludes non-cash stock compensation costs and non-recurring costs, increased for largely the same reasons.

The well servicing and abandonment business results of operations were included in the Company's consolidated results beginning on the October 1, 2021 acquisition date. The full year 2022 results for this business include services revenues of $181 million, costs of services of $143 million, general and administrative expenses of $13 million, net income before income taxes of $15 million, and Adjusted EBITDA of $26 million.

Capital expenditures, excluding acquisitions and asset retirement obligation spending totaled $145 million for 2022 (excluding well servicing and abandonment capital of $8 million) compared to $132 million for 2021. The Company's increased 2022 capital program compared to 2021 was in response to the improved oil price environment and the improving global and national economic environment. The Company allocated more capital to the Utah assets in 2022, compared to 2021, in part due to the opportunities in the newly acquired Antelope Creek properties. As a result of the significant challenges in receiving new drill permits in California, the Company drilled fewer new wells and increased the sidetrack, workover and recompletion activity in California compared to the prior year. The increase in full-year capital expenditures is also partially due to cost inflation in excess of our initial expectations, which we began to experience mid-year. Additionally, Berry spent $20 million in 2022 on plugging and abandonment activities.

At December 31, 2022, the Company had liquidity of $252 million, consisting of $46 million cash and $206 million available for borrowings under the Company's revolving credit facilities.

Proved reserves were 110 mmboe on December 31, 2022, of which 76% are located in California, which is also where 85% of the PV-10(1) value is located. In 2022, Berry achieved a reserve replacement of 236%, primarily from field extensions.

Mike Helm, Berry's Chief Financial Officer stated, "Looking ahead to 2023, our core strategy of delivering substantial shareholder returns has not changed. We are modifying our shareholder return model allocation, with the goal of increasing the value of our shares and lowering our cost of capital. Our strategy includes doubling our fixed dividends, currently planned at $0.48 per share annually. Additionally, we intend to allocate 80% of our Adjusted Free Cash Flow primarily to share repurchases and debt repurchases, while the remaining 20% will be allocated to variable dividends. Based on current prices and outlook, we are now targeting a high single-digit dividend yield, combining the fixed and variable dividends. We have crafted a capital program for 2023 that is designed to support these goals by optimizing our production and driving cost efficiencies. Berry's focus is on maximizing shareholder value through our shareholder return model and managing what we are able to control."

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(1) Please see "Non-GAAP Financial Measures and Reconciliations" later in this press release for a reconciliation and more information on these Non-GAAP measures.

Quarterly Dividend

In February 2023, the Company's Board of Directors declared dividends totaling $0.50 per share on the Company's outstanding common stock, comprising a fixed dividend of $0.06 per share and a variable dividend of $0.44 per share, based on fourth quarter 2022 Adjusted Free Cash Flow in accordance with the Company's shareholder return model. Both dividends are payable on March 23, 2023 to shareholders of record at the close of business on March 15, 2023. Cash dividends attributable to 2022 totaled $1.78 per share, as noted in the table below.

2022 Dividends

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year-to-Date
Fixed Dividends	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.24
Variable Dividends(1)	0.13	0.56	0.41	0.44	1.54
Total	$ 0.19	$ 0.62	$ 0.47	$ 0.50	$ 1.78

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(1) Variable Dividends are declared the quarter following the period of results (the period used to determine the variable divided based on the shareholder return model). The table notes total dividends earned in each quarter.

Going forward, subject to declaration by the Board, the Company intends to double the fixed dividend to $0.12 per share quarterly or $0.48 per share annually; variable dividends will be paid in accordance with its shareholder return model.

Updated Shareholder Return Model (SRM)

Beginning with first quarter 2023 results, in accordance with the updated shareholder return model, Berry plans to allocate Adjusted Free Cash Flow as follows:

- 80% primarily to share repurchases and debt repurchases, and
- 20% to variable dividends.

Adjusted Free Cash Flow does not represent the total increase or decrease in our cash balance, and it should not be inferred that the entire amount of Adjusted Free Cash Flow is available for variable dividends, debt or share repurchases or other discretionary expenditures, since we have other non-discretionary expenditures that are not deducted from this measure and would be paid out of the 80% bucket, as necessary.

The Board also increased the authorization for share repurchases to $200 million. The Board had previously authorized $75 million of debt repurchases all of which remains available.

Full-Year 2023 Guidance

Berry's 2023 capital program reflects management's prior experience with the constraints imposed by the current permitting environment impacting Kern County, with an underlying commitment to maximize Adjusted Free Cash Flow to return to shareholders. Accordingly, our current plan contemplates a slight decline in annual production year-over-year, primarily due to anticipated delays in the receipt of new drill permits. In sum, Berry's current capital program for 2023 focuses on workovers and other activities related to existing wellbores, as well as a limited number of new wells for which we already have permits in hand. The Company still, however, expects to be able to generate significant Adjusted Free Cash Flow in 2023, based on current strip pricing. For the avoidance of doubt, the expected sequential year over year decline in Adjusted Free Cash Flow is almost exclusively due to lower commodity price assumptions.

The Company has oil hedges for approximately three-quarters of its expected 2023 oil production at about $77 per barrel Brent and gas hedges for approximately three-quarters of its expected 2023 gas purchases at about $5.40 per mmbtu.

Full-Year 2023 Guidance	Low		High
Average Daily Production (boe/d)(1)	24,000		25,200
Expenses from field operations ($/boe)(2)	$35.00		$37.00
E&P non-production revenues ($/boe)(3)	$3.30		$3.50
Natural gas purchase hedge settlements ($/boe)(4)(5)	(3.60)		(3.85)
Taxes, Other than Income Taxes ($/boe)	$4.75		$5.25
Adjusted General & Administrative (G&A) expenses ($/boe)(6)(7)			
E&P Segment & Corp	$6.55		$6.95
Well Servicing and Abandonment Segment		~$1.55	
Capital Expenditures ($ millions)			
E&P Segment & Corp	$95		$105
Well Servicing and Abandonment Segment		~$8	
Well Servicing & Abandonment Segment Adjusted EBITDA ($mm)		~$27	

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(1) Oil production is expected to be approximately 92% of total.
(2) Expenses from field operations include lease operating expenses, electricity generation expenses, transportation expense, and marketing expenses.
(3) E&P non-production revenues include sales from electricity, transportation, and marketing activities.
(4) Natural gas purchase hedge settlements is the cash (received) or paid from these derivatives on a per boe basis.
(5) Based on natural gas hedge positions and basis differentials as of February 1, 2023, and the Henry Hub gas price of $3.75 per mmbtu.
(6) Adjusted General & Administrative expenses and Well Servicing and Abandonment Segment Adjusted EBITDA are non-GAAP financial measures. The Company does not provide a reconciliation of these measures because the Company believes such reconciliation would imply a degree of precision and certainty that could be confusing to investors and is unable to reasonably predict certain items included in or excluded from the GAAP financial measures without unreasonable efforts. This is due to the inherent difficulty of forecasting the timing or amount of various items that have not yet occurred and are out of the Company's control or cannot be reasonably predicted. Non-GAAP forward-looking measures

provided without the most directly comparable GAAP financial measures may vary materially from the corresponding GAAP financial measures.

(7) See further discussion and reconciliation in “Non-GAAP Financial Measures and Reconciliations”.

E&P FIELD OPERATIONS

We have changed the presentation of what we formerly referred to as Opex or operating expenses. Overall, management assesses the efficiency of our E&P field operations by considering core E&P operating expenses together with our cogeneration, marketing and transportation activities. In particular, a core component of our E&P operations in California is steam, which we use to lift heavy oil to the surface. We operate several cogeneration facilities to produce some of the steam needed in our operations. In comparing the cost effectiveness of our cogeneration plants against other sources of steam in our operations, management considers the cost of operating the cogeneration plants, including the cost of the natural gas purchased to operate the facilities, against the value of the steam and electricity used in our E&P field operations and the revenues we receive from sales of excess electricity to the grid. We strive to minimize the variability of our fuel gas costs for our California steam operations with natural gas purchase hedges. Consequently, the efficiency of our E&P field operations are impacted by the cash settlements we receive or pay from these derivatives. We also have contracts for the transportation of fuel gas from the Rockies which has historically been cheaper than the California markets. With respect to transportation and marketing, management also considers opportunistic sales of incremental capacity in assessing the overall efficiencies of E&P operations.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Electricity generation expenses include the portion of fuel, labor, maintenance, and tools and supplies from two of our cogeneration facilities allocated to electricity generation expense; the remaining cogeneration expenses are included in lease operating expense. Transportation expenses relate to our costs to transport the oil and gas that we produce within our properties or move it to the market. Marketing expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Electricity revenue is from the sale of excess electricity from two of our cogeneration facilities to a California utility company under long-term contracts at market prices. These cogeneration facilities are sized to satisfy the steam needs in their respective fields, but the corresponding electricity produced is more than the electricity that is currently required for the operations in those fields. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and marketing revenues represent sales of natural gas purchased from and sold to third parties.

Earnings Conference Call

Call Date: Wednesday, February 22, 2023

Call Time: 11:00 a.m. Eastern Time / 10:00 a.m. Central Time / 8:00 a.m. Pacific Time

Join the live listen-only audio webcast at https://edge.media-server.com/mmc/p/wjwwahmj or at https://bry.com/category/events

If you would like to ask a question on the live call, please preregister at any time using the following link:
https://register.vevent.com/register/BIc62dbff31cac400faf92dc1624074392

Once registered, you will receive the dial-in numbers and a unique PIN number. You may then dial-in or have a call back. When you dial in, you will input your PIN and be placed into the call. If you register and forget your PIN or lose your registration confirmation email, you may simply re-register and receive a new PIN.

A web based audio replay will be available shortly after the broadcast and will be archived at https://ir.bry.com/reports-resources or visit https://edge.media-server.com/mmc/p/wjwwahmj

About Berry Corporation (bry)

Berry is a publicly traded (NASDAQ: BRY) western United States independent upstream energy company with a focus on onshore, low geologic risk, long-lived conventional oil reserves in the San Joaquin basin of California and the Uinta basin of Utah, with well servicing and abandonment capabilities in California. More information can be found at the Company’s website at bry.com.

Forward-Looking Statements

The information in this press release includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this press release that address plans, activities, events, objectives, goals, strategies, or developments that the Company expects, believes or anticipates will or may occur in the future, such as those regarding our financial position; liquidity; cash flows (including, but not limited to, Adjusted Free Cash Flow); anticipated financial and operating, results; capital program and development and production plans; operations and business strategy; potential acquisition opportunities; reserves; hedging activities; capital expenditures; return of capital; our shareholder return model and the payment of any future dividends; future repurchases of stock or debt; our ESG strategy and initiation of new projects or business in connection therewith; capital investments, recovery factors and other guidance are forward-looking statements. The forward-looking statements in this press release are based upon various assumptions, many of which are based, in turn, upon further assumptions. Although we believe that these assumptions were reasonable when made, these assumptions are inherently subject to significant uncertainties and contingencies which are difficult or impossible to predict and are beyond our control. Therefore, such forward-looking statements involve significant risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects.

Berry cautions you that these forward-looking statements are subject to all of the risks and uncertainties incident to the exploration for and development, production, gathering and sale of natural gas, NGLs and oil most of which are difficult to predict and many of which are beyond Berry’s control. These risks include, but are not limited to, commodity price volatility; legislative and regulatory actions that may prevent, delay or otherwise restrict our ability to drill and develop our assets, including the implementation of additional requirements for the regulatory approval and permitting process; legislative and regulatory initiatives in California or our other areas of operation addressing climate change or other environmental concerns; investment in and development of competing or alternative energy sources; drilling, production and other operating risks; effects of competition; uncertainties inherent in estimating natural gas and oil reserves and in projecting future rates of production; our ability to replace our reserves through exploration and development activities; cash flow and access to capital; the timing and funding of development expenditures; environmental, health and safety risks; effects of hedging arrangements; potential shut-ins of production due to lack of downstream demand or storage capacity; disruptions to, capacity constraints in. or other limitations on the third-party transportation and market takeaway infrastructure (including pipeline systems) that deliver our oil and natural gas and other processing and transportation considerations; the impact and duration of the ongoing COVID-19 pandemic on demand and pricing levels; the ability to effectively deploy our ESG strategy and risks associated with initiating new projects or business in connection therewith; overall domestic and global political and economic conditions; inflation levels, particularly the recent rise to historically high levels, and government efforts to reduce inflation, including increased interest rates; changes in tax laws; and the other risks described under the heading "Item 1A. Risk Factors" in the Company's Annual Report on Form 10-K for the year ended December 31, 2021 and the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2022.

You can typically identify forward-looking statements by words such as aim, anticipate, achievable, believe, budget, continue, could, effort, estimate, expect, forecast, goal, guidance, intend, likely, may, might, objective, outlook, plan, potential, predict, project, seek, should, target, will or would and other similar words that reflect the prospective nature of events or outcomes.

Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no responsibility to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise except as required by applicable law. Investors are urged to consider carefully the disclosure in our filings with the Securities and Exchange Commission, available from us at via our website or via the Investor Relations contact below, or from the SEC's website at www.sec.gov.

TABLES FOLLOWING

The financial information and certain other information presented have been rounded to the nearest whole number or the nearest decimal. Therefore, the sum of the numbers in a column may not conform exactly to the total figure given for that column in certain tables. In addition, certain percentages presented here reflect calculations based upon the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers, or may not sum due to rounding.

SUMMARY OF RESULTS

	Quarter Ended December 31, 2022	Quarter Ended September 30, 2022	Quarter Ended December 31, 2021	Year Ended December 31, 2022	Year Ended December 31, 2021
			(unaudited) *($ and shares in thousands, except per share amounts)*		
Consolidated Statement of Operations Data:					
Revenues and other:					
Oil, natural gas and natural gas liquids sales	$ 188,442	$ 203,585	$ 181,377	$ 842,449	$ 625,475
Service revenue	46,792	48,594	35,840	181,400	35,840
Electricity sales	8,284	9,711	6,308	30,833	35,636
(Losses) gains on oil and gas sales derivatives	(48,872)	114,279	(16,378)	(137,109)	(156,399)
Marketing revenues	—	—	834	289	3,921
Other revenues	37	277	105	479	477
Total revenues and other	194,683	376,446	208,086	918,341	544,950
Expenses and other:					
Lease operating expenses	87,601	79,141	67,292	302,321	236,048
Cost of services	35,010	37,628	28,339	142,819	28,339
Electricity generation expenses	5,199	6,055	3,660	21,839	23,148
Transportation expenses	1,021	1,277	1,758	4,564	6,897
Marketing expenses	—	—	825	299	3,811
General and administrative expenses	26,926	23,388	22,357	96,439	73,106
Depreciation, depletion and amortization	39,509	39,506	38,903	156,847	144,495
Taxes, other than income taxes	14,341	7,335	11,920	39,495	46,500
(Gains) losses on natural gas purchase derivatives	(41,460)	(28,942)	15,772	(88,795)	(38,577)
Other operating (income) expenses	(1,023)	623	(1,726)	3,722	3,101
Total expenses and other	167,124	166,011	189,100	679,550	526,868
Other (expenses) income:					
Interest expense	(7,646)	(7,867)	(7,451)	(30,917)	(31,964)
Other, net	(63)	(24)	(91)	(142)	(247)
Total other (expenses) income	(7,709)	(7,891)	(7,542)	(31,059)	(32,211)
Income (loss) before income taxes	19,850	202,544	11,444	207,732	(14,129)
Income tax (benefit) expense	(52,114)	10,884	2,619	(42,436)	1,413
Net income (loss)	$ 71,964	$ 191,660	$ 8,825	$ 250,168	$ (15,542)
Net earnings (loss) per share:					
Basic	$ 0.94	$ 2.46	$ 0.11	$ 3.19	$ (0.19)
Diluted	$ 0.90	$ 2.34	$ 0.11	$ 3.03	$ (0.19)
Weighted-average common shares outstanding - basic	76,181	78,044	80,007	78,517	80,209

	Quarter Ended December 31, 2022	Quarter Ended September 30, 2022	Quarter Ended December 31, 2021	Year Ended December 31, 2022	Year Ended December 31, 2021
Weighted-average common shares outstanding - diluted	80,312	82,045	84,011	82,586	80,209
Adjusted Net Income[1]	$ 76,449	$ 76,977	$ 8,120	$ 226,463	$ 10,722
Weighted-average common shares outstanding - diluted	80,312	82,045	84,011	82,586	83,496
Diluted earnings per share on Adjusted Net Income[1]	$ 0.95	$ 0.94	$ 0.10	$ 2.74	$ 0.13
Adjusted EBITDA[1]	$ 77,508	$ 96,981	$ 60,395	$ 379,948	$ 212,146
Adjusted Free Cash Flow[1][2]	$ 55,803	$ 52,724	n/a	$ 199,766	n/a
Adjusted General and Administrative Expenses[1]	$ 19,410	$ 19,107	$ 16,870	$ 76,475	$ 57,015
Effective Tax Rate	(263) %	5%	23%	(20) %	(10) %

	Quarter Ended December 31, 2022	Quarter Ended September 30, 2022	Quarter Ended December 31, 2021	Year Ended December 31, 2022	Year Ended December 31, 2021
			(unaudited) *($ and shares in thousands, except per share amounts)*		
Cash Flow Data:					
Net cash provided by operating activities	$ 105,407	$ 95,762	$ 40,230	$ 360,941	$ 122,488
Net cash used in investing activities	$ (54,888)	$ (34,241)	$ (58,251)	$ (164,552)	$ (168,787)
Net cash used in financing activities	$ (45,742)	$ (72,543)	$ (4,857)	$ (165,422)	$ (18,975)

(1) See further discussion and reconciliation in “Non-GAAP Financial Measures and Reconciliations”. See further discussion and reconciliation in “Non-GAAP Financial Measures and Reconciliations”.

(2) Adjusted Free Cash Flow was not a metric utilized by the Company prior to 2022.

	December 31, 2022	December 31, 2021
	(unaudited) *($ and shares in thousands)*	
Balance Sheet Data:		
Total current assets	$ 218,055	$ 147,498
Total property, plant and equipment, net	$ 1,359,813	$ 1,301,349
Total current liabilities	$ 234,207	$ 187,149
Long-term debt	$ 395,735	$ 394,566
Total stockholders' equity	$ 800,485	$ 692,648
Outstanding common stock shares as of	75,768	80,007

The following table represents selected financial information for the periods presented regarding the Company's business segments on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the financial information for the Company on a consolidated basis. Berry acquired C&J Well Services on October 1, 2021 and the results of their operations were included in Berry's consolidated results beginning the fourth quarter 2021.

	Year Ended December 31, 2022			
	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
		(unaudited) *(in thousands)*		
Revenues[1]	$ 874,190	$ 184,448	$ (3,188)	$ 1,055,450
Net income (loss) before income taxes	$ 298,125	$ 14,747	$ (105,140)	$ 207,732
Adjusted EBITDA[2]	$ 411,811	$ 26,113	$ (57,976)	$ 379,948
Capital expenditures	$ 141,930	$ 8,455	$ 2,536	$ 152,921
Total assets	$ 1,563,251	$ 83,461	$ (15,682)	$ 1,631,030

Year Ended December 31, 2021

	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
		(unaudited) *(in thousands)*		
Revenues[1]	$ 665,509	$ 35,840	$ —	$ 701,349
Net income (loss) before income taxes	$ 82,826	$ 1	$ (96,956)	$ (14,129)
Adjusted EBITDA[2]	$ 251,146	$ 4,310	$ (43,310)	$ 212,146
Capital expenditures	$ 129,479	$ 1,029	$ 2,211	$ 132,719
Total assets	$ 1,450,157	$ 81,093	$ (74,771)	$ 1,456,479

(1) These revenues do not include hedge settlements.

(2) See further discussion and reconciliation in “Non-GAAP Financial Measures and Reconciliations”.

COMMODITY PRICING

	Quarter Ended December 31, 2022	Quarter Ended September 30, 2022	Quarter Ended December 31, 2021	Year Ended December 31, 2022	Year Ended December 31, 2021
Weighted Average Realized Prices					
Oil without hedge ($/bbl)	$ 80.61	$ 89.54	$ 75.11	$ 91.98	$ 66.57
Effects of scheduled derivative settlements ($/bbl)	$ (7.22)	$ (13.13)	$ (20.50)	$ (14.39)	$ (16.45)
Oil with hedge ($/bbl)	$ 73.39	$ 76.41	$ 54.61	$ 77.59	$ 50.12
Natural gas ($/mcf)	$ 12.02	$ 7.95	$ 5.60	$ 7.96	$ 5.27
NGLs ($/bbl)	$ 29.67	$ 40.72	$ 47.45	$ 43.85	$ 36.64
Index Prices					
Brent oil ($/bbl)	$ 88.63	$ 97.70	$ 79.66	$ 99.04	$ 70.95
WTI oil ($/bbl)	$ 82.51	$ 91.96	$ 76.89	$ 94.39	$ 67.90
Kern, Delivered natural gas ($/mmbtu)[1]	$ 14.94	$ 8.74	$ 5.65	$ 8.99	$ 5.65
Natural gas (mmbtu) - Northwest, Rocky Mountains[2]	$ 7.54	$ 7.79	$ 5.91	$ 6.95	$ 3.90
Henry Hub natural gas ($/mmbtu)[2]	$ 5.55	$ 8.03	$ 4.75	$ 6.45	$ 3.89

(1) Kern, Delivered Index is the relevant index used for gas purchases in California.

(2) Northwest, Rocky Mountains and Henry Hub are the relevant indices used for gas sales and purchases in the Rockies.

Natural gas prices and differentials are strongly affected by local market fundamentals, availability of transportation capacity from producing areas and seasonal impacts. Our key exposure to gas prices is in our costs. We purchase substantially more natural gas for our California steamfloods and cogeneration facilities than we produce and sell in the Rockies. In May 2022, we began purchasing most of our gas in the Rockies and transporting it to our California operations using our Kern River pipeline capacity. In 2022, we purchased approximately 60,000 mmbtu/d, of which 12,000 mmbtu/d was purchased in California beginning when we entered into the Kern River pipeline capacity agreement for 48,000 mmbtu/d. The natural gas we purchase in the Rockies is shipped to our operations in California to help limit our exposure to California fuel gas purchase price fluctuations. We strive to further minimize the variability of our fuel gas costs for our steam operations by hedging a significant portion of gas purchases. Additionally, the negative impact of higher gas prices on our California operating expenses is partially offset by higher gas sales for the gas we produce and sell in the Rockies.

CURRENT HEDGING SUMMARY

As of January 31, 2023, we had the following crude oil production and gas purchases hedges.

	Q1 2023	Q2 2023	Q3 2023	Q4 2023	FY 2024	FY 2025	FY 2026
Brent							
Swaps							
Hedged volume (bbls)	1,385,278	1,387,750	1,211,717	1,196,000	3,392,048	—	—
Weighted-average price ($/bbl)	$ 77.15	$ 77.01	$ 76.26	$ 76.18	$ 76.12	$ —	$ —
Put Spreads							
Hedged volume (bbls)	540,000	546,000	552,000	552,000	1,281,000	—	—
Weighted-average price ($/bbl)	$50.00/$40.00	$50.00/$40.00	$50.00/$40.00	$50.00/$40.00	$50.00/$40.00	$ —	$ —
Producer Collars							
Hedged volume (bbls)	360,000	364,000	368,000	368,000	1,098,000	2,486,127	472,500

Weighted-average price ($/bbl)	$40.00/$106.00	$40.00/$106.00	$40.00/$106.00	$40.00/$106.00	$40.00/$105.00	$58.53/$91.11	$60.00/$82.21
Henry Hub - Natural Gas purchases							
Consumer Collars							
Hedged volume (mmbtu)	2,110,000	1,820,000	—	—	—	—	—
Weighted-average price ($/mmbtu)	$4.00/$2.75	$4.00/$2.75	$ —	$ —	$ —	$ —	$ —
NWPL - Natural Gas purchases							
Swaps							
Hedged volume (mmbtu)	1,800,000	3,640,000	3,680,000	3,680,000	7,320,000	6,080,000	—
Weighted-average price ($/mmbtu)	$ 6.40	$ 5.34	$ 5.34	$ 5.34	$ 4.27	$ 4.27	$ —
Gas Basis Differentials							
NWPL/HH - Natural Gas Purchases							
Hedged volume (mmbtu)	1,180,000	—	—	610,000	—	—	—
Weighted-average price ($/mmbtu)	$ 1.12	$ —	$ —	$ 1.12	$ —	$ —	$ —

E&P FIELD OPERATIONS

	Quarter Ended December 31, 2022	Quarter Ended September 30, 2022	Quarter Ended December 31, 2021	Year Ended December 31, 2022	Year Ended December 31, 2021
			(unaudited) *($ in per boe amounts)*		
Expenses from field operations					
Lease operating expenses	$ 36.95	$ 33.40	$ 26.23	$ 31.72	$ 23.60
Electricity generation expenses	2.19	2.56	1.43	2.29	2.31
Transportation expenses	0.43	0.54	0.69	0.48	0.69
Marketing expenses	—	—	0.32	0.03	0.38
Total	$ 39.57	$ 36.50	$ 28.67	$ 34.52	$ 26.98
Cash settlements received for gas purchase hedges	$ (5.28)	$ (5.82)	$ (3.37)	$ (4.00)	$ (5.09)
E&P non-production revenues					
Electricity sales	$ 3.49	$ 4.10	$ 2.46	$ 3.24	$ 3.56
Transportation sales	0.02	0.12	0.05	0.05	0.05
Marketing revenue	—	—	0.33	0.03	0.39
Total	$ 3.51	$ 4.22	$ 2.84	$ 3.32	$ 4.00
Total mboe	2,371	2,369	2,566	9,532	10,004

We have changed the presentation of what we formerly referred to as Opex or operating expenses. Overall, management assesses the efficiency of our E&P field operations by considering core E&P operating expenses together with our cogeneration, marketing and transportation activities. In particular, a core component of our E&P operations in California is steam, which we use to lift heavy oil to the surface. We operate several cogeneration facilities to produce some of the steam needed in our operations. In comparing the cost effectiveness of our cogeneration plants against other sources of steam in our operations, management considers the cost of operating the cogeneration plants, including the cost of the natural gas purchased to operate the facilities, against the value of the steam and electricity used in our E&P field operations and the revenues we receive from sales of excess electricity to the grid. We strive to minimize the variability of our fuel gas costs for our California steam operations with natural gas purchase hedges. Consequently, the efficiency of our E&P field operations are impacted by the cash settlements we receive or pay from these derivatives. We also have contracts for the transportation of fuel gas from the Rockies which has historically been cheaper than the California markets. With respect to transportation and marketing, management also considers opportunistic sales of incremental capacity in assessing the overall efficiencies of E&P operations.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Electricity generation expenses include the portion of fuel, labor, maintenance, and tools and supplies from two of our cogeneration facilities allocated to electricity generation expense; the remaining cogeneration expenses are included in lease operating expense. Transportation expenses relate to our costs to transport the oil and gas that we produce within our properties or move it to the market. Marketing expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Electricity revenue is from the sale of excess electricity from two of our cogeneration facilities to a California utility company under long-term contracts at market prices. These cogeneration facilities are sized to satisfy the steam needs in their respective fields, but the corresponding electricity produced is more than the electricity that is currently required for the operations in those fields. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and marketing revenues represent sales of natural gas purchased from and sold to third parties.

PRODUCTION STATISTICS

	Quarter Ended December 31, 2022	Quarter Ended September 30, 2022	Quarter Ended December 31, 2021	Year Ended December 31, 2022	Year Ended December 31, 2021
Net Oil, Natural Gas and NGLs Production Per Day[(1)]:					
Oil (mbbl/d)					
California[(2)]	21.1	20.8	22.7	21.3	22.0
Utah[(3)]	3.0	2.9	2.1	2.7	2.2
Colorado[(4)]	—	—	—	—	—
Total oil	24.1	23.7	24.8	24.0	24.2
Natural gas (mmcf/d)					
California	—	—	—	—	—
Utah[(3)]	7.8	10.4	10.0	9.6	10.2
Colorado[(4)]	—	—	6.4	0.6	6.9
Total natural gas	7.8	10.4	16.4	10.2	17.1
NGLs (mbbl/d)					
California	—	—	—	—	—
Utah[(3)]	0.4	0.4	0.4	0.4	0.4
Colorado[(4)]	—	—	—	—	—
Total NGLs	0.4	0.4	0.4	0.4	0.4
Total Production (mboe/d)[(5)]	25.8	25.8	27.9	26.1	27.4

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(1) Production represents volumes sold during the period. We also consume a portion of the natural gas we produce on lease to extract oil and gas.

(2) Includes production for Placerita properties though the end of October 2021 when they were divested. These properties had average daily production in 2021 of approximately 700 boe/d.

(3) Includes production for Antelope Creek area from February 2022, when it was acquired, through the end of 2022.

(4) In January 2022, we divested all of our natural gas properties in Colorado.

(5) Natural gas volumes have been converted to boe based on energy content of six mcf of gas to one bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2022, the average prices of Brent oil and Henry Hub natural gas were $99.04 per bbl and $6.45 per mmbtu respectively.

CAPITAL EXPENDITURES

	Quarter Ended December 31, 2022	Quarter Ended September 30, 2022	Quarter Ended December 31, 2021	Year Ended December 31, 2022	Year Ended December 31, 2021
			(unaudited) *(in thousands)*		
Capital expenditures[(1)(2)]	$ 50,398	$ 40,817	$ 27,673	$ 152,921	$ 132,719

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(1) Capital expenditures include capitalized overhead and interest and excludes acquisitions and asset retirement spending.

(2) Capital expenditures in the quarters ended December 31, 2022, September 30, 2022 and December 31, 2021 included $5 million, $2 million and $1 million, respectively, for the well servicing and abandonment business, which was acquired on October 1, 2021. Capital expenditures in the years ended December 31, 2022 and December 31, 2021 included $8 million and $1 million, respectively, for the well servicing and abandonment business.

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

Adjusted Net Income (Loss) is not a measure of net income (loss), Adjusted Free Cash Flow is not a measure of cash flow, and Adjusted EBITDA is not a measure of either net income (loss) or cash flow, in all cases, as determined by GAAP. Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses are supplemental non-GAAP financial measures used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, and amortization; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and unusual and infrequent items. Our management believes Adjusted EBITDA provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry and the investment community. The measure also allows our management to more effectively evaluate our operating performance and compare the results between periods without regard to our financing methods or capital structure. We also use Adjusted EBITDA in planning our capital allocation to sustain production levels and to determine our strategic hedging needs aside from the hedging requirements of the 2021 RBL Facility.

We define Adjusted Net Income (Loss) as net income (loss) adjusted for derivative gains or losses net of cash received or paid for scheduled derivative settlements, unusual and infrequent items, and the income tax expense or benefit of these adjustments using our statutory tax rate. Adjusted Net Income (Loss) excludes the impact of unusual and infrequent items affecting earnings that vary widely and unpredictably, including non-cash items such as derivative gains and losses. This measure is used by management when comparing results period over period. We believe Adjusted Net Income (Loss) is useful to investors because it reflects how management evaluates the Company's ongoing financial and operating performance from period-to-period after removing certain transactions and activities that affect comparability of the metrics and are not reflective of the Company's core operations. We believe this also makes it easier for investors to compare our period-to-period results with our peers.

We define Adjusted Free Cash Flow, which is a non-GAAP financial measure, as cash flow from operations less regular fixed dividends and maintenance capital. Maintenance capital represents the capital expenditures needed to maintain the same volume of annual oil and gas production and is defined as capital expenditures, excluding, when applicable, E&P capital expenditures that are related to strategic business expansion, such as acquisitions and divestitures of oil and gas properties and any exploration and development activities to increase production beyond the prior year's annual production volumes and capital expenditures in our Well Servicing and Abandonment and Corporate segments that are related to ancillary sustainability initiatives or other expenditures that are discretionary and unrelated to maintenance of our core business. Management believes Adjusted Free Cash Flow may be useful in an investor analysis of our ability to generate cash from operating activities from our existing oil and gas asset base after maintaining the existing production volumes of that asset base to return capital to stockholders, fund further business expansion through acquisitions or investments in our existing asset base to increase production volumes and pay other non-discretionary expenses. Management also uses Adjusted Free Cash Flow as the primary metric to determine the quarterly variable dividend. Under our shareholder return model, in 2022, we expected to allocate 60% of Adjusted Free Cash Flow to direct shareholder returns, predominantly in the form of cash variable dividends, as well as opportunistic debt repurchases. We expected to use the remaining 40% for opportunistic growth, including from our extensive inventory of drilling opportunities, advancing our short- and long-term sustainability initiatives, share repurchases, capital retention and funding mandatory debt service requirements or other non-discretionary expenditures. In early 2023, we updated our shareholder return model including to double our quarterly fixed dividend to $0.12 per share. Any dividends actually paid will be determined by our Board of Directors in light of existing conditions, including our earnings, financial condition, restrictions in financing agreements, business conditions and other factors. We also modified the allocations of Adjusted Free Cash Flow. Our goal is to continue maximizing shareholder value through overall returns. The allocation beginning in 2023 will be (a) 80% in the form of debt or share repurchases, or other items including growth and sustainability initiatives, as well as funding mandatory debt service requirements or other non-discretionary expenditures; (b) 20% in the form of variable cash dividends.

Adjusted Free Cash Flow does not represent the total increase or decrease in our cash balance, and it should not be inferred that the entire amount of Adjusted Free Cash Flow is available for variable dividends, debt or share repurchase or other discretionary expenditures, since we have mandatory debt service requirements and other non-discretionary expenditures that are not deducted from this measure.

We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for non-cash stock compensation expense and unusual and infrequent costs. Management believes Adjusted General and Administrative Expenses is useful because it allows us to more effectively compare our performance from period to period. We believe Adjusted General and Administrative Expenses is useful to investors because it reflects how management evaluates the Company's ongoing general and administrative expenses from period-to-period after removing non-cash stock compensation, as well as unusual or infrequent costs that affect comparability of the metrics and are not reflective of the Company's administrative costs. We believe this also makes it easier for investors to compare our period-to-period results with our peers.

While Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses are non-GAAP measures, the amounts included in the calculation of Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses were computed in accordance with GAAP. These measures are provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP and should not be considered as an alternative to, or more meaningful than income and liquidity measures calculated in accordance with GAAP. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing our financial performance, such as our cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. Our computations of Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses may not be comparable to other similarly titled measures used by other companies. Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

PV-10 is a non-GAAP financial measure, which is widely used by the industry to understand the present value of oil and gas companies. It represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows and does not give effect to derivative transactions or estimated future income taxes. Management believes that PV-10 provides useful information to investors because it is widely used by analysts and investors in evaluating oil and natural gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, management believes the use of a pre-tax measure is valuable for evaluating the Company. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

ADJUSTED EBITDA

The following tables present a reconciliation of the non-GAAP measure Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided (used) by operating activities, as applicable, for each of the periods indicated.

	Quarter Ended December 31, 2022	Quarter Ended September 30, 2022	Quarter Ended December 31, 2021	Year Ended December 31, 2022	Year Ended December 31, 2021
			(unaudited) *(in thousands)*		
Adjusted EBITDA reconciliation to net income (loss) and net cash provided by operating activities:					
Net income (loss)	$ 71,964	$ 191,660	$ 8,825	$ 250,168	$ (15,542)

Add (Subtract):					
Interest expense	7,646	7,867	7,451	30,917	31,964
Income tax (benefit) expense	(52,114)	10,884	2,619	(42,436)	1,413
Depreciation, depletion, and amortization	39,509	39,506	38,903	156,847	144,495
Losses (gains) on derivatives	7,412	(143,221)	32,150	48,314	117,822
Net cash paid for scheduled derivative settlements	(3,504)	(14,739)	(33,421)	(88,023)	(87,625)
Other operating (income) expenses	(1,023)	623	(1,726)	3,722	3,101
Stock compensation expense	4,350	4,401	3,564	16,973	13,783
Non-recurring costs(1)	3,268	—	2,030	3,466	2,735
Adjusted EBITDA	$ 77,508	$ 96,981	$ 60,395	$ 379,948	$ 212,146
Net cash provided by operating activities	$ 105,407	$ 95,762	$ 40,230	$ 360,941	$ 122,488
Add (Subtract):					
Cash interest payments	311	14,493	97	29,792	29,211
Cash income tax payments	828	321	405	3,633	699
Non-recurring costs(1)	3,268	—	2,030	3,466	2,735
Changes in operating assets and liabilities - working capital(2)	(31,003)	(14,151)	14,884	(21,446)	53,425
Other operating (income) expenses, net (noncash portion)	(1,303)	556	2,749	3,562	3,588
Adjusted EBITDA	$ 77,508	$ 96,981	$ 60,395	$ 379,948	$ 212,146

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(1) Non-recurring costs include legal and professional service expenses related to acquisition and divestiture activity for the fourth quarter of 2021 and the first quarter of 2022 and the executive transition costs in the fourth quarter of 2022.

(2) Changes in other assets and liabilities consists of working capital and various immaterial items.

Adjusted EBITDA is the measure reported to the chief operating decision maker (CODM) for purposes of making decisions about allocating resources to and assessing performance of each segment. EBITDA represents earnings before interest expense; income taxes; depreciation, depletion, and amortization; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and unusual and infrequent items.

	Year Ended December 31, 2022			
	E&P	**Well Servicing and Abandonment**	**Corporate/Eliminations**	**Consolidated Company**
	(unaudited) *(in thousands)*			
Adjusted EBITDA reconciliation to net income (loss):				
Net income (loss)	$ 298,125	$ 14,747	$ (62,704)	$ 250,168
Add (Subtract):				
Interest expense	5,053	23	25,841	30,917
Income tax benefit	—	—	(42,436)	(42,436)
Depreciation, depletion, and amortization	139,886	12,548	4,413	156,847
Losses on derivatives	48,314	—	—	48,314
Net cash paid for scheduled derivative settlements	(88,023)	—	—	(88,023)
Other operating expenses (income)	3,827	(1,690)	1,585	3,722
Stock compensation expense	1,361	287	15,325	16,973
Non-recurring costs(1)	3,268	198	—	3,466
Adjusted EBITDA	$ 411,811	$ 26,113	$ (57,976)	$ 379,948

	Year Ended December 31, 2021			
	E&P	**Well Servicing and Abandonment**	**Corporate/Eliminations**	**Consolidated Company**
	(unaudited) *(in thousands)*			
Adjusted EBITDA reconciliation to net income (loss):				
Net income (loss)	$ 82,825	$ 1	$ (98,368)	$ (15,542)
Add (Subtract):				
Interest expense	—	—	31,964	31,964

Income tax expense	—	—	1,413	1,413
Depreciation, depletion, and amortization	136,915	2,974	4,606	144,495
Losses on derivatives	117,822	—	—	117,822
Net cash paid for scheduled derivative settlements	(87,625)	—	—	(87,625)
Other operating expenses	109	—	2,992	3,101
Stock compensation expense	1,100	—	12,683	13,783
Non-recurring costs(1)	—	1,335	1,400	2,735
Adjusted EBITDA	$ 251,146	$ 4,310	$ (43,310)	$ 212,146

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(1) Non-recurring costs include legal and professional service expenses related to acquisition and divestiture activity for the fourth quarter of 2021 and the first quarter of 2022 and the executive transition costs in the fourth quarter of 2022.

ADJUSTED FREE CASH FLOW

The following table presents a reconciliation of the non-GAAP financial measure Adjusted Free Cash Flow to the GAAP financial measure of operating cash flow in the period indicated. We use Adjusted Free Cash Flow for our shareholder return model, which began in 2022.

	Quarter Ended		Year Ended
	December 31, 2022	**September 30, 2022**	**December 31, 2022(4)**
		(unaudited) *(in thousands)*	
Adjusted Free Cash Flow:			
Net cash provided by operating activities(1)	$ 105,407	$ 95,762	$ 360,941
Subtract:			
Maintenance capital(2)	(45,047)	(38,312)	(141,930)
Fixed dividends(3)	(4,557)	(4,726)	(19,245)
Adjusted Free Cash Flow	$ 55,803	$ 52,724	$ 199,766

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(1) On a consolidated basis.

(2) Maintenance capital is the capital required to keep annual production flat, and is calculated as follows:

	Quarter Ended		Year Ended
	December 31, 2022	**September 30, 2022**	**December 31, 2022**
		(unaudited) *(in thousands)*	
Consolidated capital expenditures(a)	$ (50,398)	$ (40,817)	$ (152,921)
Excluded items(b)	5,351	2,505	10,991
Maintenance capital	$ (45,047)	$ (38,312)	$ (141,930)

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(a) Capital expenditures include capitalized overhead and interest and excludes acquisitions and asset retirement spending.

(b) Comprised of the capital expenditures in our E&P segment that are related to strategic business expansion, such as acquisitions and divestitures of oil and gas properties and any exploration and development activities to increase production beyond the prior year's annual production volumes and capital expenditures in our well servicing and abandonment segment and corporate expenditures that are related to ancillary sustainability initiatives or other expenditures that are discretionary and unrelated to maintenance of our core business. For the quarter ended December 31, 2022, the quarter ended September 30, 2022, and the year ended December 31, 2022 we excluded approximately $5 million, $2 million, and $8 million of capital expenditures related to our well servicing and abandonment segment, which was substantially all used for sustainability initiatives. For the quarter ended December 31, 2022, the quarter ended September 30, 2022, and the year ended December 31, 2022 we excluded approximately $0.5 million, $0.8 million, and $3 million of corporate capital expenditures, which we determined was not related to the maintenance of our baseline production.

(3) Represents fixed dividends declared which are included in the "Dividends declared on common stock" line in the consolidated statement of stockholders' equity.

(4) Adjusted Free Cash Flow was not a metric utilized by the Company prior to 2022.

ADJUSTED NET INCOME (LOSS)

The following table presents a reconciliation of the non-GAAP financial measure Adjusted Net Income (Loss) to the GAAP financial measure of net income (loss) and Adjusted Net Income (Loss) per share — diluted to net income per share — diluted

	Quarter Ended					
	December 31, 2022		September 30, 2022		December 31, 2021	
	(in thousands)	per share - diluted	(in thousands)	per share - diluted	(in thousands)	per share - diluted
	(unaudited)					
Adjusted Net Income (Loss) reconciliation to net income (loss):						
Net income	$ 71,964	$ 0.90	$ 191,660	$ 2.34	$ 8,825	$ 0.11
Add (Subtract):						
Losses (gains) on derivatives	7,412	0.09	(143,221)	(1.75)	32,150	0.38
Net cash paid for scheduled derivative settlements	(3,504)	(0.04)	(14,739)	(0.18)	(33,421)	(0.40)
Other operating (income) expenses	(1,023)	(0.02)	623	0.01	(1,726)	(0.01)
Non-recurring costs[1]	3,268	0.04	—	—	2,030	0.02
Total additions (subtractions), net	6,153	0.07	(157,337)	(1.92)	(967)	(0.01)
Income tax (expense) benefit of adjustments[2]	(1,668)	(0.02)	42,654	0.52	262	—
Adjusted Net Income	$ 76,449	$ 0.95	$ 76,977	$ 0.94	$ 8,120	$ 0.10
Basic EPS on Adjusted Net Income	$ 1.00		$ 0.99		$ 0.10	
Diluted EPS on Adjusted Net Income	$ 0.95		$ 0.94		$ 0.10	
Weighted average shares outstanding - basic	76,181		78,044		80,007	
Weighted average shares outstanding - diluted	80,312		82,045		84,011	

(1) Non-recurring costs include legal and professional service expenses related to acquisition and divestiture activity for the fourth quarter of 2021 and the first quarter of 2022 and the executive transition costs in the fourth quarter of 2022.

(2) The federal and state statutory rate was utilized in both 2022 and 2021. We updated the disclosure for 2021 to reflect the statutory rate, instead of the effective tax rate previously utilized.

	Year Ended			
	December 31, 2022		December 31, 2021	
	(in thousands)	per share- diluted	(in thousands)	per share- diluted
	(unaudited)			
Adjusted Net Income (Loss) reconciliation to net (loss) income:				
Net income (loss)	$ 250,168	$ 3.03	$ (15,542)	$ (0.19)
Add (Subtract):				
Losses on derivatives	48,314	0.59	117,822	1.41
Net cash paid for scheduled derivative settlements	(88,023)	(1.07)	(87,625)	(1.05)
Other operating expenses	3,722	0.04	3,101	0.05
Non-recurring costs[1]	3,466	0.04	2,735	0.03
Total (subtractions) additions, net	(32,521)	(0.40)	36,033	0.44
Income tax benefit (expense) of adjustments[2]	8,816	0.11	(9,769)	(0.12)
Adjusted Net Income	$ 226,463	$ 2.74	$ 10,722	$ 0.13
Basic EPS on Adjusted Net Income	$ 2.88		$ 0.13	
Diluted EPS on Adjusted Net Income	$ 2.74		$ 0.13	
Weighted average shares outstanding - basic	78,517		80,209	
Weighted average shares outstanding - diluted	82,586		83,496	

(1) Non-recurring costs include legal and professional service expenses related to acquisition and divestiture activity for the fourth quarter of 2021 and the first quarter of 2022 and the executive transition costs in the fourth quarter of 2022.
(2) The federal and state statutory rate was utilized in both 2022 and 2021. We updated the disclosure for 2021 to reflect the statutory rate, instead of the effective tax rate previously utilized.

ADJUSTED GENERAL AND ADMINISTRATIVE EXPENSES

The following table presents a reconciliation of the GAAP financial measure of general and administrative expenses to the non-GAAP financial measures of Adjusted General and Administrative Expenses.

	Quarter Ended December 31, 2022	Quarter Ended September 30, 2022	Quarter Ended December 31, 2021	Year Ended December 31, 2022	Year Ended December 31, 2021
			(unaudited) *($ in thousands except per mboe amounts)*		
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:					
General and administrative expenses	$ 26,926	$ 23,388	$ 22,357	$ 96,439	$ 73,106
Subtract:					
Non-cash stock compensation expense (G&A portion)	(4,248)	(4,281)	(3,457)	(16,498)	(13,356)
Non-recurring costs[1]	(3,268)	—	(2,030)	(3,466)	(2,735)
Adjusted General and Administrative Expenses	$ 19,410	$ 19,107	$ 16,870	$ 76,475	$ 57,015
Well servicing and abandonment segment	$ 3,296	$ 3,324	$ 3,193	$ 12,975	$ 3,193
E&P segment, and corporate	$ 16,114	$ 15,783	$ 13,677	$ 63,500	$ 53,822
E&P segment, and corporate ($/boe)	$ 6.80	$ 6.66	$ 5.33	$ 6.66	$ 5.38
Total mboe	2,371	2,369	2,566	9,532	10,004

(1) Non-recurring costs include legal and professional service expenses related to acquisition and divestiture activity for the fourth quarter of 2021 and the first quarter of 2022 and the executive transition costs in the fourth quarter of 2022.

RESERVES AND PV-10

The following table summarizes our estimated proved reserves and related PV-10 as of December 31, 2022.

	Proved Reserves as of December 31, 2022[1]		
	California (San Joaquin basin)	Utah (Uinta basin)	Total
		(unaudited)	
Proved developed reserves:			
Oil (mmbbl)	43	11	54
Natural Gas (bcf)	—	44	44
NGLs (mmbbl)	—	1	1
Total (mmboe)[2][3]	43	19	62
Proved undeveloped reserves:			
Oil (mmbbl)	41	4	45
Natural Gas (bcf)	—	15	15
NGLs (mmbbl)	—	1	1
Total (mmboe)[3]	41	7	48
Total proved reserves:			
Oil (mmbbl)	84	15	99
Natural Gas (bcf)	—	59	59
NGLs (mmbbl)	—	2	2
Total (mmboe)[3]	84	26	110
PV-10 (in millions)[4]	$ 2,240	$ 384	$ 2,624

(1) Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $100.25 per bbl Brent for oil and NGLs and $6.40 per mmbtu Henry Hub for natural gas at December 31, 2022. The volume-weighted average realized prices over the lives of the properties were $91.33 per bbl of oil and condensate, $48.76 per bbl of NGLs and $6.76 per mcf. The prices were held constant for the lives of the properties and we took into account pricing differentials reflective of the market environment. Prices were calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules including adjustments by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

(2) For proved developed reserves approximately 14% of total and 14% of oil are non-producing.

(3) Natural gas volumes have been converted to boe based on energy content of six mcf of gas to one bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2022, the average prices of Brent oil and Henry Hub natural gas were $99.04 per bbl and $6.45 per mmbtu, respectively.

(4) For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see the table below. PV-10 does not give effect to derivatives transactions.

The following table provides a reconciliation of PV-10 of our proved reserves to the standardized measure of discounted future net cash flows at December 31, 2022:

	At December 31, 2022
	(unaudited) *(in millions)*
California PV-10	$ 2,240
Utah PV-10	384
Total Company PV-10	2,624
Less: present value of future income taxes discounted at 10%	(550)
Standardized measure of discounted future net cash flows	$ 2,074

The following table presents reserves changes and production for 2022:

	Total Company	California
	(unaudited) *(in mmboe)*	
Extensions and discoveries	25.5	19.6
Revisions of previous estimates	(5.9)	(6.8)
Purchases of minerals[1]	7.1	—
Sales of minerals[2]	(4.2)	—
Total reserves changes	22.5	12.8
Production	9.5	7.8
Reserve replacement ratio	236%	164%

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(1) Purchases of minerals are primarily the Antelope Creek properties we acquired in February 2022.

(2) Sales of minerals are related to all of our natural gas properties in Colorado, which were divested in January 2022.

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