Berry Corporation Reports Third Quarter 2024 Results

November 7, 2024

Refinances Debt, Announces Uinta Basin Opportunities, and Declares Quarterly Dividend

DALLAS, Nov. 07, 2024 (GLOBE NEWSWIRE) -- Berry Corporation (bry) (NASDAQ: BRY) ("Berry" or the "Company") today reported third quarter 2024 results and quarterly fixed dividends totaling $0.03 per share. The Company also announced entry into a new $545 million term loan facility that will enable the successful completion of a transformative debt refinancing. The details for today's earnings call, also accessible by webcast, are listed below.

Quarterly Highlights

- Third quarter production averaged 24,800 BOE per day, with production increasing at the end of the quarter as additional wells were brought online
- Annual 2024 production expected to reach the mid-point of guidance of 24,600 to 25,800 BOE per day
- Increased Free Cash Flow(1) 55% quarter over quarter
- Declared third quarter fixed dividends of $0.03 per share

Other Updates

- Entered $545 million term loan credit facility to redeem all the Company's $400 million notes due 2026 and refinance the current RBL credit facility due August 2025. Valor Upstream Credit Partners, L.P., which is managed by Breakwall Capital LP in partnership with Vitol, is the sole lender on the new term loan credit facility
- Based on the outperformance of the initial four well Uinta farm-in confirming significant value potential, executed another larger farm-in deal and actively marketing an opportunity to accelerate horizontal well development of the Company's Utah assets

"Berry delivered another good operational quarter with production ramping up as we exited September, and we are on track to reach the mid-point of our full year production guidance. We generated $71 million of cash flow from operations for the quarter and a 55% sequential increase in Free Cash Flow(1), while decreasing capital expenditures as planned. We have now completed our 2024 drilling plan and have permits in-hand to support activities well into the new year, including drilling new wells and sidetracks and working over existing wells. Based on current permitting processes and our healthy California inventory, we are confident we can maintain consistent production levels for 2025, as we have for the last six years. We are also excited about promising upside opportunities in Utah and California that should yield increasing benefits in 2025 and beyond," said Fernando Araujo, Berry's Chief Executive Officer.

"Based on activity across the Uinta basin, much of which is adjacent to our existing acreage, we believe our Utah assets have the potential to be a substantial long-term value driver for our shareholders. We entered a second farm-in agreement covering approximately 5,800 gross acres, which will help accelerate the appraisal of our acreage. Additionally, we are evaluating potential JV partners to accelerate our phase 1 plans to drill up to two multi-well horizontal drilling pads starting in 2025.

"We also have promising upside opportunities in California. Success from new sidetracks drilled in the Thermal Diatomite reservoir are yielding over 100% rates of return, further driving our capital efficiency efforts. By executing on these opportunities to leverage our world class California assets, we are stronger, more resilient, and better positioned to accelerate development in Utah while still honoring our commitment to generate sustainable Free Cash Flow," Araujo continued.

"Finally, we are excited to partner with Valor, Breakwall and Vitol on a new term loan facility This financing will enable us to redeem all of our notes due in 2026 and refinance our existing credit facility, while also providing us with the ability to deploy capital into high rate of return projects, including the significant opportunity we see in our Uinta position. Importantly, the unique structure provides Berry with great flexibility to repay the loan in advance, pursue strategic opportunities, and return capital to shareholders," Araujo concluded.

Selected Comparative Results

	Three Months Ended		
	September 30, 2024	June 30, 2024	September 30, 2023
	(unaudited) (in millions, except per share amounts)		
Oil, natural gas & NGL revenues(1)	$ 154	$ 169	$ 173
Net income (loss)	$ 70	$ (9)	$ (45)
Adjusted Net Income(2)	$ 11	$ 14	$ 12
Adjusted EBITDA(2)	$ 67	$ 74	$ 70

Income (loss) earnings per diluted share	$ 0.91	$ (0.11)	$ (0.60)
Adjusted earnings per diluted share[2]	$ 0.14	$ 0.18	$ 0.15
Cash Flow from Operations	$ 71	$ 71	$ 55
Capital expenditures	$ 26	$ 42	$ 14
Free cash flow[2]	$ 45	$ 29	$ 42
Production (mboe/d)	24.8	25.3	25.3

(1) Revenues do not include hedge settlements.

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

"We generated Adjusted EBITDA [1] of $67 million in the third quarter, a 10% decrease from the second quarter of 2024, driven by lower oil prices and partially offset by lower lease operating expenses on a hedged basis and Adjusted G&A[1] expenses. Cash Flow from Operations totaled $71 million which was flat with the second quarter and Free Cash Flow[1] was $45 million, a 55% increase over the second quarter, driven by lower capital expenditures consistent with our expectations. We have continued to optimize cash operating costs throughout the organization and prioritize debt reduction, notably by reducing our revolver balance by 24% from the end of the second quarter to the end of the third quarter," stated Mike Helm, Berry's Chief Financial Officer.

"Our new term loan credit facility will allow us to redeem our 2026 Notes and refinance our current RBL before year end. To comply with the new debt covenants and support our exciting plans for further development in our Utah assets, we are transitioning our shareholder return model to prioritize the repayment of debt and investment in opportunities that will generate sustainable Free Cash Flow[1] and drive long-term shareholder value. We remain committed to a disciplined approach to maintaining a healthy balance sheet, and our dividend policy now targets a fixed dividend rate of $0.12 per share annually, subject to board approval. This new approach is designed to return capital to our shareholders at a sustainable level, while enabling us to pursue the highest capital return opportunities in front of us, including developing our assets in the Uinta Basin."

Third Quarter 2024 Financial and Operating Results

Q3 2024 Compared to Q2 2024

Oil, natural gas and NGL revenues (excluding hedging settlements) for the third quarter of 2024 decreased from the second quarter of 2024, driven by a decrease in oil prices and, to a lesser extent, lower volumes. Net income for the third quarter of 2024 increased compared to the second quarter due to unrealized hedge gains in the third quarter, the impairment charge in the second quarter and the income tax impact. Adjusted EBITDA[1] and Adjusted Net Income[1] decreased in the third quarter of 2024, compared to the prior quarter generally due to decreased commodity revenues (as a result of lower prices and volumes), as well as lower margins from the well servicing and abandonment segment. Decreased capital expenditures for the third quarter drove increased Free Cash Flow[1] compared to the second quarter of 2024, while Cash Flow from Operations remained steady. Capital expenditures were $26 million in the third quarter of 2024 compared to $42 million in the second quarter of 2024, with the decrease driven by lower drilling activity, as expected, and the second quarter also included capital related to the Utah farm-in development program. At September 30, 2024, the Company had liquidity of $104 million, consisting of $9 million cash and $95 million available for borrowings under its revolving credit facilities.

Q3 2024 Compared to Q3 2023

Compared to the third quarter of 2023, oil, natural gas and NGL revenues (excluding hedging settlements) decreased, which was mainly driven by lower oil prices and lower volumes in the third quarter of 2024. Adjusted EBITDA[1] and Adjusted Net Income[1] for the third quarter of 2024 also decreased compared to the third quarter of 2023, driven by the decreased commodity revenues (as a result of lower prices and volumes) and lower margins from the well servicing and abandonment segment, offset by a decrease in lease operating costs. Free Cash Flow[1] in the third quarter of 2024 was slightly higher than the third quarter of 2023, while both Cash Flow from Operations and capital expenditures increased.

Guidance Update

For the full year 2024, the new Company guidance for Adjusted General & Administrative (G&A)[2] expenses for the E&P Segment & Corp is an increased range of $6.30/boe to $6.50/boe due to inflationary pressure, and for the Well Servicing & Abandonment Segment Adjusted EBITDA[2] is a decreased range of $6 million to $8 million due to local market disruption resulting in lower rates and activity.

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

(2) Adjusted General & Administrative expenses and Well Servicing & 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. See further discussion and reconciliation in "Non-GAAP Financial Measures and Reconciliations".

Quarterly Dividends

The Company's Board of Directors declared fixed dividends totaling $0.03 per share on the Company's outstanding common stock. The dividends are payable on November 25, 2024 to shareholders of record at the close of business on November 15, 2024.

Earnings Conference Call

The Company will host a conference call to discuss these results:

Call Date: Thursday, November 7, 2024

Call Time: 11:00 a.m. Eastern Time / 10:00 am 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/tysxczje
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/BIe48b23e273834c71bc53e0d17114932f.

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/tysxczje or https://bry.com/category/events.

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, low decline, long-lived oil and gas reserves. We operate in two business segments: (i) exploration and production ("E&P") and (ii) well servicing and abandonment. Our E&P assets are located in California and Utah, are characterized by high oil content and are predominantly located in rural areas with low population. Our California assets are in the San Joaquin basin (100% oil), while our Utah assets are in the Uinta basin (60% oil and 40% gas). We operate our well servicing and abandonment segment 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. 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. 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; our ability to refinance our indebtedness; our ability to satisfy our debt obligations and comply with all covenants, agreements and conditions under our 2024 Term Loan Agreement; cash flows (including, but not limited to, Free Cash Flow); financial and operating results; capital program and development and production plans and expectations (including about potential results and impact); operations and business strategy; potential acquisition and other strategic opportunities; reserves; hedging activities; capital expenditures; return of capital; the payment of future dividends; future repurchases of stock; capital investments; our ESG strategy and the initiation of new projects or business in connection therewith, recovery factors; and other guidance are forward-looking statements. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, sometimes materially.

Berry cautions you that these forward-looking statements are subject to all of the risks and uncertainties incident to acquisition transactions and 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 with respect to existing and/or new requirements in 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 or strategic transactions; 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 ability to effectively deploy our ESG strategy and risks associated with initiating new projects or business in connection therewith; our ability to successfully integrate the Macpherson assets into our operations; we fail to identify risks or liabilities related to Macpherson, its operations or assets; our inability to achieve anticipated synergies; our ability to successfully execute other strategic bolt-on acquisitions; overall domestic and global political and economic conditions; inflation levels, including increased interest rates and volatility in financial markets and banking; 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, 2023 and subsequent filings with the SEC.

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

	Three Months Ended		
	September 30, 2024	**June 30, 2024**	**September 30, 2023**
	(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	$ 154,438	$ 168,781	$ 172,611
Service revenue	25,465	31,155	45,511
Electricity sales	4,410	3,691	3,849
Gains (losses) on oil and gas sales derivatives	75,434	(5,844)	(103,282)
Other revenues	37	36	113
Total revenues and other	259,784	197,819	118,802
Expenses and other:			
Lease operating expenses	54,801	53,989	59,842
Cost of services	22,911	25,021	35,806
Electricity generation expenses	1,245	552	1,479
Transportation expenses	1,332	1,039	1,089
Acquisition costs	971	1,394	2,082
General and administrative expenses	19,111	18,881	20,987
Depreciation, depletion and amortization	42,749	42,843	39,729
Impairment of oil and gas properties	—	43,980	—
Taxes, other than income taxes	10,351	12,674	17,980
Losses on natural gas purchase derivatives	7,775	2,642	(8,425)
Other operating (income)	(4,687)	(3,204)	(505)
Total expenses and other	156,559	199,811	170,064
Other expenses:			
Interest expense	(8,986)	(10,050)	(9,101)
Other, net	56	(53)	(42)
Total other expenses	(8,930)	(10,103)	(9,143)
Income (loss) before income taxes	94,295	(12,095)	(60,405)
Income tax expense (benefit)	24,432	(3,326)	(15,343)
Net income (loss)	$ 69,863	$ (8,769)	$ (45,062)
Net income (loss) per share:			
Basic	$ 0.91	$ (0.11)	$ (0.60)
Diluted	$ 0.91	$ (0.11)	$ (0.60)
Weighted-average shares of common stock outstanding - basic	76,939	76,939	75,662
Weighted-average shares of common stock outstanding - diluted	77,060	76,939	75,662
Adjusted Net Income[1]	$ 10,839	$ 14,155	$ 11,831
Weighted-average shares of common stock outstanding - diluted	77,060	77,161	77,606
Diluted earnings per share on Adjusted Net Income[1]	$ 0.14	$ 0.18	$ 0.15

	Three Months Ended		
	September 30, 2024	**June 30, 2024**	**September 30, 2023**
	(unaudited) *($ and shares in thousands, except per share amounts)*		
Adjusted EBITDA[1]	$ 67,121	$ 74,329	$ 69,829
Free Cash Flow[1]	$ 44,821	$ 28,566	$ 41,724
Adjusted General and Administrative Expenses[1]	$ 16,466	$ 17,038	$ 16,763
Effective Tax Rate	26%	28%	25%

Cash Flow Data:			
Net cash provided by operating activities	$ 70,695	$ 70,891	$ 55,320
Net cash used in investing activities	$ (24,502)	$ (42,486)	$ (68,029)
Net cash used in financing activities	$ (43,410)	$ (25,174)	$ 21,343

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

	September 30, 2024	December 31, 2023
	(unaudited) *($ and shares in thousands)*	
Balance Sheet Data:		
Total current assets	$ 136,864	$ 140,800
Total property, plant and equipment, net	$ 1,337,275	$ 1,406,612
Total current liabilities	$ 171,686	$ 223,182
Long-term debt	$ 398,000	$ 427,993
Total stockholders' equity	$ 732,209	$ 757,976
Outstanding common stock shares as of	76,939	75,667

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.

	Three Months Ended September 30, 2024			
	E&P	Well Servicing and Abandonment	Corporate/ Eliminations	Consolidated Company
	(unaudited) *(in thousands)*			
Revenues[1]	$ 158,886	$ 30,836	$ (5,372)	$ 184,350
Net income (loss) before income taxes	$ 118,271	$ 2,748	$ (26,724)	$ 94,295
Capital expenditures	$ 24,793	$ 498	$ 583	$ 25,874
Total assets	$ 1,545,517	$ 56,528	$ (84,897)	$ 1,517,148

	Three Months Ended June 30, 2024			
	E&P	Well Servicing and Abandonment	Corporate/ Eliminations	Consolidated Company
	(unaudited) *(in thousands)*			
Revenues[1]	$ 172,508	$ 36,680	$ (5,525)	$ 203,663
Net income (loss) before income taxes	$ 13,860	$ 1,122	$ (27,077)	$ (12,095)
Capital expenditures	$ 41,735	$ 468	$ 122	$ 42,325
Total assets	$ 1,547,334	$ 63,329	$ (77,754)	$ 1,532,909

	Three Months Ended September 30, 2023			
	E&P	Well Servicing and Abandonment	Corporate/ Eliminations	Consolidated Company
	(unaudited) *(in thousands)*			
Revenues[1]	$ 176,573	$ 47,259	$ (1,748)	$ 222,084
Net income (loss) before income taxes	$ (35,485)	$ 3,295	$ (28,215)	$ (60,405)
Capital expenditures	$ 10,833	$ 2,104	$ 659	$ 13,596

Total assets	$ 1,604,253	$ 71,891	$ (62,219)	$ 1,613,925

(1) These revenues do not include hedge settlements.

COMMODITY PRICING

	Three Months Ended		
	September 30, 2024	June 30, 2024	September 30, 2023
Weighted Average Realized Prices			
Oil without hedge ($/bbl)	$ 72.40	$ 78.18	$ 78.89
Effects of scheduled derivative settlements ($/bbl)	(1.39)	(4.60)	(5.76)
Oil with hedge ($/bbl)	$ 71.01	$ 73.58	$ 73.13
Natural gas ($/mcf)	$ 2.01	$ 1.78	$ 3.57
NGLs ($/bbl)	$ 24.01	$ 24.46	$ 22.54
Purchased Natural Gas			
Purchase price, before the effects of derivative settlements ($/mmbtu)	$ 2.70	$ 2.26	$ 4.18
Effects of derivative settlements ($/mmbtu)	1.64	2.04	1.43
Purchase price, after the effects of derivative settlements ($/mmbtu)	$ 4.34	$ 4.30	$ 5.61
Index Prices			
Brent oil ($/bbl)	$ 78.71	$ 85.03	$ 85.92
WTI oil ($/bbl)	$ 75.26	$ 80.60	$ 81.99
Natural gas ($/mmbtu) – SoCal Gas city-gate(1)	$ 2.68	$ 1.86	$ 7.10
Natural gas ($/mmbtu) - Northwest, Rocky Mountains(2)	$ 1.92	$ 1.40	$ 3.40
Henry Hub natural gas ($/mmbtu)(2)	$ 2.11	$ 2.07	$ 2.59

(1) The natural gas we purchase to generate steam and electricity is primarily based on Rockies price indexes, including transportation charges, as we currently purchase a substantial majority of our gas needs from the Rockies, with the balance purchased in California. SoCal Gas city-gate Index is the relevant index used only for the portion of gas purchases in California.

(2) Most of our gas purchases and gas sales in the Rockies are predicated on the Northwest, Rocky Mountains index, and to a lesser extent based on Henry Hub.

Natural gas prices and differentials are strongly affected by local market fundamentals, availability of transportation capacity from producing areas and seasonal impacts. The Company's key exposure to gas prices is in costs. The Company purchases substantially more natural gas for California steamfloods and cogeneration facilities than what is produced and sold in the Rockies. The Company purchases most of its gas in the Rockies and transports it to its California operations using the Kern River pipeline capacity. The Company buys approximately 48,000 mmbtu/d in the Rockies, and the remainder comes from California markets. The volume purchased in California fluctuates and averaged 2,000 mmbtu/d in the third quarter of 2024, 2,000 mmbtu/d in the second quarter of 2024 and 6,000 mmbtu/d in the third quarter of 2023. The natural gas purchased in the Rockies is shipped to operations in California to help limit exposure to California fuel gas purchase price fluctuations. The Company strives to further minimize the variability of fuel gas costs for steam operations by hedging a significant portion of gas purchases. Additionally, the negative impact of higher gas prices on California operating expenses is partially offset by higher gas sales for the gas produced and sold in the Rockies. The Kern capacity allows us to purchase and sell natural gas at the same pricing indices.

CURRENT HEDGING SUMMARY

As of November 1, 2024, we had the following crude oil production and gas purchases hedges.

	Q4 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Brent - Crude Oil production						
Swaps						
Hedged volume (bbls)	1,438,656	4,951,125	2,633,268	3,056,000	2,378,000	724,000
Weighted-average price ($/bbl)	$ 76.93	$ 76.06	$ 71.76	$ 70.66	$ 68.36	$ 67.44
Sold Calls(1)						
Hedged volume (bbls)	92,000	296,127	1,251,500	318,500	—	—
Weighted-average price ($/bbl)	$ 105.00	$ 88.69	$ 85.53	$ 80.03	$ —	$ —
Purchased Puts (net)(2)						
Hedged volume (bbls)	322,000	—	—	—	—	—
Weighted-average price ($/bbl)	$ 50.00	$ —	$ —	$ —	$ —	$ —
Purchased Puts (net)(2)						
Hedged volume (bbls)	—	296,127	1,251,500	318,500	—	—
Weighted-average price ($/bbl)	$ —	$ 60.00	$ 60.00	$ 65.00	$ —	$ —

Sold Puts (net)(2)						
Hedged volume (bbls)	46,000	—	—	—	—	—
Weighted-average price ($/bbl)	$ 40.00	$ —	$ —	$ —	$ —	$ —
NWPL - Natural Gas purchases(3)						
Swaps						
Hedged volume (mmbtu)	3,680,000	13,380,000	3,040,000	—	—	—
Weighted-average price ($/mmbtu)	$ 3.96	$ 4.27	$ 4.26	$ —	$ —	$ —

(1) Purchased calls and sold calls with the same strike price have been presented on a net basis.
(2) Purchased puts and sold puts with the same strike price have been presented on a net basis.
(3) The term “NWPL” is defined as Northwest Rocky Mountain Pipeline.

(LOSSES) GAINS ON DERIVATIVES

A summary of gains and losses on the derivatives included on the statements of operations is presented below:

	Three Months Ended		
	September 30, 2024	June 30, 2024	September 30, 2023
	(unaudited) *(in thousands)*		
Realized (losses) on commodity derivatives:			
Realized (losses) on oil sales derivatives	$ (2,907)	$ (9,801)	$ (12,304)
Realized (losses) on natural gas purchase derivatives	(7,490)	(9,314)	(7,128)
Total realized (losses) on derivatives	$ (10,397)	$ (19,115)	$ (19,432)
Unrealized gains (losses) on commodity derivatives:			
Unrealized gains (losses) on oil sales derivatives	$ 78,341	$ 3,957	$ (90,977)
Unrealized (losses) gains on natural gas purchase derivatives	(285)	6,672	15,552
Total unrealized gains (losses) on derivatives	$ 78,056	$ 10,629	$ (75,425)
Total gains (losses) on derivatives	$ 67,659	$ (8,486)	$ (94,857)

E&P FIELD OPERATIONS

	Three Months Ended		
	September 30, 2024	June 30, 2024	September 30, 2023
	(unaudited) *($ in per boe amounts)*		
Expenses from field operations			
Lease operating expenses	$ 24.02	$ 23.47	$ 25.73
Electricity generation expenses	0.55	0.24	0.64
Transportation expenses	0.58	0.45	0.47
Total	$ 25.15	$ 24.16	$ 26.84
Cash settlements paid for gas purchase hedges	$ 3.28	$ 4.05	$ 3.06
E&P non-production revenues			
Electricity sales	$ 1.93	$ 1.60	$ 1.65
Transportation sales	0.02	0.02	0.05
Total	$ 1.95	$ 1.62	$ 1.70

Overall, management assesses the efficiency of the Company's E&P field operations by considering core E&P operating expenses together with cogeneration, marketing and transportation activities. In particular, a core component of E&P operations in California is steam, which is used to lift heavy oil to the surface. The Company operates several cogeneration facilities to produce some of the steam needed in operations. In comparing the cost effectiveness of cogeneration plants against other sources of steam in 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 E&P field operations and the revenues received from sales of excess electricity to the grid. The Company strives to minimize the variability of its fuel gas costs for California steam operations with natural gas purchase hedges. Consequently, the efficiency of E&P field operations are impacted by the cash settlements received or paid from these derivatives. The Company also has 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 the Company's cogeneration facilities allocated to electricity generation expense; the remaining cogeneration expenses are included in lease operating expense. Transportation expenses relate to costs to transport the oil and gas that is produced within the Company's properties or moved to the market. Marketing expenses mainly relate to natural gas purchased from third parties that moves through gathering and processing systems and then is sold to third parties. Electricity revenue is from the sale of excess electricity from two of the Company's 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 are transported on the Company's systems on behalf of third parties and marketing revenues represent sales of natural gas purchased from and sold to third parties.

PRODUCTION STATISTICS

	Three Months Ended		
	September 30, 2024	**June 30, 2024**	**September 30, 2023**
Net Oil, Natural Gas and NGLs Production Per Day[1]:			
Oil (mbbl/d)			
California	20.1	21.1	20.5
Utah	2.7	2.3	2.7
Total oil	22.8	23.4	23.2
Natural gas (mmcf/d)			
California	—	—	—
Utah	9.5	8.9	9.5
Total natural gas	9.5	8.9	9.5
NGLs (mbbl/d)			
California	—	—	—
Utah	0.4	0.4	0.5
Total NGLs	0.4	0.4	0.5
Total Production (mboe/d)[2]	24.8	25.3	25.3

(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) 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 three months ended September 30, 2024, the average prices of Brent oil and Henry Hub natural gas were $78.71 per bbl and $2.11 per mmbtu respectively.

CAPITAL EXPENDITURES

	Three Months Ended		
	September 30, 2024	**June 30, 2024**	**September 30, 2023**
		(unaudited) *(in thousands)*	
Capital expenditures [1][2]	$ 25,874	$ 42,325	$ 13,596

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

(2) Capital expenditures for the three months ended September 30, 2024 and June 30, 2024 were less than $1 million, respectively, related to the well servicing and abandonment business. Capital expenditures for the three months ended September 30, 2023 were $2 million related to the well servicing and abandonment business.

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

Adjusted EBITDA is not a measure of either net income (loss) or cash flow, Free Cash Flow is not a measure of cash flow, Adjusted Net Income (Loss) is not a measure of net income (loss), and Adjusted General and Administrative Expenses is not a measure of general and administrative expenses, in all cases, as determined by GAAP. Rather, Adjusted EBITDA, 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 expenditure allocation to sustain production levels and to determine our strategic hedging needs aside from the hedging requirements of the 2021 RBL Facility and 2024 Term Loan Credit Agreement.

We define Free Cash Flow as cash flow from operations less capital expenditures. We use Free Cash Flow as the primary metric to measure our ability to pay dividends, pay down debt, repurchase stock, and make strategic growth and bolt-on acquisitions. Management believes 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 capital expenditures and to fund such activities. 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 Free Cash Flow is available for dividends, debt repayment, share repurchases, strategic acquisitions or other growth opportunities, or other discretionary expenditures, since we have mandatory debt service requirements and other non-discretionary expenditures that are not deducted from this measure.

We previously reported Adjusted Free Cash Flow, a non-GAAP measure, and made allocations of Adjusted Free Cash Flow in connection with our shareholder return model, most recently (a) 80% primarily in the form of debt repurchases, stock repurchases, strategic growth, and acquisitions of producing bolt-on assets; and (b) 20% in the form of variable dividends. However, in October 2024, in connection with entry into the 2024 Term Loan Credit Agreement, we transitioned away from the shareholder return model to a more flexible approach to capital allocation that aligns with the restrictive covenants contained in the 2024 Term Loan Credit Agreement and prioritizes debt repayment while facilitating our planned development capital expenditures in Utah as well as California. For a discussion and presentation of Adjusted Free Cash Flow for the prior period, see our previous filings with the SEC.

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 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, 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, 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, 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, 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.

ADJUSTED EBITDA

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

	Three Months Ended		
	September 30, 2024	**June 30, 2024**	**September 30, 2023**
		(unaudited) *(in thousands)*	
Adjusted EBITDA reconciliation:			
Net income (loss)	$ 69,863	$ (8,769)	$ (45,062)
Add (Subtract):			
Interest expense	8,986	10,050	9,101
Income tax expense (benefit)	24,432	(3,326)	(15,343)
Depreciation, depletion, and amortization	42,749	42,843	39,729
Impairment of oil and gas properties	—	43,980	—
(Gains) losses on derivatives	(67,659)	8,486	94,857
Net cash (paid) for scheduled derivative settlements	(10,397)	(19,115)	(19,432)
Other operating (income)	(4,687)	(3,204)	(505)
Stock compensation expense	2,301	1,990	3,018
Acquisition costs[1]	971	1,394	2,082
Non-recurring costs[2]	562	—	1,384
Adjusted EBITDA	$ 67,121	$ 74,329	$ 69,829
Net cash provided by operating activities	$ 70,695	$ 70,891	$ 55,320

Add (Subtract):			
Cash interest payments	16,174	1,395	15,065
Cash income tax payments	2,286	491	2,087
Acquisition costs[1]	971	1,394	—
Non-recurring costs[2]	562	—	1,384
Changes in operating assets and liabilities - working capital[3]	(13,605)	3,293	(3,032)
Other operating (income) - cash portion[4]	(9,962)	(3,135)	(995)
Adjusted EBITDA	$ 67,121	$ 74,329	$ 69,829

(1) Includes legal and other professional expenses related to various transactions activities.

(2) In 2024, non-recurring costs included cost savings initiatives. In 2023, non-recurring costs consisted of costs related to the settlement of shareholder litigation.

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

(4) Represents the cash portion of other operating (income) from the income statement, net of the non-cash portion in the cash flow statement.

FREE CASH FLOW

The following table presents a reconciliation of the GAAP financial measure of operating cash flow to the non-GAAP financial measure of Free Cash Flow for each of the periods indicated. We use Free Cash Flow as the primary metric to measure our ability to pay dividends, pay down debt, repurchase our stock, and make strategic growth and bolt-on acquisitions.

	Three Months Ended		
	September 30, 2024	**June 30, 2024**	**September 30, 2023**
		(unaudited) *(in thousands)*	
Free Cash Flow reconciliation:			
Net cash provided by operating activities	$ 70,695	$ 70,891	$ 55,320
Subtract:			
Capital expenditures	(25,874)	(42,325)	(13,596)
Free Cash Flow	$ 44,821	$ 28,566	$ 41,724

ADJUSTED NET INCOME (LOSS)

The following table presents a reconciliation of the GAAP financial measures of net income (loss) and net income (loss) per share — diluted to the non-GAAP financial measures of Adjusted Net Income (Loss) and Adjusted Net Income (Loss) per share — diluted for each of the periods indicated.

	Three Months Ended					
	September 30, 2024		**June 30, 2024**		**September 30, 2023**	
	(in thousands)	**per share - diluted**	**(in thousands)**	**per share - diluted**	**(in thousands)**	**per share - diluted**
			(unaudited)			
Adjusted Net Income (Loss) reconciliation:						
Net income (loss)	$ 69,863	$ 0.91	$ (8,769)	$ (0.11)	$ (45,062)	$ (0.58)
Add (Subtract):						
(Gains) losses on derivatives	(67,659)	(0.88)	8,486	0.11	94,857	1.22
Net cash (paid) for scheduled derivative settlements	(10,397)	(0.13)	(19,115)	(0.25)	(19,432)	(0.25)
Other operating (income)	(4,687)	(0.07)	(3,204)	(0.05)	(505)	(0.01)
Impairment of oil and gas properties	—	—	43,980	0.57	—	—
Acquisition costs[1]	971	0.01	1,394	0.02	2,082	0.03
Non-recurring costs[2]	562	0.01	—	—	1,384	0.02
Total additions (subtractions), net	(81,210)	(1.06)	31,541	0.40	78,386	1.01
Income tax expense (benefit) of adjustments[3]	22,186	0.29	(8,617)	(0.11)	(21,493)	(0.28)
Adjusted Net Income	$ 10,839	$ 0.14	$ 14,155	$ 0.18	$ 11,831	$ 0.15
Basic EPS on Adjusted Net Income	$ 0.14		$ 0.18		$ 0.16	

Diluted EPS on Adjusted Net Income	$ 0.14	$ 0.18	$ 0.15
Weighted average shares of common stock outstanding - basic	76,939	76,939	75,662
Weighted average shares of common stock outstanding - diluted	77,060	77,161	77,606

(1) Includes legal and other professional expenses related to various transactions activities.

(2) In 2024, non-recurring costs included cost savings initiatives. In 2023, non-recurring costs included costs related to the settlement of shareholder litigation.

(3) The federal and state statutory rates were utilized for all periods presented.

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 measure of Adjusted General and Administrative Expenses for each of the periods indicated.

	Three Months Ended		
	September 30, 2024	**June 30, 2024**	**September 30, 2023**
		(unaudited) *($ in thousands)*	
Adjusted General and Administrative Expense reconciliation:			
General and administrative expenses	$ 19,111	$ 18,881	$ 20,987
Subtract:			
Non-cash stock compensation expense (G&A portion)	(2,083)	(1,843)	(2,840)
Non-recurring costs[1]	(562)	—	(1,384)
Adjusted General and Administrative Expenses	$ 16,466	$ 17,038	$ 16,763
Well servicing and abandonment segment	$ 2,351	$ 2,454	$ 2,910
E&P segment, and corporate	$ 14,115	$ 14,584	$ 13,853
E&P segment, and corporate ($/boe)	$ 6.19	$ 6.34	$ 5.96
Total mboe	2,281	2,300	2,326

(1) In 2024, non-recurring costs included cost savings initiatives. In 2023, non-recurring costs included costs related to the settlement of shareholder litigation.

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