2Q 2023

INVESTOR PRESENTATION

AUGUST 2023

CALLON
PETROLEUM

Important Disclosures

Cautionary Statement Regarding Forward-Looking Information

This presentation contains 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. Forward-looking statements include all statements regarding the Company's expectations and plans with respect to the Delaware Basin acquisition and Eagle Ford disposition; the Company's expectations and plans with respect to its share repurchase program; wells anticipated to be drilled and placed on production; future levels of development activity and associated production, capital expenditures, cash flow expectations and expected uses thereof, and margins; estimated realizations; estimated reserve quantities and the present value thereof; future income and returns; future debt levels and leverage and the implementation of the Company's business plans and strategy, as well as statements including the words "believe," "expect," "plans," "may," "will," "should," "could," and words of similar meaning. These statements reflect the Company's current views with respect to future events and financial performance based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. No assurances can be given, however, that these events will occur or that these projections will be achieved, and actual results could differ materially from those projected as a result of certain factors. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation 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. Some of the factors which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include the volatility of oil and natural gas prices; changes in the supply of and demand for oil and natural gas, including as a result of actions by, or disputes among members of OPEC and other oil and natural gas producing countries with respect to production levels or other matters related to the price of oil; general economic conditions, including the availability of credit, inflation and rising interest rates; or our ability to drill and complete wells; operational, regulatory and environment risks; the cost and availability of equipment and labor; our ability to finance our development activities at expected costs or at expected times or at all; rising interest rates and inflation; our inability to realize the benefits of recent transactions; currently unknown risks and liabilities relating to the newly acquired assets and operations; adverse actions by third parties involved with the transactions; risks that are not yet known or material to us; and other risks more fully discussed in our filings with the SEC, including our most recent Annual Report on Form 10-K and subsequent Quarterly Reports on Form 10-Q, available on our website or the SEC's website at www.sec.gov. Any forward-looking statement speaks only as of the date on which such statement is made, and the Company undertakes no obligation 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.

Non-GAAP Financial Measures

This presentation refers to non-GAAP financial measures such as "adjusted income," "adjusted income per diluted share," "adjusted free cash flow," "adjusted EBITDAX," "adjusted EBITDAX per Boe," "operating margin," and "net debt". These measures, detailed below, are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our filings with the U.S. Securities and Exchange Commission (the "SEC") and posted on our website.

Adjusted free cash flow is a supplemental non-GAAP measure that is defined by the Company as net cash provided by operating activities before net change in working capital, changes in accrued hedge settlements, merger, integration and transaction expense, and other income and expense less capital expenditures before increase (decrease) in accrued capital expenditures. We believe adjusted free cash flow provides useful information to investors because it is a comparable metric against other companies in the industry and is a widely accepted financial indicator of an oil and natural gas company's ability to generate cash for the use of internally funding their capital development program and to service or incur debt. Adjusted free cash flow is not a measure of a company's financial performance under GAAP and should not be considered as an alternative to net cash provided by operating activities, or as a measure of liquidity.

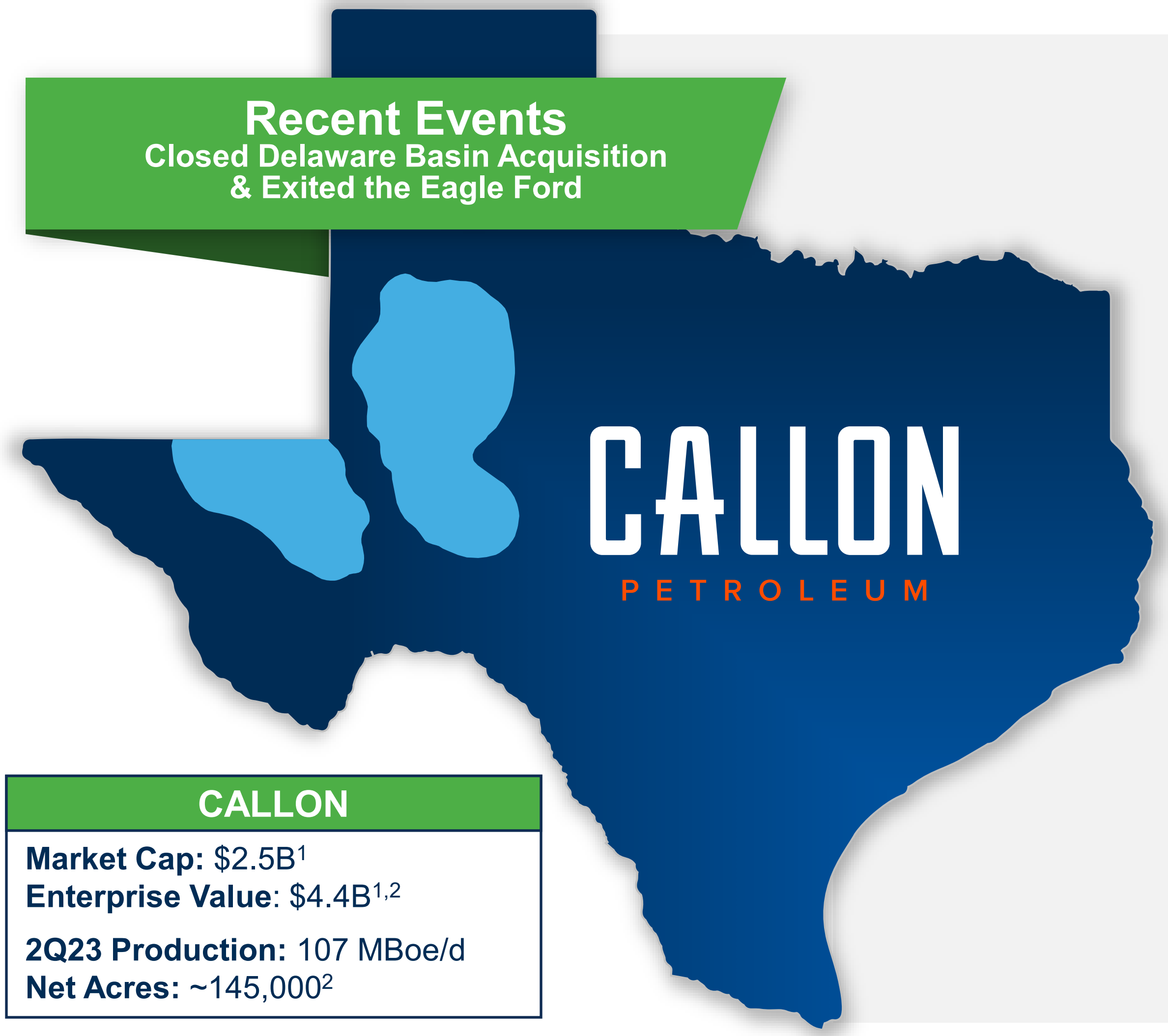
Callon calculates adjusted EBITDAX as net income (loss) before interest expense, income tax expense (benefit), depreciation, depletion and amortization, (gains) losses on derivative instruments excluding net settled derivative instruments, impairment of oil and gas properties, non-cash share-based compensation expense, exploration expense, merger, integration and transaction expense, (gain) loss on extinguishment of debt, and certain other expenses. Adjusted EBITDAX is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income (loss), operating income (loss), cash flow provided by operating activities or other income or cash flow data prepared in accordance with GAAP. However, the Company believes that adjusted EBITDAX provides useful information to investors because it provides additional information with respect to our performance or ability to meet our future debt service, capital expenditures and working capital requirements. Because adjusted EBITDAX excludes some, but not all, items that affect net income (loss) and may vary among companies, the adjusted EBITDAX presented below may not be comparable to similarly titled measures of other companies.

Callon believes that operating margin is a comparable metric against other companies in the industry and is useful to investors because it is an indicator of an oil and natural gas company's operating profitability per unit of production. Operating margin is a supplemental non-GAAP measure that is defined by the Company as oil, natural gas, and NGL revenues sales price less lease operating expense, production and ad valorem taxes and gathering, transportation and processing fees divided by total production for the period.

Net debt is a supplemental non-GAAP measure that is defined by the Company as total debt excluding unamortized premiums, discount, and deferred loan costs, less cash and cash equivalents. Net debt should not be considered an alternative to, or more meaningful than, total debt, the most directly comparable GAAP measure. Management uses net debt to determine the Company's outstanding debt obligations that would not be readily satisfied by its cash and cash equivalents on hand. We believe this metric is useful to analysts and investors in determining the Company's leverage position since the Company has the ability to, and may decide to, use a portion of its cash and cash equivalents to reduce debt.

The Company is unable to reconcile the projected adjusted free cash flow (non-GAAP), net debt and adjusted EBITDAX (non-GAAP) metrics included in this release to projected net cash provided by operating activities (GAAP), total debt and net income (loss) (GAAP), respectively, without unreasonable efforts because components of the calculations are inherently unpredictable, such as changes to current assets and liabilities, the timing of capital expenditures, movements in oil and gas pricing, unknown future events, and estimating future certain GAAP measures. The inability to project certain components of the calculation would significantly affect the accuracy of the reconciliation.

Why Callon Today?



Recent Events
Closed Delaware Basin Acquisition & Exited the Eagle Ford

CALLON
Market Cap: \$2.5B[1]
Enterprise Value: \$4.4B[1,2]
2Q23 Production: 107 MBoe/d
Net Acres: ~145,000[2]

- **Permian-Focused Asset Base**
- **"Life of Field" Co-Development Model**
- **Decade-Plus of Permian Basin Inventory**
- **Improving Well Productivity and Capital Efficiency**
- **Launching Shareholder Return Program in 3Q23**

1. Market capitalization and enterprise value calculated using 68.2 million shares and closing price as of July 28, 2023
2. Reflects estimated impact of Delaware Basin acquisition and Eagle Ford divestiture, which closed July 3, 2023

2Q 2023 Value Drivers

PRODUCTION

107 MBoe/d
Total

63 MBbl/d
Oil

HIGH OPERATING MARGINS

$35.76
Operating Margin ($/Boe)[1]

70%
Strong Adj. EBITDAX margin[2]

2Q23 ADJ. EBITDAX[1]

$332MM
Increased sequentially despite lower benchmark pricing

DECLINING OPERATING COSTS

6%
Sequential decrease in per unit LOE costs

3%
Sequential decrease in per unit GP&T costs

CAPITAL SPENDING

$285MM
At the low end of quarterly guidance

CONTINUED ADJ FREE CASH FLOW

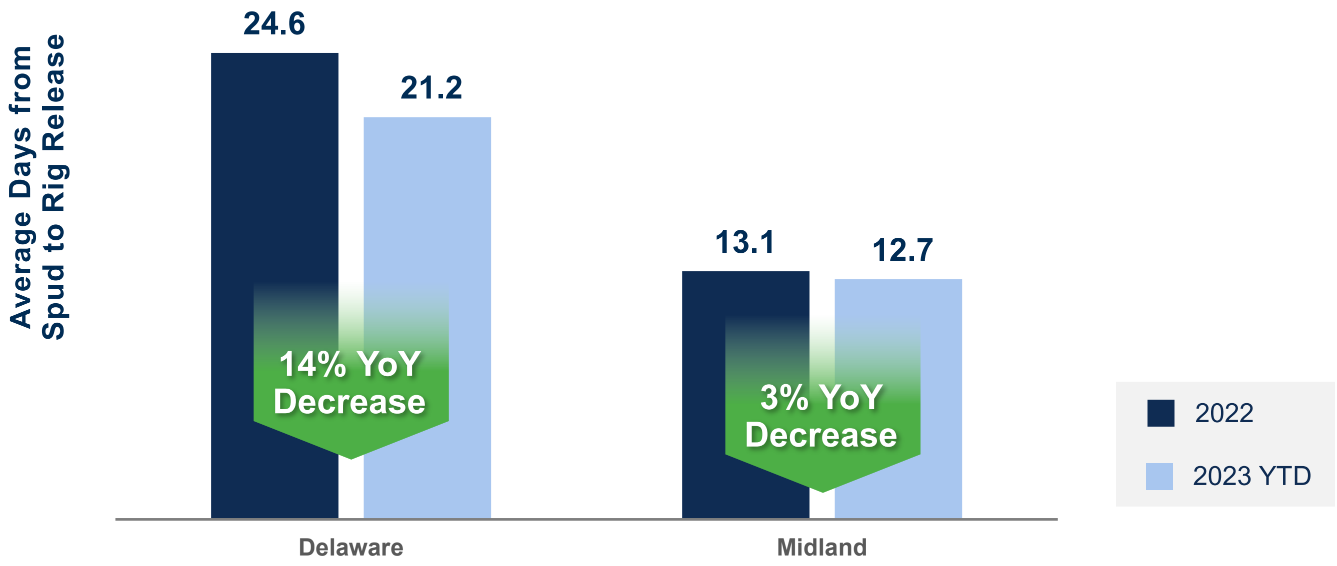
$12.3MM
of Adj. Free Cash Flow[1]

13
Consecutive quarters of free cash flow generation

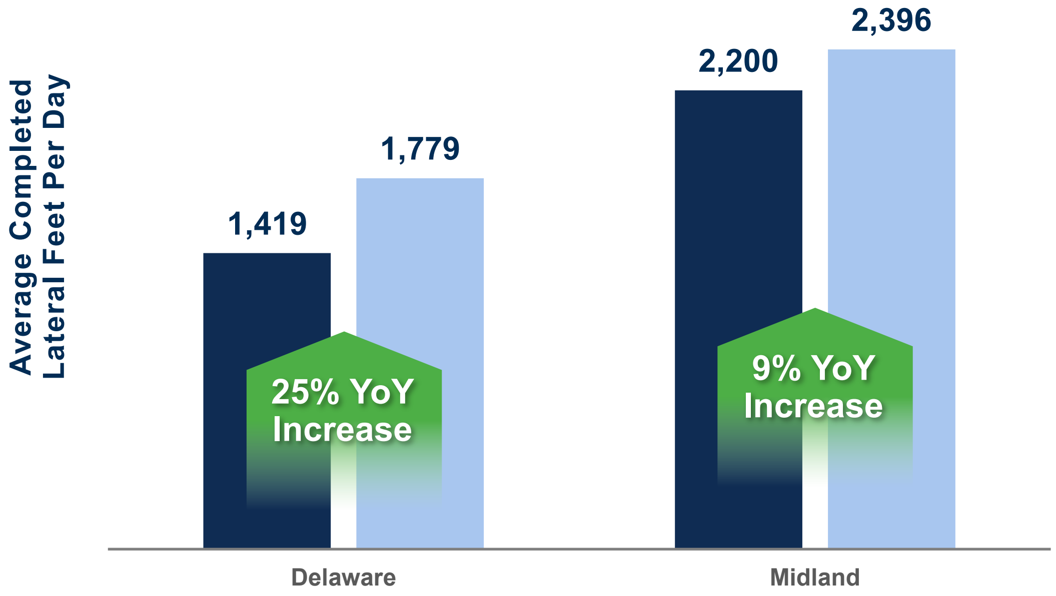
1. Adjusted EBITDAX, Adjusted Free Cash Flow and Operating Margin are non-GAAP measures. Please see the appendix for a reconciliation
2. Defined as Adjusted EBITDAX divided by revenue from oil and gas sales

Drilling and Completion Execution

DRILLING[1]



COMPLETIONS[2]



DRILLING[1]

- Improvement in reducing days to the intermediate casing in the Delaware Basin
- Good performance with slim hole rotary steerable tools

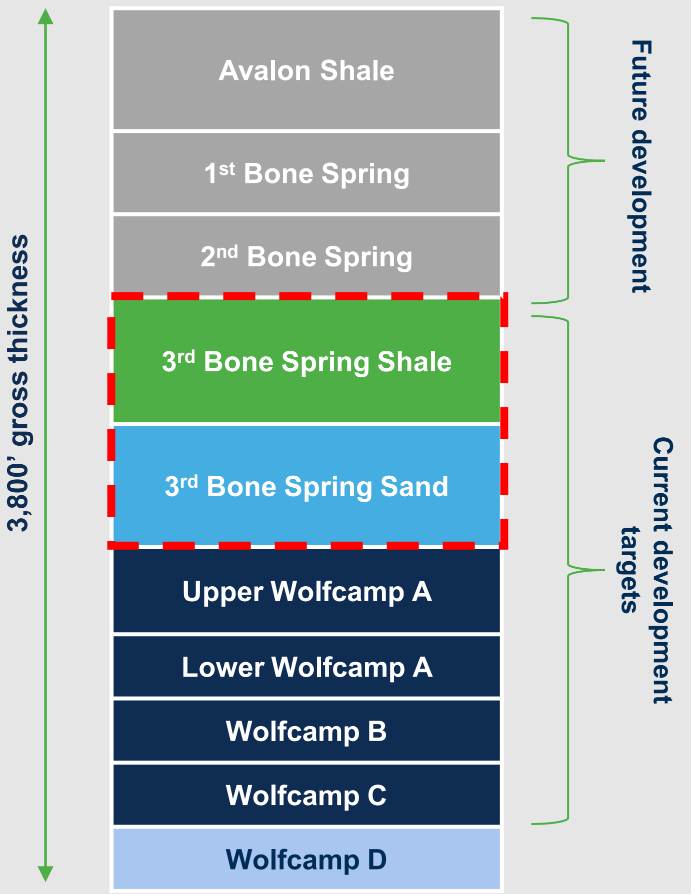
COMPLETIONS[2]

- 25% increase in completed lateral feet per day in Delaware
- Reached a new record 23 pumping hours in a day

1. 2023 YTD drilling data through June 30, 2023
2. 2023 YTD completions data through July 17, 2023

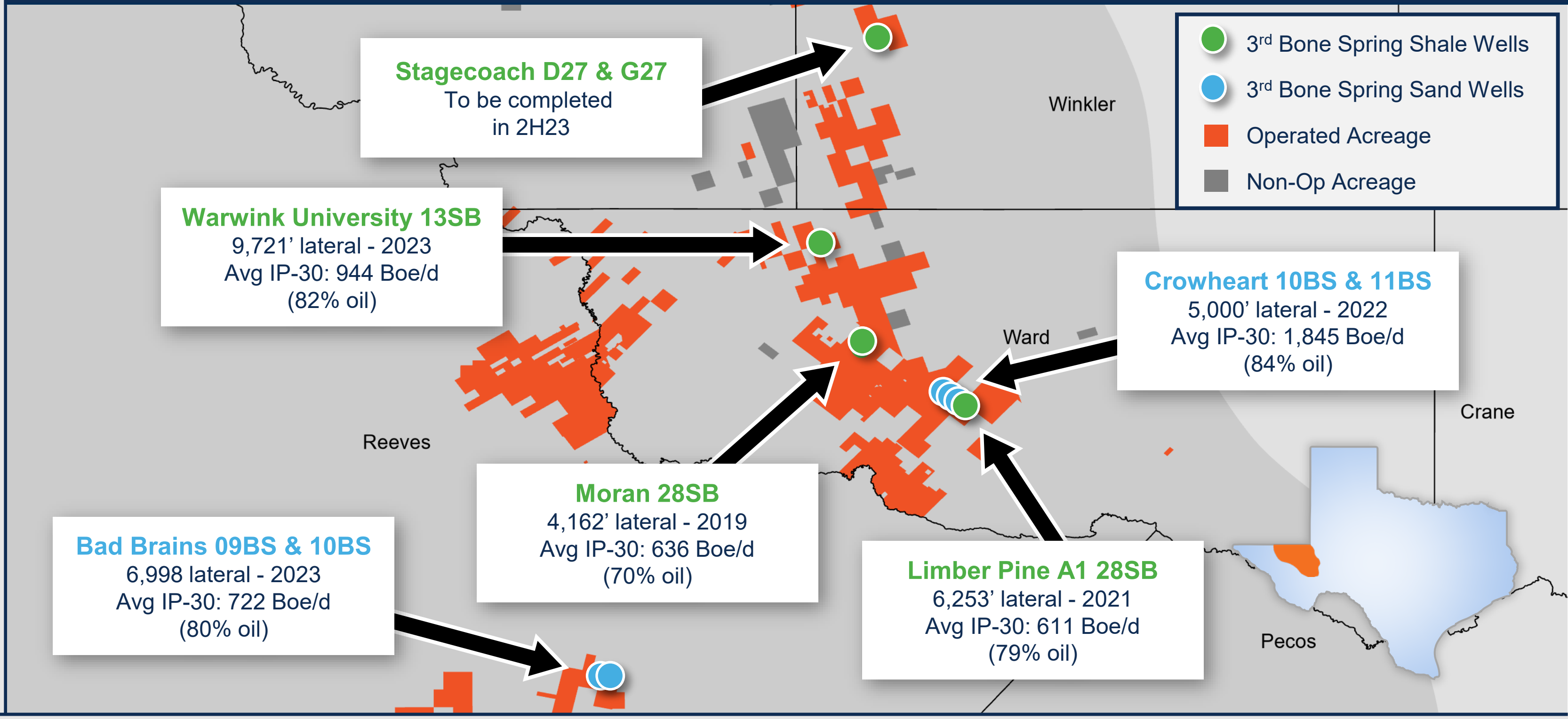
Expanding Bone Spring Development

Delaware:
~120,000 net acres



RECENT AND FUTURE 3rd BONE SPRING COMPLETIONS

- 3rd Bone Spring results demonstrate similar oil EUR per foot to Wolfcamp A
- Recent well results exhibit a shallower pressure decline with a change of completion technique
- Evaluating acceleration of 3rd Bone Spring into near-term drilling inventory

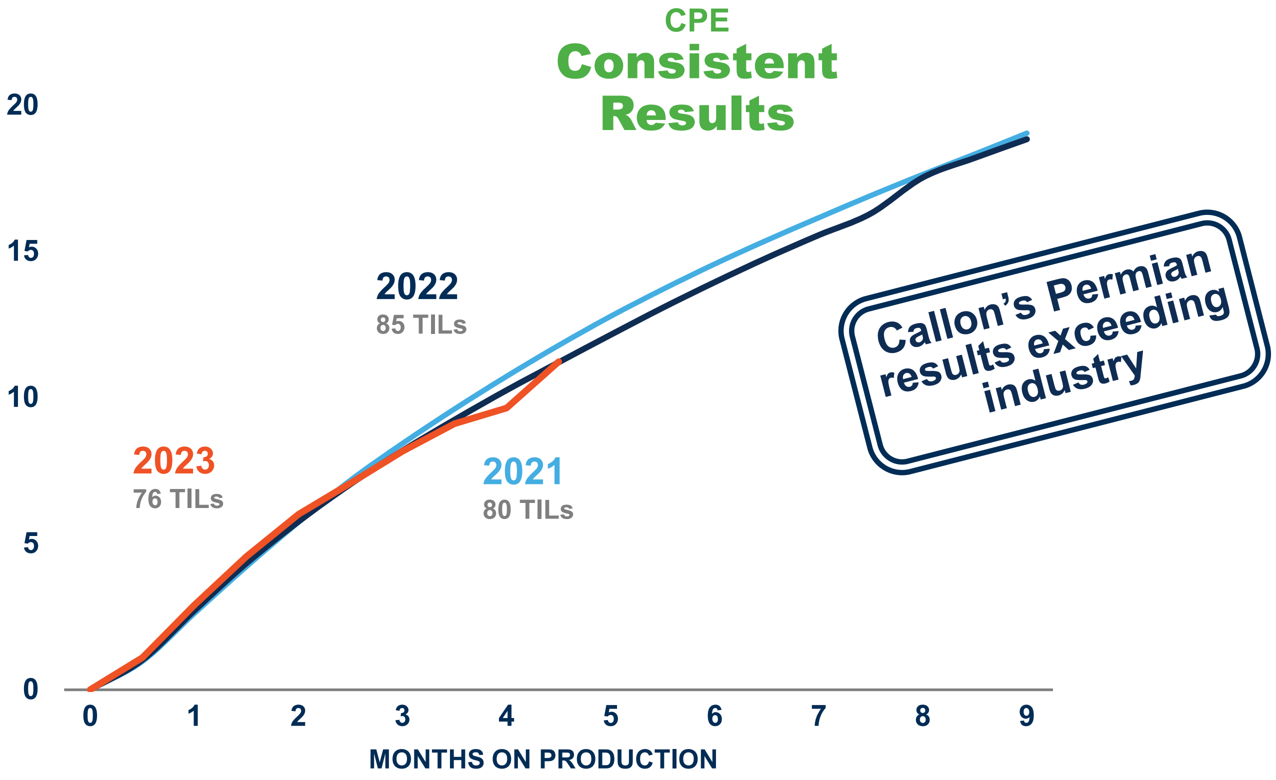


"Life of Field" Co-Development Model Enhances Rate of Return

CALLON'S STABLE WELL PRODUCTIVITY[1]

AVERAGE PERMIAN BASIN CUMULATIVE PRODUCTION BY MONTH

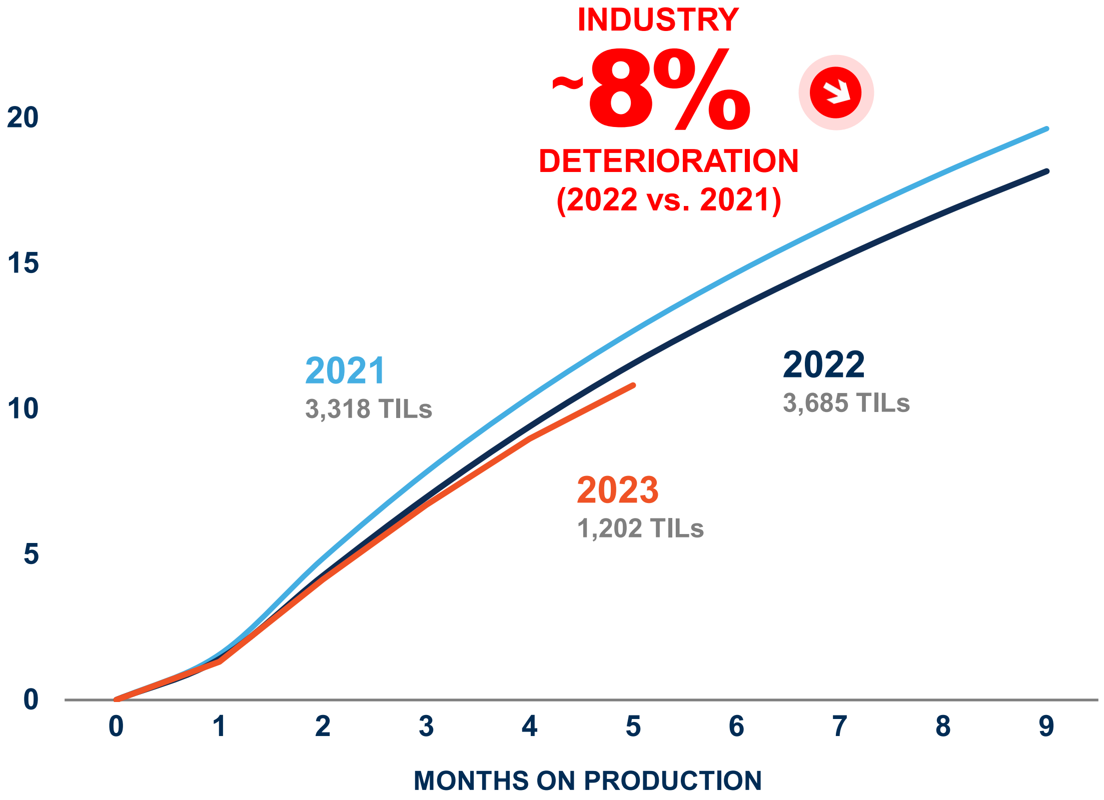
MBoe per 1,000 ft



INDUSTRY'S DEGRADING WELL PRODUCTIVITY[2]

AVERAGE PERMMIAN BASIN CUMULATIVE PRODUCTION BY MONTH

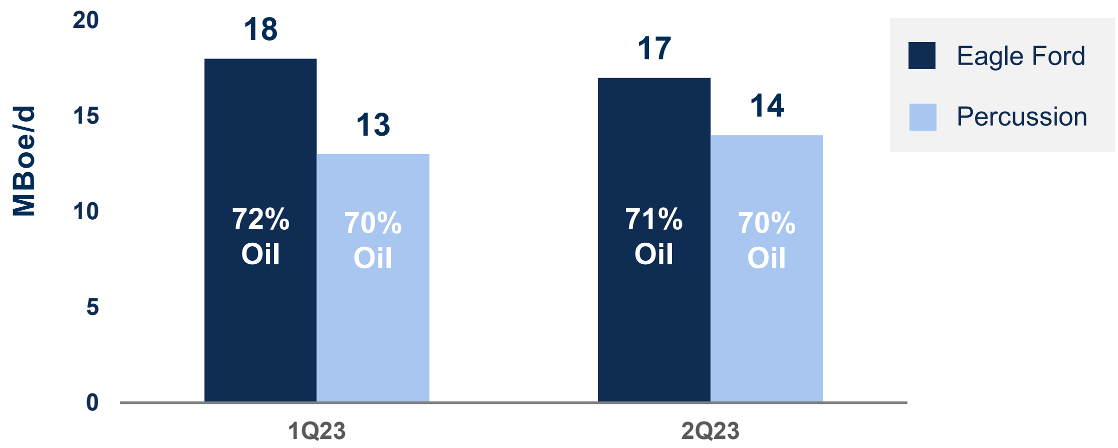
MBoe per 1,000 ft



1. Based on internal estimates as of August 2, 2023, includes 15 turned in-line wells subsequent to June 30, 2023
2. Based on data from Enverus as of August 2, 2023

Operational Activity Transition

Net Daily Production



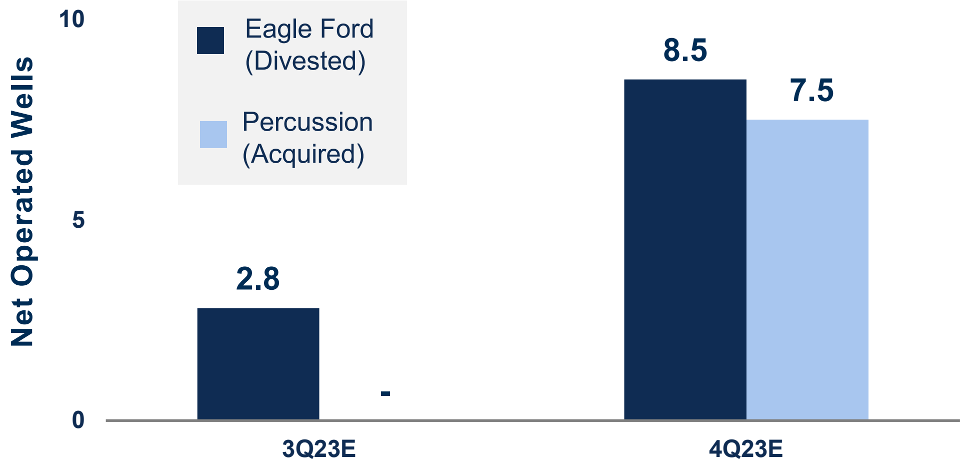
PRODUCTION IMPACT

- ~3 MBoe/d decrease in production upon transaction closings
- 2023E pro forma net production of ~2 MBoe/d on an annualized basis assuming both transactions completed on January 1, 2023

Turned In – Lines (TILs)

DEVELOPMENT PACE

- TILs under new activity plan[1] occur later in 2023 (no activity in acquired assets since 1Q / six gross Eagle Ford TILs in 2Q and 3Q)
- Original 2023 capital plan reduced by $30MM[2] despite increase in net lateral feet (acquired laterals of ~10,000' vs Eagle Ford average of ~6,000')



1. Not inclusive of non-op wells
2. 2023 capital plan was revised May 2023 to reflect pro forma activity

Operational Priorities

FOCUSED ON USING TECHNOLOGY TO PROVIDE REALTIME DATA

COMMITTED TO IMPROVING MARGINS

DEDICATED TO DELIVERING FREE CASH FLOW

TOP PRIORITIES

- **Evolve "Life of Field" Co-Development Model**
  - Leverage established infrastructure
  - Optimize artificial lift and water handling
- **Streamline operating structure and greater adoption of technology**
  - Organizational focus exclusively on Permian Basin
  - Provide real time data clarity and real time ownership of results
- **Reduce cost structure**
  - Capital and expense reductions from design changes
  - Capture anticipated service cost reductions
- **Increase downhole innovation**
  - Improve well performance, ultimate recovery per section, ROCI and ultimately add inventory
  - Increase future inventory and associated economics through additional experimentation in emerging intervals

Improving Capital Structure & Financial Flexibility

CONTINUE TO PRIORITIZE DEBT REDUCTION[1]

~$1B DEBT REDUCTION SINCE 1Q21

RECENT CREDIT RATING UPGRADES[2,3]

S&P Global Ratings: B+

FitchRatings: B+

SOLID LIQUIDITY[1]

~$1.1B AVAILABILITY ON THE RBL FACILITY

~25% RBL UTILIZATION

PEER LEADING WEIGHTED AVG. MATURITY PROFILE[4]

~5.5 YEARS

1. Reflects 2Q23 pro forma for the recent transactions and the redemption of the 8.25% Senior Notes due 2025
2. S&P Global Ratings upgraded Callon's credit rating on April 26, 2023
3. FitchRatings upgraded Callon's long-term issuer default rating on July 5, 2023
4. As of June 30, 2023 pro forma for the redemption of the 8.25% Senior notes due 2025 and includes only Callon's term debt

2023 Outlook

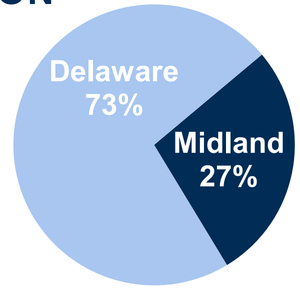
2023 GUIDANCE DETAILS

	3Q23	FY23
Total (MBoe/d)	**100 – 103**	**103 – 106**
Oil (MBbls/d)	60 – 62	62 – 64
Lease Operating ($/Boe)	7.75 – 8.25	7.75 – 8.25
GP&T ($/Boe)	2.95 – 3.05	2.95 – 3.05
Prod & Ad Val Taxes (% of revs)	6.25% – 6.75%	6.25% – 6.75%
Cash G&A ($MM)	30 – 34	105 – 115
DD&A ($/Boe)	14.75 – 15.25	14.50 – 15.00
Exploration Expense ($MM)	1 – 3	5 – 10
Effective Tax Rate		21% – 23%
Cash Taxes ($MM)		5 – 15

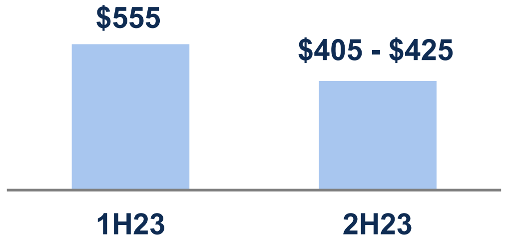
2023 CAPITAL EXPENDITURES

	3Q23	FY23
Capital Expenditures ($MM)[1]	250 – 275	960 – 980
Operated TILs (gross wells)	30 – 35	105 – 110

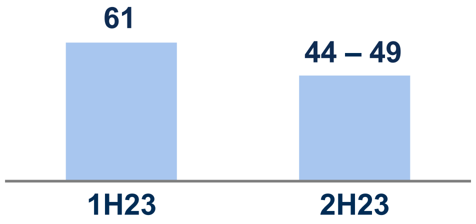
CAPITAL ALLOCATION
2H 2023



CAPITAL EXPENDITURES[1]
2023 ($MM)



OPERATED TILs
2023



1. Excludes land expenses

APPENDIX

CALLON
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Increasing the Value Chain of Our Molecules

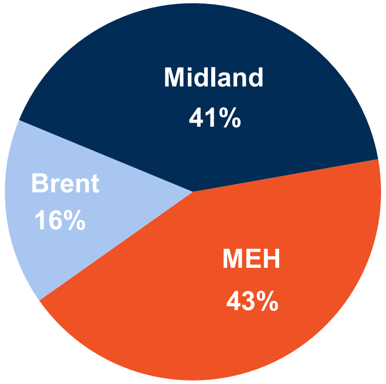
OIL

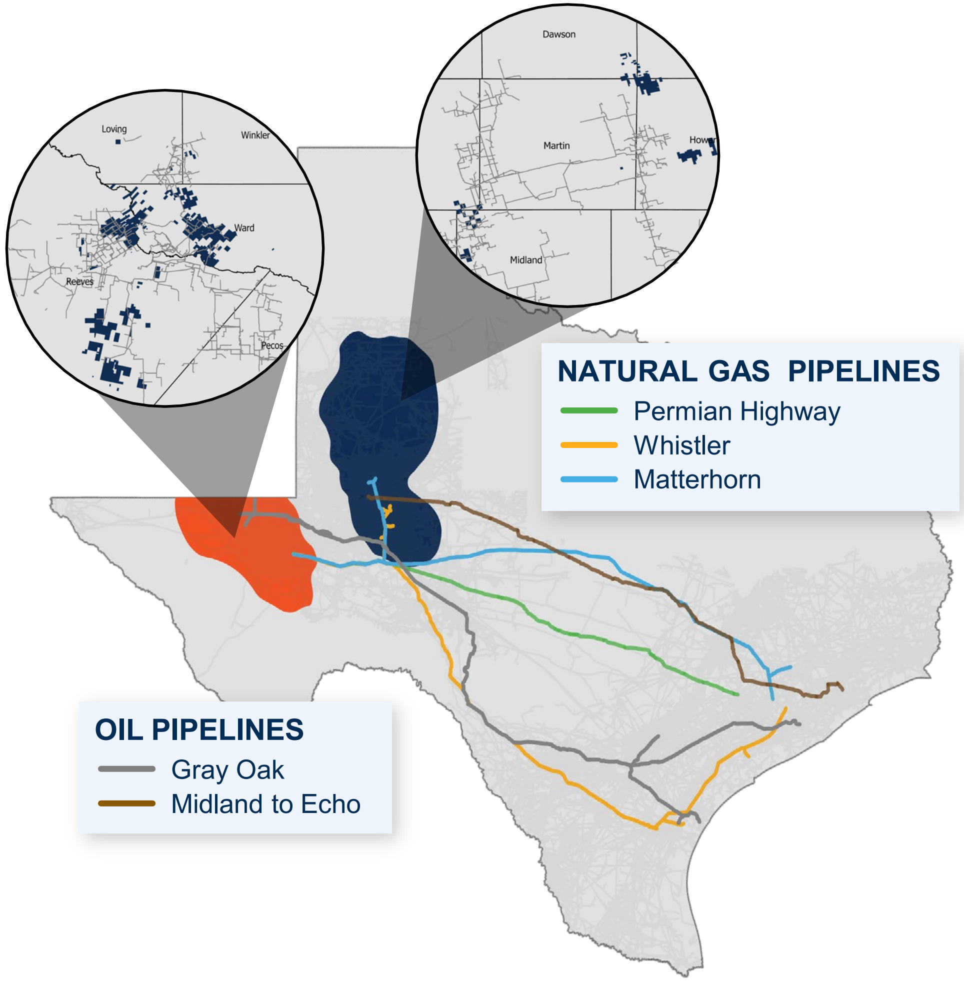
TAKEAWAY CAPACITY

- Portfolio approach employs a combination of in-basin sales and transportation arrangements to the Gulf Coast
- ~35,000 Bbls/d of transportation contracted on multiple long-haul pipelines to provide flow assurance and price diversification

PRICE EXPOSURE[2]

2H23-24





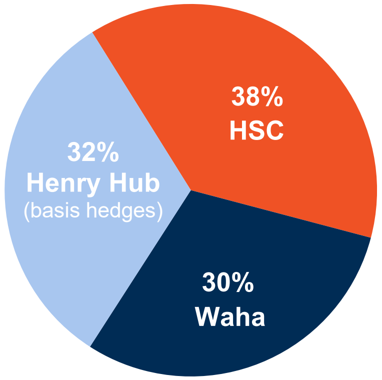
NATURAL GAS

TAKEAWAY CAPACITY

- "Take-in-kind" optionality in various gas gathering agreements
- ~75,000 MMBtu/d of transportation contracted on multiple long-haul pipelines[1]
- Entered into basis hedges from Waha and Houston Ship Channel to Henry Hub
- Started transporting ~15,000 MMBtu/d on Whistler Pipeline beginning July 1, 2023

PRICE EXPOSURE[2]

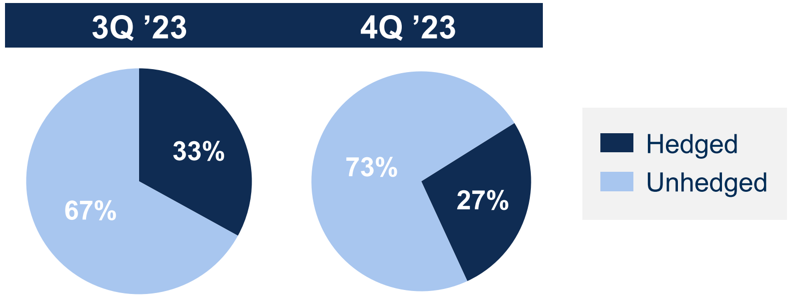
2H23-24



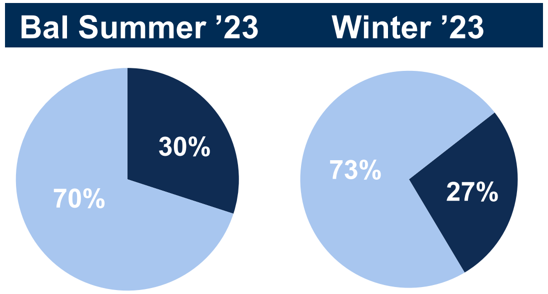
1. Dates assumed for long-haul transportation agreements are in-line with publicly available pipeline start-up information as of July 25, 2023
2. Projections based on current hedge book and development plan as of July 25, 2023

Derivative Positions

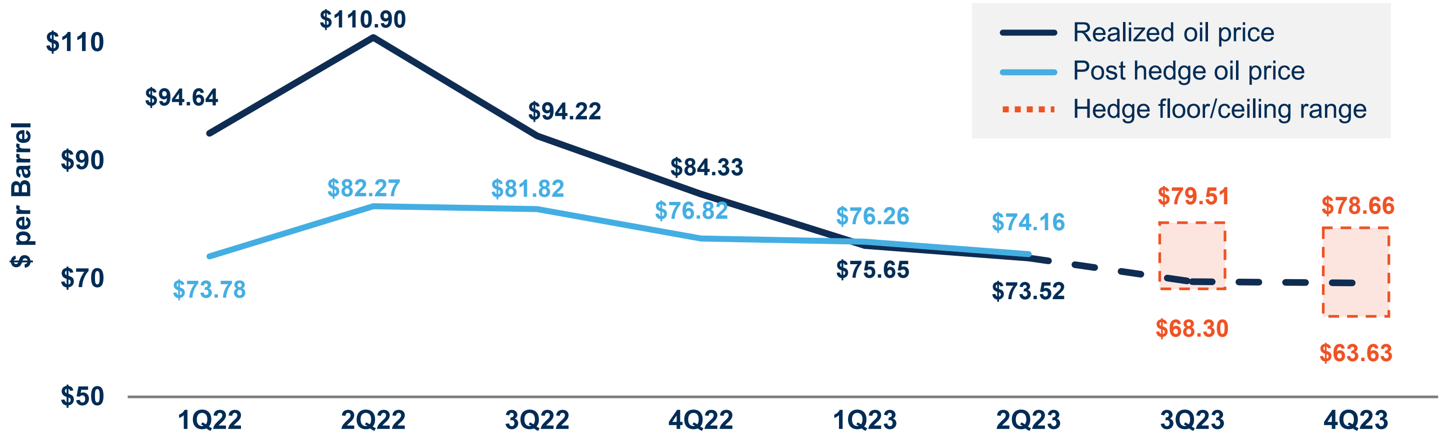
OIL VOLUMES[1]



NATURAL GAS VOLUMES[1]



CALLON'S OIL PRICE REALIZATIONS[2]



HEDGE GAINS / LOSSES BY QUARTER ($MM)

WTI Oil[3]	1Q23	2Q23	3Q23	4Q23
$70	$12	$14	$8	$2
$80	$12	$14	($2)	($3)
$90	$12	$14	($14)	($12)
NYMEX Gas[4]	**1Q23**	**2Q23**	**3Q23**	**4Q23**
$2.00	$12	$14	$0	($2)
$2.50	$12	$14	($2)	($3)
$3.00	$12	$14	($3)	($5)

2H23 CASH FLOW SENSITIVITIES ($MM)[3,4,5]

Annual Run Rate	Cash Flow from Operations
Oil: +$10	$88
Gas: +$0.50	$6

1. Based on consensus estimates as of July 25, 2023
2. Represents realized prices including hedging settlements, WTI strip price as of July 25, 2023
3. Assumes flat natural gas price of $2.50/MMBtu; oil & gas derivatives position as of August 2, 2023
4. Assumes flat oil price of $80/Bbls; oil & gas derivates position as of August 2, 2023
5. Assumes NGLs held flat at 35% of WTI; all derivatives positions as of August 2, 2023

Oil Hedges[1]

	3Q23	4Q23	3Q23 - 4Q23	FY 2024
NYMEX WTI (Bbls, $/Bbl)				
Swaps				
Total Volumes	460,000	-	460,000	-
Total Daily Volumes	5,000	-	2,500	-
Avg. Swap Price	$82.10	-	$82.10	-
Puts				
Total Volumes	368,000	368,000	736,000	-
Total Daily Volumes	4,000	4,000	4,000	-
Avg. Swap Price	$70.00	$70.00	$70.00	-
Collars				
Total Volumes	603,599	625,455	1,229,054	-
Total Daily Volumes	6,561	6,798	6,680	-
Avg. Short Call Strike	$85.81	$85.34	$85.57	-
Avg. Long Put Strike	$67.62	$67.35	$67.49	-
Three-Way Collars				
Total Volumes	493,028	541,528	1,034,556	3,963,023
Total Daily Volumes	5,359	5,886	5,623	10,828
Avg. Short Call Strike	$69.38	$70.95	$70.20	$78.86
Avg. Long Put Strike	$55.00	$55.00	$55.00	$58.16
Avg. Short Put Strike	$45.00	$45.00	$45.00	$48.16
Total WTI Volume Hedged (Bbls)	1,924,627	1,534,983	3,459,610	3,963,023
Average WTI Ceiling Strike ($/Bbl)	$79.51	$78.66	$79.15	$78.86
Average WTI Floor Strike ($/Bbl)	$68.30	$63.63	$66.23	$58.16

	3Q23	4Q23	3Q23 - 4Q23	FY 2024
WTI CMA Roll (Bbls, $/Bbl)				
Swaps				
Total Volumes	673,535	838,828	1,512,363	-
Total Daily Volumes	7,321	9,118	8,219	-
Avg. Swap Price	$0.29	$0.30	$0.30	-

1. As of August 2, 2023

Natural Gas Liquids Hedges[1]

	3Q23	4Q23	3Q23 - 4Q23	FY 2024
NATURAL GAS LIQUIDS (Bbls, $/Bbl)				
MBV Ethane Purity				
Total Volumes	35,333	35,095	70,428	-
Total Daily Volumes	384	381	383	-
Avg. Swap Price	$9.66	$9.66	$9.66	-
MBV Propane EPC				
Total Volumes	36,077	35,754	71,831	-
Total Daily Volumes	392	389	390	-
Avg. Short Call Strike	$31.37	$31.37	$31.37	-
MBV n-Butane EPC				
Total Volumes	31,137	33,470	64,606	72,105
Total Daily Volumes	338	364	351	197
Avg. Swap Price	$35.55	$35.65	$35.60	$33.18
MBV i-Butane EPC				
Total Volumes	10,174	10,967	21,141	23,462
Total Daily Volumes	111	119	115	64
Avg. Swap Price	$35.42	$35.53	$35.47	$33.18
MBV Natural Gasoline EPC				
Total Volumes	40,405	43,105	83,510	-
Total Daily Volumes	439	469	454	-
Avg. Swap Price	$56.28	$56.34	$56.31	-

1. As of August 2, 2023

Natural Gas Hedges[1]

	3Q23	4Q23	3Q23 - 4Q23	FY 2024
NYMEX HENRY HUB (MMBtu, $/MMBtu)				
Swaps				
Total Volumes	1,840,000	620,000	2,460,000	-
Total Daily Volumes	20,000	6,739	13,370	-
Avg. Swap Price	$3.00	$3.00	$3.00	-
Collars				
Total Volumes	1,572,296	2,201,102	3,773,398	8,598,555
Total Daily Volumes	17,090	23,925	20,508	23,493
Avg. Short Call Strike	$5.21	$5.37	$5.30	$3.89
Avg. Long Put Strike	$3.63	$3.14	$3.35	$3.00
Total NYMEX Volume Hedged (MMBtu)	3,412,296	2,821,102	6,233,398	8,598,555
Average NYMEX Ceiling Strike ($/MMBtu)	$4.02	$4.85	$4.39	$3.89
Average NYMEX Floor Strike ($/MMBtu)	$3.29	$3.11	$3.21	$3.00
WAHA DIFFERENTIAL (MMBtu, $/MMBtu)				
Swaps				
Total Volumes	3,680,000	2,460,000	6,140,000	7,320,000
Total Daily Volumes	40,000	26,739	33,370	20,000
Avg. Swap Price	($1.25)	($1.49)	($1.34)	($1.06)
HOUSTON SHIP CHANNEL DIFFERENTIAL (MMBtu, $/MMBtu)				
Swaps				
Total Volumes	2,760,000	2,760,000	5,520,000	14,640,000
Total Daily Volumes	30,000	30,000	30,000	40,000
Avg. Swap Price	($0.29)	($0.29)	($0.29)	($0.42)

1. As of August 2, 2023

Non-GAAP Operating Margin[1]

(Per Boe data)	1Q 23	2Q 23
Sales price[2]		
Permian	$51.50	$47.63
Eagle Ford	60.42	56.44
Total sales price	$53.07	$49.00
Lease operating expense		
Permian	$7.87	$7.42
Eagle Ford	10.66	10.44
Total lease operating expense	$8.36	$7.89
Production and ad valorem taxes		
Permian	$3.43	$2.40
Eagle Ford	4.62	3.29
Total production and ad valorem taxes	$3.64	$2.54
Gathering, transportation and processing		
Permian	$3.07	$2.97
Eagle Ford	2.06	1.94
Total gathering, transportation and processing	$2.89	$2.81
Operating margin		
Permian	$37.13	$34.84
Eagle Ford	43.08	40.77
Total Operating Margin	**$38.18**	**$35.76**

1. See “Important Disclosures” slide for additional information related to Supplemental Non-GAAP Financial Measures
2. Excludes the impact of settled derivatives.

Non-GAAP Adjusted EBITDAX[1]

($ thousands)	1Q 23	2Q 23
Net income (loss)	**$220,638**	**($107,896)**
Gain on derivative contracts	(25,645)	(5,941)
Gain on commodity derivative settlements, net	12,012	13,663
Non-cash expense related to share-based awards	1,881	3,688
Impairment of oil and gas properties	-	406,898
Merger, integration and transaction	-	1,543
Other (income) expense	(6,414)	54
Income tax benefit	(50,695)	(156,212)
Interest expense	46,306	47,239
Depreciation, depletion and amortization	125,965	127,348
Exploration	2,232	1,882
Adjusted EBITDAX	**$326,280**	**$332,266**

1. See “Important Disclosures” slide for additional information related to Supplemental Non-GAAP Financial Measures.

Non-GAAP Adjusted Free Cash Flow[1]

($ thousands)	1Q 23	2Q 23
Net cash provided by operating activities	**$247,913**	**$279,522**
Changes in working capital and other	18,869	11,188
Changes in accrued hedge settlements	12,791	638
Merger, integration and transaction	-	1,543
Cash flow from operations before net changes in working capital	**$279,573**	**$292,891**
Capital expenditures	**$204,900**	**$293,697**
Increase (decrease) in accrued capital expenditures	67,460	(13,083)
Capital expenditures before accruals	**$272,360**	**$280,614**
Adjusted Free Cash Flow	**$7,213**	**$12,277**

1. See "Important Disclosures" slide for additional information related to Supplemental Non-GAAP Financial Measures

Non-GAAP Net Debt[1]

($ millions)	3/31/23	6/30/23
Total debt	**$2,204**	**$2,268**
Unamortized premiums, discount, and deferred loan costs, net	19	18
Adjusted total debt	**$2,223**	**$2,286**
Less: Cash and cash equivalents	3	4
Net Debt	**$2,220**	**$2,282**

1. See "Important Disclosures" slide for additional information related to Supplemental Non-GAAP Financial Measures