SEPTEMBER 2023

INVESTOR PRESENTATION

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; inventory, delineation, and breakeven costs; 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 free cash flow," "adjusted EBITDAX," "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.

Recent Highlights

Strong 2Q Financial and Operational Performance
Bested production estimates with lower than expected capital expenditures

Solidified Focus on Permian Basin
Acquired Delaware Basin assets & divested Eagle Ford Shale

Seamless Integration of New Assets
Realizing sustainable synergies to improve cost structure and enhance margins

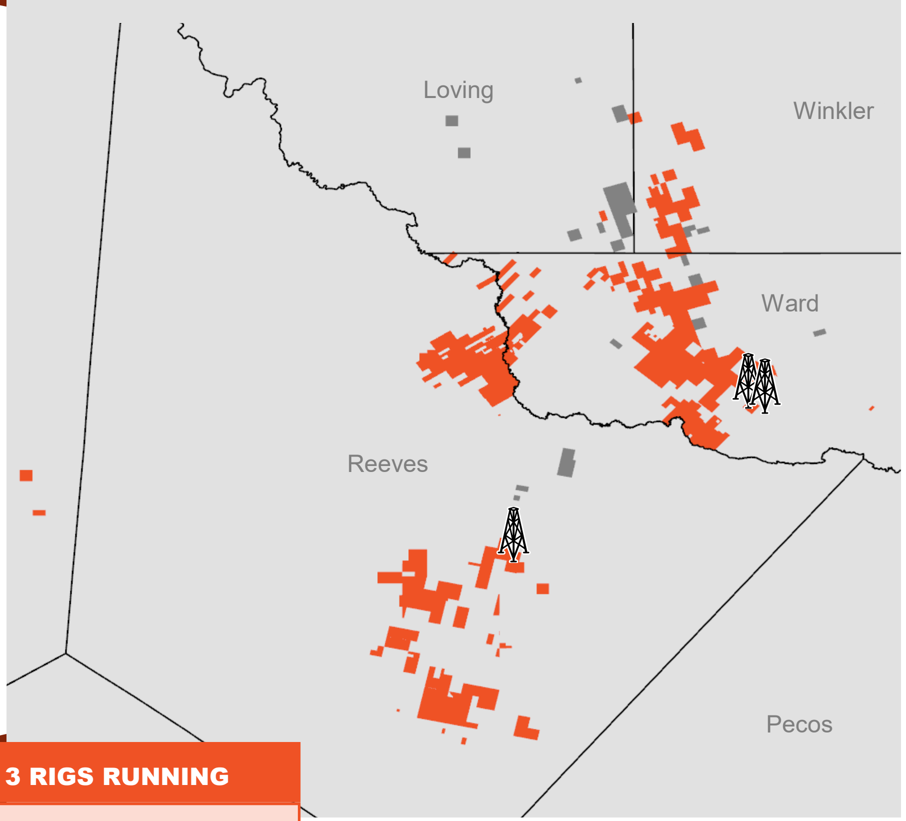
Leadership Aligning Talent & Technology
New COO focused on driving operational efficiencies

Improved Capital Structure & Financial Flexibility
Ample liquidity & improving leverage recognized through credit rating upgrades

Initiated Shareholder Return Program
2-year, $300 million share buyback

Permian-Focused Asset Base

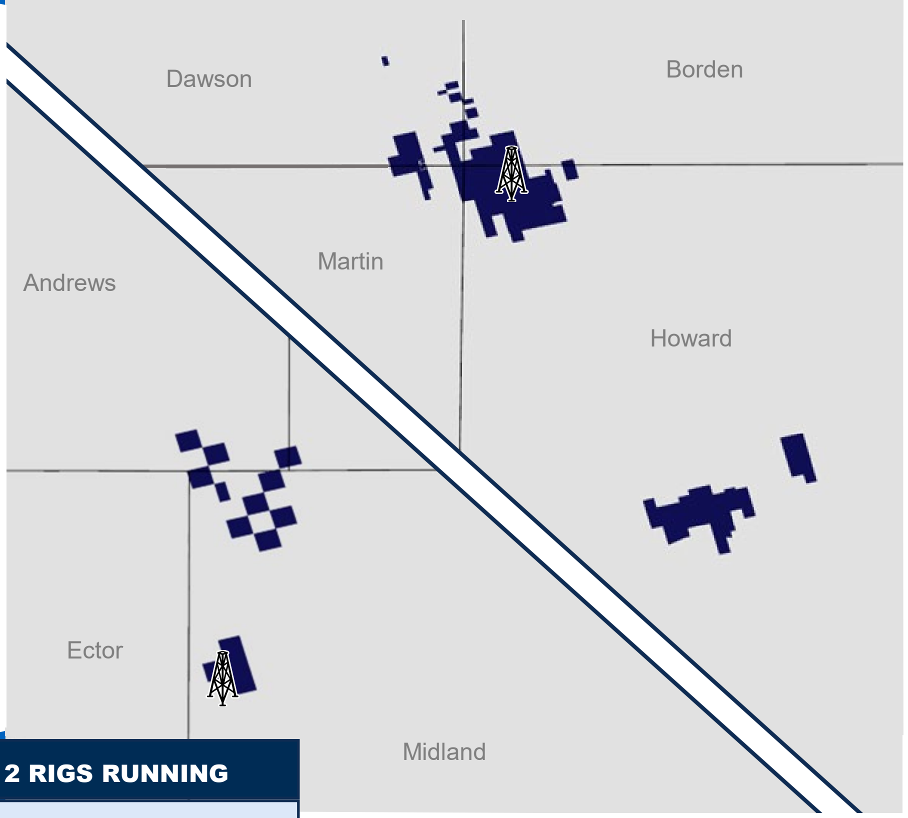
DELAWARE



3 RIGS RUNNING

119K NET ACRES

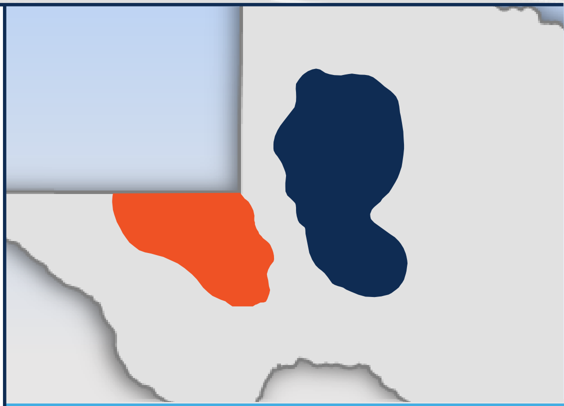
MIDLAND



2 RIGS RUNNING

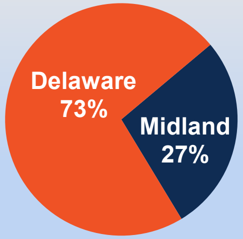
26K NET ACRES

Delaware Operated Acreage | Midland Operated Acreage | Non-Op Acreage



CALLON	
Market Cap[1] ($B)	$2.6
Enterprise Value[1,2] ($B)	$4.6
Net Acres	~145,000
Current Rigs Running	5
FY23E Production (MBoe/d)	103 – 106
FY23E Oil Production (MBbl/d)	62 – 64
FY23E Operated TILs (gross wells)	105 – 110
Delaware Well Costs[3] (D&C / ft)	$960
Midland Well Costs[3] (D&C / ft)	$730

CAPITAL ALLOCATION
2H23



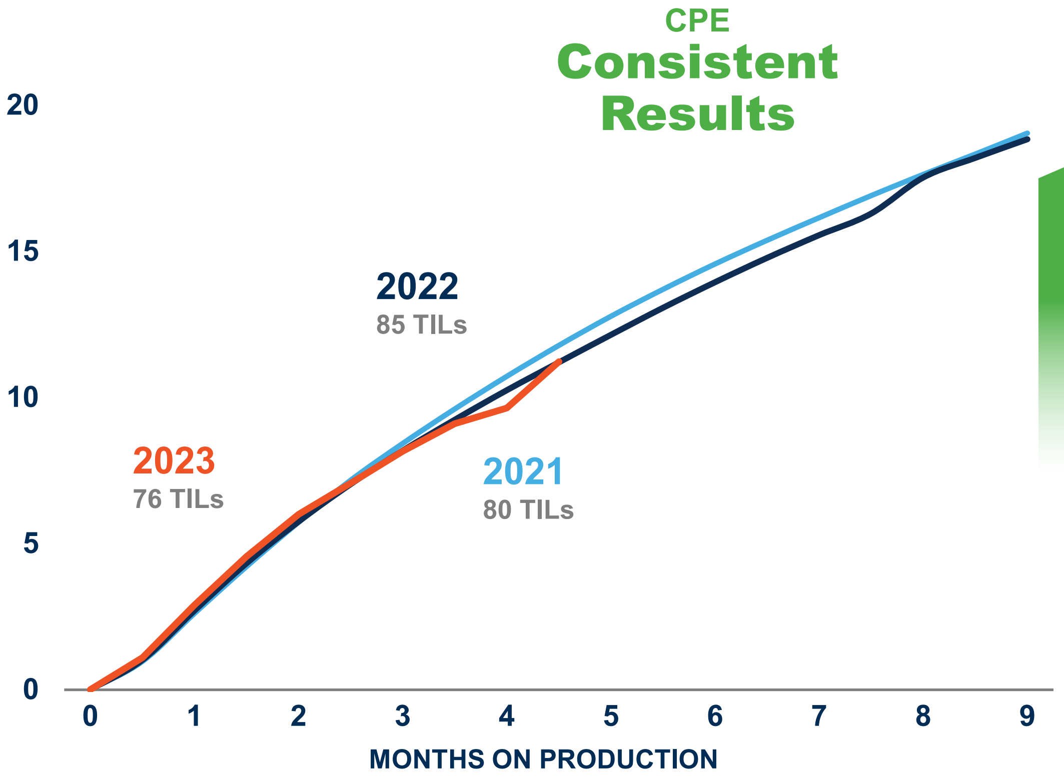
1. Market capitalization and enterprise value calculated using 68.1 million shares and closing price as of August 30, 2023
2. Reflects estimated impact of Delaware Basin acquisition and Eagle Ford divestiture, which closed July 3, 2023
3. Costs represent 2H23 wells normalized for 10k ft laterals and do not include facility costs

“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

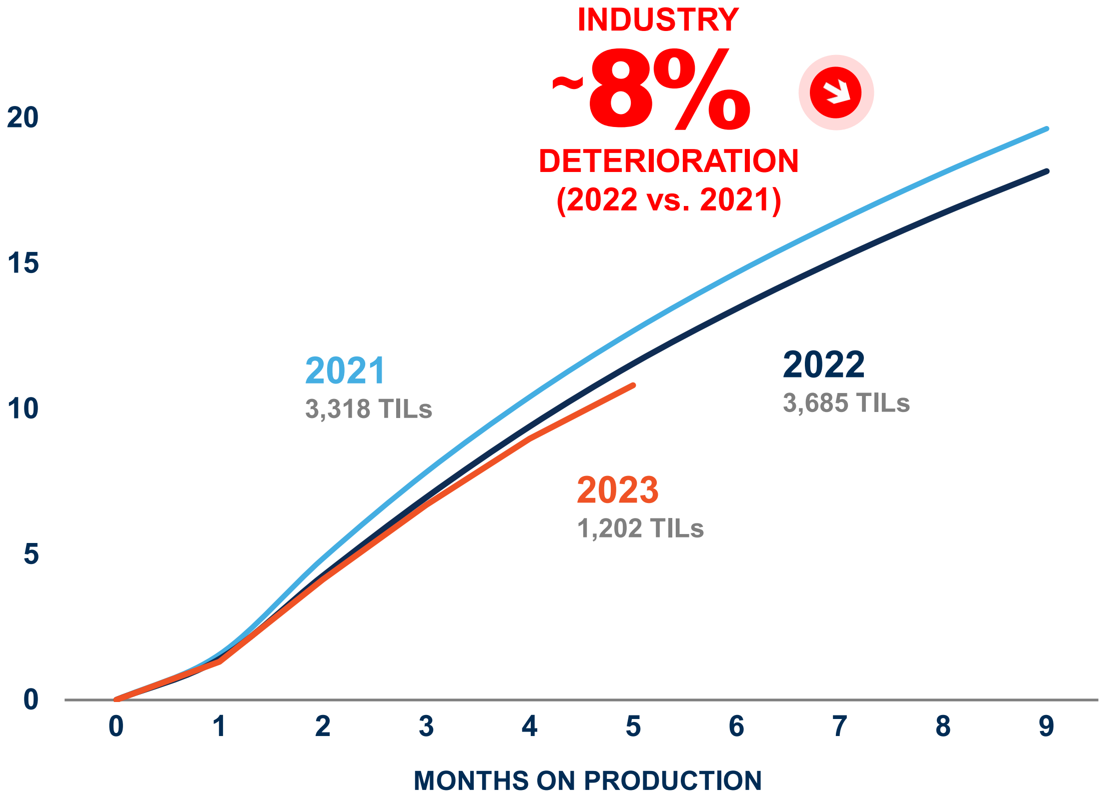


Callon’s Permian results exceeding industry’s

INDUSTRY’S DEGRADING WELL PRODUCTIVITY[2]

AVERAGE PERMIAN BASIN CUMULATIVE PRODUCTION BY MONTH

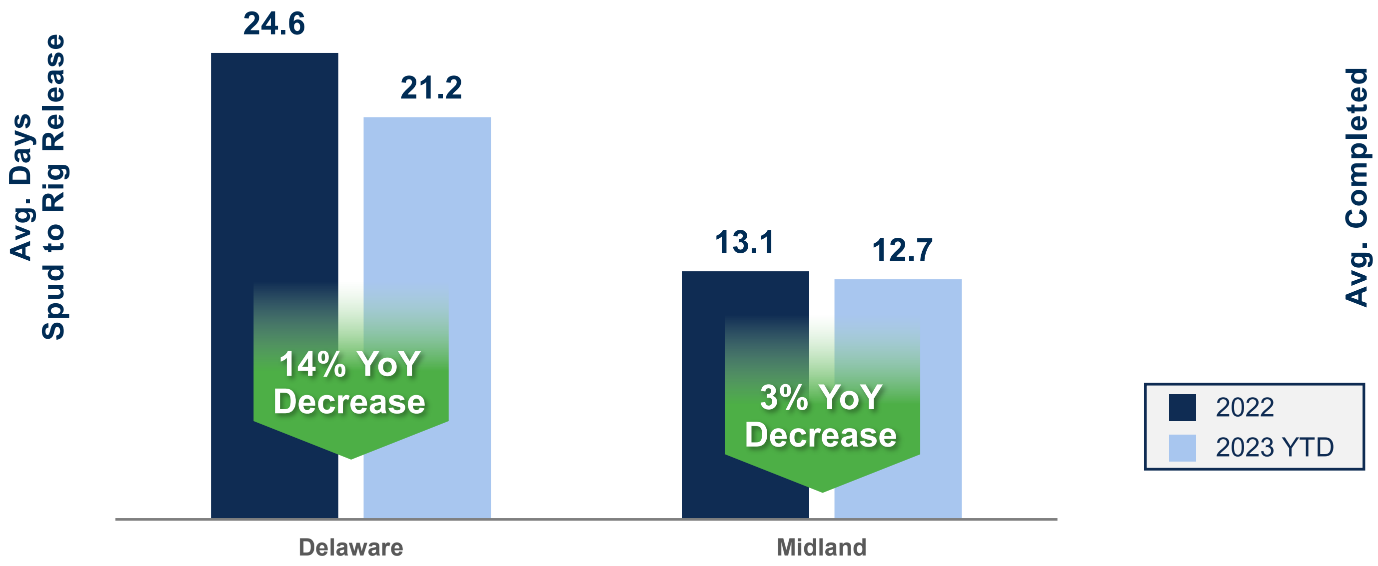
MBoe per 1,000 ft



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

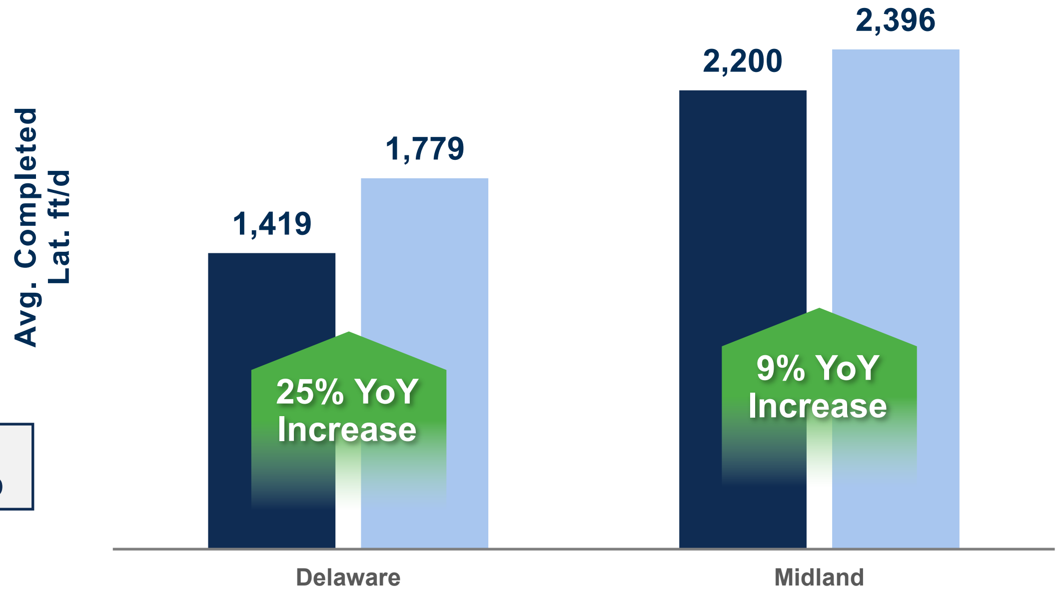
Drilling and Completion Execution

DRILLING[1]



- Reduced days to intermediate casing in the Delaware
- Strong performance with slim hole rotary steerable tools

COMPLETIONS[2]



- 25% increase in completed lateral feet per day in Delaware
- 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

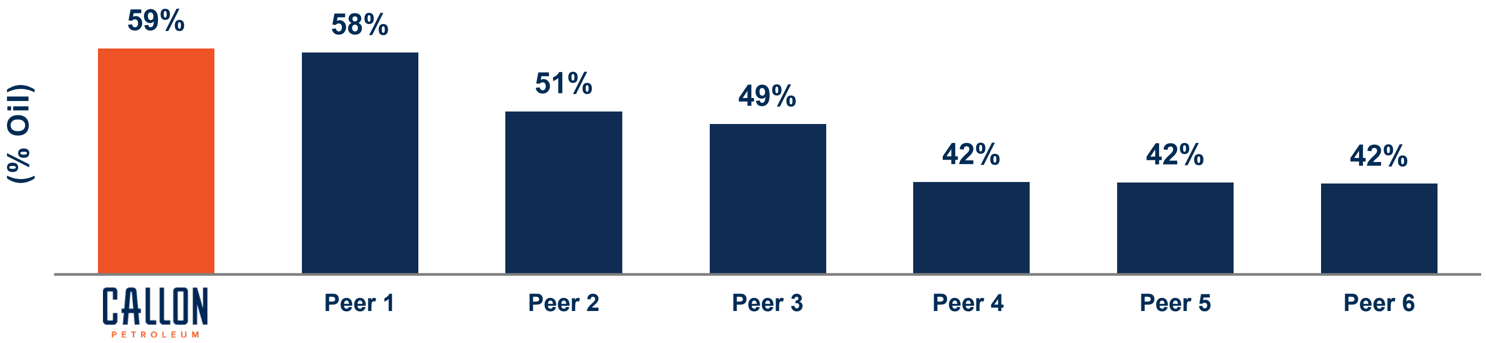
High Oil Cut Yields Top-Tier Margins

59% Oil Mix

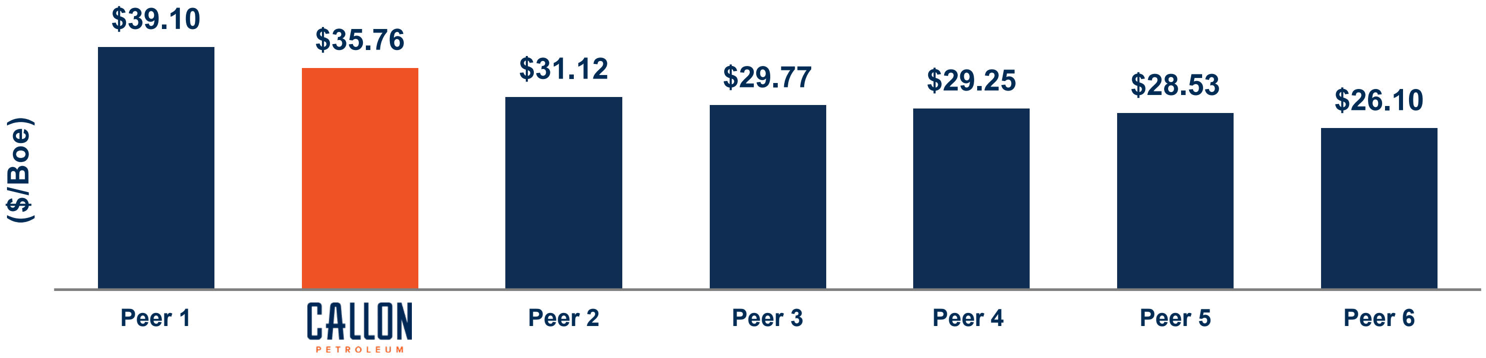
80% Liquids

97% of O&G Revenue derived from Liquids

PEER LEADING OIL WEIGHTING[1]…



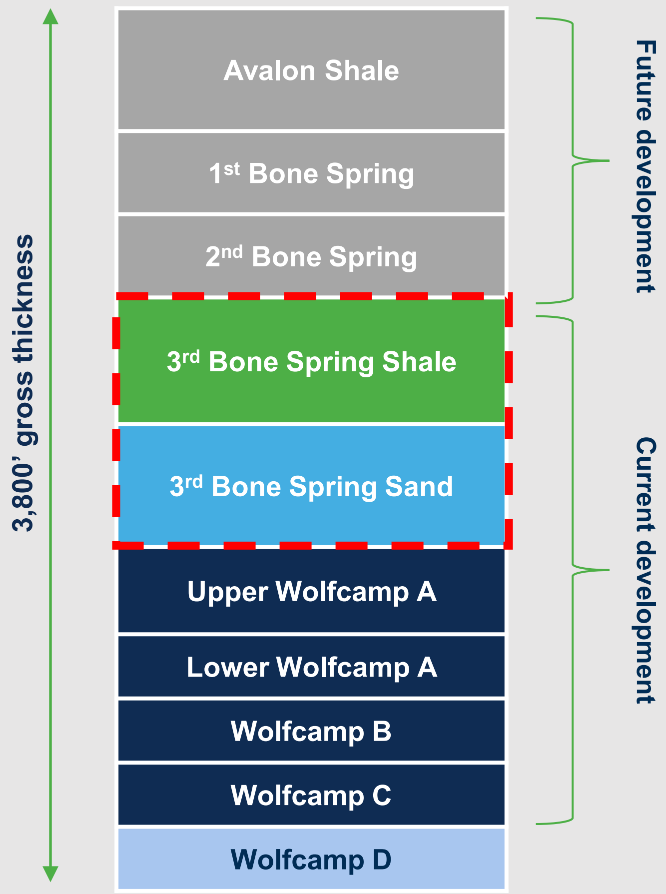
…TOP TIER OPERATING MARGINS[1,2]



1. Sourced from 2Q 2023 company financials; Peers include ESTE, MGY, MTDR, PR, SM and VTLE
2. Operating Margin is a non-GAAP measure. Please see the appendix for a reconciliation

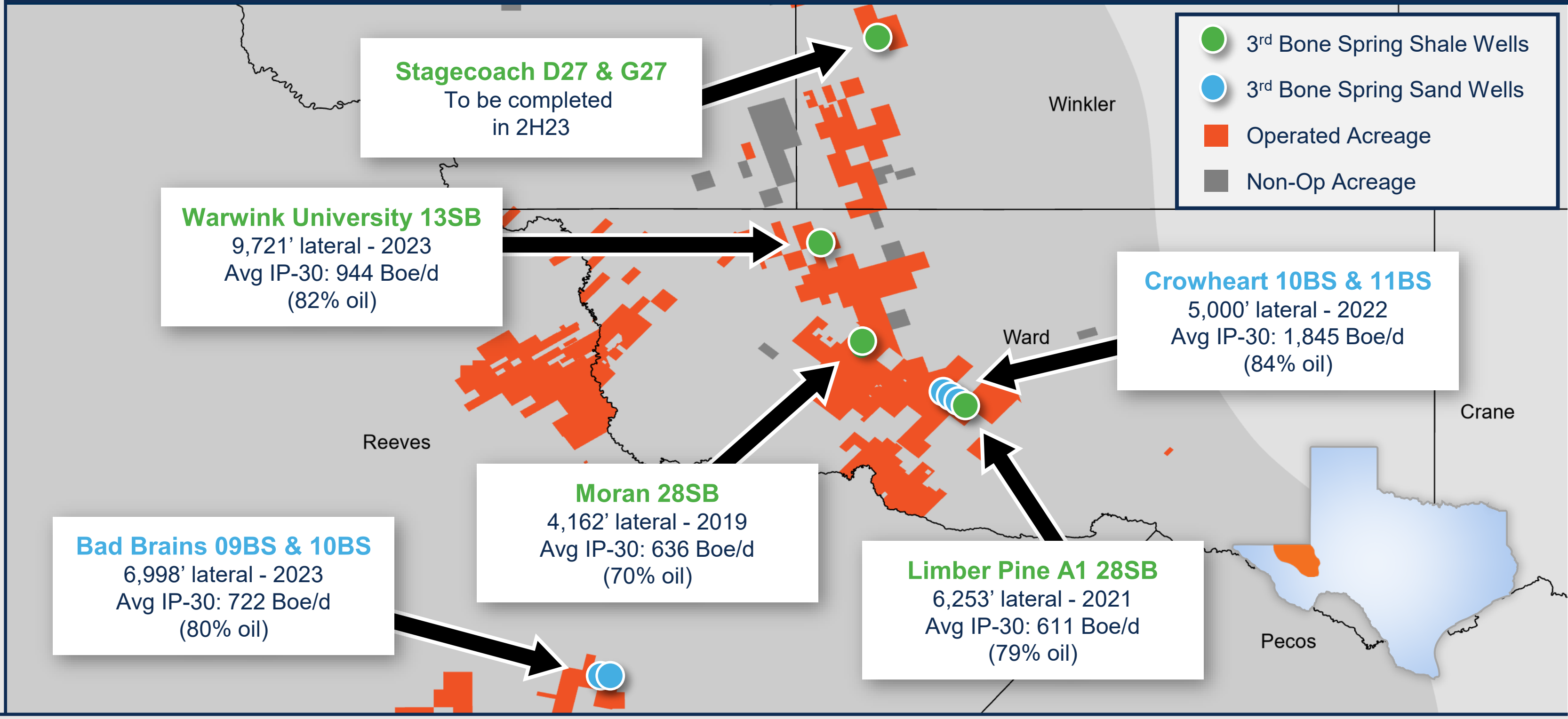
Expanding Bone Spring Development

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
- Optimized completions yielding shallowed pressure declines
- Evaluating acceleration of 3rd Bone Spring into near-term drilling inventory



Operational Priorities

TECHNOLOGY
TO PROVIDE
REAL-TIME DATA

IMPROVE MARGINS

GENERATE
FREE CASH FLOW

TOP PRIORITIES

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

Improving Capital Structure & Financial Flexibility

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 RBL FACILITY

~25% RBL UTILIZATION

ADVANTAGED 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

Launched Shareholder Return Program

SHARE REPURCHASE PROGRAM

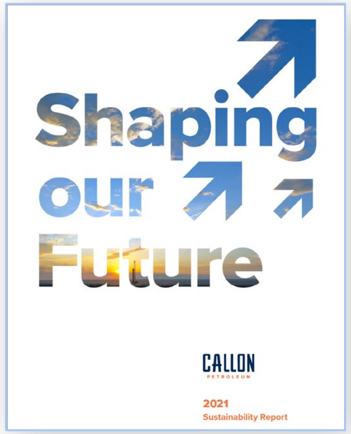
$300MM BUYBACK

- Two-year program **through 2Q25**
- 3Q23 guidance: ~50% of Adjusted FCF to repurchases

USES OF FUTURE FREE CASH FLOW

Deleveraging / Enhance Liquidity	Shareholder Returns	Reinvestment that Improves Returns

ESG Leadership

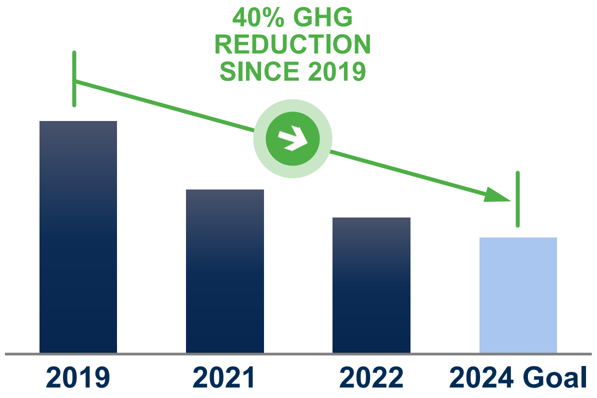


SUSTAINABILITY REPORT

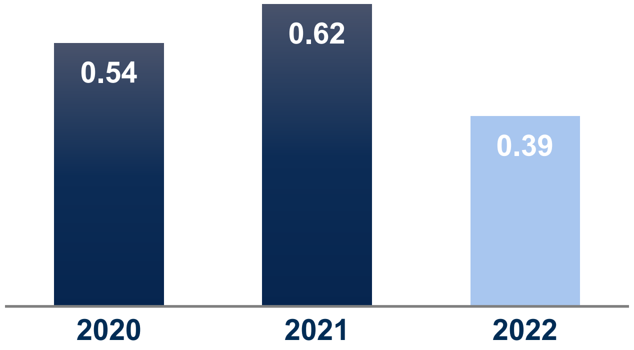
For more information:

Callon.com/sustainability

SCOPE 1 GHG INTENSITY



TOTAL REPORTABLE INCIDENT RATE



ENVIRONMENTAL TARGETS

50% Reduction in GHG intensity by 2024[1]

<0.2% Methane emissions by 2024

<1% Reduce controlled flaring to <1% by 2024

1. Relative to 2019 baseline

A Stronger Callon

- FOCUSED PERMIAN OPERATIONS WITH SCALE
- ENHANCED CAPITAL STRUCTURE
- DECADE-PLUS PREMIUM INVENTORY
- LOWER COSTS, HIGHER MARGINS
- LAUNCHED SHAREHOLDER RETURN PROGRAM 3Q23

APPENDIX

CALLON
PETROLEUM

2023 Outlook

2023 GUIDANCE

	3Q23	4Q23	FY23
Production (MBoe/d)	**100 – 103**	**104 – 108**	**103 – 106**
Oil (MBbls/d)	60 – 62	63 – 65	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

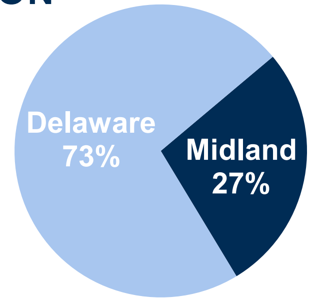
Effective Tax Rate			21% – 23%
Cash Taxes ($MM)			5 – 15

2023 CAPITAL EXPENDITURES

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

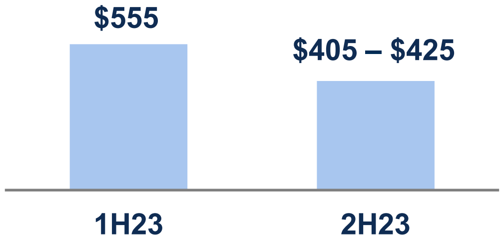
CAPITAL ALLOCATION

2H23



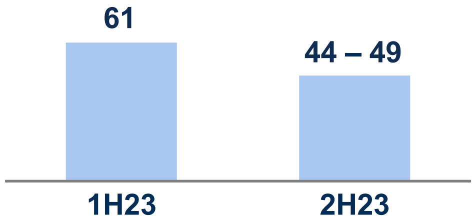
CAPITAL EXPENDITURES[1]

($MM)



OPERATED TILs

(gross wells)



1. Capital expenditures exclude land and seismic expenses

2Q23 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

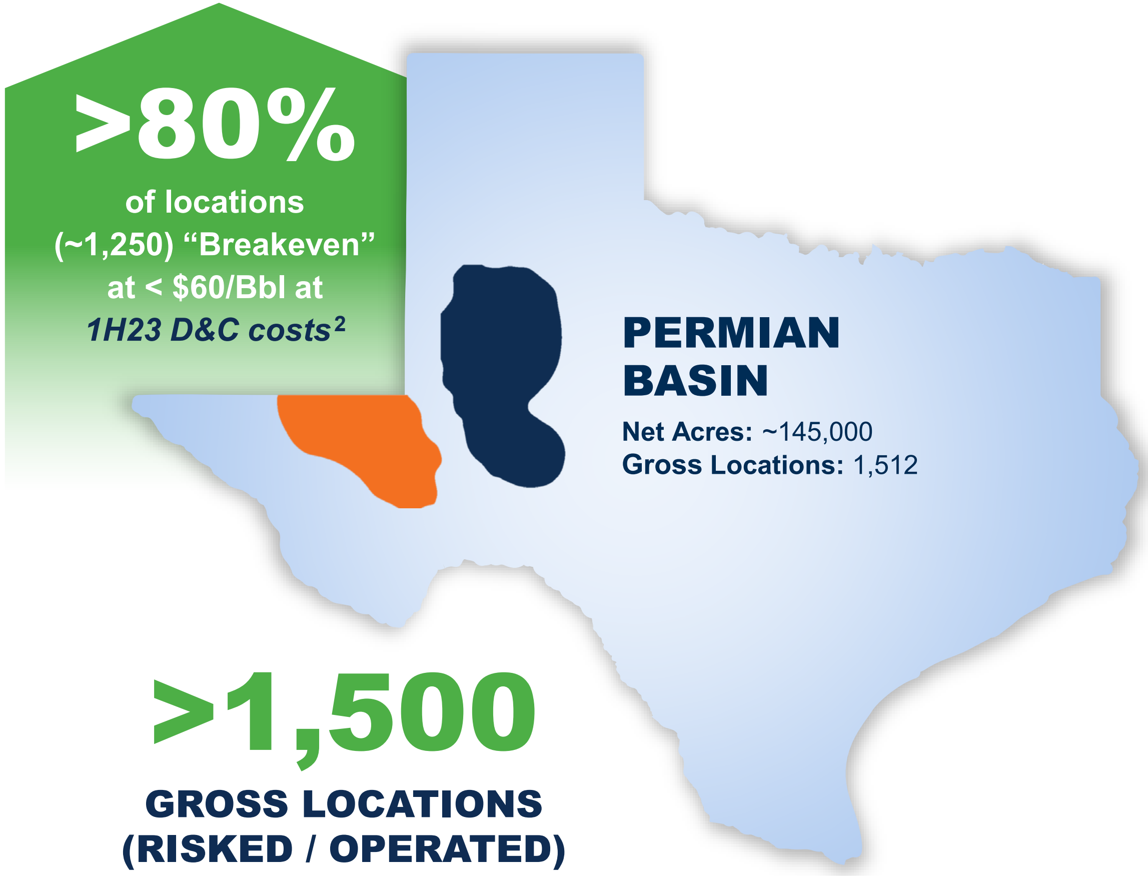
Deep Inventory of High-Quality Risked Locations

DELAWARE BASIN GROSS OPERATED LOCATIONS IN CORE ZONES[1]

	Total	Avg. Lateral (ft)
BONE SPRING	219	9,452’
WOLFCAMP A	478	8,314’
WOLFCAMP B	251	8,624’
WOLFCAMP C	99	8,838’
TOTAL	**1,047**	**8,676’**

MIDLAND BASIN GROSS OPERATED LOCATIONS IN CORE ZONES

	Total	Avg. Lateral (ft)
MIDDLE SPRABERRY	106	6,599’
LOWER SPRABERRY	90	6,755’
WOLFCAMP A	118	6,619’
WOLFCAMP B	151	7,199’
TOTAL	**465**	**6,829’**



1. Callon’s Permian inventory position as of December 31, 2022 plus acquired inventory in Delaware Basin through a transaction that closed in July 2023
2. Assumes flat price deck of $60/Bbl, $30/Bbl NGLs, and $3.00/MMBtu. "Breakeven" is defined as PV-10 positive

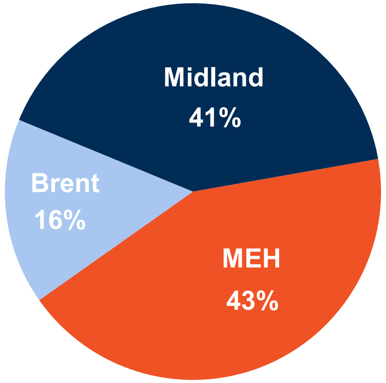
Increasing the Value Chain of Our Molecules

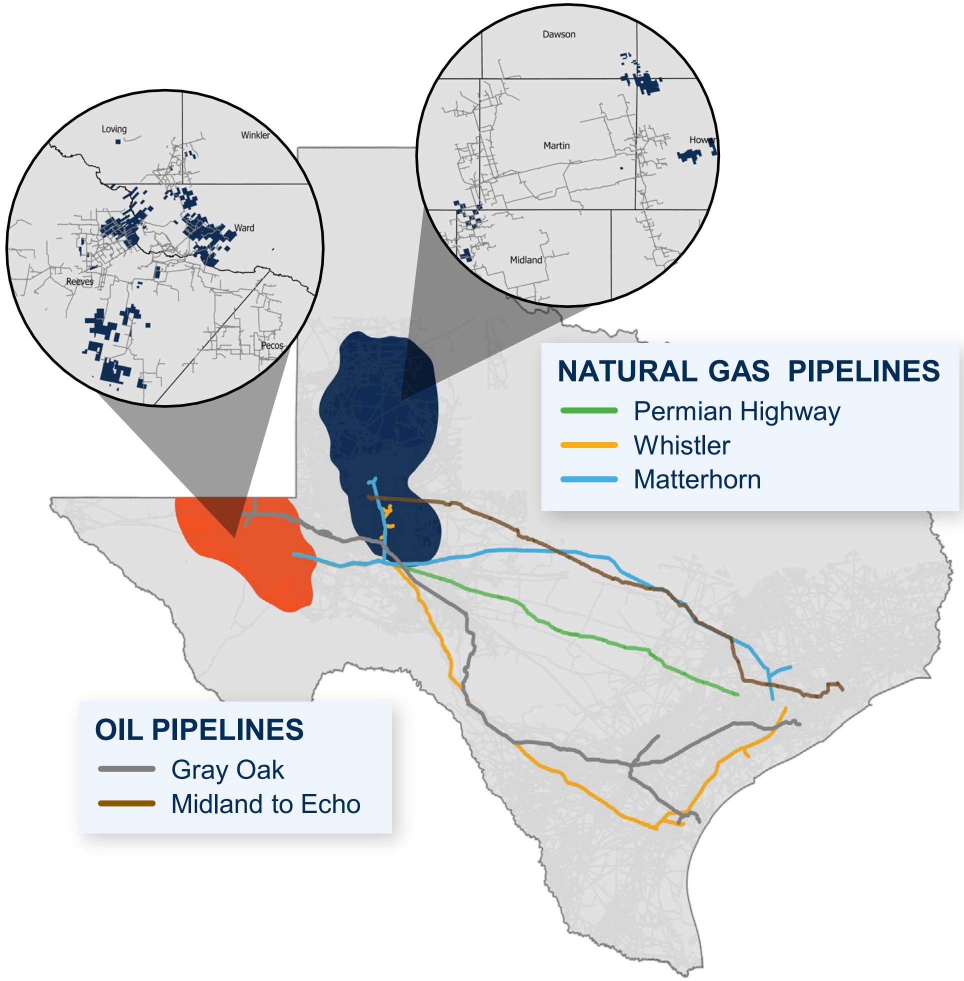
OIL

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



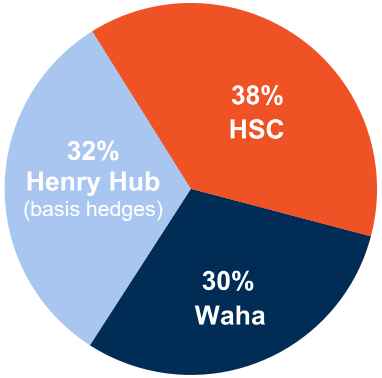


NATURAL GAS

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
- Transporting ~15,000 MMBtu/d on Whistler Pipeline as of July 1, 2023

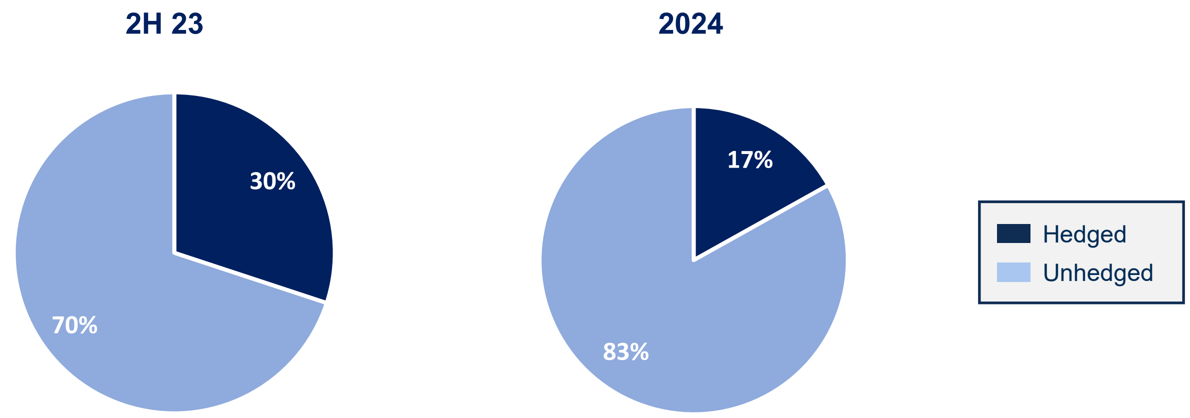
PRICE EXPOSURE[2]
2H23-24

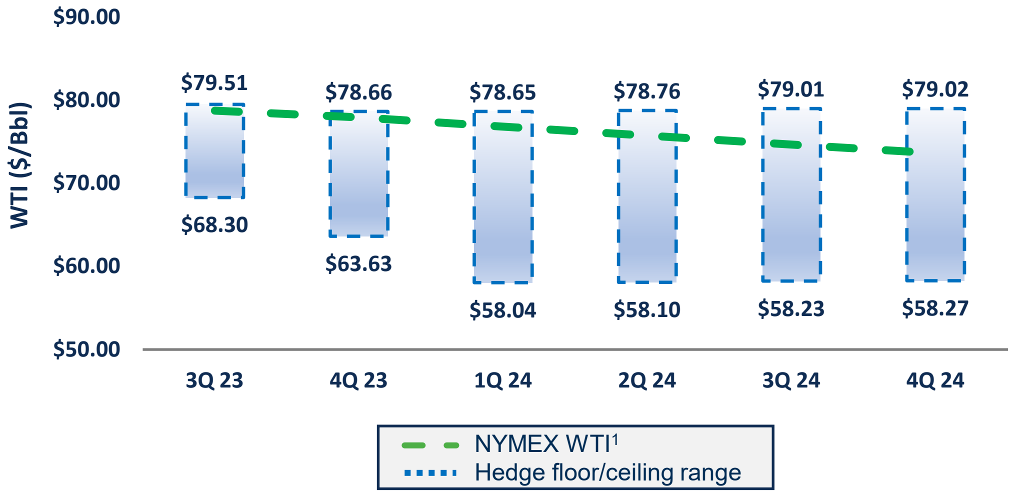


1. Dates assumed for long-haul transportation agreements are in-line with publicly available pipeline start-up information as of August 31, 2023
2. Projections based on current hedge book and development plan as of August 31, 2023

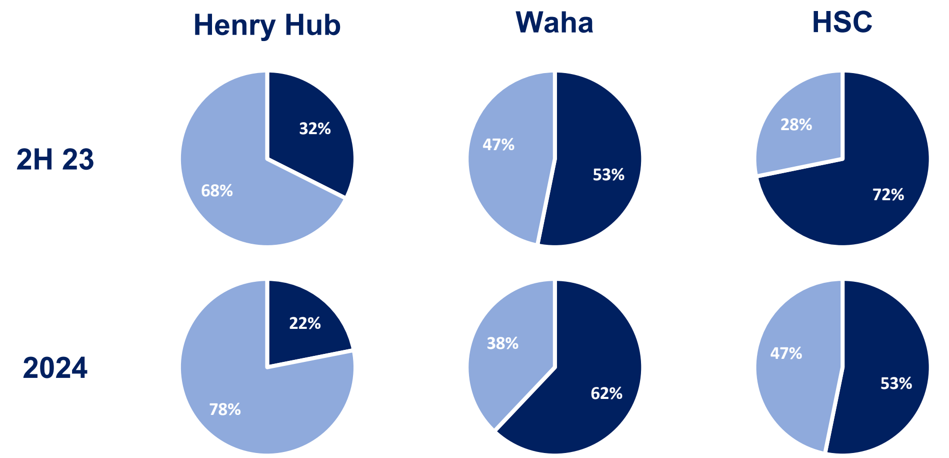
Derivative Positions[1]

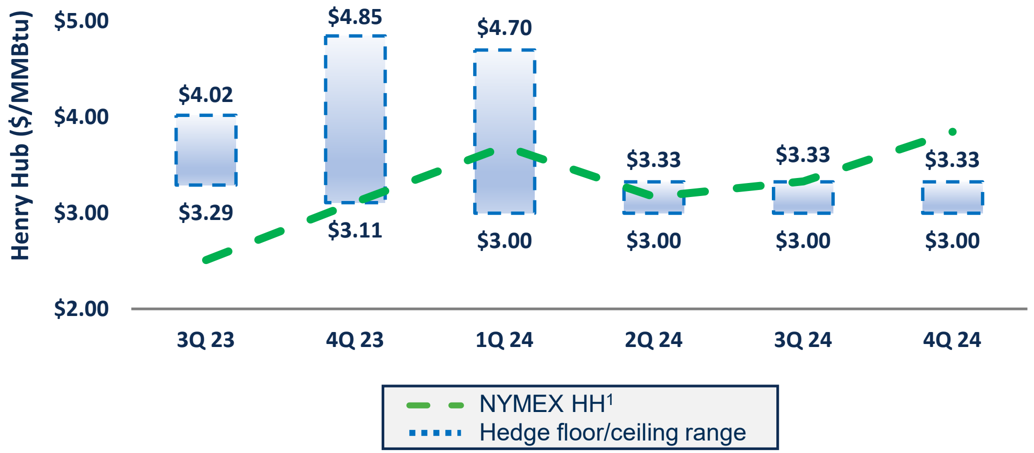
Crude Oil Derivative Position[2]





Natural Gas Derivative Position[2]





1. Derivatives positions and NYMEX pricing as of August 31, 2023
2. Hedge percentages derived from Bloomberg consensus production as of August 31, 2023

Oil Hedges[1]

	3Q23	4Q23	3Q23-4Q23	1Q24	2Q24	3Q23-2Q24	3Q24	4Q24	FY 2024
NYMEX WTI (Bbls, $/Bbl)									
Swaps									
Total Volumes	460,000	-	460,000	273,000	-	733,000	-	-	273,000
Total Daily Volumes	5,000	-	2,500	3,000	-	2,003	-	-	746
Avg. Swap Price	$82.10	-	$82.10	$80.01	-	$81.32	-	-	$80.01
Puts									
Total Volumes	368,000	368,000	736,000	-	-	736,000	-	-	-
Total Daily Volumes	4,000	4,000	4,000	-	-	2,011	-	-	-
Avg. Put Strike	$70.00	$70.00	$70.00	-	-	$70.00	-	-	-
Collars									
Total Volumes	603,599	625,455	1,229,054	-	-	1,229,054	-	-	-
Total Daily Volumes	6,561	6,798	6,680	-	-	3,358	-	-	-
Avg. Short Call Strike	$85.81	$85.34	$85.57	-	-	$85.57	-	-	-
Avg. Long Put Strike	$67.62	$67.35	$67.49	-	-	$67.49	-	-	-
Three-Way Collars									
Total Volumes	493,028	541,528	1,034,556	1,023,643	995,213	3,053,413	997,239	946,928	3,963,023
Total Daily Volumes	5,359	5,886	5,623	11,249	10,936	8,343	10,840	10,293	10,828
Avg. Short Call Strike	$69.38	$70.95	$70.20	$78.65	$78.76	$75.82	$79.01	$79.02	$78.86
Avg. Long Put Strike	$55.00	$55.00	$55.00	$58.04	$58.10	$57.03	$58.23	$58.27	$58.16
Avg. Short Put Strike	$45.00	$45.00	$45.00	$48.04	$48.10	$47.03	$48.23	$48.27	$48.16
Total WTI Volume Hedged (Bbls)	1,924,627	1,534,983	3,459,610	1,296,643	995,213	5,751,466	997,239	946,928	4,236,023
Average WTI Ceiling Strike ($/Bbl)	$79.51	$78.66	$79.15	$78.94	$78.76	$79.02	$79.01	$79.02	$78.93
Average WTI Floor Strike ($/Bbl)	$68.30	$63.63	$66.23	$62.66	$58.10	$64.02	$58.23	$58.27	$59.56

	3Q23	4Q23	3Q23-4Q23	1Q24	2Q24	3Q23-2Q24	3Q24	4Q24	FY 2024
WTI CMA ROLL (Bbls, $/Bbl)									
Swaps									
Total Volumes	673,535	838,828	1,512,363	-	-	1,512,363	-	-	-
Total Daily Volumes	7,321	9,118	8,219	-	-	4,132	-	-	-
Avg. Swap Price	$0.29	$0.30	$0.30	-	-	$0.30	-	-	-

1. Derivative positions as of August 31, 2023

Natural Gas Liquids Hedges[1]

	3Q23	4Q23	3Q23-4Q23	1Q24	2Q24	3Q23-2Q24	3Q24	4Q24	FY 2024
NATURAL GAS LIQUIDS (Bbls, $/Bbl)									
MBV Ethane Purity									
Total Volumes	35,333	35,095	70,428	-	-	70,428	-	-	-
Total Daily Volumes	384	381	383	-	-	192	-	-	-
Avg. Swap Price	$9.66	$9.66	$9.66	-	-	$9.66	-	-	-
MBV Propane EPC									
Total Volumes	36,077	35,754	71,831	-	-	71,831	-	-	-
Total Daily Volumes	392	389	390	-	-	196	-	-	-
Avg. Swap Price	$31.37	$31.37	$31.37	-	-	$31.37	-	-	-
MBV n-Butane EPC									
Total Volumes	31,137	33,470	64,606	18,390	17,835	100,832	18,451	17,429	72,105
Total Daily Volumes	338	364	351	202	196	275	201	189	197
Avg. Swap Price	$35.55	$35.65	$35.60	$33.18	$33.18	$34.73	$33.18	$33.18	$33.18
MBV i-Butane EPC									
Total Volumes	10,174	10,967	21,141	6,004	5,808	32,952	5,992	5,658	23,462
Total Daily Volumes	111	119	115	66	64	90	65	61	64
Avg. Swap Price	$35.42	$35.53	$35.47	$33.18	$33.18	$34.65	$33.18	$33.18	$33.18
MBV Natural Gasoline EPC									
Total Volumes	40,405	43,105	83,510	-	-	83,510	-	-	-
Total Daily Volumes	439	469	454	-	-	228	-	-	-
Avg. Swap Price	$56.28	$56.34	$56.31	-	-	$56.31	-	-	-

1. Derivative positions as of August 31, 2023

Natural Gas Hedges[1]

	3Q23	4Q23	3Q23-4Q23	1Q24	2Q24	3Q23-2Q24	3Q24	4Q24	FY 2024
NYMEX HENRY HUB (MMBtu, $/MMBtu)									
Swaps									
Total Volumes	1,840,000	620,000	2,460,000	-	-	2,460,000	-	-	-
Total Daily Volumes	20,000	6,739	13,370	-	-	6,721	-	-	-
Avg. Swap Price	$3.00	$3.00	$3.00	-	-	$3.00	-	-	-
Collars									
Total Volumes	1,572,296	2,201,102	3,773,398	3,537,136	1,663,051	8,973,585	1,744,498	1,653,871	8,598,555
Total Daily Volumes	17,090	23,925	20,508	38,870	18,275	24,518	18,962	17,977	23,493
Avg. Short Call Strike	$5.21	$5.37	$5.30	$4.70	$3.33	$4.70	$3.33	$3.33	$3.89
Avg. Long Put Strike	$3.63	$3.14	$3.35	$3.00	$3.00	$3.15	$3.00	$3.00	$3.00
Total NYMEX Volume Hedged (MMBtu)	3,412,296	2,821,102	6,233,398	3,537,136	1,663,051	11,433,585	1,744,498	1,653,871	8,598,555
Average NYMEX Ceiling Strike ($/MMBtu)	$4.02	$4.85	$4.39	$4.70	$3.33	$4.33	$3.33	$3.33	$3.89
Average NYMEX Floor Strike ($/MMBtu)	$3.29	$3.11	$3.21	$3.00	$3.00	$3.11	$3.00	$3.00	$3.00

	3Q23	4Q23	3Q23-4Q23	1Q24	2Q24	3Q23-2Q24	3Q24	4Q24	FY 2024
WAHA DIFFERENTIAL (MMBtu, $/MMBtu)									
Swaps									
Total Volumes	3,680,000	2,460,000	6,140,000	1,820,000	1,820,000	9,780,000	1,840,000	1,840,000	7,320,000
Total Daily Volumes	40,000	26,739	33,370	20,000	20,000	26,721	20,000	20,000	20,000
Avg. Swap Price	($1.25)	($1.49)	($1.34)	($1.06)	($1.06)	($1.24)	($1.06)	($1.06)	($1.06)

	3Q23	4Q23	3Q23-4Q23	1Q24	2Q24	3Q23-2Q24	3Q24	4Q24	FY 2024
HOUSTON SHIP CHANNEL DIFFERENTIAL (MMBtu, $/MMBtu)									
Swaps									
Total Volumes	2,760,000	2,760,000	5,520,000	3,640,000	3,640,000	12,800,000	3,680,000	3,680,000	14,640,000
Total Daily Volumes	30,000	30,000	30,000	40,000	40,000	34,973	40,000	40,000	40,000
Avg. Swap Price	($0.29)	($0.29)	($0.29)	($0.42)	($0.42)	(0.36)	($0.42)	($0.42)	($0.42)

1. Derivative positions as of August 31, 2023

Non-GAAP Operating Margin[1]

(Per Boe data)	1Q23	2Q23
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)	1Q23	2Q23
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)	1Q23	2Q23
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