CALLON
PETROLEUM

Second Quarter Earnings Presentation

AUGUST 2022

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 wells anticipated to be drilled and placed on production; inventory; future levels of development activity and associated production, capital expenditures, cash flow expectations, and margins; the Company's guidance for income statement expenditures and capital expenditures; estimated realizations; estimated reserve quantities and the present value thereof; 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 the COVID-19 pandemic and various governmental actions taken to mitigate its impact or 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; 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; 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 Reports 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 EBITDA," "operating margin", "all-in cash 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 adjusted EBITDA less operational capital expenditures (accrual), capitalized cash interest, capitalized cash G&A (which excludes capitalized expense related to share-based awards), and cash interest expense, net. 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, or as an alternative to net income (loss).

Callon calculates adjusted EBITDA 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 evaluated oil and gas properties, non-cash share-based compensation expense, merger, integration and transaction expense, (gain) loss on extinguishment of debt, and certain other expenses. Adjusted EBITDA 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 EBITDA 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 EBITDA excludes some, but not all, items that affect net income (loss) and may vary among companies, the adjusted EBITDA presented in this presentation 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.

"All-in" cash margin is a supplemental non-GAAP measure that is defined by the Company as oil, natural gas, and NGL revenues sales price including the impact of commodity derivative settlements less; lease operating expense; production and ad valorem taxes; gathering, transportation and processing fees; adjusted cash G&A; and cash interest expense divided by total production for the period. We believe "all-in" cash margin is a comparable metric against other companies in the industry and is an indicator of an oil and natural gas company's profitability per unit of production.

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. This metric is sometimes presented as a ratio with Adjusted EBITDA in order to provide investors with another means of evaluating the Company's ability to service its existing debt obligations as well as any future increase in the amount of such obligations.

The Company is unable to reconcile the projected adjusted free cash flow (non-GAAP) and adjusted EBITDA (non-GAAP) metrics included in this release to projected net cash provided by operating activities (GAAP) and net income (loss) (GAAP), respectively, 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.

Focused On Capital Discipline and Creating Shareholder Value

Sustainable Development Focus

Committed to ESG Excellence

Disciplined Capital Spending Program

Focused on Free Cash Flow

Dedicated to Improving Balance Sheet

Disciplined Strategy Delivers Results

Delivering on Commitments
Q2 2022 Highlights

Production Volumes — **101** MBoe/d (61% oil)

Reinvestment Percentage[1] — **50%** % of cash flow

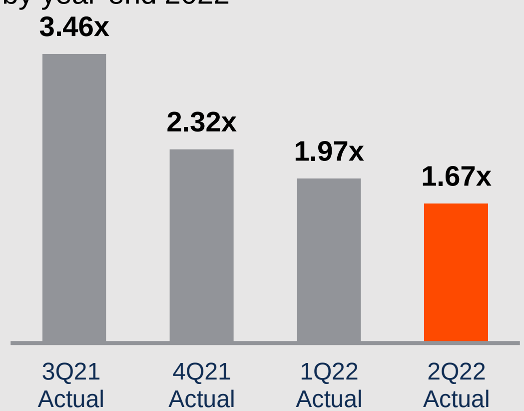
Operational Capital[2] ($MM) — **$238** Within Guidance

Operating Margin
per Boe[3]

8th
consecutive quarterly increase

Leverage Ratio
Net Debt / LTM Adj. EBITDA[3]

1.00x - 1.25x
by year-end 2022



Built DUC Backlog for Efficient Completion Schedule

Improved D&C Efficiencies and Well Productivity

Contracted Firm Natural Gas Transportation to Gulf Coast

Reduced Total Debt Level to $2.5 Billion

Refinanced Senior Notes and 2nd Lien Notes[4]

First Half of 2022 Accomplishments

1. Reinvestment percentage is calculated by dividing operational capital expenditures by adjusted discretionary cash flow minus capitalized interest minus capitalized G&A
2. Operational capital includes drilling, completions, facilities, and equipment, but excludes land and seismic
3. Operating margin & net debt are non-GAAP financial measures, please see the Appendix for the reconciliation. Net Debt / LTM Adjusted EBITDA calculations are pursuant to the credit facility
4. On June 9th, Callon priced a $600 million senior unsecured notes offering. The proceeds were used to redeem $460.2 million of outstanding 6.125% Senior Notes due 2024 and $319.7 million of 9.0% Second Lien Senior Secured Notes due in 2025

Strong Execution Advances Our Goals

2Q22 by the Numbers

Metric	2Q22 Result
Total production (MBoe/d)	100.7 *(Guidance 100 - 102)*
Oil production	61% *(Guidance 64%)*
LOE ($MM)	$72.9
Production and ad valorem tax *(% of total oil, natural gas, and NGL revenue)*	5.9%
GP&T ($MM)	$23.3
Operational capital[1] ($MM)	$237.8 *(Guidance $225 - $240)*
Adjusted EBITDA[2] ($MM)	$418.5
Adjusted Free Cash Flow[2] ($MM)	$125.6

Second Quarter Accomplishments

Operational

Increased Completion Activity
Sequential increase over Q1 of 75%

Successfully Tested Larger Completion Design
Potential for further productivity improvements

Reduced GHG Through Replacement of Pneumatics
GHG emissions reduction goals on track

Contracted Firm Natural Gas Transportation
Entered into multiple agreements for 75,000 MMBtu/d of firm transportation to the Gulf Coast

Continue to Drive Acquisition Synergies
Accelerated adoption of new artificial lift program

Financial

Eighth Sequential Increase in Operating Margin
Up 16% sequentially to $67.58 per Boe

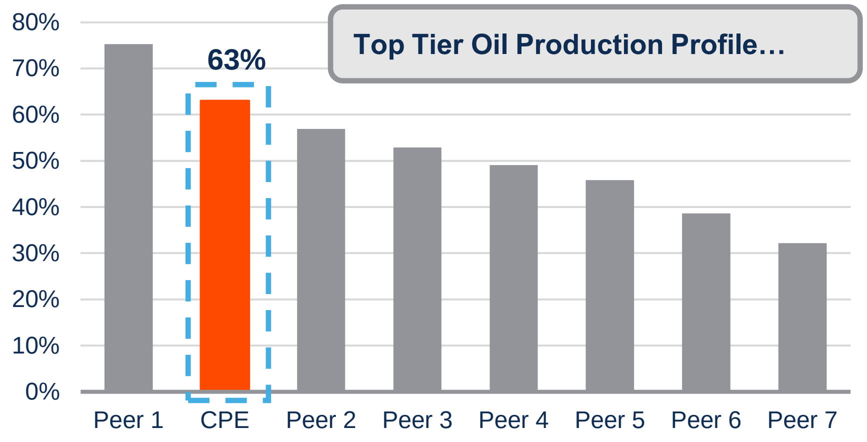
Disciplined Reinvestment Rate
Approximately 50% of cash flow reinvested

Further Debt Reduction
Paid down approximately $200 million of debt during the first half of 2022

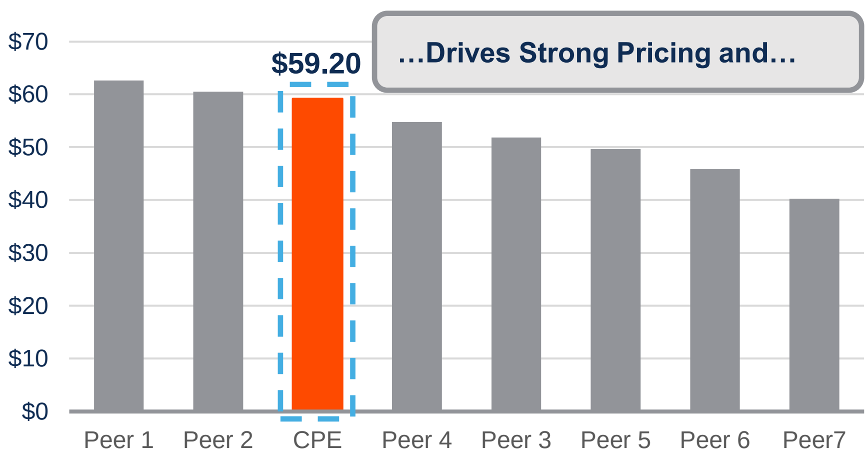
1. Operational capital includes drilling, completions, facilities, and equipment, but excludes land and seismic
2. Adjusted EBITDA and Adjusted Free Cash Flow are non-GAAP measures. Please see Appendix for reconciliation

Focused on High Margin Assets to Drive Differentiated Margins

Percentage of Oil Production on LTM Basis[1]



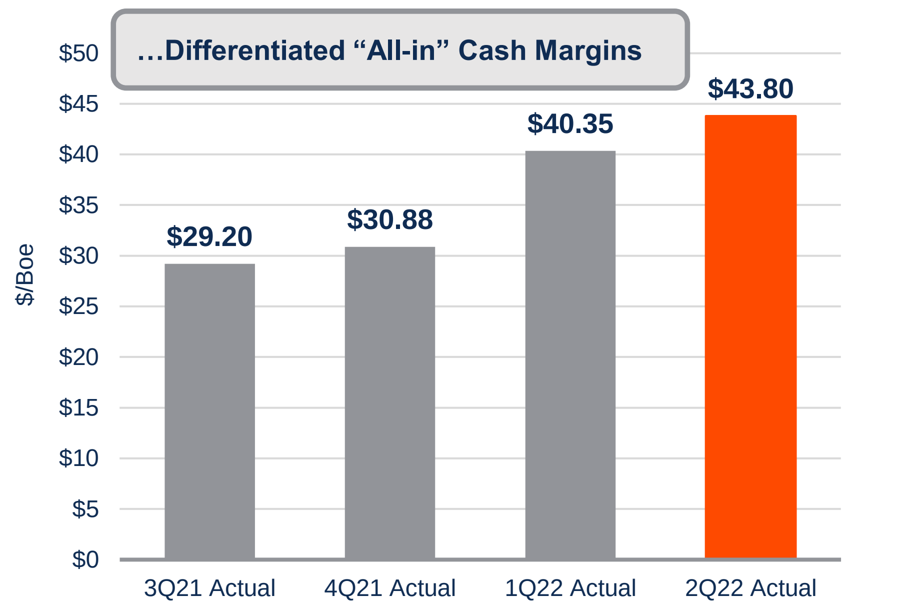
Wellhead Price Realizations[2] on LTM Basis



Driving Differentiated Margins

- **2nd Highest** Oil Weighted Production Profile
- **Top-Tier** Wellhead Price Realizations
- **8 Consecutive** Quarters of Margin Growth

"All-in" Cash Margin[3]



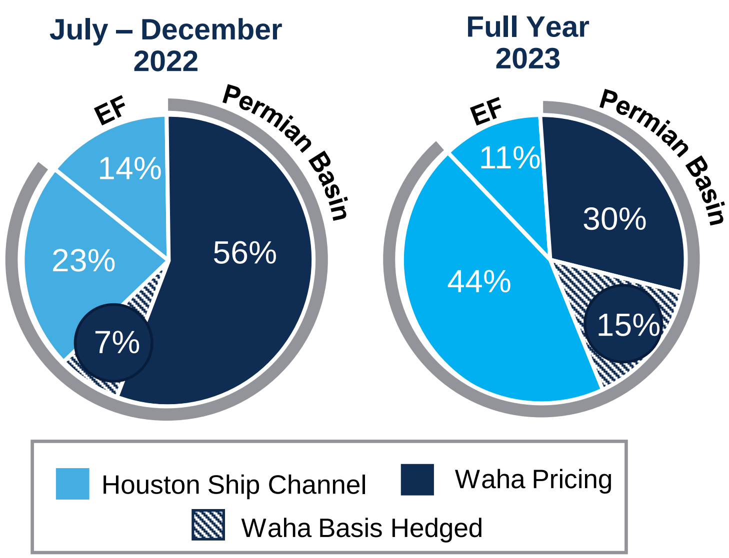
1. Peer group consists of CDEV, LPI, MGY, MTDR, PDCE, ROCC and SM. Data is trailing twelve months from Q1 2022 to Q2 2021
2. Realized price is calculated excluding the impacts of hedging gains / losses. Peer group consists of CDEV, LPI, MGY, MTDR, PDCE, ROCC and SM. Data is trailing twelve months from Q1 2022 to Q2 2021
3. "All-in" Cash margin is a non-GAAP measure and includes hedged realized prices minus LOE, GP&T, Adjusted Cash G&A, Cash Interest Expense, and Production and Ad Valorem Taxes. Please see the Appendix for additional details and reconciliation

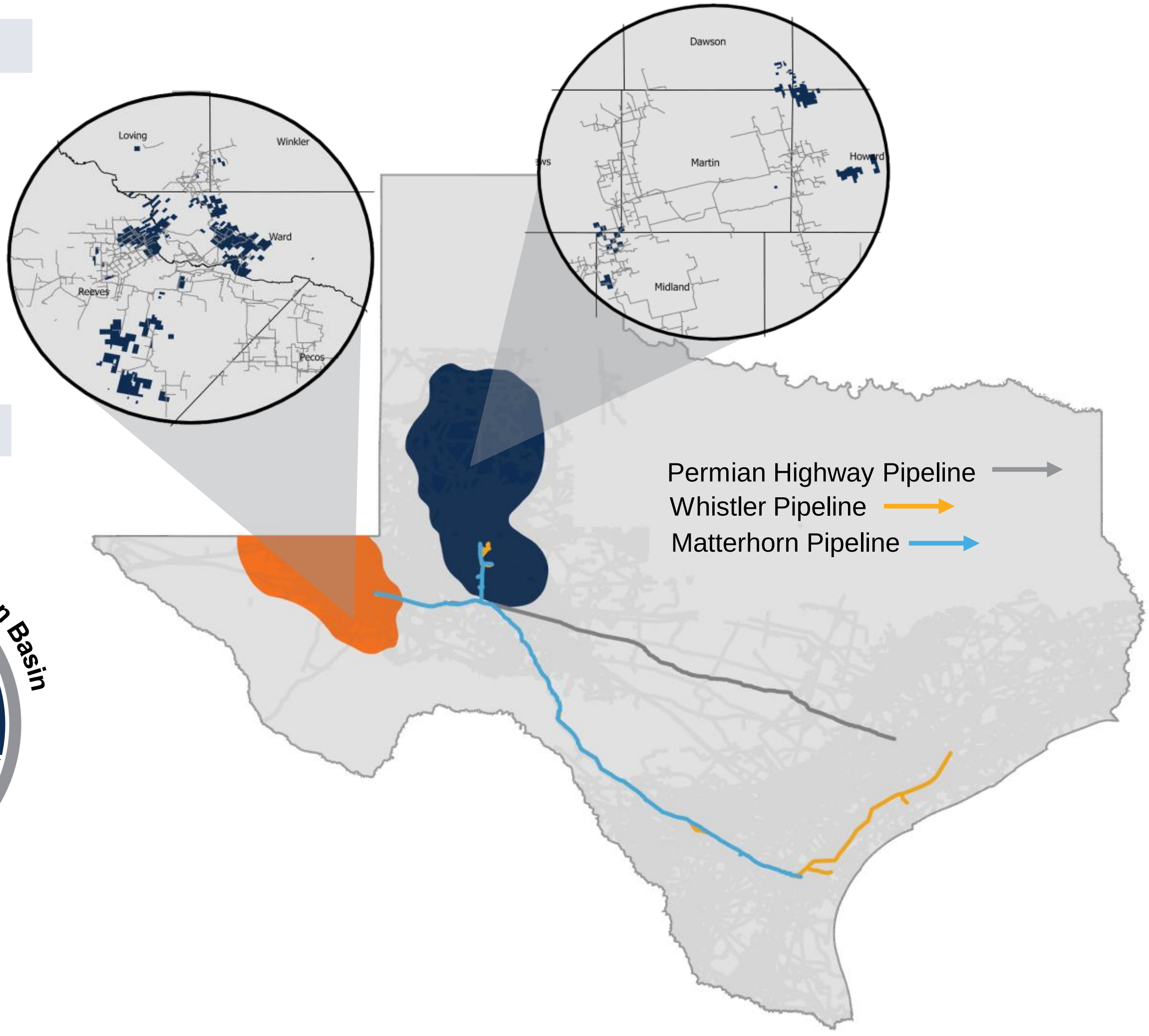
Providing Flow Assurance and Price Protection for Natural Gas

Natural Gas Takeaway Capacity

- Callon has "take-in-kind" optionality in various gas gathering agreements
- Contracted ~75,000 MMBtu/d of transportation on multiple long-haul pipelines to provide flow assurance and price diversification[1]
- Entered into ~20,000 MMBtu/d of Waha basis hedges[2]

Natural Gas Price Exposure[3]



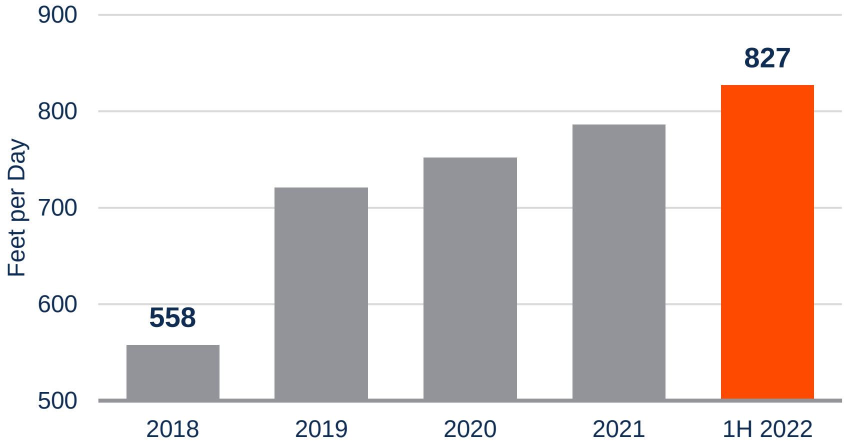


Only ~30% of 2023 gas volumes are exposed to Waha pricing

1. Dates assumed for long haul transportation agreements are in-line with publicly available pipeline start up information as of August 3, 2022
2. The hedge contract starts in November 2022 and extends through October 2023
3. Based on current hedge book and development plan as of July 27, 2022, for 2022 and 2023

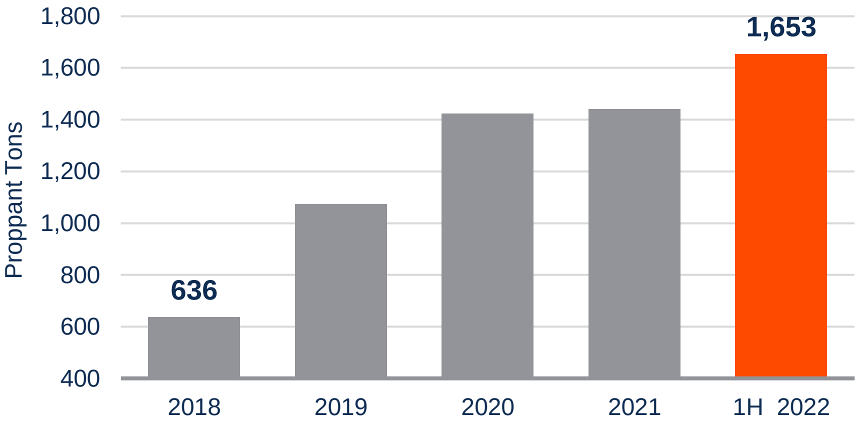
Improving Efficiencies Help Offset Inflationary Pressures

Delaware Basin Drilling Feet per Day



48% Improvement since 2018

Proppant Tons per Day



160% Improvement since 2018

Driving Improvements in Drilling

Rotary Steering Tools → Allows operator to stay in zone longer and increase the pace of drilling

Multi-Bowl Wellhead → Results in a reduction of flat time and increased drilling operations

Improved Bit/ BHA Designs → Improved bit /BHA designs reduces the number of trips, resulting in increased average footage per day drilled

Improving Pressure Pumping Efficiencies

Dedicated Completions Crew → Consistent completions crew enables continuous improvement

Optimized Completion Design → Results in more efficient proppant placement

Equipment Improvements → Surface layout, monobore design, and hydraulics enable improved transition times

Accelerating Operational Synergies

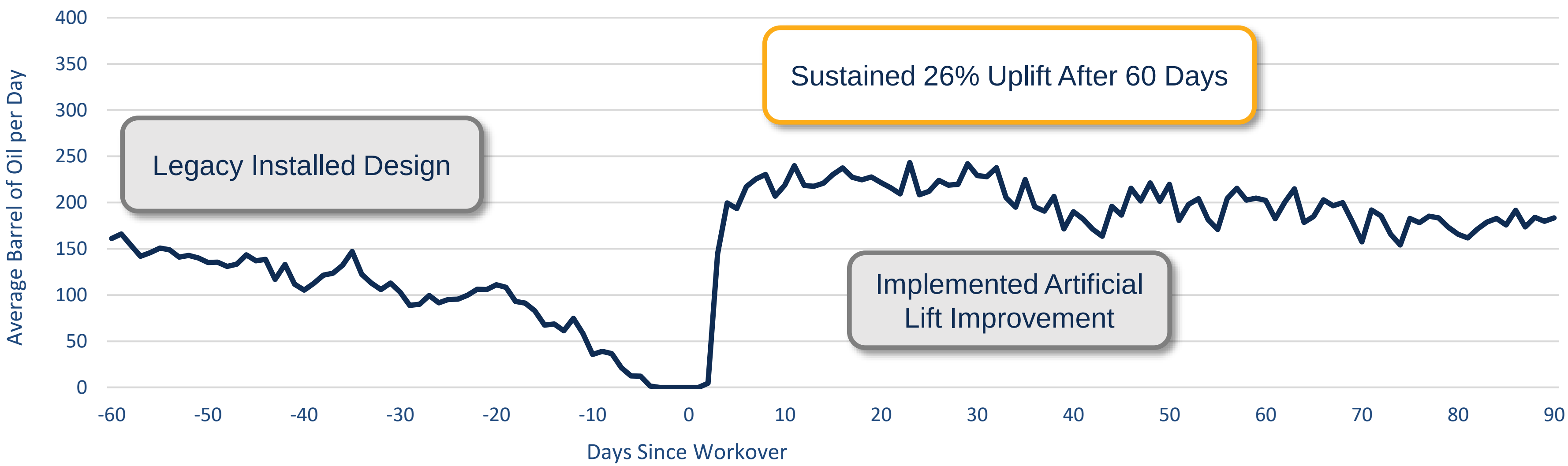
Artificial Lift Improvements for Increased Performance

- Accelerated adoption of electric submersible pump program
- Focus on Delaware South advancements
- Optimized chemical treatments prevent scale and corrosion
- Realizing sustained 26% uplift in production after 60 days

Second Quarter Artificial Lift Activity

- 5 initial artificial lift installs on new wells
- 39 artificial lift repair / conversions completed in the second quarter
  - Replacements in normal course as legacy equipment experiences failures after useful life reached
  - Proactive conversions during power outages to improve well economics

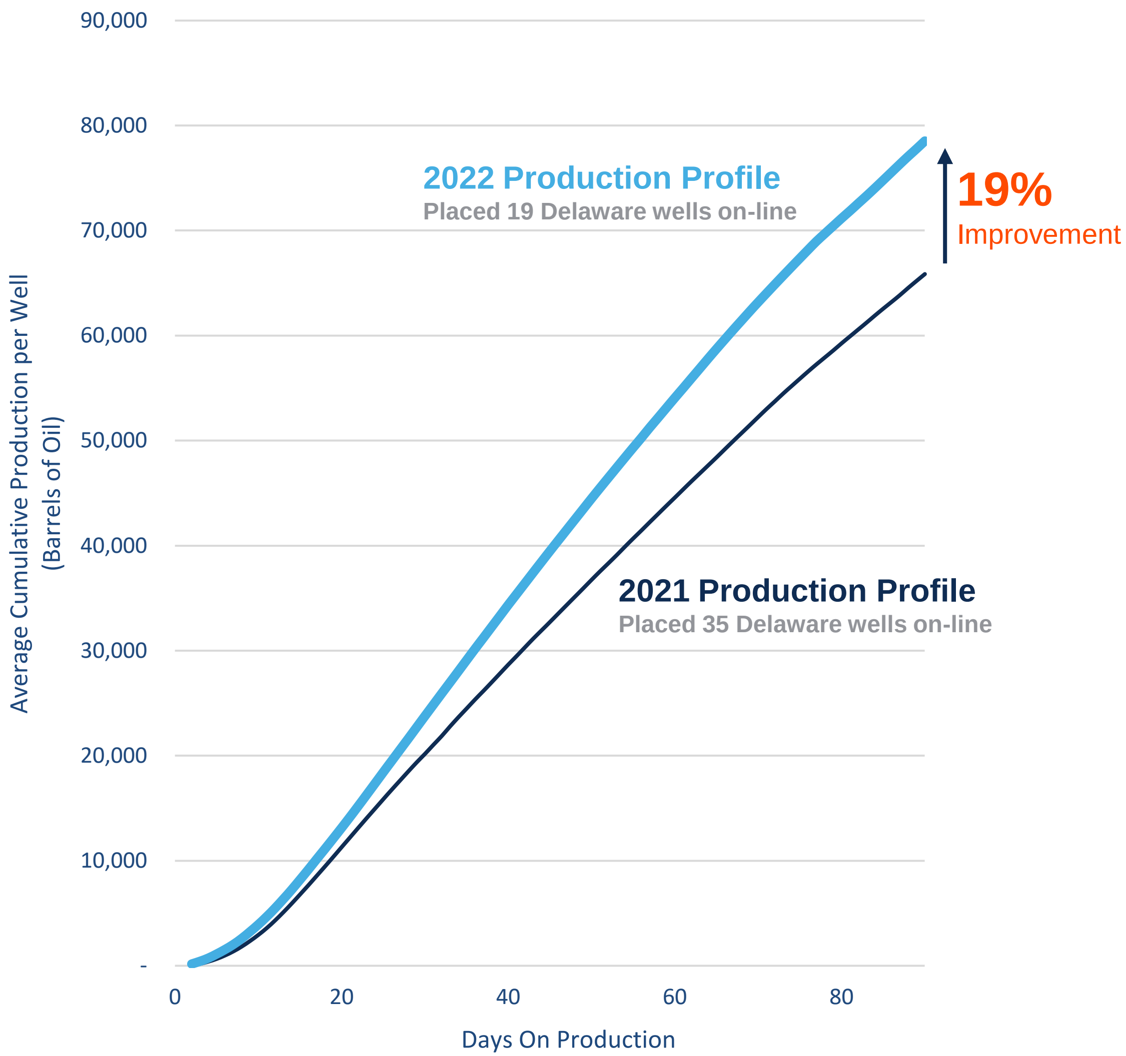
First Half Artificial Lift in Delaware South[1]



1. Includes 14 wells (excludes initial installs for wells placed on production since closing).

High Quality Inventory Plus Improving Completion Design

Delaware Basin Well Production Profile



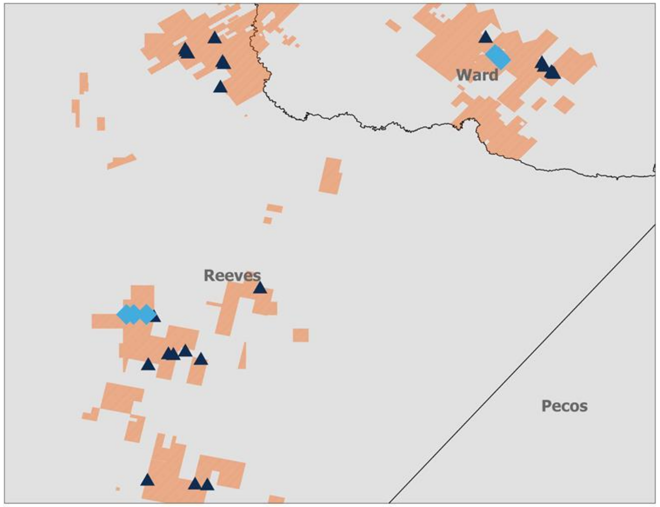
Optimizing Development Economics

Increased Well Spacing
Utilizing ~1,000 ft well spacing

Larger Completion Design
Testing ~3,000 lb/ft of proppant

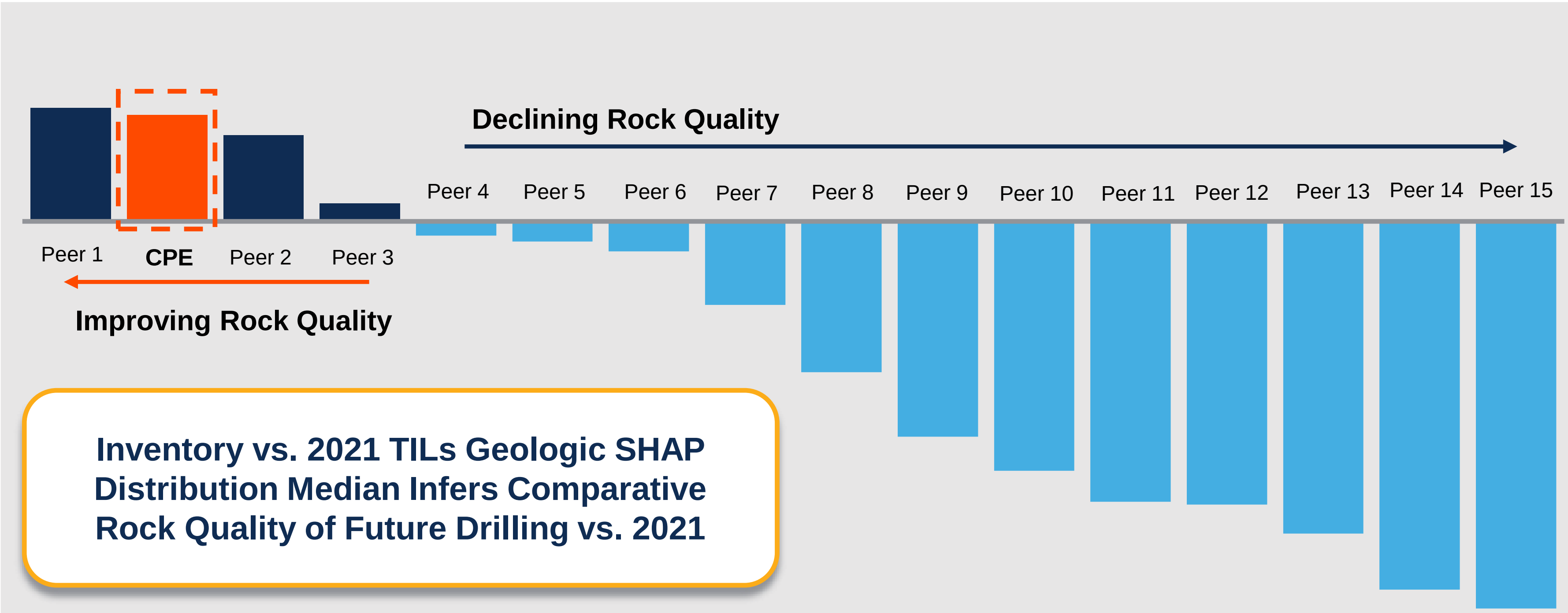
Improved Lateral Placement
Rotary steering to optimize lateral placement

Delaware Basin Acreage

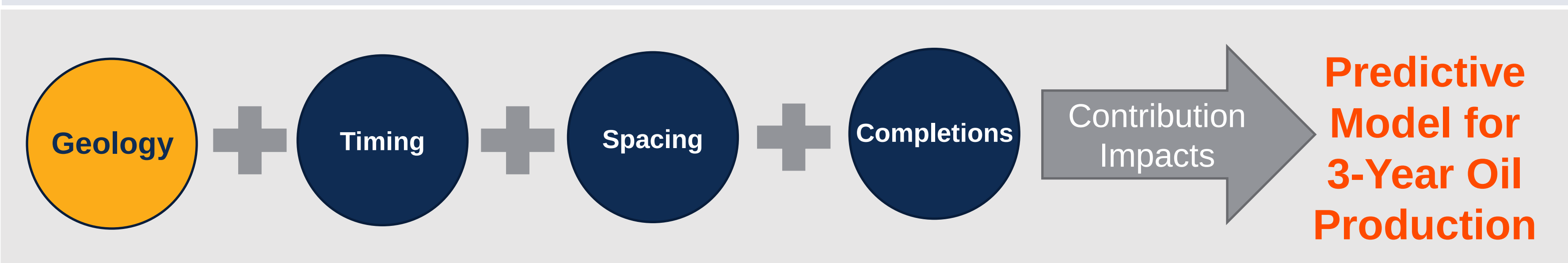


Differentiated Remaining Inventory Quality

Delaware Future Drilling Inventory vs 2021 Turn-in-Lines SHAP Difference (Median) by Operator



Geologic Shapley Additive Explanation (SHAP) Values Quantify The Marginal Impact Of Rock Quality On Well Performance[1]



1. Source: Enervus Report titled “Permian Basin Play Fundamentals” Published on May 19th 2022
2. Peer group includes: BTA Oil, DVN, EOG, COP, Tap Rock, OXY, XOM, CVX, MTDR, Mewbourne, BP, FANG, CTRA, CDEV, and Colgate

Third Quarter 2022 Outlook

Maintaining Capital *Discipline*

Guidance and Financial Estimates

Total Production **102-105** MBoe/d (63% oil / 82% liquids)

2Q22: 101 MBoe/d

Operational CapEx **$245-$255** million

2Q22: $238MM

Adj. Free Cash Flow Generation (2H22) **~$450** million[1]

1H22: $309MM

Key Focus Areas for the Second Half

Operational

- Sequential organic production growth
  - *Expected 2-3% growth from 3Q into 4Q*
- Large, oil-weighted projects across all operating areas
  - *Multiple pad co-development ranging from 6 – 12 wells*
- Increased proppant loadings in Delaware
  - *Encouraging early time performance from recent wells*
- Organic inventory expansion
  - *Initial Austin Chalk delineation well in 3Q*
- Proactively manage tight oilfield service market
  - *Partnering to ensure access to top tier services for 2023*

Financial

- Advancement of reduction in leverage metrics
  - *Targeting $2 billion in debt and 1x leverage ratio*
- Decreasing financial hedge exposure
  - *Reduction in oil volumes and price increase in swaps / ceiling*

1. Based on strip pricing as of July 27, 2022

Proactively Addressed Near-Term Maturities

Highlights

- ~$1.76 B of term debt outstanding
  - 100% fixed rate
  - Weighted average coupon: 7.56%
  - Weighted average maturity: 6.0 years
- Issued $600 MM 7.5% Unsecured Notes due 2030
- Repaid $460 MM 6.125% Unsecured Notes due 2024
- Redeemed $320 MM 9.0% Second Lien Notes due 2025

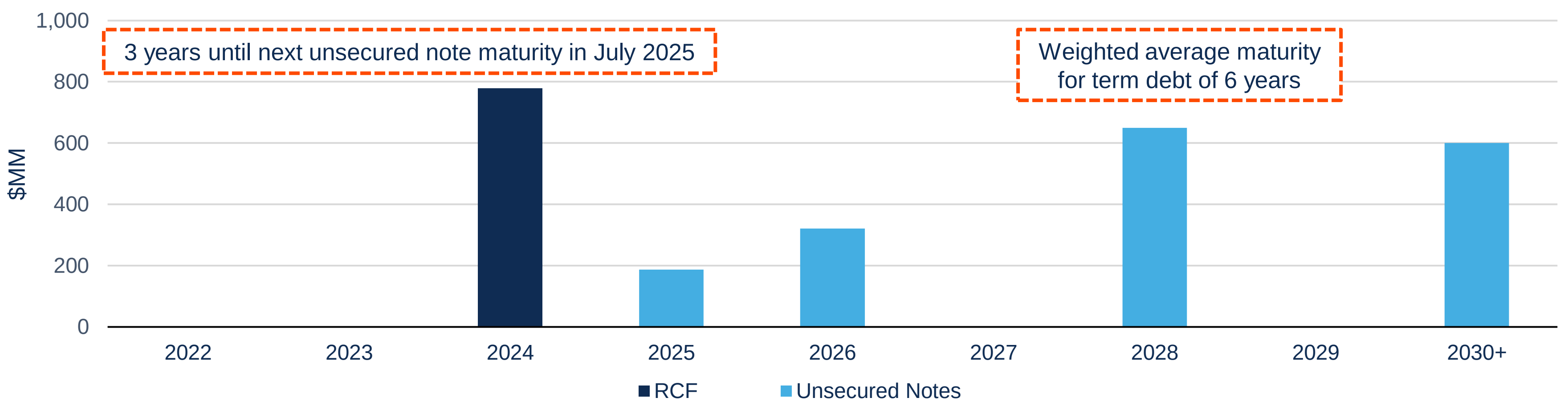
Positive Ratings Momentum

B2 / Moody's
One Notch Upgrade on Unsecured Rating to B3

B / S&P
One Notch Upgrade on Issuer Rating to B and Unsecured Rating to B+

B / Fitch
One Notch Upgrade on Unsecured Rating to B+

2Q 2022 Debt Maturity Profile



2022 Guidance

	Prior	Updated	COMMENTARY
Total production (MBoe/d)	**101 - 105**	**102 – 105**	Increased bottom end of the range
Oil	**64%**	**63%**	
NGL	**19%**	**19%**	
Gas	**17%**	**18%**	Increased to account for amended gathering contract
Income statement expenses **($MM, except where noted)**			
LOE, including workovers	**$275 - $295**	**$275 - $295**	
Gathering, processing, and transportation	**$75 - $85**	**$80 - $90**	Contract restructuring
Production taxes, including ad valorem (% of total oil, natural gas, and NGL revenues)	**6.0%**	**6.0%**	
Adjusted G&A: cash component[1]	**$50 - $60**	**$50 - $60**	
Adjusted G&A: non-cash component[2]	**$5 - $15**	**$5 - $15**	
Cash interest expense, net	**$55 - $60**	**$60 - $65**	Effects of rising interest rates on floating rate borrowings
Estimated effective income tax rate	**22%**	**22%**	
Capital expenditures **($MM, accrual basis)**			
Total operational capital[3]	**$790 - $810**	**$790 - $810**	
Cash capitalized interest	**$95 - $105**	**$95 - $105**	
Cash capitalized G&A	**$35 - $40**	**$35 - $40**	
Gross Operated Wells Drilled / Completed	**125-130 / 113-118**	**125-130 / 113-118**	

1. Excludes the change in fair value and amortization of share-based incentive awards and other non-recurring expenses
2. Amortization of equity-settled, share based incentive awards
3. Includes facilities, equipment, seismic, land, and other items, excludes capitalized expenses

APPENDIX

Oil Hedges

	3Q22	4Q22	2H22	1Q23	2Q23	3Q23	4Q23	FY 2023	FY 2024
NYMEX WTI (Bbls, $/Bbl)									
Swaps									
Total Volumes	1,656,000	1,978,000	3,634,000	765,000	773,500	-	-	1,538,500	-
Total Daily Volumes	18,000	21,500	19,750	8,500	8,500	-	-	4,215	-
Avg. Swap Price	$61.88	$67.29	$64.83	$81.04	$81.04	-	-	$81.04	-
Collars									
Total Volumes	1,196,000	1,196,000	2,392,000	900,000	910,000	460,000	460,000	2,730,000	-
Total Daily Volumes	13,000	13,000	13,000	10,000	10,000	5,000	5,000	7,479	-
Avg. Short Call Strike	$70.12	$70.12	$70.12	$90.74	$90.74	$80.11	$80.11	$87.15	-
Avg. Long Put Strike	$60.00	$60.00	$60.00	$72.90	$72.90	$70.00	$70.00	$71.92	-
Three-Way Collars									
Total Volumes	-	-	-	450,000	455,000	460,000	460,000	1,825,000	-
Total Daily Volumes	-	-	-	5,000	5,000	5,000	5,000	5,000	-
Avg. Short Call Strike	-	-	-	$90.00	$90.00	$90.00	$90.00	$90.00	-
Avg. Long Put Strike	-	-	-	$70.00	$70.00	$70.00	$70.00	$70.00	-
Avg. Short Put Strike	-	-	-	$50.00	$50.00	$50.00	$50.00	$50.00	-
Total WTI Volume Hedged (Bbls)	2,852,000	3,174,000	6,026,000	2,115,000	2,138,500	920,000	920,000	6,093,500	-
Average WTI Ceiling Strike ($/Bbl)	$65.34	$68.36	$66.93	$87.07	$87.07	$85.06	$85.06	$86.46	-
Average WTI Floor Strike ($/Bbl)	$61.09	$64.54	$62.91	$75.23	$75.23	$70.00	$70.00	$73.65	-
NYMEX WTI (Bbls, $/Bbl)									
Swaptions									
Total Volumes	-	-	-	-	-	-	-	-	1,830,000
Total Daily Volumes	-	-	-	-	-	-	-	-	5,000
Avg. Swap Price	-	-	-	-	-	-	-	-	$80.30
MIDLAND-CUSHING DIFFERENTIAL (Bbls, $/Bbl)									
Swaps									
Total Volumes	598,000	598,000	1,196,000	-	-	-	-	-	-
Total Daily Volumes	6,500	6,500	6,500	-	-	-	-	-	-
Avg. Swap Price	$0.50	$0.50	$0.50	-	-	-	-	-	-

Notes:
- All hedge positions are as of July 29, 2022

Natural Gas Hedges

	3Q22	4Q22	2H22	1Q23	2Q23	3Q23	4Q23	FY 2023
NYMEX HENRY HUB (MMBtu, $/MMBtu)								
Swaps								
Total Volumes	4,600,000	1,550,000	6,150,000	-	-	-	-	-
Total Daily Volumes	50,000	16,848	33,424	-	-	-	-	-
Avg. Swap Price	$3.62	$3.62	$3.62	-	-	-	-	-
Collars								
Total Volumes	1,840,000	3,670,000	5,510,000	4,500,000	910,000	920,000	310,000	6,640,000
Total Daily Volumes	20,000	39,891	29,946	50,000	10,000	10,000	3,370	18,192
Avg. Short Call Strike	$4.06	$6.91	$5.96	$7.49	$4.75	$4.75	$4.75	$6.60
Avg. Long Put Strike	$3.30	$4.67	$4.21	$4.95	$3.50	$3.50	$3.50	$4.48
Total NYMEX Volume Hedged (MMBtu)	6,440,000	5,220,000	11,660,000	4,500,000	910,000	920,000	310,000	6,640,000
Average NYMEX Ceiling Strike ($/MMBtu)	$3.75	$5.93	$4.73	$7.49	$4.75	$4.75	$4.75	$6.60
Average NYMEX Floor Strike ($/MMBtu)	$3.53	$4.36	$3.90	$4.95	$3.50	$3.50	$3.50	$4.48
WAHA DIFFERENTIAL (MMBtu, $/MMBtu)								
Swaps								
Total Volumes	-	1,220,000	1,220,000	1,800,000	1,820,000	1,840,000	620,000	6,080,000
Total Daily Volumes	-	13,261	3,342	20,000	20,000	20,000	6,739	16,658
Avg. Swap Price	-	($0.75)	($0.75)	($0.75)	($0.75)	($0.75)	($0.75)	($0.75)

Notes:
- All hedge positions are as of July 29, 2022

Non-GAAP Adjusted EBITDA[1]

($000s)	2Q 21	3Q 21	4Q 21	1Q 22	2Q 22
Net income (loss)	**($11,695)**	**$171,902**	**$285,351**	**$39,737**	**$348,009**
Loss on derivative contracts	190,463	107,169	10,145	358,300	81,648
Loss on commodity derivative settlements, net	(100,128)	(110,960)	(149,938)	(133,476)	(184,558)
Non-cash expense (benefit) related to share-based awards	5,279	(903)	939	4,166	(3,210)
Merger, integration, transaction and other	5,584	7,323	12,343	(13)	1,051
Income tax (benefit) expense	(478)	2,416	(837)	484	3,009
Interest expense, net	24,634	27,736	25,226	21,558	20,691
Depreciation, depletion and amortization	83,128	89,890	112,551	102,979	109,409
(Gain) loss on extinguishment of debt	-	(2,420)	43,460	-	42,417
Adjusted EBITDA	**$196,787**	**$292,153**	**$339,240**	**$393,735**	**$418,466**
Primexx EBITDA[2]	$51,463	$71,767			

1. See "Important Disclosures" slide for additional information related to Supplemental Non-GAAP Financial Measures
2. Represents EBITDA from April 1st through September 30th, 2021 prior to closing on transaction on October 1st

Non-GAAP Adjusted EBITDA and Adjusted Free Cash Flow[1]

($000s)	4Q 21	1Q 22	2Q 22
Net cash provided by operating activities	**$366,310**	**$281,270**	**$372,325**
Changes in working capital and other	(67,390)	123,805	25,096
Change in accrued hedge settlements	6,781	(31,951)	1,839
Cash interest expense, net	22,268	19,842	19,206
Merger, integration and transaction	11,271	769	-
Adjusted EBITDA	**$339,240**	**$393,735**	**$418,466**
Less: Operational capital expenditures (accrual)	159,786	157,378	237,812
Less: Capitalized cash interest	22,591	23,506	24,416
Less: Cash interest expense, net	22,268	19,842	19,206
Less: Capitalized cash G&A	11,035	9,703	11,432
Adjusted Free Cash Flow	**$123,560**	**$183,306**	**$125,600**

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

Non-GAAP Operating Margin[1]

Per Boe data	3Q 21	4Q 21	1Q 22	2Q 22
Sales price				
Permian Basin	$52.37	$59.64	$70.29	$80.64
Eagle Ford	59.63	66.10	78.50	92.75
Total sales price	$54.93	$61.22	$71.97	$82.98
Lease operating expense				
Permian	$4.19	$7.22	$6.85	$7.33
Eagle Ford	5.51	6.77	8.99	10.59
Total lease operating expense	$4.66	$7.11	$7.29	$7.96
Production and ad valorem taxes				
Permian	$2.80	$3.15	$3.89	$4.66
Eagle Ford	2.89	3.60	4.82	5.89
Total production and ad valorem taxes	$2.84	$3.26	$4.08	$4.90
Gathering, transportation and processing				
Permian	$2.70	$2.26	$2.33	$2.69
Eagle Ford	1.49	1.76	1.92	1.93
Total gathering, transportation and processing	$2.28	$2.14	$2.25	$2.54
Operating margin				
Permian	$42.68	$47.01	$57.22	$65.96
Eagle Ford	49.74	53.97	62.77	74.34
Total operating margin	**$45.16**	**$48.71**	**$58.35**	**$67.58**

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

Non-GAAP All-In Cash Margin[1]

Per Boe data	3Q 21	4Q 21	1Q 22	2Q 22
Average realized sales price	$54.93	$61.22	$71.97	$82.98
Impact of derivative settlements	(12.09)	(14.50)	(14.45)	(20.14)
Average realized sales price (including impact of derivative settlements)	$42.84	$46.72	$57.52	$62.84
Lease operating expense	4.66	7.11	7.29	7.96
Production and ad valorem taxes	2.84	3.26	4.08	4.90
Gathering, transportation and processing	2.28	2.14	2.25	2.54
Adjusted cash G&A	1.13	1.18	1.40	1.54
Cash interest expense, net	2.73	2.15	2.15	2.10
All-in cash margin	**$29.20**	**$30.88**	**$40.35**	**$43.80**

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

Non-GAAP Net Debt Reconciliation[1]

($ millions)	9/30/21	12/31/21	3/31/22	6/30/22
Total debt	$2,810	$2,694	$2,623	$2,516
Unamortized premiums, discount, and deferred loan costs, net	48	29	27	21
Adjusted total debt	**$2,858**	**$2,723**	**$2,650**	**$2,537**
Less: Cash and cash equivalents	4	10	4	6
Net Debt	**$2,854**	**$2,713**	**$2,646**	**$2,531**

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