Vital Energy

2Q-23 Earnings Presentation

Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, contains forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Vital Energy, Inc. (together with its subsidiaries, the “Company”, “Vital” or “VTLE”) assumes, plans, expects, believes, intends, projects, indicates, enables, transforms, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. The forward-looking statements are based on management’s current belief, based on currently available information, as to the outcome and timing of future events. Such statements are not guarantees of future performance and involve risks, assumptions and uncertainties.

General risks relating to Vital Energy include, but are not limited to, continuing and worsening inflationary pressures and associated changes in monetary policy that may cause costs to rise; changes in domestic and global production, supply and demand for commodities, including as a result of actions by the Organization of Petroleum Exporting Countries and other producing countries ("OPEC+") and the Russian-Ukrainian military conflict, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, reduced demand due to shifting market perception towards the oil and gas industry; competition in the oil and gas industry; the ability of the Company to execute its strategies, including its ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to its financial results and to successfully integrate acquired businesses, assets and properties, pipeline transportation and storage constraints in the Permian Basin, the effects and duration of the outbreak of disease and any related government policies and actions, long-term performance of wells, drilling and operating risks, the possibility of production curtailment, the impact of new laws and regulations, including those regarding the use of hydraulic fracturing, and under the Inflation Reduction Act (the “IRA"), including those related to climate change, the impact of legislation or regulatory initiatives intended to address induced seismicity on our ability to conduct our operations; hedging activities, tariffs on steel, the impacts of severe weather, including the freezing of wells and pipelines in the Permian Basin due to cold weather, possible impacts of litigation and regulations, the impact of the Company's transactions, if any, with its securities from time to time, the impact of new environmental, health and safety requirements applicable to the Company's business activities, the possibility of the elimination of federal income tax deductions for oil and gas exploration and development and imposition of any additional taxes under the IRA or otherwise, and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2022 and those set forth from time to time in other filings with the Securities and Exchange Commission ("SEC").

Any forward-looking statement speaks only as of the date on which such statement is made. Vital does not intend to, and disclaims any obligation to, correct, update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

The SEC generally permits oil and natural gas companies, in filings made with the SEC, to disclose proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, and certain probable and possible reserves that meet the SEC’s definitions for such terms. In this presentation, the Company may use the terms “resource potential,” “resource play,” “estimated ultimate recovery,” or “EURs,” “type curve” and “standardized measure,” each of which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. These terms refer to the Company’s internal estimates of unbooked hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. “Resource potential” is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play potentially supporting numerous drilling locations. A “resource play” is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. “EURs” are based on the Company’s previous operating experience in a given area and publicly available information relating to the operations of producers who are conducting operations in these areas. Unbooked resource potential and “EURs” do not constitute reserves within the meaning of the Society of Petroleum Engineer’s Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities of reserves that may be ultimately recovered from the Company’s interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company’s ongoing drilling program, which will be directly affected by the availability of capital, decreases in oil, natural gas liquids and natural gas prices, well spacing, drilling and production costs, availability and cost of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals, negative revisions to reserve estimates and other factors, as well as actual drilling results, including geological and mechanical factors affecting recovery rates. “EURs” from reserves may change significantly as development of the Company’s core assets provides additional data. In addition, the Company’s production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. “Type curve” refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. The “standardized measure” of discounted future new cash flows is calculated in accordance with SEC regulations and a discount rate of 10%. Actual results may vary considerably and should not be considered to represent the fair market value of the Company’s proved reserves.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles (“GAAP”), such as Free Cash Flow and Consolidated EBITDAX. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. For definitions of such non-GAAP financial measures and their reconciliations to the most comparable GAAP measures, please see the Appendix.
Unless otherwise specified, references to “average sales price” refer to average sales price excluding the effects of the Company’s derivative transactions. All amounts, dollars and percentages presented in this presentation are rounded and therefore approximate.

Strong Second-Quarter 2023 Performance

✓ **$61 million** Free Cash Flow[1]

✓ **$249 million** Cash Flows from Operating Activities

1 Exceeded high-end of guidance for both oil and total production

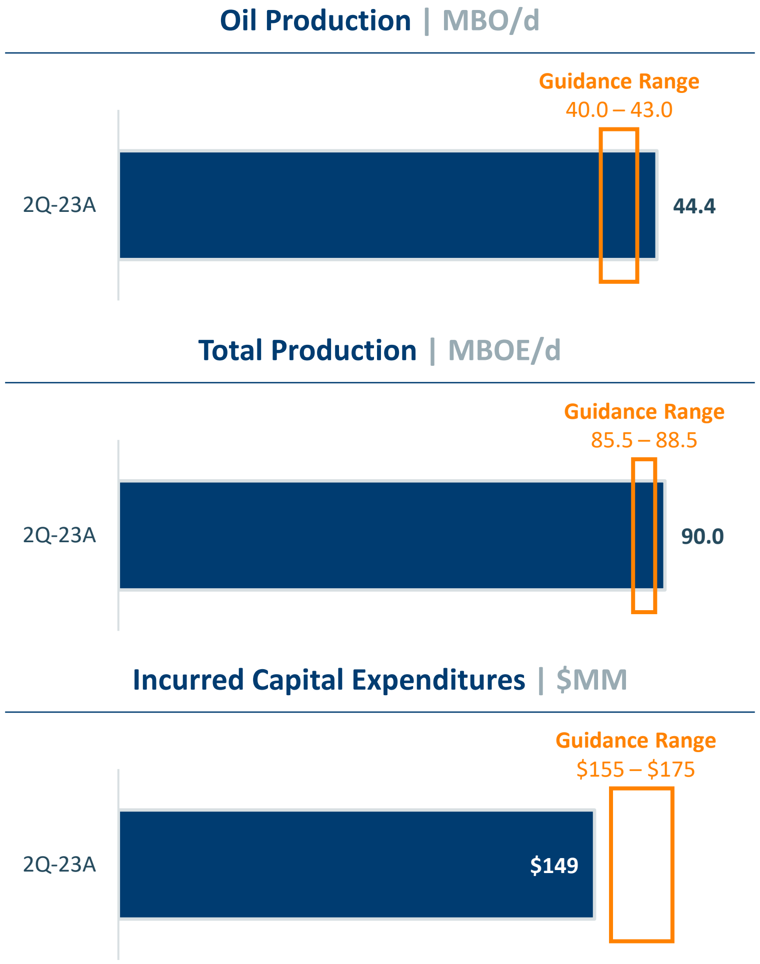
- Base production in 1H-23 exceeded expectations by ~10%
- Increased full-year 2023 oil and total production guidance

2 Incurred capital expenditures below guidance

- Inflationary pressures moderating for key products and services
- Reduced full-year 2023 capital investment guidance

3 Strong operational expense control

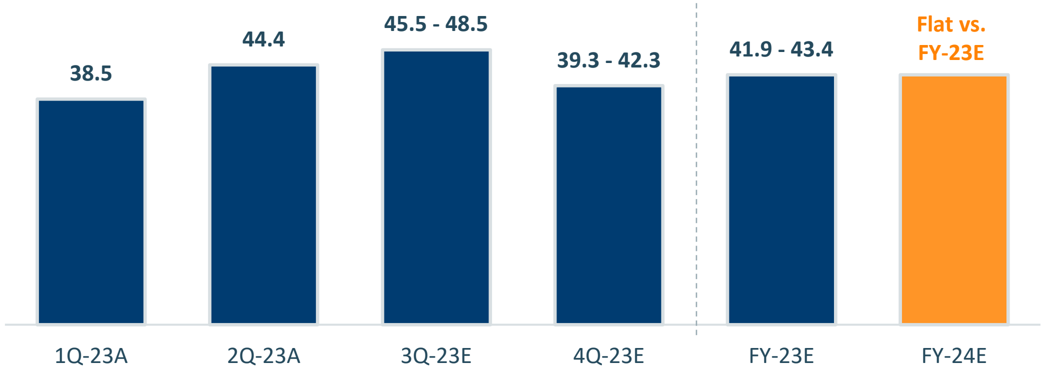
- Managing total operating expenses at higher projected volumes
- Unit LOE 6% below expectations



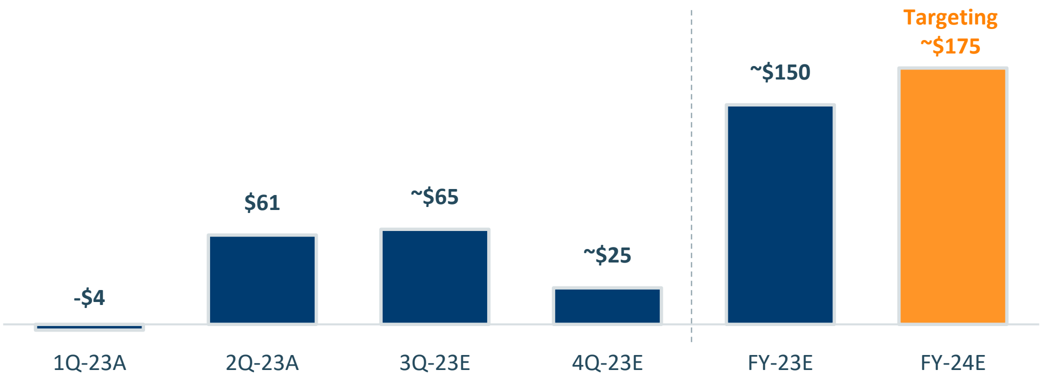
[1]See Appendix for definitions and reconciliations of non-GAAP financial measures.

Continued Execution of Strategy Driving Positive 2H-23 and FY-24 Outlook

Oil Production | MBO/d

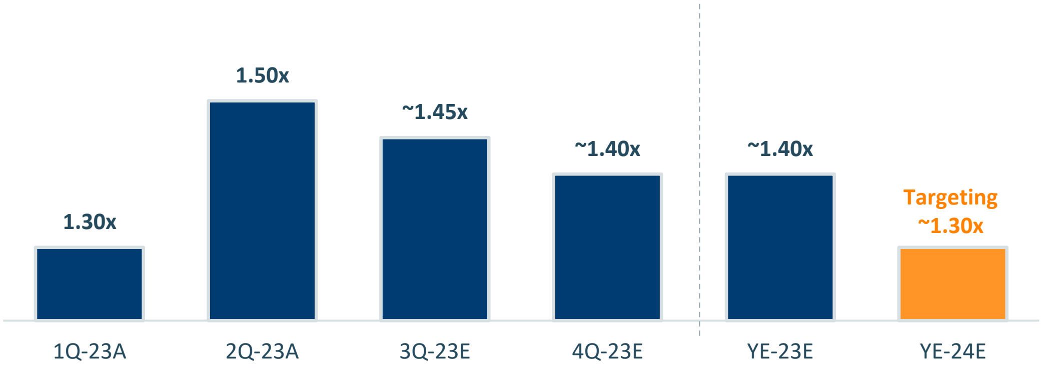


Free Cash Flow[1,2] | $MM



Incurred Capital Expenditures | $MM

Net Debt to Consolidated EBITDAX[1,3] | 0.0x



Strong Operational Performance and Accretive Transactions Enhance Free Cash Flow[1] Outlook

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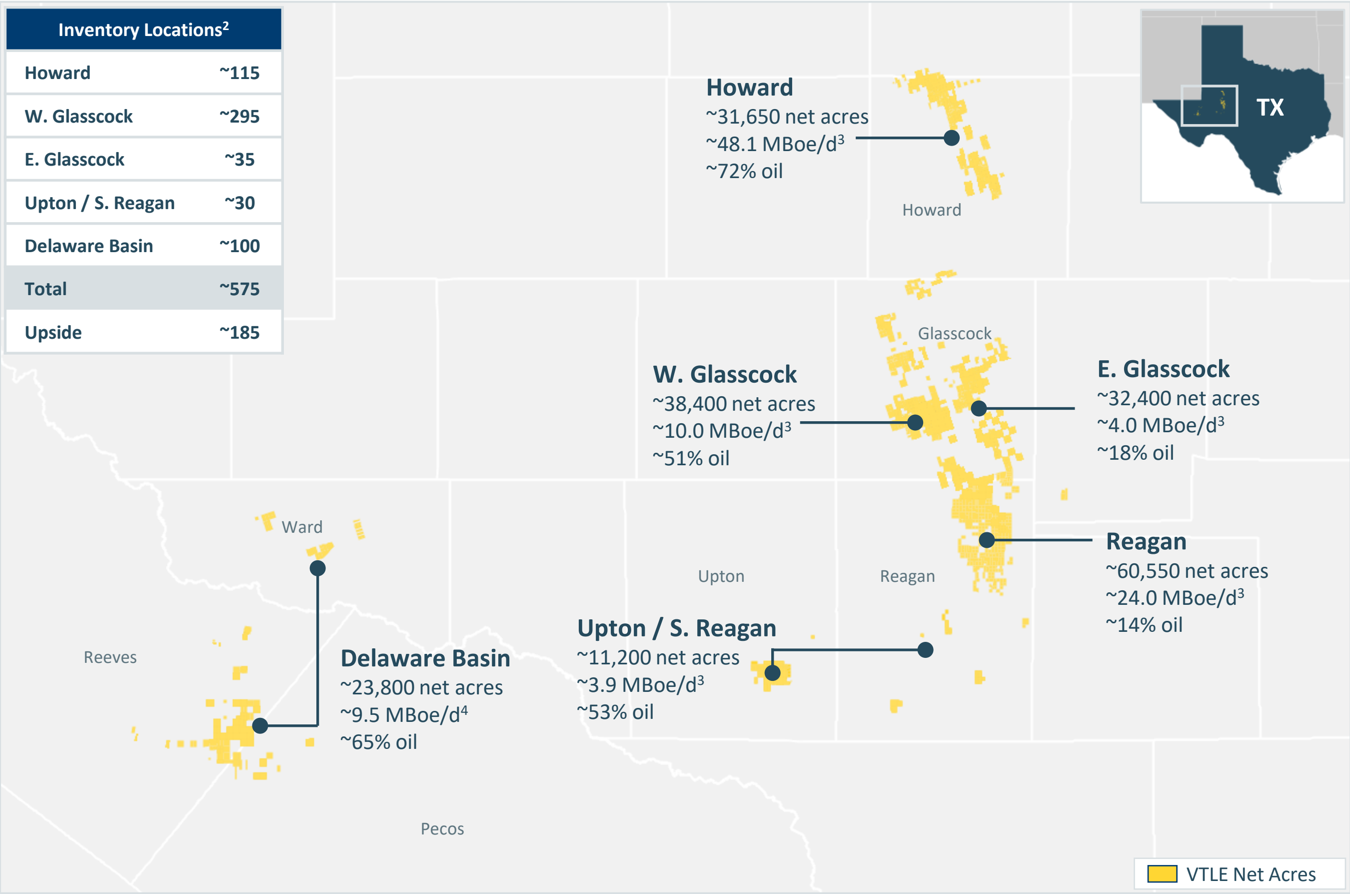
[1]See Appendix for definitions and reconciliations of non-GAAP financial measures. [2]Assumes the following commodity prices: 1H-23 $75 oil / $2.75 gas, 2H-23 $80 oil / $2.75 gas price, and FY-24 $77 oil / $3.40 gas price.
[3]Calculation conforms to credit facility covenant which requires various treatment of asset transaction impacts and utilizes mid-point of guidance ranges.

Disciplined Strategy Underpins Long-Term Value Creation

- **Maintain** Capital Discipline
- **Generate** Free Cash Flow[1]
- **Reduce** Debt and Leverage
- **Target** Accretive Transactions
- **Advance** Sustainability
- **Integrate** Digital Solutions

Pure-Play Permian Basin Producer



Inventory Locations[2]	
Howard	~115
W. Glasscock	~295
E. Glasscock	~35
Upton / S. Reagan	~30
Delaware Basin	~100
Total	~575
Upside	~185

[1]See Appendix for definitions and reconciliations of non-GAAP financial measures. [2]Gross operated locations as of January 2023, Delaware Basin & Upton/S. Reagan as of closing. [3]2Q-23 Actuals.
[4]Current production; not included in 2Q-23 production.

Accretive Transactions Driving Company Performance

Oil-Weighted Transactions

2019

Initial Howard County
(4Q-19) ~7,400 net acres

Initial W. Glasscock
(4Q-19) ~4,475 net acres

2020

Howard Bolt-On
(1Q-20) ~1,100 net acres

Howard Bolt-On
(4Q-20) ~2,750 net acres

2021

Howard County
(2Q-21) ~21,000 net acres

E. Glasscock / Reagan
(2Q-21) WI Divestiture

W. Glasscock County
(3Q-21) ~20,000 net acres

2022

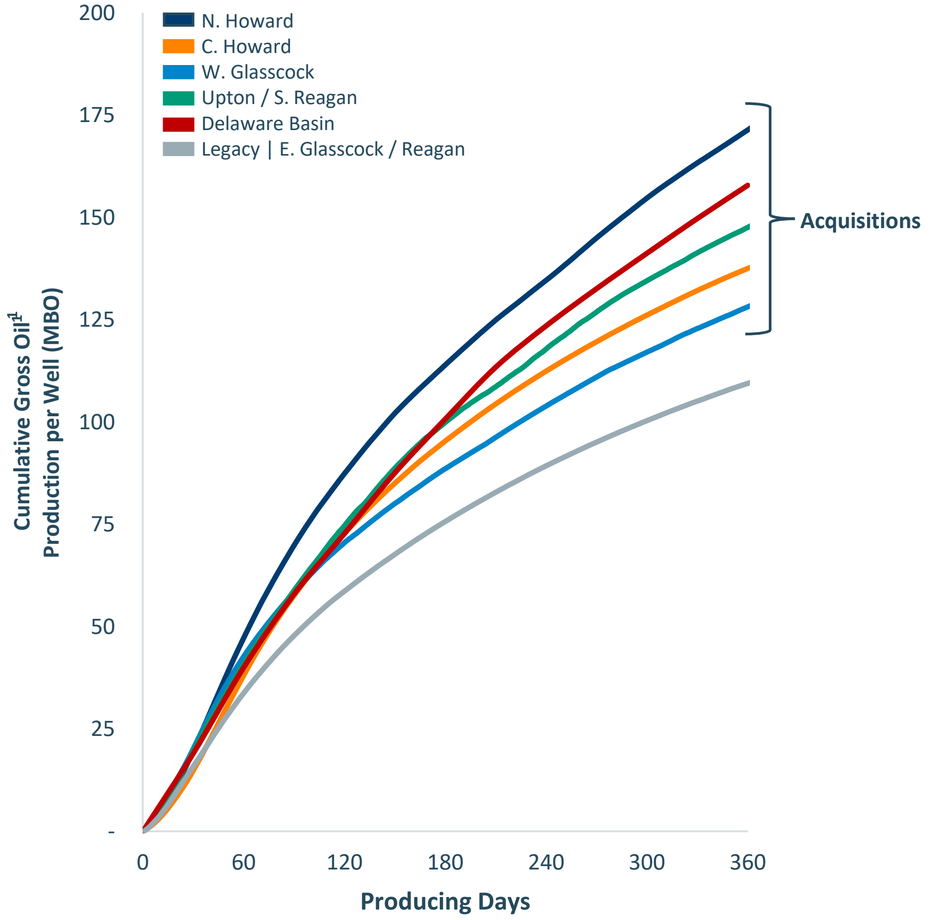
Non-Op Divestiture
(3Q-22) ~1,650 net acres

2023

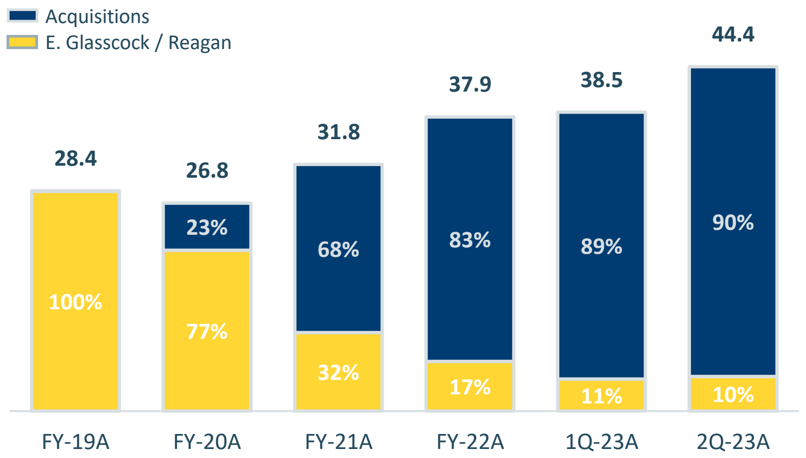
Upton / S. Reagan
(1Q-23) ~11,200 net acres

Delaware Basin
(2Q-23) ~24,000 net acres

High-Grading Portfolio through Accretive Transactions

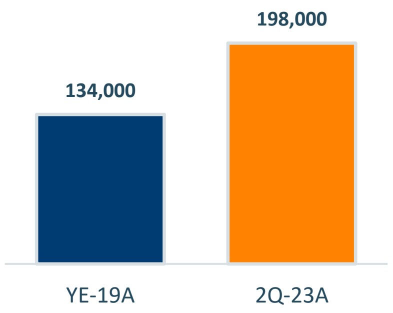


~55% Increase in Oil Production | MBO/d

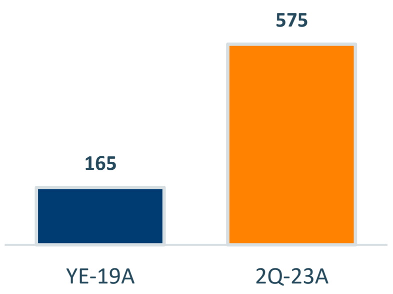


Oil-Weighted Inventory Increased to Eight Years

Net Acres | #



Gross Locations | #



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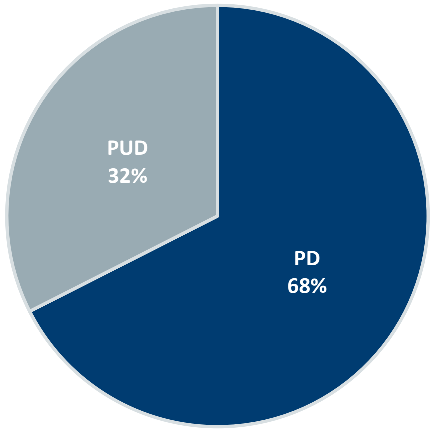
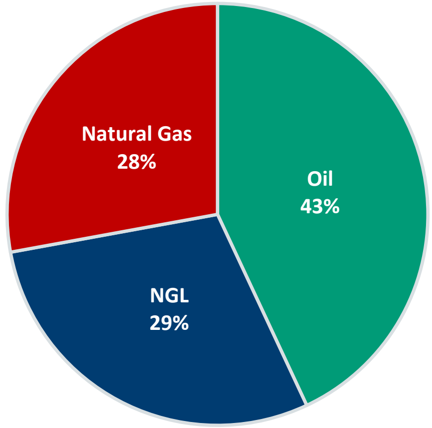
[1]Production data normalized for 10,000' lateral length and downtime.

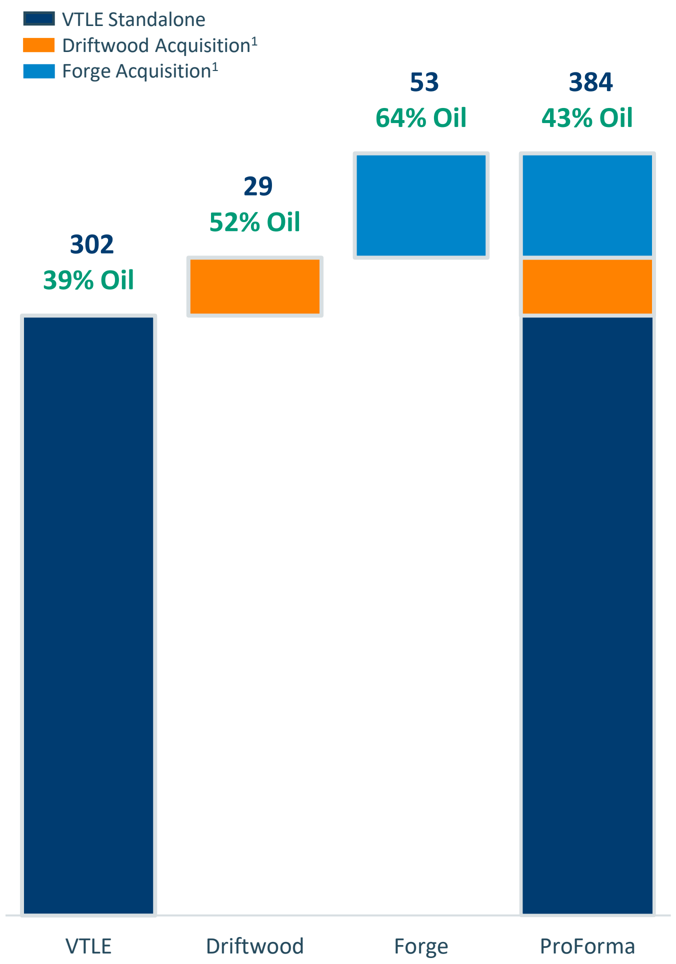
Expanded Reserve Value through Disciplined Acquisitions

Proved Reserves Components | YE-22

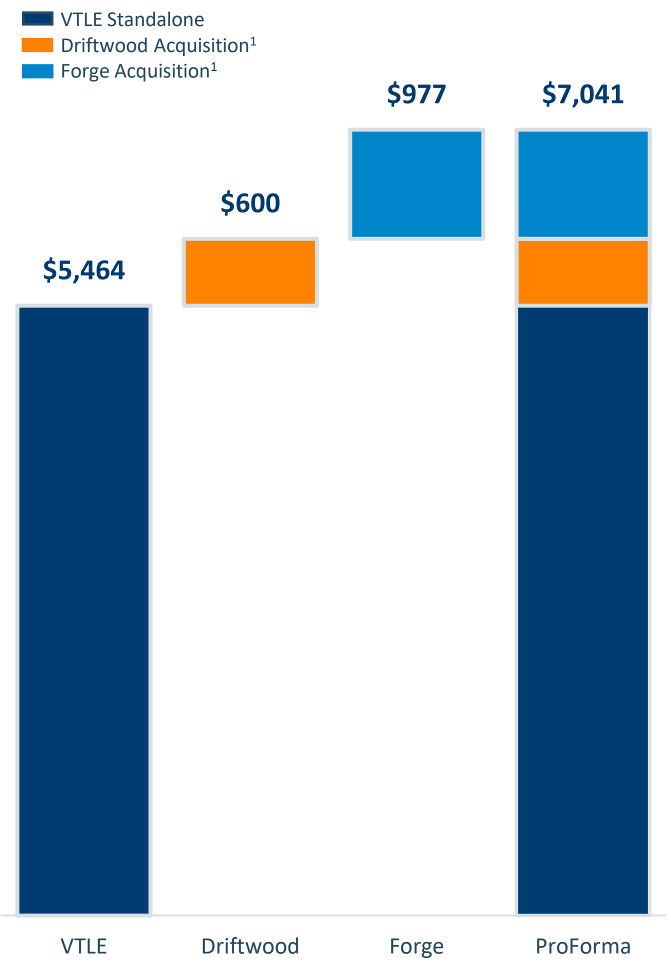




YE-22 Total Proved Reserves | MMBOE



YE-22 PV-10 Reserve Value[2,3] | $MM



[1]Acquired reserves represent VTLE economic interest and as provided by the acquired company. [2]See Appendix for definitions and reconciliations of non-GAAP financial measures.
[3]SEC benchmark pricing (VTLE $90.15 oil / $5.20 gas | Driftwood $94.14 oil / $6.36 gas | Forge $93.67 oil / $6.36 gas).

Operational Performance Driven by Change Leadership and Differential Technology

Organizational Structure Built for Continuous Improvement

- Created dedicated teams focused on compression and artificial lift performance
- Implementation of 24-hour field response procedures
- Employing digital solutions throughout field organization

Differential Digital Technologies Enhancing Operations

- Proprietary, AI-driven algorithms to continually adjust artificial lift and chemical pump settings
- Route optimization through analysis of real-time field surveillance data
- Access to digital tools and optimization technology distributed at route level

Results Driving Production Improvements

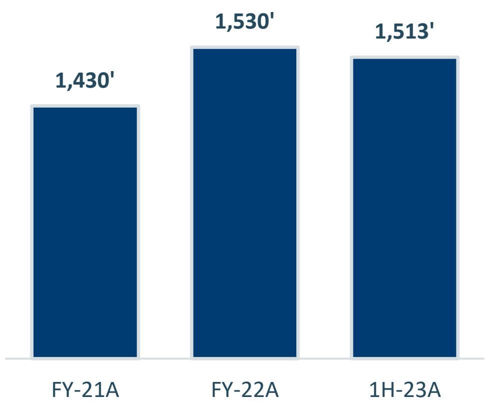
- Increased total field production by 2-3%
- Increased gas-lift runtime by 15%
- Increased ESP runtime by 4%

Continuous Improvements Drive Capital Efficiencies

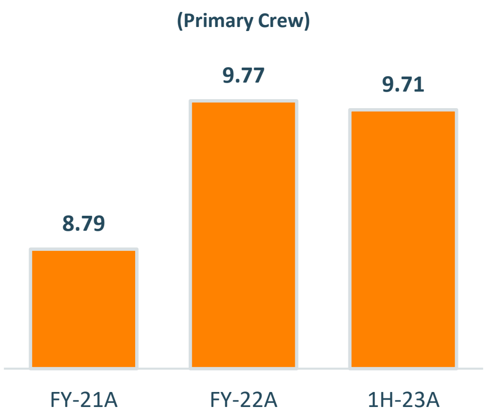
Capital Program & Capital Allocation

Guidance	FY-23E
Capital Expenditures | $MM	$665 - $695
Avg. Rig Count | Op	~2.5
Avg. Frac Crew | Op	~1.5
Spuds | Op	~55 Gross (~47.1 Net)
Completions | Op	~62 Gross (~57.8 Net)
Turn-in-Lines | Op	~64 Gross (~59.8 Net)
Total Production | MBOE/d	87.0 - 89.0
Oil Production | MBO/d	41.9 - 43.4

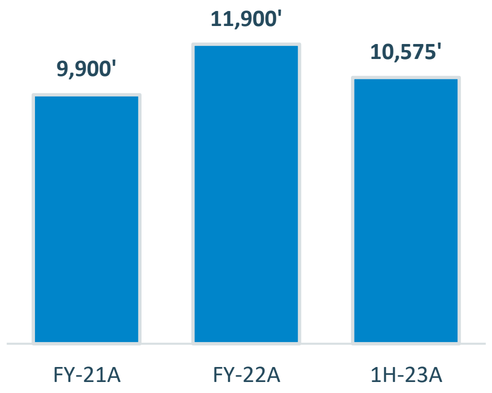
Drilling Ft. Per Day Per Rig



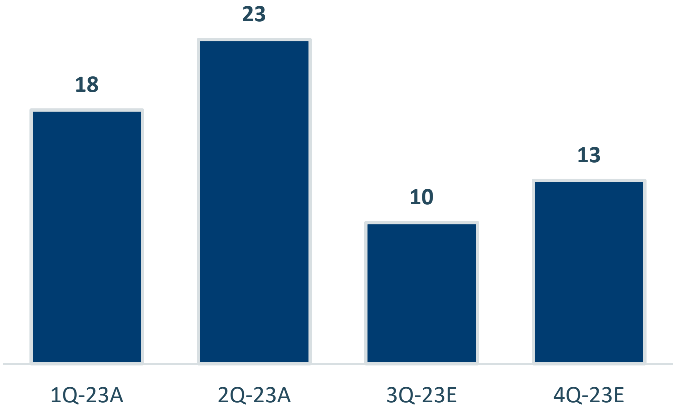
Completed Stages Per Day



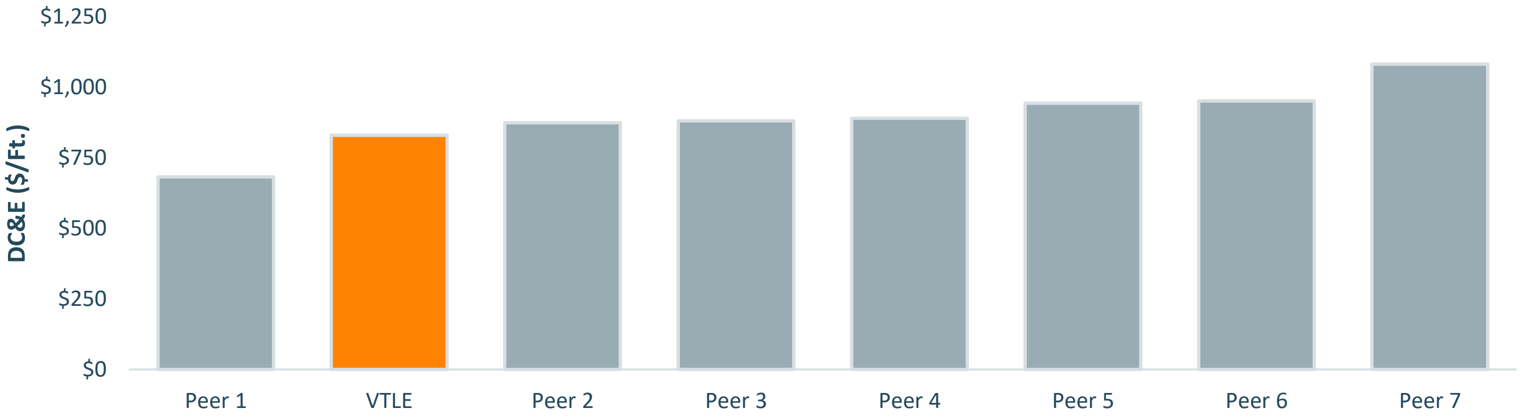
Avg. Completed Lateral Length



Operated Turn-in-Lines |



Top Quartile Permian Basin Well Cost[1,2]



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[1]Source Enverus Intelligence Research / Midland Basin, Peer Group (FANG, HPK, OVV, PXD, ESTE, SM, CPE). [2]Estimated 2023 well costs.

Free Cash Flow Generation Strengthening Balance Sheet

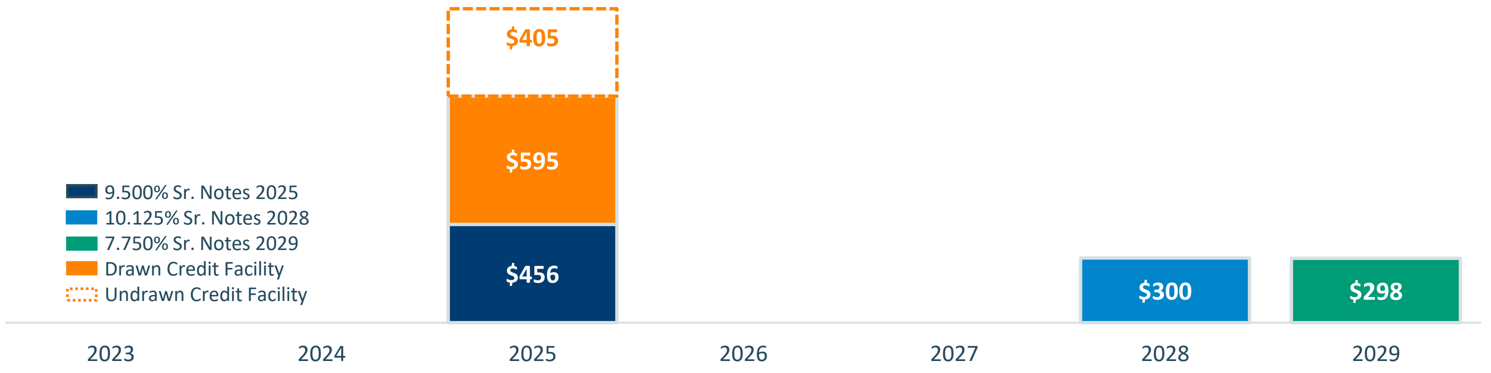
$1.3 billion
Borrowing Base (Credit Facility)

$1.0 billion
Elected Commitments (Credit Facility)

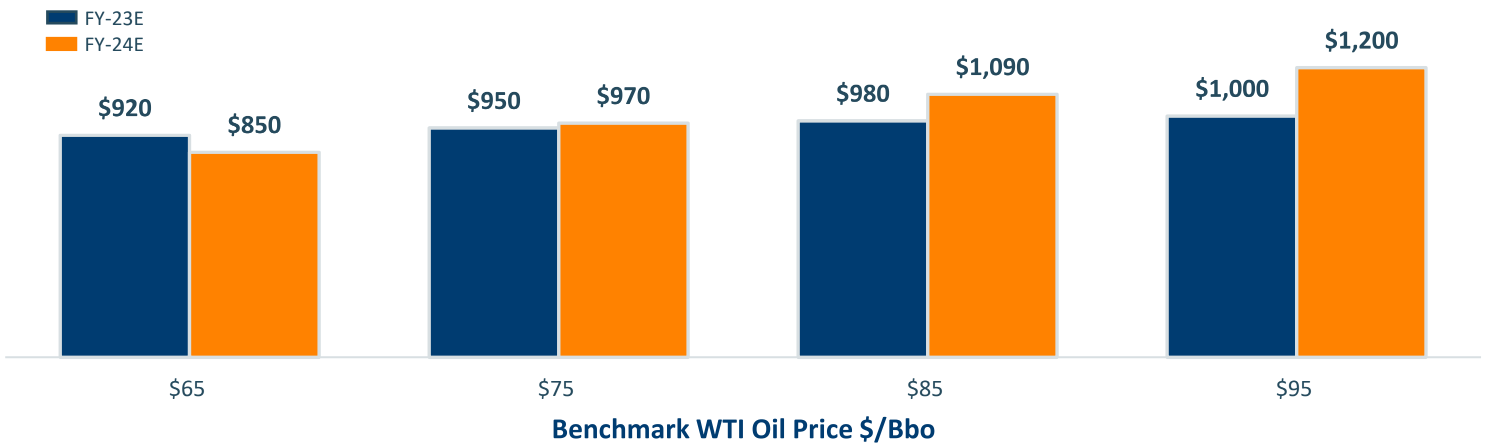
$73 million
Current Cash Balance[1]

$478 million
Current Liquidity[1]

Current Debt Maturity Profile[1] | $MM



Consolidated EBITDAX[2,3] Sensitivity | $MM



[1]As of August 4, 2023. [2]See Appendix for definitions and reconciliations of non-GAAP financial measures.
[3]Assumes the following commodity prices: 1H-23 $75 oil / $2.75 gas, 2H-23 WTI benchmarks / $2.75 gas price, and FY-24 WTI benchmarks / $3.40 gas price.

Progress Toward Emissions Targets Demonstrates Continued ESG Leadership

59% Reduction
2022 Scope 1 GHG Intensity vs. 2019 Baseline

89% Reduction
2022 Methane Intensity[1] vs. 2019 Baseline

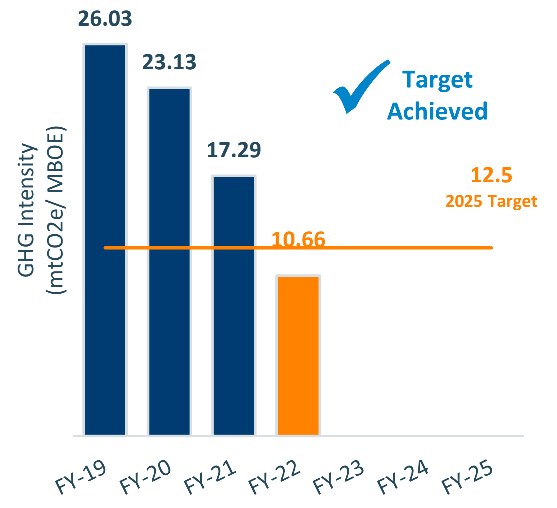
42% Reduction
2022 Routine Flaring vs. 2019 Baseline

Zero Incidents
2022 Employee Total Recordable Incident Rate

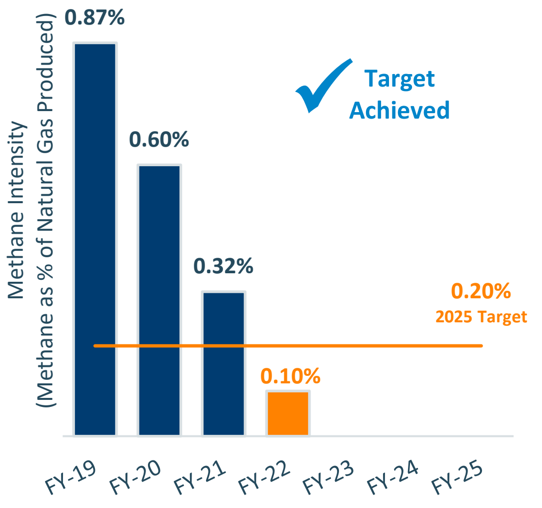
2022 ESG Highlights

- Achieved two of three 2025 emission reduction targets in 2022
- 58% reduction in absolute emissions driven by pneumatics and monitoring
- 53% reduction in combined Scope 1 & Scope 2 GHG emissions intensity
- 1st Permian Basin operator with certified responsibly sourced production[1]
- Lowest employee and contractor combined TRIR in Company history

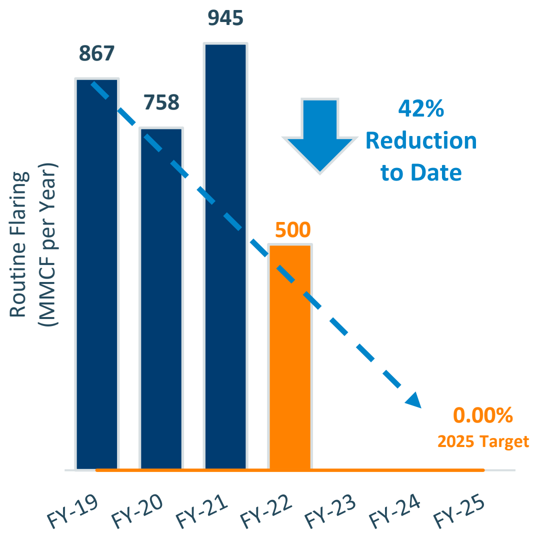
2025 Greenhouse Gas Intensity



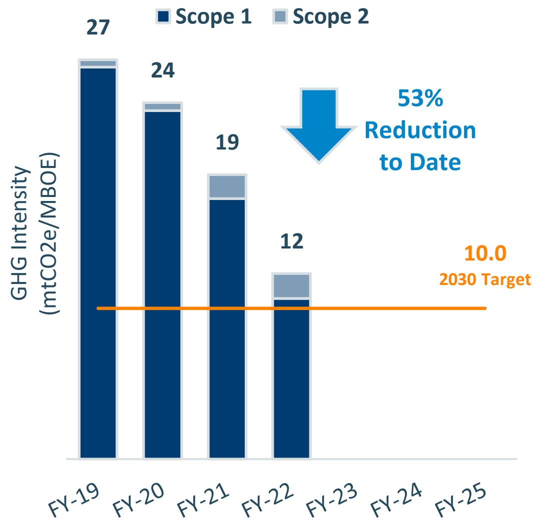
2025 Methane Intensity[2]



2025 Elimination of Routine Flaring



2030 Greenhouse Gas Intensity



[1]Certified by TRUSTWELL™. [2]As a percentage of natural gas produced.

Appendix

2H-23 & FY-23 Guidance

Guidance

	3Q-23	4Q-23	FY-23
Production:			
Total Production (MBOE/D)	94.0 - 98.0	83.3 - 87.3	87.0 - 89.0
Crude Oil Production (MBO/D)	45.5 - 48.5	39.3 - 42.3	41.9 - 43.4
Incurred Capital Expenditures ($MM):	$165 - $180	$165 - $180	$665 - $695
Average Sales Price Realizations (excluding derivatives):			
Crude Oil (% of WTI)	101%	-	-
Natural Gas Liquids (% of WTI)	19%	-	-
Natural Gas (% of Henry Hub)	63%	-	-
Net Settlements Received (Paid) for Matured Commodity Derivatives ($MM):			
Crude Oil ($MM)	($13)	-	-
Natural Gas Liquids ($MM)	-	-	-
Natural Gas ($MM)	($3)	-	-
Operating Costs and Expenses ($/BOE):			
Lease Operating Expenses	$7.00	-	-
Production and Ad Valorem Taxes (% of Oil, NGL & Natural Gas Revenues)	6.50%	-	-
Transportation and Marketing Expenses	$1.20	-	-
General and Administrative Expenses (excluding LTIP & Transaction Expense)	$2.00	-	-
General and Administrative Expenses (LTIP Cash)	$0.11	-	-
General and Administrative Expenses (LTIP Non-Cash)	$0.30	-	-
Depletion, Depreciation and Amortization	$12.75	-	-

Commodity Prices Used for 3Q-23

	Jul-23	Aug-23	Sep-23	3Q-23 Avg.
Crude Oil:				
WTI NYMEX ($/BBO)	$76.04	$81.31	$80.92	$79.40
Brent ICE ($/BBO)	$80.16	$85.03	$84.67	$83.26
Natural Gas:				
Henry Hub ($/MMBTU)	$2.60	$2.49	$2.57	$2.55
Waha ($/MMBTU)	$2.43	$2.29	$2.11	$2.28
Natural Gas Liquids:				
C2 ($/BBL)	$13.35	$11.12	$10.40	$11.63
C3 ($/BBL)	$26.07	$29.42	$31.55	$28.99
IC4 ($/BBL)	$35.35	$43.21	$41.53	$40.01
NC4 ($/BBL)	$31.61	$36.31	$37.75	$35.20
C5+ ($/BBL)	$58.55	$63.36	$63.95	$61.93
Composite ($/BBL)[1]	$25.19	$26.64	$27.21	$26.34

[1]Current NGL composition C2 (42%), C3 (33%), IC4 (3%), NC4 (11%) and C5+ (11%).

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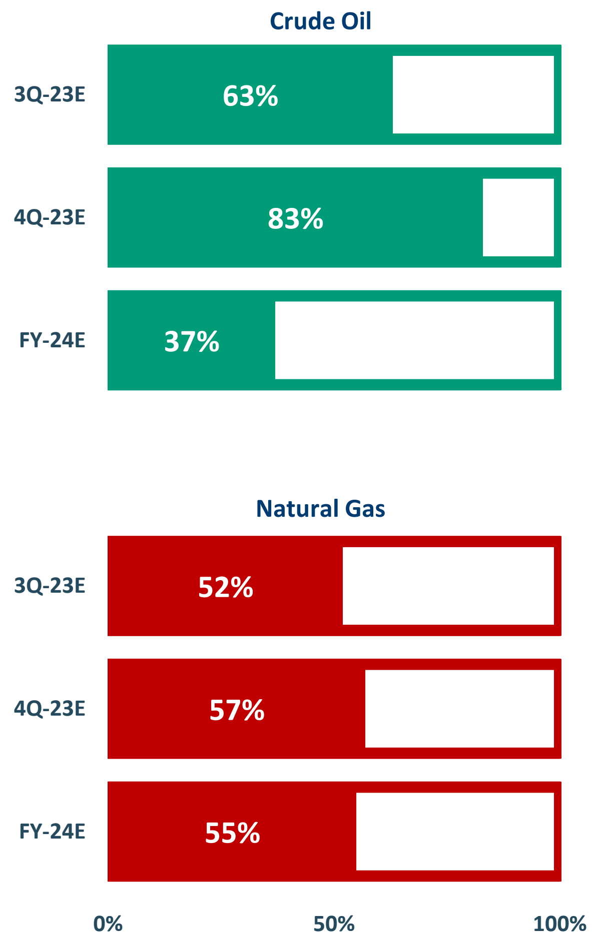
Current Hedge Book Position

		3Q-23	4Q-23	FY-23	1Q-24	2Q-24	3Q-24	4Q-24	FY-24
Crude Oil (Volume MBO; Price $/BBO)	WTI Swaps	1,744	2,116	**3,860**	2,660	1,839	570	569	**5,639**
	Price	$73.43	$73.58	**$73.51**	$70.46	$71.02	$74.62	$74.65	**$71.49**
	WTI Collars	903	891	**1,793**	-	-	-	-	**-**
	Bought Put	$69.55	$69.60	**$69.58**	-	-	-	-	**-**
	Sold Call	$86.98	$87.04	**$87.01**	-	-	-	-	**-**
	WTI Three-Way Collars	100	92	**192**	61	56	52	49	**217**
	Sold Put	$45.59	$45.50	**$45.54**	$50.00	$50.00	$50.00	$50.00	**$50.00**
	Bought Put	$57.72	$57.64	**$57.68**	$66.57	$66.50	$66.47	$66.45	**$66.51**
	Sold Call	$74.48	$74.25	**$74.37**	$87.14	$87.09	$87.06	$87.05	**$87.09**
	WTI Midland Basis Swaps	175	154	**329**	82	75	70	66	**293**
	Price	$0.18	$0.17	**$0.18**	$0.11	$0.11	$0.11	$0.12	**$0.11**
Natural Gas (Volume MMBTU; Price $/MMBTU)	Henry Hub Swaps	40,100	38,000	**78,100**	6,479,500	6,475,350	6,562,600	6,558,250	**26,075,700**
	Price	$2.46	$2.46	**$2.46**	$3.48	$3.48	$3.47	$3.47	**$3.47**
	Henry Hub Collars	6,858,873	6,826,534	**13,685,407**	243,128	214,333	169,320	149,511	**776,292**
	WTD Floor Price	$4.11	$4.11	**$4.11**	$3.40	$3.36	$3.44	$3.40	**$3.40**
	WTD Ceiling Price	$8.33	$8.34	**$8.33**	$6.11	$6.00	$6.22	$6.12	**$6.11**
	Henry Hub Three-Way Collars	35,500	33,500	**69,000**	-	-	-	-	**-**
	Sold Put	$2.00	$2.00	**$2.00**	-	-	-	-	**-**
	Bought Put	$2.50	$2.50	**$2.50**	-	-	-	-	**-**
	Sold Call	$3.01	$3.01	**$3.01**	-	-	-	-	**-**
	Waha Basis Swaps	10,614,473	10,578,034	**21,192,507**	6,722,628	6,689,683	6,731,920	6,707,761	**26,851,992**
	Price	($1.53)	($1.53)	**($1.53)**	($0.74)	($0.74)	($0.74)	($0.74)	**($0.74)**

Volumes Hedged[2]



[1]Hedges executed as of August 4, 2023. [2]Calculated using guidance mid-point.

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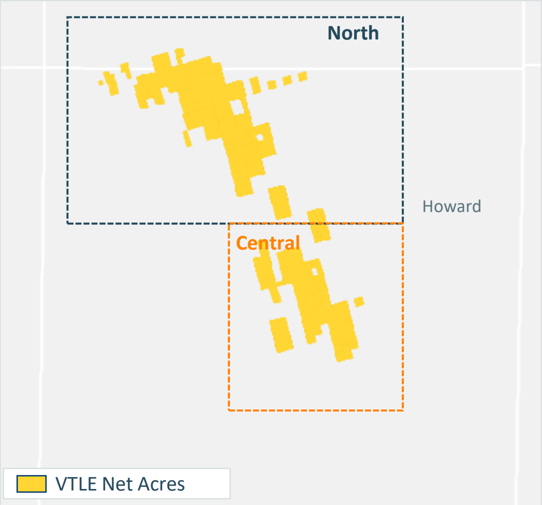
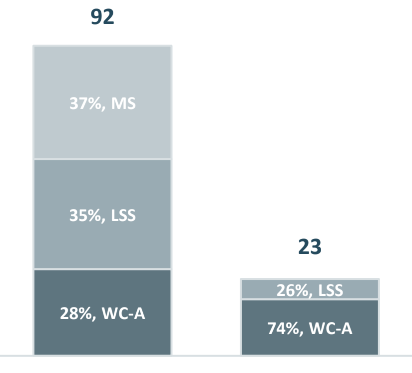
Howard County Development Program

Development

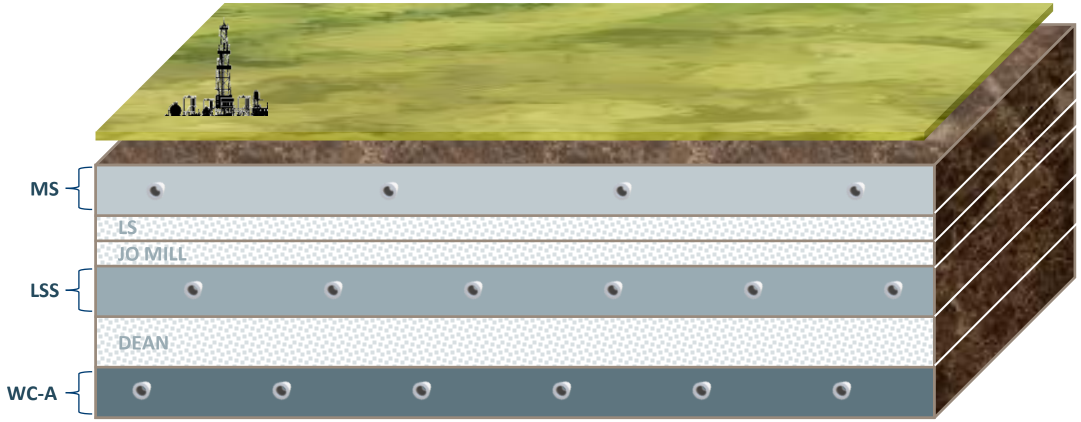


Inventory Locations[1]

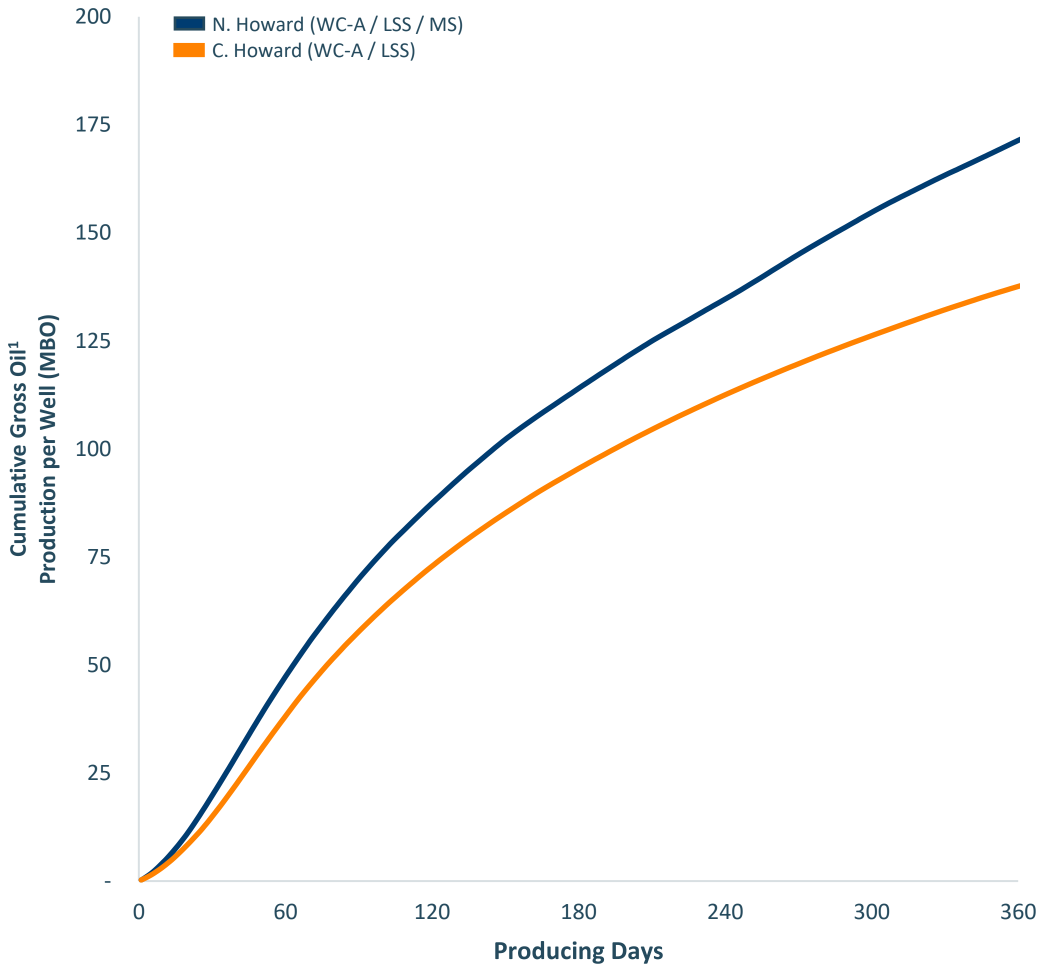


	N. Howard	C. Howard
Avg. WI	~95%	~85%
Avg. LL	~11,000'	~10,250'

Primary Development Targets



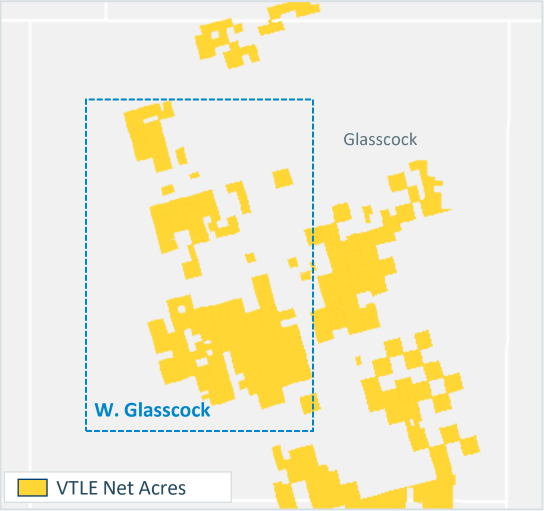
Average Well Performance[2]



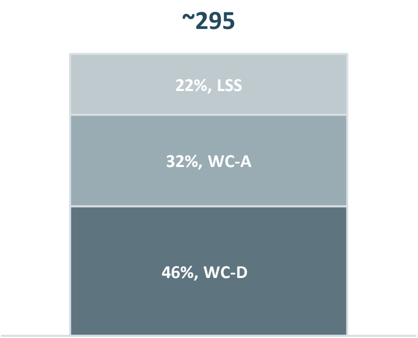
[1]Gross operated locations as of January 2023. [2]Production data normalized for 10,000' lateral length and downtime.

W. Glasscock County Development Program

Development Area

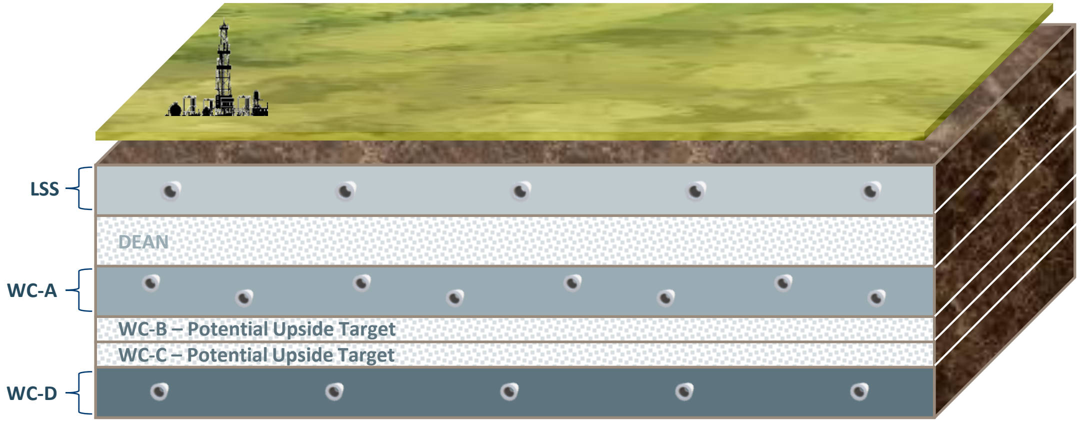


Inventory Locations[1]

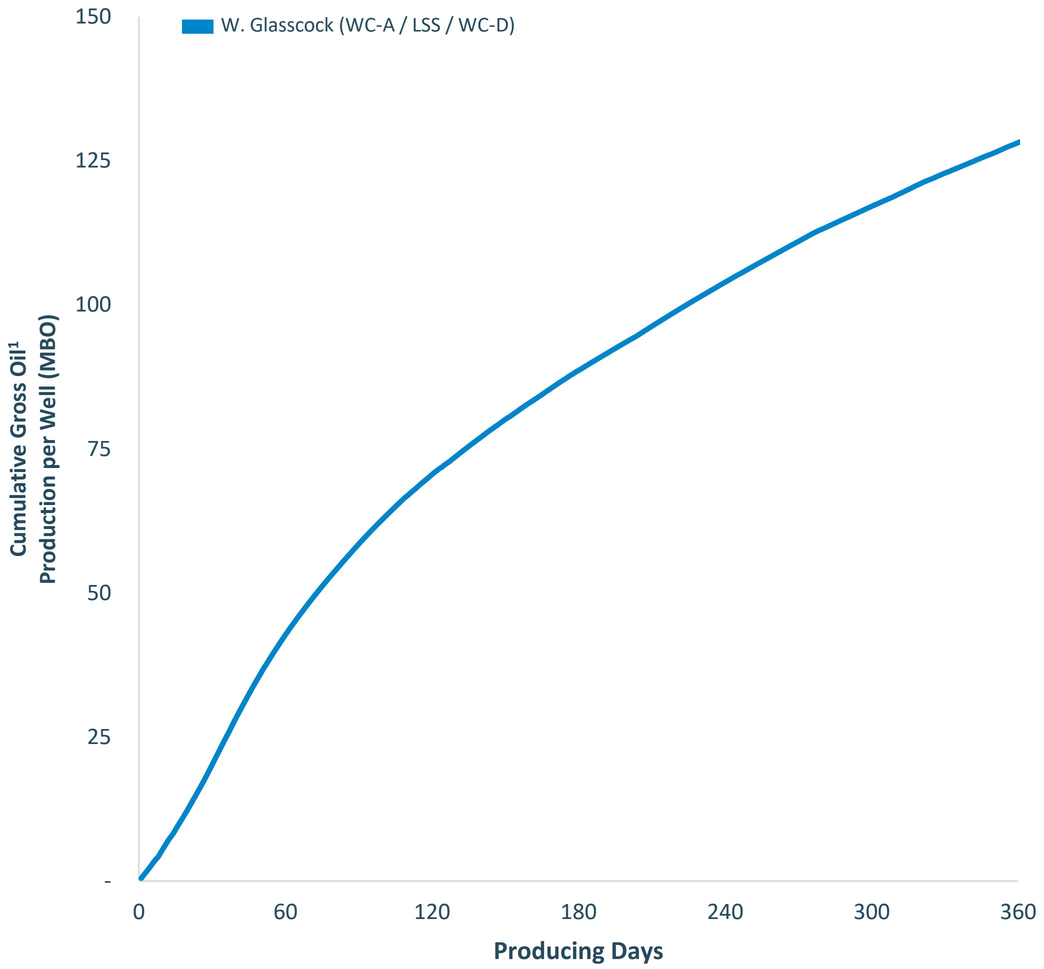


	W. Glasscock
Avg. WI	~90%
Avg. LL	~11,500’

Primary Development Targets



Average Well Performance[2]

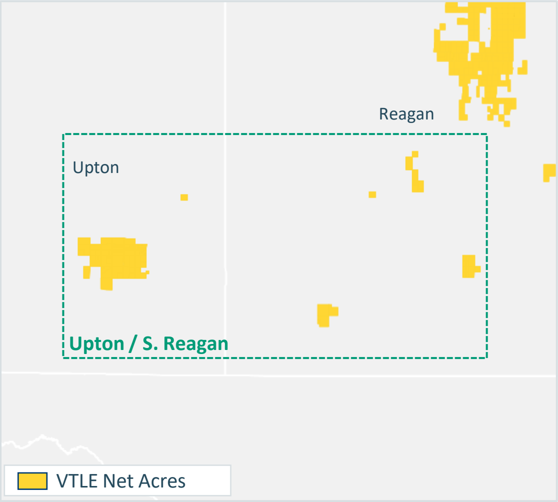


[1]Gross operated locations as of January 2023. [2]Production data normalized for 10,000’ lateral length and downtime.

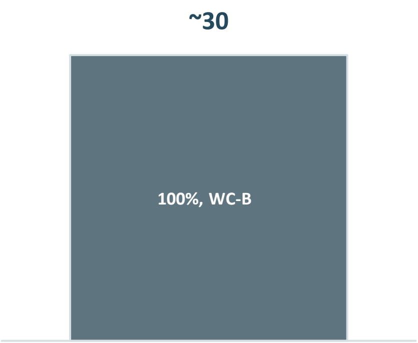
Vital Energy

Upton / S. Reagan County Development Program

Development Area

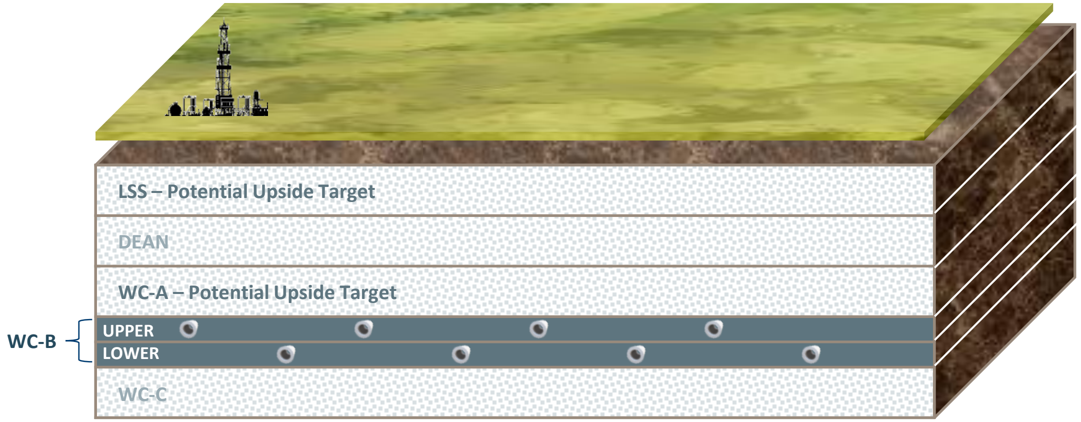


Inventory Locations[1]

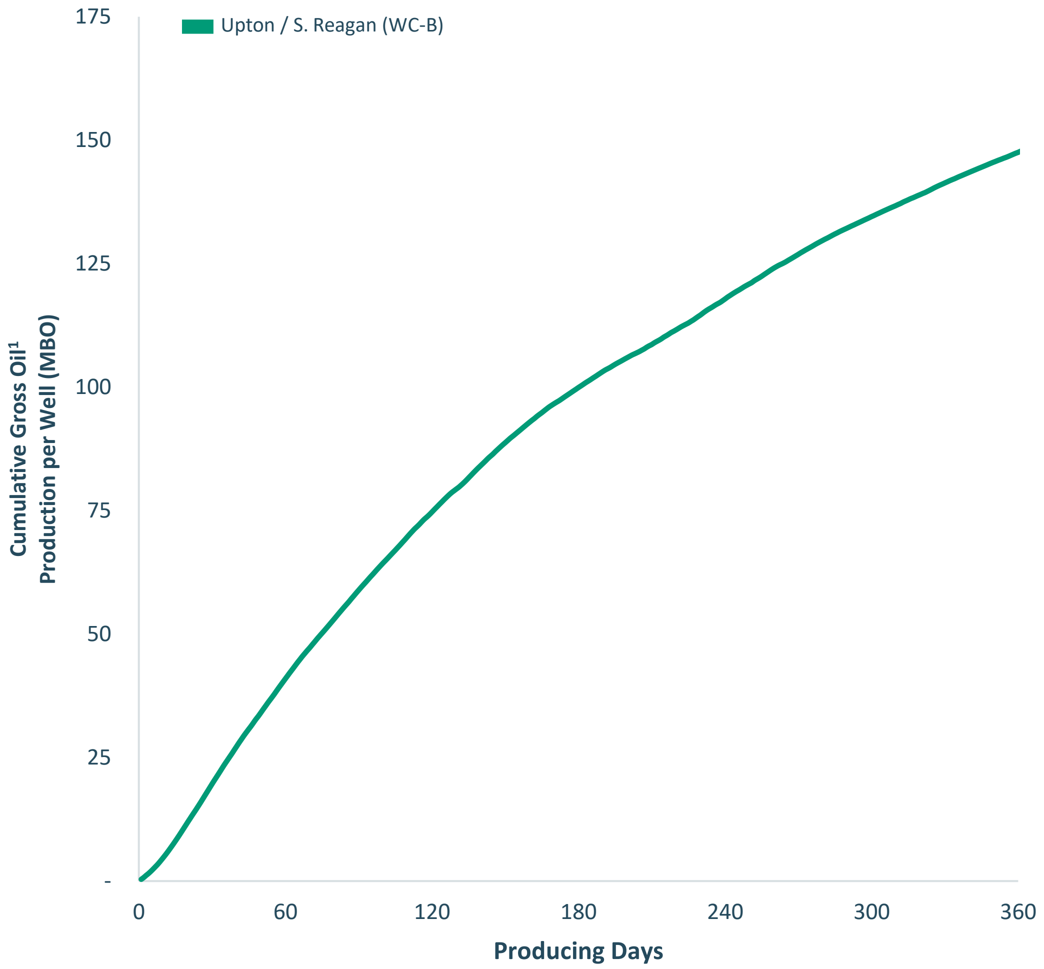


	Upton / S. Reagan
Avg. WI	~75%
Avg. LL	~10,000'

Primary Development Targets



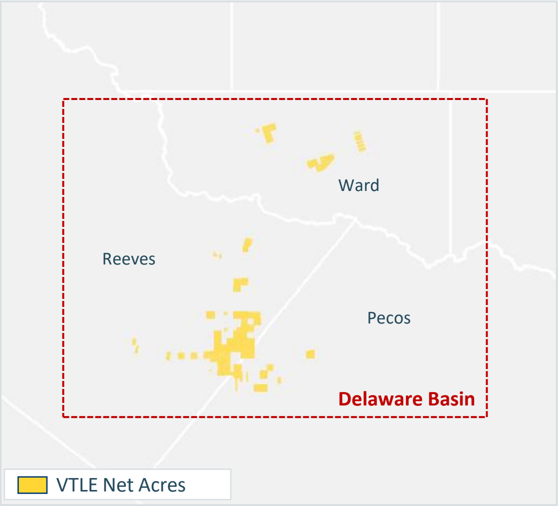
Average Well Performance[2]



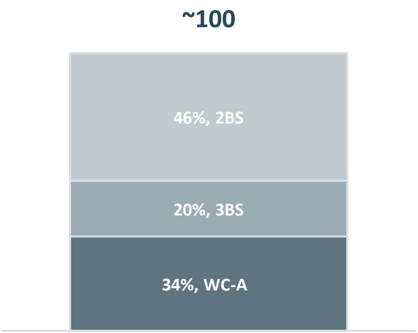
[1]Gross operated locations as of acquisition closing. [2]Production data normalized for 10,000' lateral length and downtime.

Delaware Basin Development Program

Development Area

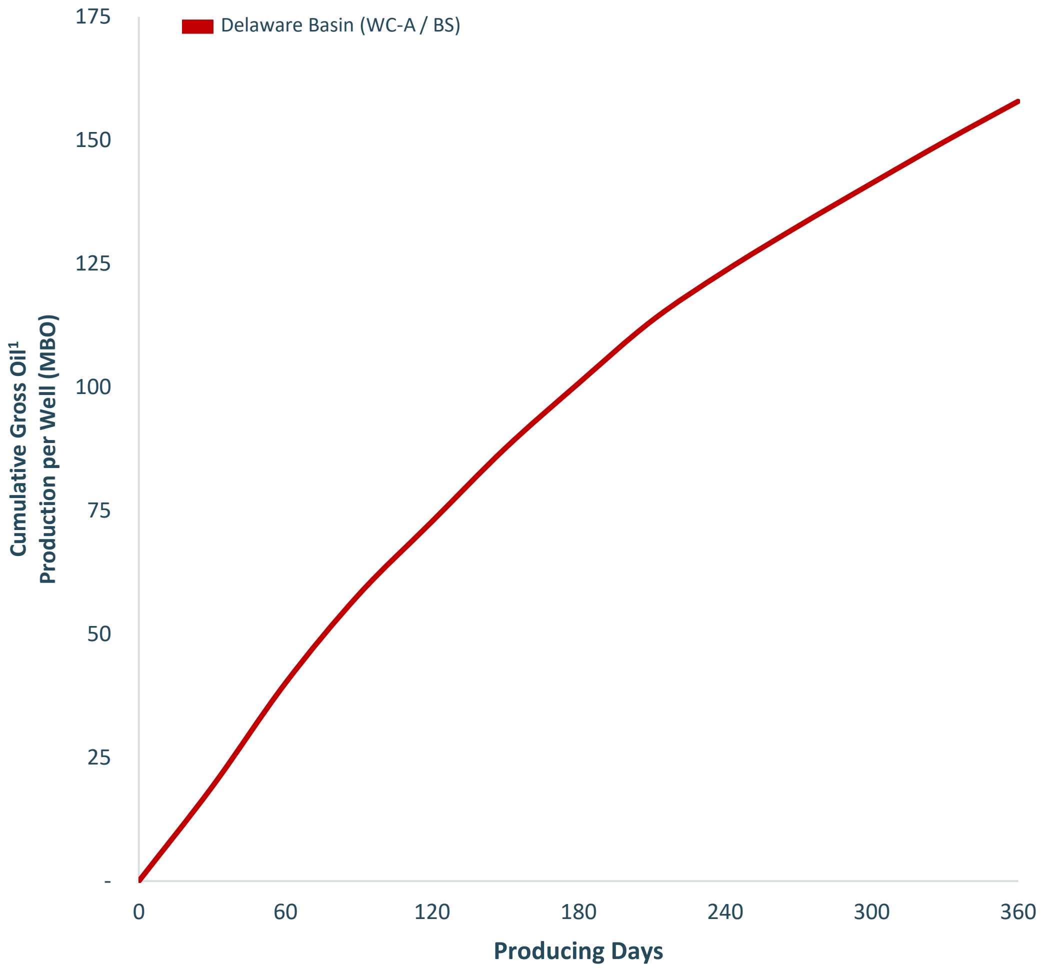


Inventory Locations[1]

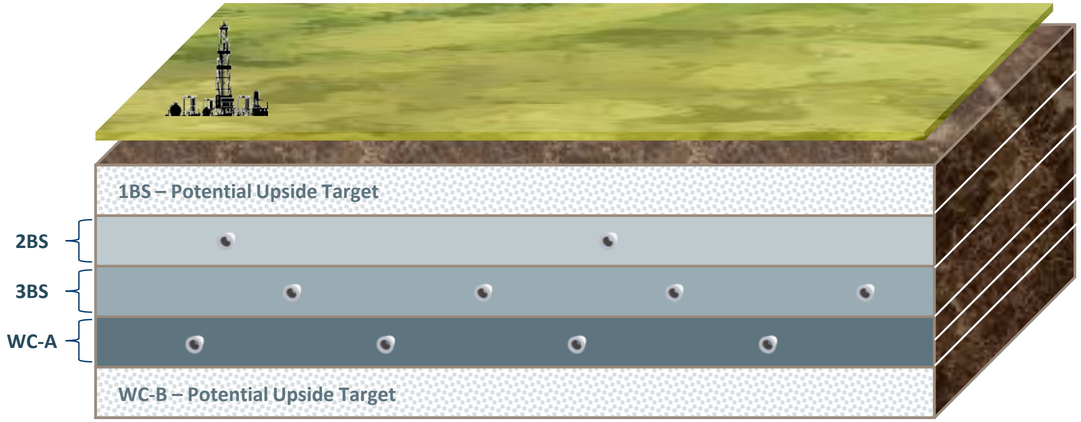


	Delaware Basin
Avg. WI	~55%
Avg. LL	~10,000'

Average Well Performance[2]



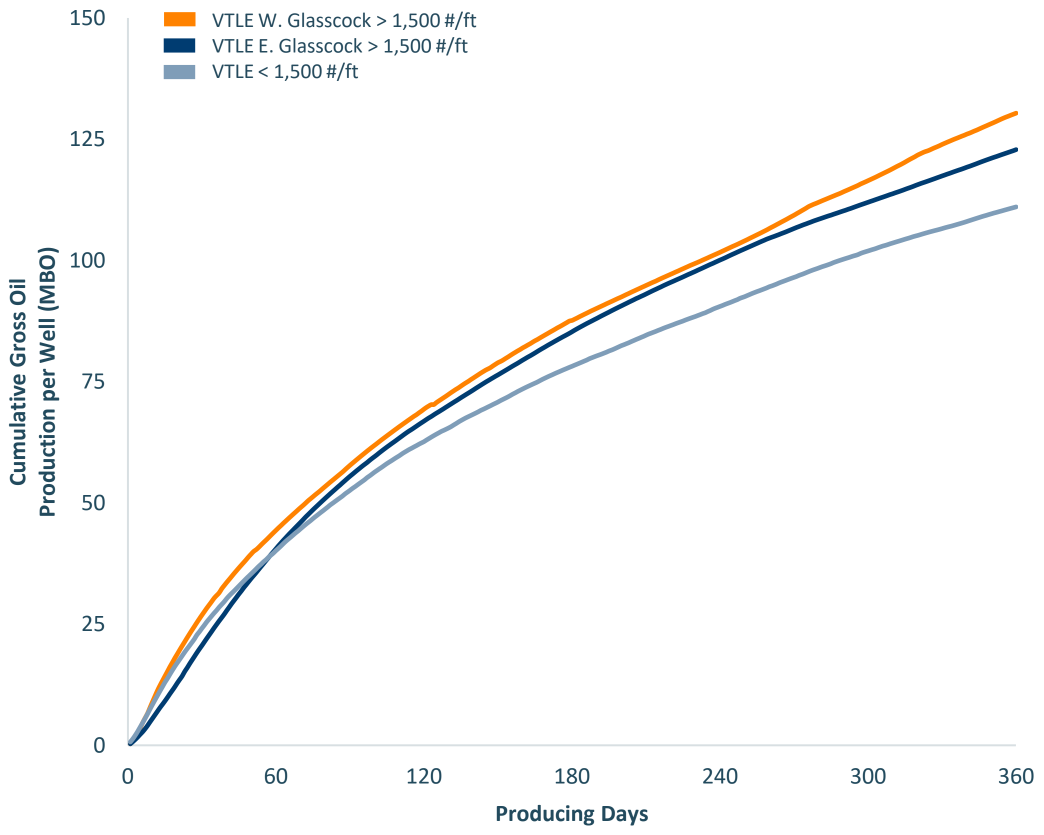
Primary Development Targets



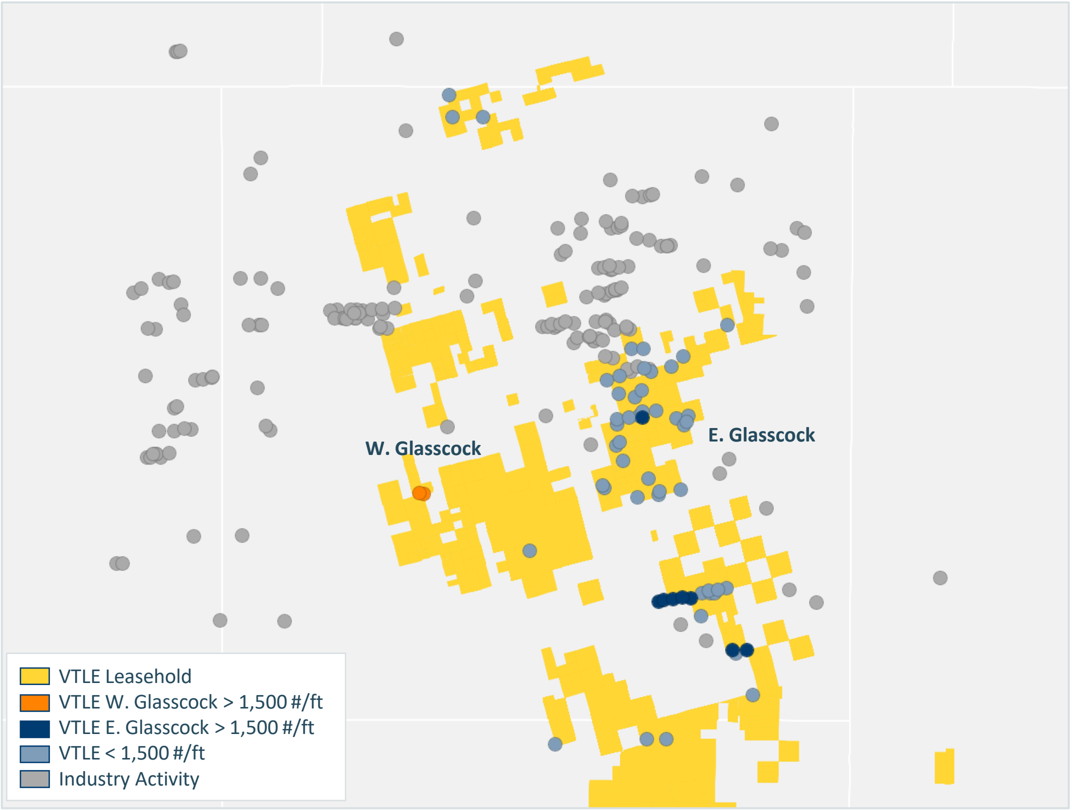
[1]Gross operated locations as of acquisition closing. [2]Production data normalized for 10,000' lateral length and downtime.

Wolfcamp D in Glasscock County Extends Oil-Weighted Inventory

Average Well Performance by Completion Design[1]



Wolfcamp D Producing Wells



Organically added ~80 oil-weighted Wolfcamp D locations in Glasscock County

[1]Production data normalized for 10,000’ lateral length, downtime and completion design > 1,500 #/ft.

Leadership in a Low-Carbon Future

OUR ENVIRONMENTAL TARGETS

<12.5 MTCO2e/MBOE
SCOPE 1 GHG EMISSIONS INTENSITY
BY 2025

ZERO ROUTINE FLARING
BY 2025

CH_4
<0.20% METHANE EMISSIONS
BY 2025
(AS A PERCENT OF NATURAL GAS PRODUCTION)

SCOPE 1 AND 2 GHG EMISSIONS
INTENSITY < 10 MTCO2e/MBOE
BY 2030

50% RECYCLED WATER
FOR COMPLETION OPERATIONS
BY 2025

ESG PROGRESS

42% REDUCTION
IN ROUTINE FLARING SINCE 2019

59% REDUCTION in SCOPE 1 GHG
EMISSIONS INTENSITY SINCE 2019[1]

89% REDUCTION IN METHANE
INTENSITY SINCE 2019

FIRST PERMIAN OPERATOR TO ACHIEVE THE TRUSTWELL™
CERTIFICATION FOR RESPONSIBLE OPERATIONS

FOCUSED SHORT-TERM INCENTIVE PROGRAM SO THAT
ENVIRONMENTAL GOALS MAKE UP 20% AND IMPLMENTED A
LONG-TERM INCENTIVE PROGRAM METRIC TIED TO ACHIEVING
2025 EMISSIONS REDUCTION GOALS

INCREASED ACTIVE MANAGEMENT AND HIGH GRADING
OF OUR VENDORS BASED ON SAFETY METRICS

CONDUCTED FIRST SUPPLIER ESG SURVEY TO BETTER
UNDERSTAND THE DIVERSITY OF OUR SUPPLY BASE
AND THE ESG POLICIES THEY HAVE IN PLACE

INCREASED BOARD GENDER AND
ETHNIC DIVERSITY TO 60%, A
270% INCREASE SINCE 2019

CONDUCTED COMPANY-WIDE
UNCONSCIOUS BIAS TRAINING

43% OF 2021 NEW HIRES
WERE DIVERSE

Achieved target during 2022

Vital Energy

[1]In 2021, we closed on two acquisitions. The 2019 and 2020 emissions data published in this report has been calculated to include emissions for these acquisitions.

Supplemental Non-GAAP Financial Measures

Free Cash Flow

Free Cash Flow is a non-GAAP financial measure that the Company defines as net cash provided by operating activities (GAAP) before net changes in operating assets and liabilities and non-budgeted acquisition costs, less incurred capital expenditures, excluding non-budgeted acquisition costs. Management believes Free Cash Flow is useful to management and investors in evaluating operating trends in its business that are affected by production, commodity prices, operating costs and other related factors. There are significant limitations to the use of Free Cash Flow as a measure of performance, including the lack of comparability due to the different methods of calculating Free Cash Flow reported by different companies.

The following table presents a reconciliation of net cash provided by operating activities (GAAP) to Free Cash Flow (non-GAAP) for the periods presented:

	Three Months Ended	
(in thousands, unaudited)	March 31, 2023	June 30, 2023
Net cash provided by operating activities	$116,125	$248,888
Less:		
Net changes in operating assets and liabilities	(66,756)	38,742
General and administrative (transaction expenses)	(861)	861
Cash flows from operating activities before net changes in operating assets and liabilities and non-budgeted acquisition costs	183,742	209,285
Less incurred capital expenditures, excluding non-budgeted acquisition costs:		
Oil and natural gas properties[1]	184,114	144,350
Midstream and other fixed assets[1]	3,530	4,239
Total incurred capital expenditures, excluding non-budgeted acquisition costs	187,644	148,589
Free Cash Flow (*non-GAAP*)	**($3,902)**	**$60,696**

[1]Includes capitalized share-settled equity-based compensation and asset retirement costs.

Supplemental Non-GAAP Financial Measures

Consolidated EBITDAX

Consolidated EBITDAX is a non-GAAP financial measure defined in the Company's Senior Secured Credit Facility as net income or loss (GAAP) plus adjustments for share-settled equity-based compensation, depletion, depreciation and amortization, impairment expense, gains or losses on disposal of assets, mark-to-market on derivatives, accretion expense, interest expense, income taxes and other non-recurring income and expenses. Consolidated EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Consolidated EBITDAX does not represent funds available for future discretionary use because it excludes funds required for debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, management believes Consolidated EBITDAX is useful to an investor because this measure:

- is used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items that can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of the Company's operations from period to period by removing the effect of the Company's capital structure from the Company's operating structure; and
- is used by management for various purposes, including (i) as a measure of operating performance, (ii) as a measure of compliance under the Senior Secured Credit Facility, (iii) in presentations to the board of directors and (iv) as a basis for strategic planning and forecasting.

There are significant limitations to the use of Consolidated EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect the Company's net income or loss and the lack of comparability of results of operations to different companies due to the different methods of calculating Consolidated EBITDAX, or similarly titled measures, reported by different companies. The Company is subject to financial covenants under the Senior Secured Credit Facility, one of which establishes a maximum permitted ratio of Net Debt, as defined in the Senior Secured Credit Facility, to Consolidated EBITDAX. See Note 7 in the 2022 Annual Report for additional discussion of the financial covenants under the Senior Secured Credit Facility. Additional information on Consolidated EBITDAX can be found in the Company's Tenth Amendment to the Senior Secured Credit Facility, as filed with the SEC on November 3, 2022.

Supplemental Non-GAAP Financial Measures

Consolidated EBITDAX

The following table presents a reconciliation of net income (GAAP) to Consolidated EBITDAX (non-GAAP) for the periods presented:

	Trailing Twelve Months ended	
(in thousands, unaudited)	**March 31, 2023**	**June 20, 2023**
Net income	$832,233	$864,498
Plus:		
Share-settled equity-based compensation	8,922	9,211
Depletion, depreciation and amortization	324,927	350,132
Impairment expense	40	40
Organizational restructuring expenses	10,420	10,420
Loss on disposal of assets, net	582	1,358
Mark-to-market on derivatives:		
Gain on derivatives, net	(47,583)	(95,466)
Settlements paid for matured derivatives, net	(363,146)	(178,354)
Settlements received for contingent consideration	3,912	2,357
Accretion expense	3,759	3,689
Interest expense	121,198	119,920
Loss on extinguishment of debt, net	1,459	661
Income tax (benefit) expense	7,986	(220,937)
General and administrative (transaction expenses)	861	—
Consolidated EBITDAX (*non-GAAP*)	**$905,570**	**$867,529**
Transaction adjustments (Senior Secured Credit Facility covenant compliance)[1]	(21,562)	185,470
Consolidated EBITDAX (*non-GAAP*) (Senior Secured Credit Facility covenant compliance)[1]	**$884,008**	**$1,052,999**

[1] Calculation conforms to credit facility covenant which requires various treatment of asset transaction impacts.

Supplemental Non-GAAP Financial Measures

Consolidated EBITDAX

The following table presents a reconciliation of net cash provided by operating activities (GAAP) to Consolidated EBITDAX (non-GAAP) for the periods presented:

	Trailing Twelve Months ended	
(in thousands, unaudited)	**March 31, 2023**	**June 30, 2023**
Net cash provided by operating activities	$775,783	$656,546
Plus:		
Interest expense	121,198	119,920
Organizational restructuring expenses	10,420	10,420
Current income tax expense	6,234	2,224
Net changes in operating assets and liabilities	15,148	96,093
General and administrative (transaction expenses)	861	—
Settlements received for contingent consideration	3,912	2,357
Other, net	(27,986)	(20,031)
Consolidated EBITDAX (*non-GAAP*)	**$905,570**	**$867,529**

Supplemental Non-GAAP Financial Measures

Net Debt

Net Debt is a non-GAAP financial measure defined in the Company's Senior Secured Credit Facility as the face value of long-term debt plus any outstanding letters of credit, less cash and cash equivalents, where cash and cash equivalents are capped at $50 million when there are borrowings on the Senior Secured Credit Facility. Management believes Net Debt is useful to management and investors in determining the Company's leverage position since the Company has the ability, and may decide, to use a portion of its cash and cash equivalents to reduce debt.

(in thousands, unaudited)	March 31, 2023	June 30, 2023
Total senior unsecured notes	$1,054,151	$1,054,151
Senior Secured Credit Facility	120,000	575,000
Letters of credit	—	—
Total long-term debt	1,174,151	1,629,151
Less:		
Cash and cash equivalents	27,682	50,000
Net Debt (*non-GAAP*)	**$1,146,469**	**$1,579,151**

Net Debt to Consolidated EBITDAX

Net Debt to Consolidated EBITDAX, a non-GAAP financial measure, is calculated as Net Debt divided by Consolidated EBITDAX, for the previous four quarters, as defined in the Company's Senior Secured Credit Facility. Net Debt to Consolidated EBITDAX is used by the Company's management for various purposes, including as a measure of operating performance, in presentations to its board of directors and as a basis for strategic planning and forecasting.

Supplemental Non-GAAP Financial Measures

PV-10

PV-10 is a non-GAAP financial measure that is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. Management believes that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to the Company’s estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of the Company's proved oil, NGL and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of proved reserves to other companies. The Company uses this measure when assessing the potential return on investment related to proved oil, NGL and natural gas assets. However, PV-10 is not a substitute for the standardized measure of discounted future net cash flows. The PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of the Company’s oil, NGL and natural gas reserves of the property.

	As of December 31, 2022			
(in millions)	Vital	Driftwood	Forge	Total Combined
Standardized measure of discounted future net cash flows	$4,755	$595	$967	$6,317
Less present value of future income taxes discounted at 10%	(709)	(5)	(10)	(724)
PV-10 (*non-GAAP*)	$5,464	$600	$977	$7,041