HighPeak Energy

Investor Presentation

March 2023

Disclaimer

FORWARD-LOOKING STATEMENTS

The information in this presentation and in any oral statements made in connection herewith contains forward-looking statements that involve risks and uncertainties. When used in or in connection with this document, the words “believes,” “plans,” “expects,” “anticipates,” “forecasts,” “intends,” “projects,” “continue,” “may,” “will,” “could,” “should,” “future,” “potential,” “estimate” or the negative of such terms and similar expressions as they relate to HighPeak Energy, Inc. (“HighPeak Energy” or the “Company”) are intended to identify forward-looking statements, which are generally not historical in nature. The forward-looking statements are based on the Company's current expectations, assumptions, estimates and projections about the Company and the industry in which the Company operates. Although the Company believes that the expectations and assumptions reflected in the forward-looking statements are reasonable as and when made, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond the Company's control. For example, the Company’s review of strategic alternatives may not result in a sale of the Company, a recommendation that a transaction occur or result in a completed transaction, and any transaction that occurs may not increase shareholder value, in each case as a result of such risks and uncertainties.

These risks and uncertainties include, among other things, the results of the strategic review being undertaken by the Company’s Board and the interest of prospective counterparties, the Company’s ability to realize the results contemplated by the 2023 and 2024 guidance contained herein, volatility of commodity prices, political instability or armed conflict in crude oil or natural gas producing regions such as the ongoing war between Russia and Ukraine, OPEC+ policy decisions, inflationary pressures on costs of oilfield goods, services and personnel, product supply and demand, the impact of a widespread outbreak of an illness, such as the coronavirus disease 2019 (“COVID-19”) pandemic, on global and U.S. economic activity, competition, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms, litigation, the costs and results of drilling and operations, availability of equipment, services, resources and personnel required to perform the Company’s drilling and operating activities, access to and availability of transportation, processing, fractionation, refining and storage facilities, HighPeak Energy’s ability to replace reserves, implement its business plans or complete its development activities as scheduled, access to and cost of capital, the financial strength of counterparties to any credit facility and derivative contracts entered into by HighPeak Energy, if any, and purchasers of HighPeak Energy's oil, NGL and gas production, uncertainties about estimates of reserves, identification of drilling locations and the ability to add proved reserves in the future, the assumptions underlying forecasts, including forecasts of production, expenses, cash flow from sales of oil and gas and tax rates, quality of technical data, environmental and weather risks, including the possible impacts of climate change, cybersecurity risks and acts of war or terrorism. These and other risks are described in the Company’s Annual Report on Form 10-K filed with the Securities and Exchange Commission (the “SEC”) on March 6, 2023 (the “Annual Report”), and in its other filings with the SEC. In addition, the Company may be subject to currently unforeseen risks that may have a materially adverse effect on it. Accordingly, no assurances can be given that the actual events and results will not be materially different than the anticipated results described in the forward-looking statements. See “Risk Factors,” “Business,” “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures About Market Risk” in the Registration Statement for a description of various factors that could materially affect the ability of HighPeak Energy to achieve the anticipated results described in the forward-looking statements. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. The Company undertakes no duty to publicly update these statements except as required by law.

RESERVE INFORMATION

Reserve engineering is a process of estimating the recovery of underground accumulations of hydrocarbons that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. Reserves estimates included herein may not be indicative of the level of reserves or PV-10 value of oil and natural gas production in the future, as they are based on prices significantly higher than current commodity prices. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could impact HighPeak’s strategy and change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Estimated Ultimate Recoveries, or “EURs,” refers to estimates of the sum of total gross remaining reserves per well as of a given date and cumulative production prior to such given date for developed wells. “Resource” refers to gross volumes of hydrocarbons without giving effect to recovery efficiency or the economic viability of production. Neither EURs nor resource constitute or represent reserves as defined by the SEC and neither is intended to be representative of anticipated future well results or aggregate production volumes. Each such metric is inherently more uncertain than proved reserve estimates prepared in accordance with SEC guidelines.

USE OF PROJECTIONS

The financial, operational, industry and market projections, estimates and targets in this presentation (including production, operating expenses, capital expenditures, EBITDAX and Asset FCF in future periods) are based on assumptions that are inherently subject to significant uncertainties and contingencies, many of which are beyond the Company’s control. The assumptions and estimates underlying the projected, expected or target results are inherently uncertain and are subject to a wide variety of significant business, economic, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those contained in the financial, operational, industry and market projections, estimates and targets, including assumptions, risks and uncertainties described in “Cautionary Note Regarding Forward-Looking Statements” above. These projections are speculative by their nature and, accordingly, are subject to significant risk of not being actually realized by the Company. Projected results of the Company for Q4'23, FY2023, Q4'24 and FY2024 are particularly speculative and subject to change. Actual results may vary materially from the current projections, including for reasons beyond the Company’s control. The projections are based on current expectations and available information as of the date of this release. The Company undertakes no duty to publicly update these projections except as required by law.

In particular, you should be aware that, unless otherwise indicated, projections shown herein are based on management's "flat" commodity price parameters rather than SEC pricing guidelines or current NYMEX forward pricing. The flat prices used in preparing the projections contained herein were $90 per Bbl of oil and $4 per MMBtu of natural gas, as compared to prices of $93.67 per Bbl for oil and $6.358 per MMBtu that would have been used if using SEC reserve pricing guidelines. HighPeak believes that the use of flat pricing provides useful information as the flat prices reflect what management believes to be reasonable assumptions as to future commodity prices over the productive lives of its properties. However, HighPeak cautions you that the flat pricing used in preparing its projections is not necessarily a projection of future oil and natural gas prices, and should be carefully considered in addition to, and not as a substitute for, other commodity price assumptions held by third parties.

Disclaimer (Cont'd)

USE OF NON-GAAP FINANCIAL MEASURES

This presentation may include non-GAAP financial measures, including EBITDAX and adjusted EBITDAX, unlevered asset free cash flow, operating margin and unhedged cash operating margin, and PV-10. HighPeak believes these non-GAAP measures are useful because they allow HighPeak to more effectively evaluate its operating performance and compare the results of its operations from period to period and against its peers without regard to financing methods, capital structure or tax status. HighPeak does not consider these non-GAAP measures in isolation or as alternatives to similar financial measures determined in accordance with GAAP. HighPeak's computations of these non-GAAP financial measures may not be comparable to other similarly titled measures of other companies.

HighPeak defines EBITDAX as net income before interest expense, income taxes, depreciation, depletion and amortization, exploration and other expenses, impairment and abandonment expenses, non-cash gains or losses on derivatives, stock-based compensation, gain on exchange of debt, gains and losses from the sale of assets, transaction costs and nonrecurring workforce reduction severance payments. HighPeak defines Adjusted EBITDAX as EBITDAX excluding cash G&A expenses. HighPeak's management believes EBITDAX is useful as it allows them to more effectively evaluate HighPeak's operating performance and compare the results of its operations from period to period and against its peers without regard to financing methods or capital structure. HighPeak excludes the items listed above from net income in arriving at EBITDAX because these amounts can vary substantially from company to company within the industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. HighPeak also presented EBITDAX on an "annualized" basis, which represents EBITDAX for a fiscal quarter annualized for a 12-month period as if EBITDAX for each fiscal quarter in such period was equal to the quarter specified. HighPeak defines cash operating margin as realized price less lease operating expenses, gathering, processing and transportation expenses and production taxes, on a per-Boe basis. HighPeak defines cash margin as realized price less lease operating expense, gathering, processing and transportation expenses, cash general and administrative expenses and production taxes, on a per-Boe basis. HighPeak defines unhedged as excluding the effects of derivatives and hedged as including the effects of derivatives. HighPeak defines Unlevered Asset Free Cash Flow as Adjusted EBITDAX less Capex. HighPeak defines PV-10 as the present value of estimated future net revenues to be generated from the production of proved reserves, without giving effect to non-property related expenses, discounted at 10% per year before income taxes. For reconciliations of each such non-GAAP measure as presented herein to its most comparable measure prepared in accordance with GAAP, see the Appendix to this presentation.

In the case of non-GAAP financial measures presented for future periods, HighPeak advises that it is unable to provide reconciliations of such measures without unreasonable efforts. Accordingly, such measures should be considered in light of the fact that no GAAP measure of performance or liquidity is available as a point of comparison to such non-GAAP measures.

INDUSTRY AND MARKET DATA

This presentation has been prepared by HighPeak and may include market data and other statistical information from sources believed by HighPeak to be reliable, including independent industry publications, governmental publications or other published independent sources. Some data is also based on HighPeak's good faith estimates, which are derived from its review of internal sources as well as the independent sources described above. Although HighPeak believes these sources are reliable, they have not independently verified the information and cannot guarantee its accuracy and completeness.

DRILLING LOCATIONS

The Company has estimated its drilling locations based on well spacing assumptions and upon the evaluation of its drilling results and those of other operators in its area, combined with its interpretation of available geologic and engineering data. The drilling locations actually drilled on the Company's properties will depend on the availability of capital, regulatory approvals, commodity prices, costs, actual drilling results and other factors. Any drilling activities conducted on these identified locations may not be successful and may not result in additional proved reserves. Further, to the extent the drilling locations are associated with acreage that expires, the Company would lose its right to develop the related locations.

HighPeak Overview

Northern Midland Basin Pure-Play Capitalized For Profitable Oil-Weighted Value Creation

Key Highlights

- Q4’22 production average **~37.3 MBoe/d**
  - **Increased ~42% QoQ and ~151% YoY**
- YE’22 exit production **~39.9 MBoe/d**
- YE’22 proved reserves **~123 MMBoe**
  - **~92% increase YoY**
- ~112,500 net acres (~62k Flat Top, ~50.5k Signal Peak)(1)
- ~56% HBP, ~98% operated, ~12,000’ average lateral length(1)
- Additional 65 gross (57.5 net) horizontal wells in progress(1)
- ~2,500 gross locations remaining (~86% average working interest)(1)
- Q4’22 unhedged cash operating margin of $64.45/Boe(2)

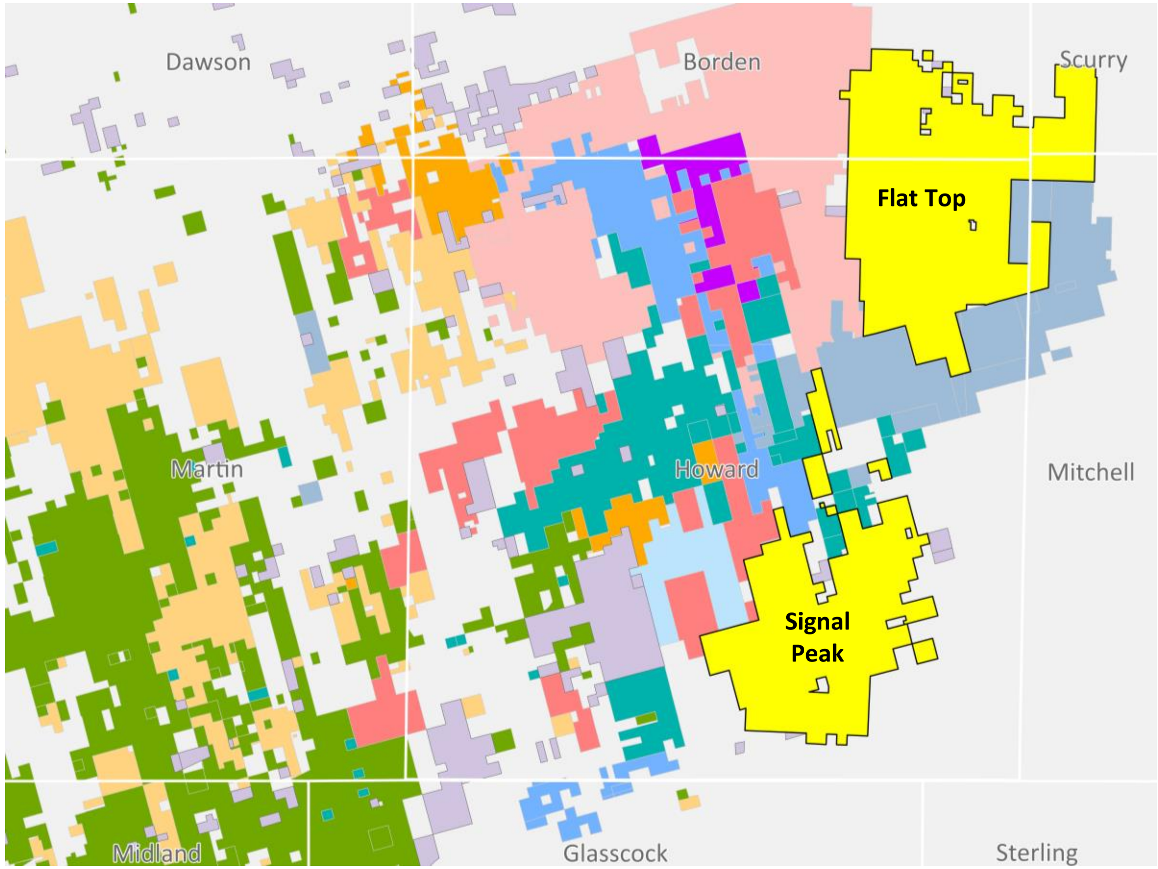
Operating Statistics(3)

Total Wells Drilled / Online as of 12/31/22	**215 / 165**
% Oil / % Liquids as of Q4’22	**85% / 94%**
2023E Exit Production (Mboe/d)	**~62**
2024E Exit Production (Mboe/d)	**~76**

Financial Statistics ($mm)(3)

Q4‘23E LQA Adj. EBITDAX(4)	**$1,528**
Q4‘24E LQA Adj. EBITDAX(4)	**$1,964**
2024E Unlevered Asset FCF(5)	**$1,006**
YE’22 Net Debt / Q4’22 LQA EBITDAX(6)	**0.8x**

Acreage Position and Select Offset Operators



Rigs Running:

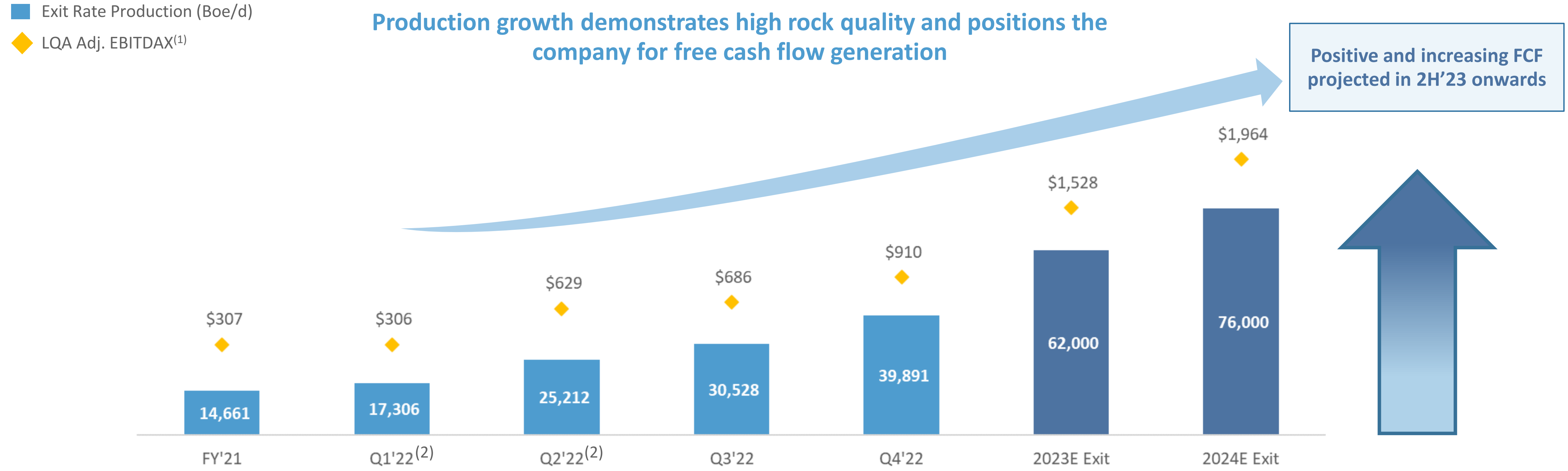
Completion Crews:

HighPeak | Bayswater | Callon | Diamondback | Vital
Occidental | Ovintiv | Pioneer | Surge | SM Energy

Note: Acreage map per Enverus and company data. Cash flows calculated using flat $90 WTI / $4 HH price deck.
(1) Net acreage as of 2/28/2023. HBP %, % operated, avg. WI %, locations and wells in progress as of 12/31/22.
(2) Unhedged cash operating margin is a non-GAAP financial measure. See the Appendix for a reconciliation to the most comparable GAAP measure.
(3) All forward-looking metrics based on midpoint of company guidance released in January 2023.
(4) Adjusted EBITDAX is a non-GAAP financial measure and defined as EBITDAX excluding cash G&A expenses.
(5) Unlevered Asset FCF is a non-GAAP financial measure and defined as Adjusted EBITDAX less Capex.
(6) Net debt as of 12/31/22.

Differentiated Growth Story Now Shifting to FCF Harvest

Value Creation Over Time



	FY'21	Q1'22	Q2'22	Q3'22	Q4'22	2023E Exit	2024E Exit	
Reinvestment Rate[3]						64%	40%	
Significant value created through consistent, repeatable development results								
Avg. Rigs Running	~1	4	5	6	6	4-5	4	
# of Wells Drilled	44	34	26	26	35	110-115	105-110	
# of Wells TIL	25	20	15	27	22	135-145	105-110	

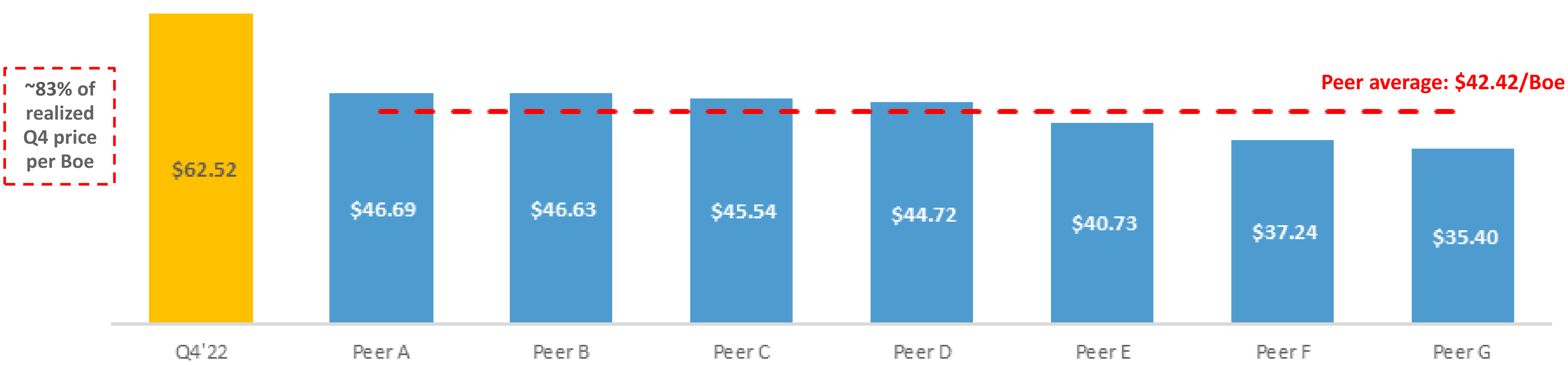
Note: All forward-looking metrics based on midpoint of company guidance released in January 2023. Cash flows calculated using flat $90 WTI / $4 HH price deck.
(1) Adjusted EBITDAX is a non-GAAP financial measure defined as EBITDAX excluding cash G&A expenses.
(2) Includes Hannathon acquisition.
(3) Reinvestment rate defined as Q4 LQA Capex / Adjusted EBITDAX.

HighPeak Has Peer Leading Margins

High oil cut, low-cost structure, and continued scaling of production lead to HPK's peer leading margins

- Q4 margins are **34% above** nearest peer with continued expansion expected as production scales
  - Further near-term margin improvements expected from Company power projects and dilution of fixed costs
- HPK Q4'22 margin including G&A ($62.52/Boe) is **~47% higher** vs. Q4'22 peer average

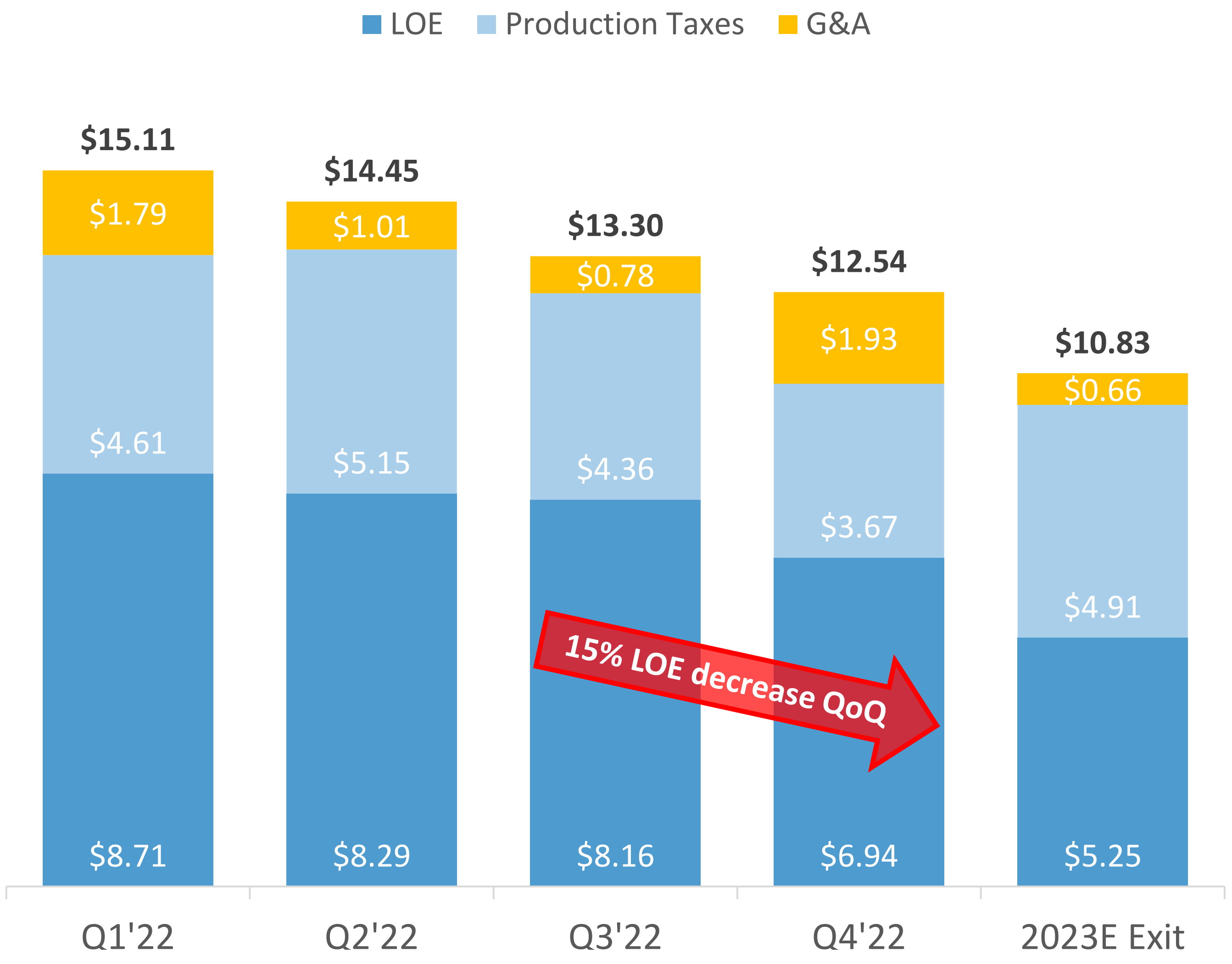
Unhedged EBITDAX Margins for the 3 Months Ended 12/31/22 ($/Boe)(1)



	Q4'22	Peer A	Peer B	Peer C	Peer D	Peer E	Peer F	Peer G
% Oil	**85%**	62%	56%	58%	53%	51%	43%	46%
% Liquids	**94%**	82%	56%(2)	79%	78%	72%	59%	73%

Source: Public filings.
(1) Q4'22 unhedged EBITDAX and production figures as reported. EBITDAX calculation for peers reflects adjusted EBITDAX for the 3M ended period as calculated by respective companies. Peers include CPE, FANG, MTDR, PR, PXD, SM, and VTLE (LPI).
(2) Peer B reports production on a 2-stream basis

Q4'22 Costs Per BOE



Continued Optimization Gains:

- **A** Continued generator removal and solar farm integration
- **B** Volume dilution of fixed costs
- **C** Infrastructure buildout in Signal Peak and Borden County

Power

Efficient
Removal of Generators, running 1-2 rigs on electric power, 2 rigs & 2 frac crews operating on dual-fuel

Clean
10MW solar farm in progress

Scalable
Expandable substation is operational

Facilities

Quality
First class, newly built VRU, VRT & instrument air

Expandable
Large scale, expandable CTBs & production corridors minimizes surface impact

On Pipe
> 75% oil / 100% gas minimizes trucking

Fluid

Recycling
Can supply 100% of the stimulation fluid for 2 frac crews at Flat Top, currently expanding recycle capabilities at Signal Peak

Infrastructure
Pipeline connected horizontal SWDs with high-volume, low-pressure injection

Sand

Environmental
Local sand mine (less than 20-mile round trip) currently supplying 3 frac crews, reducing trucking miles

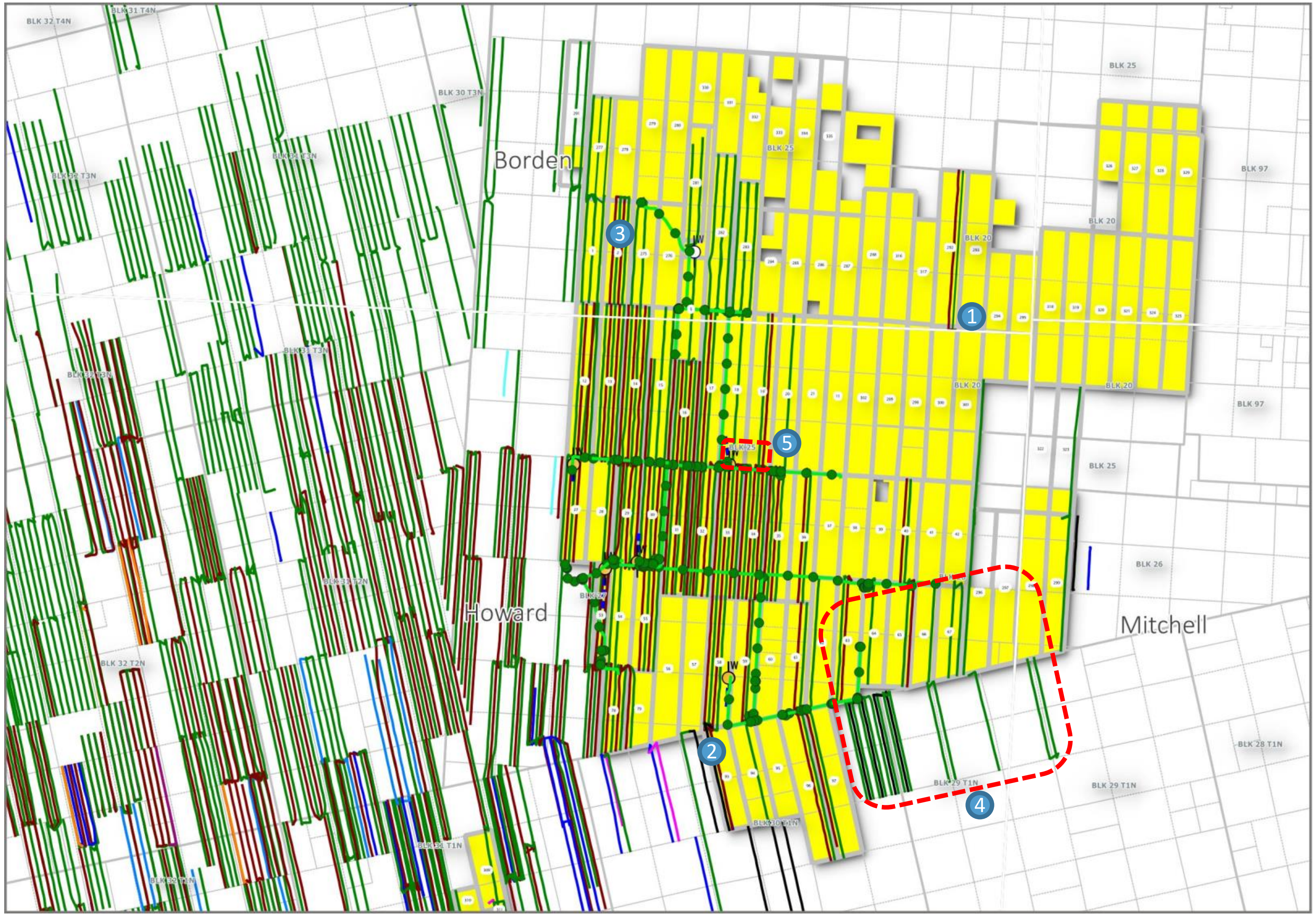
Energy Savings
Using wet sand eliminates natural gas burned in drying process

Continuing our efficiency and environmental stewardship

Operations – Flat Top

Summary

- Key Pads/Areas
  1. Conrad pad
     - 2 well LS/WCA pad – online
       - Extended LS/WCA ~4 miles northeast of development area
  2. Fleeman pad
     - 4 well stacked lateral pad – online
       - WCD- 3 finger test (1 well)
       - WCB test (1)
       - LS/WCA development (2)
  3. Griffin 48-37 B pad
     - 5 well unit – online
       - LS wells producing similar to WCA
  4. Southeast Flat Top
     - Demonstrated well performance similar to core Flat Top area
  5. HighPeak company owned surface
     - 1MM barrel recycle facility
     - Solar farm in progress
     - Horizontal SWD
     - Field office



Operations – Signal Peak

Summary

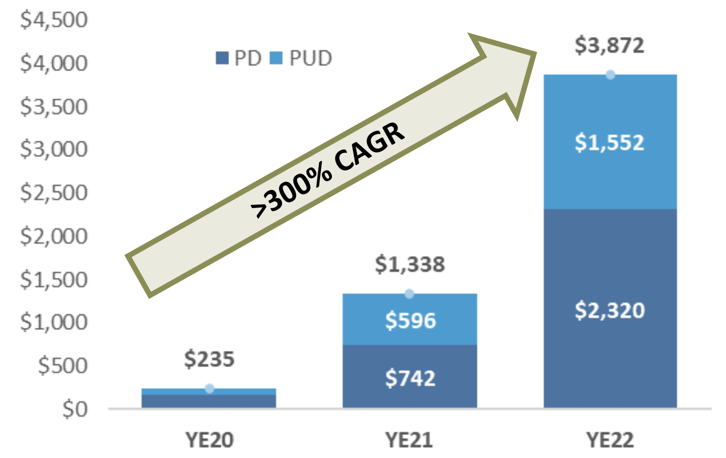
- Key Pads/Wells
  - 1 Marchbanks/Powell/Partee pad
    - 4 well pad – Running ESP's/Gas-lift
      - WCD-3 Finger test (1 well)
      - WCC-Hutto test (1)
      - WCD-Base development (2)
  - 2 St. Rita pad
    - 5 well pad – finishing fracs
      - WCD-3 Finger test (1)
      - WCD-Base development (4)
  - 3 Alsobrooks pad
    - 2 well pad – Running ESP's
      - WCA/LS pair
  - 4 Morgan 35-47 pad
    - WCA/LS pair
  - 5 Click-Chevron pad
    - 4 well pad – drilling
    - 1st WCA/LS multi-well pad @ Signal Peak

- Infrastructure
  - 3 SWD wells in operation
    - Plan to drill 1-2 additional wells in 2023
  - Constructing 20" water gathering system
  - Build out of main electrical system

Year-End Proved Reserves Summary (1)(2)

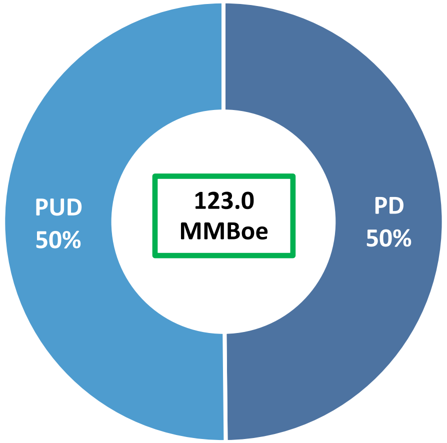
2022 SEC Pricing - $93.67/Bbl & $6.358/MMBtu

PV10 ($mm)

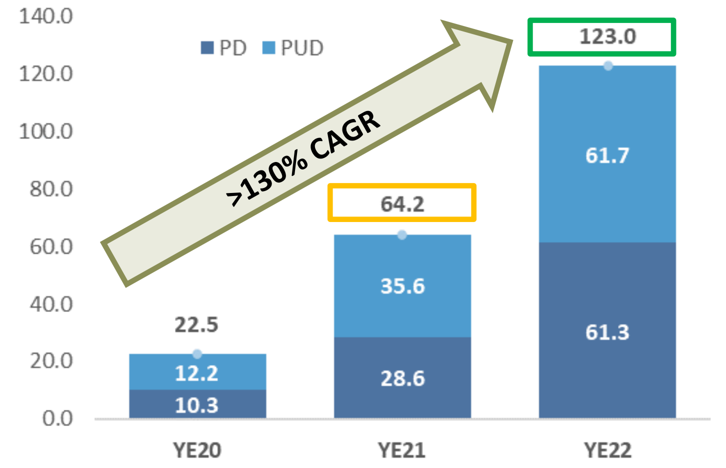


- Multi-year drilling program has driven significant reserves additions and PV10 growth
- 2022 Replacement Ratio(3)
  – Drill Bit: 546%
  – Drill Bit + Acquisitions: 757%

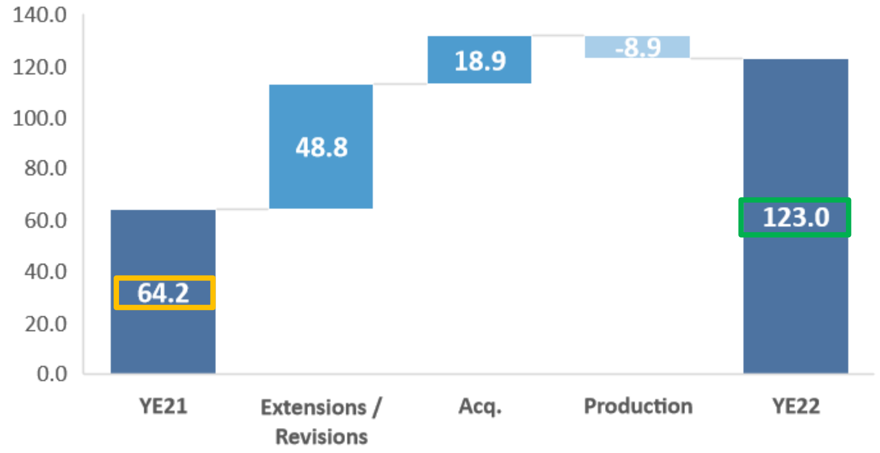
YE22 Proved Reserves by Category



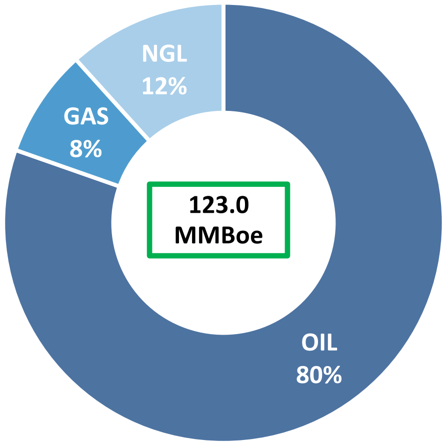
Net Reserves (MMBoe)



Proved Reserves (MMBoe)



YE22 Proved Reserves Mix

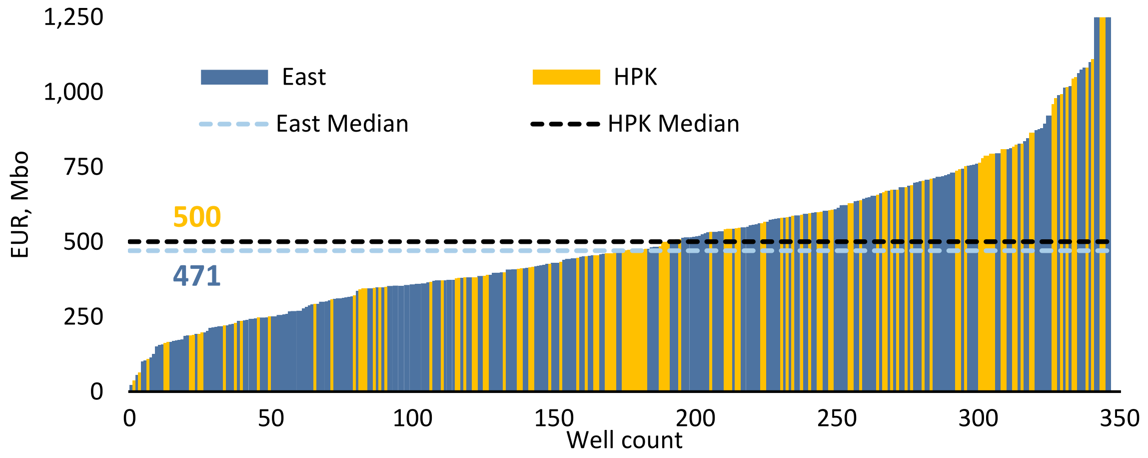


(1) Reserves per HighPeak's year-end 2020/2021/2022 third party reserve reports prepared by Cawley Gillespie & Associates ("CGA").
(2) SEC pricing (oil, $/Bbl / gas, $/MMBtu) each report: 2020: $39.57/$1.985, 2021: $66.56/$3.598, 2022: $93.67/$6.358.
(3) Drill Bit Replacement Ratio is defined as reserves from Extensions plus Revisions divided by Production; Drill Bit + Acquisitions Replacement Ratio is defined as reserves from Extensions plus Revisions plus Acquisitions divided by Production.

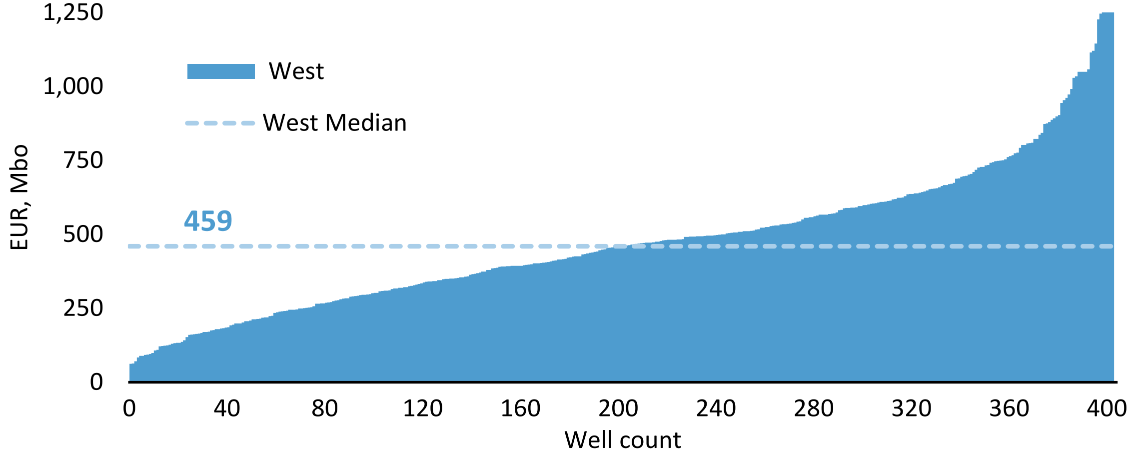
HighPeak Exhibiting Leading Results in Howard and South Borden Counties

Oil EUR Distributions per Enverus Relative to HPK Results

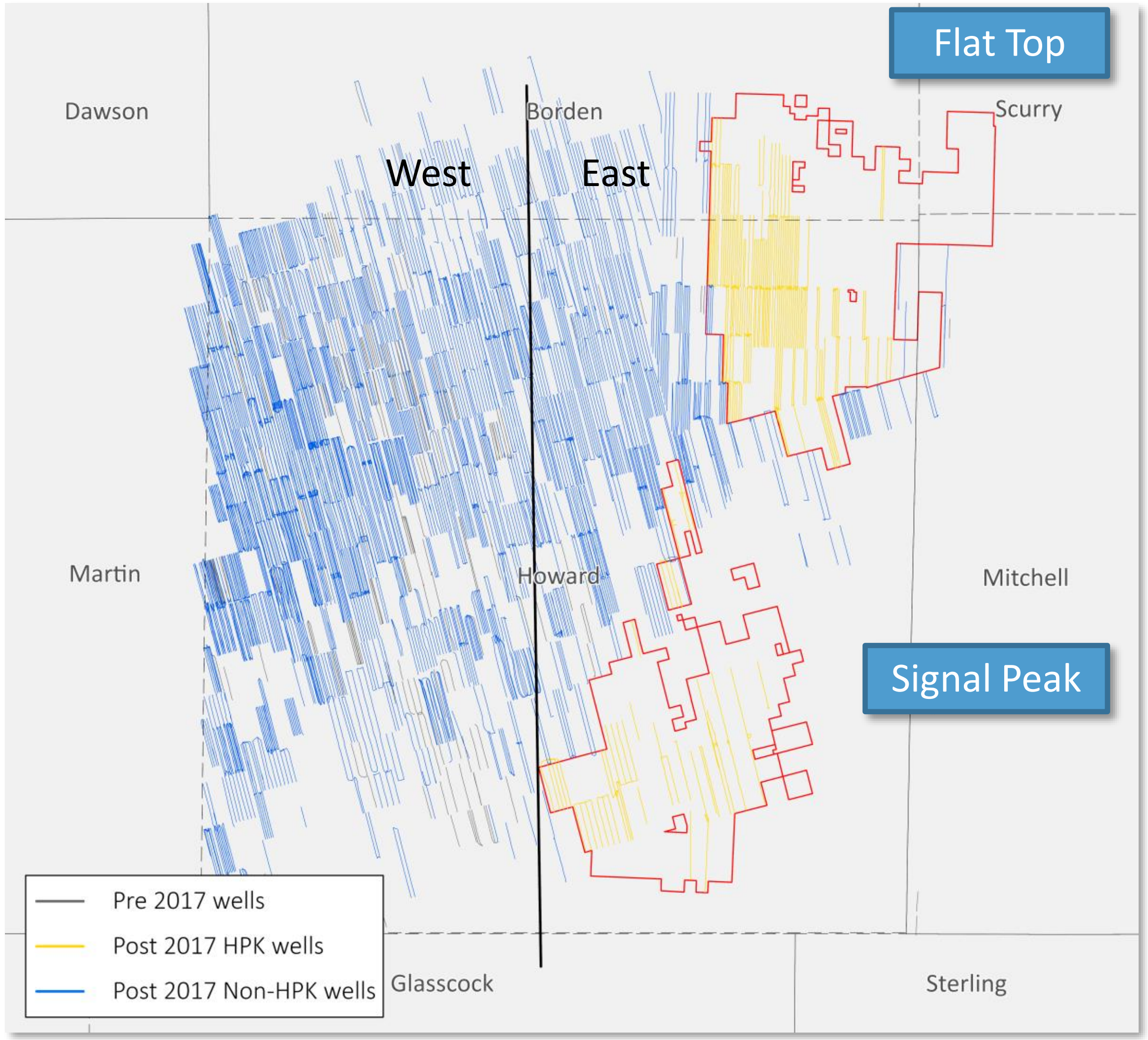
East Howard & South Borden Oil EUR Distribution



West Howard & South Borden Oil EUR Distribution



Delineation and Laterals to Date



Source: Enverus, company provided.
Note: Wells used for EUR distribution as of 1/1/20 spud date, lateral length >7,500', minimum 4 producing months.

Substantial Inventory[1]

Results Driven By Excellent Reservoir Performance Across Multiple Targets

HIGHPEAK ENERGY

~ 2,500

Total Gross Locations

Inventory Details

- Approximately 1,300 delineated primary locations from current producing intervals
- Primary inventory exhibiting an avg. 95% IRR[2]
- **>14 years** of anticipated primary at 4-rig cadence; > **58 rig-years** of primary
- Approximately 1,200 additional upside locations; > **51 rig-years** of upside
- Conservative 6 wells/section spacing[3]
- ~12,000 ft avg. lateral length

Rock & Fluid Properties

- High TOC (up to 9%)
- Thermally mature (oil window)
- 34 – 38 API crude with high BTU gas

Remaining Inventory (Gross Locations)

	Flat Top		Signal Peak		Total		
	Primary	Upside	Primary	Upside	Primary	Upside	All
Middle Spraberry	-	150	-	111	-	**261**	**261**
Jo Mill	-	174	-	111	-	**285**	**285**
Lower Spraberry	182	-	138	-	**320**	-	**320**
Wolfcamp A	198	-	144	-	**342**	-	**342**
Wolfcamp B	59	240	98	24	**157**	**264**	**421**
Wolfcamp C	-	-	-	165	-	**165**	**165**
Wolfcamp C (Hutto)	-	-	-	169	-	**169**	**169**
Wolfcamp D (3-Fingers)	47	45	238	-	**285**	**45**	**330**
Wolfcamp D (Base)	-	-	191	19	**191**	**19**	**210**
TOTAL	**486**	**609**	**809**	**599**	**1,295**	**1,208**	**2,503**

Note: Rig years based on illustrative 20 gross wells drilled per year/rig in Wolfcamp D, 24/year in all others.
(1) As of December 31, 2022.
(2) IRR calculated at flat pricing WTI/HH $90/$4.
(3) Assumes 1-mile-wide drilling units.

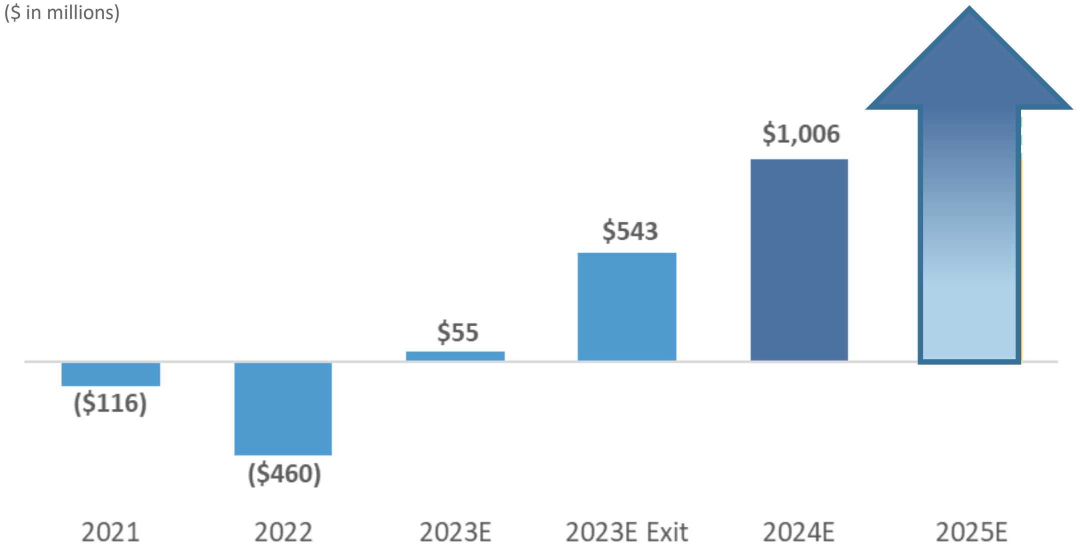
2023 and 2024 Development Outlook

Production (MBoe/d)	2023	2024
Average production rate	47 – 53	70 – 76
Exit production rate	58 – 66	72 – 80

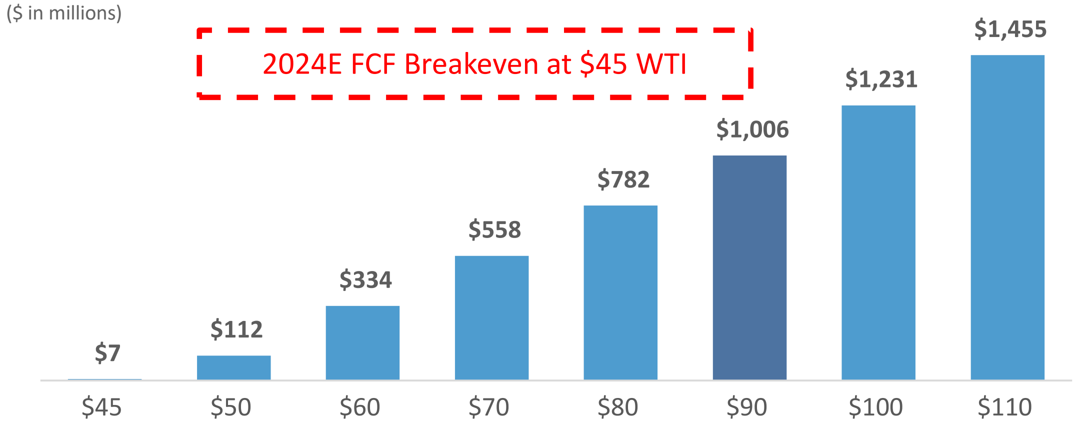
Capex ($mm)	2023	2024
Gross Operated Wells TIL	135 – 145	105 – 110
Capital Expenditures D,C,E&F	$1,100 - $1,200	$850 - $900
Capital Expenditures, Infra/Land/Other	$50 - $60	$20 - $30
Total Capital Expenditures	$1,150 - $1,260	$870 - $930
Average Rigs	4 – 5	4
Average Frac Crews	2 – 3	2

Unit Measures ($/Boe)	2023	2024
Lease Operating Expenses	$5.25 - $5.75	$5.00 - $5.50
General & Administrative	$0.75 - $1.00	$0.60 - $0.80

FCF Inflection Point in 2023 – Entering FCF Growth Mode Thereafter[1]



Illustrative 2024E FCF at Various WTI Oil Prices[1]



(1) Unlevered Asset FCF defined as Adjusted EBITDAX less capex. Cash flows calculated using flat $90 WTI/ $4 HH price deck.

Contiguous Acreage

- ~112,500 net acres located in two highly contiguous blocks
- Optimal large-scale development provides for maximum capital efficiency

Operational & Environmental Focus

- Developed for long-term operations
- ESG initiatives are both environmentally and fiscally rewarding to all stakeholders

Inventory Depth

- ~2,500 gross locations across multiple benches (~30% at > 15,000’ lateral length)
- ~1,300 primary delineated locations; > 14-year inventory life at 4-rig cadence

Leading Margins

- High oil cut and low-cost operations
- Leading margins among public companies in the Permian Basin

Consistent Well Results

- 215 horizontal wells drilled supporting primary inventory exhibiting an average 95% IRR(1)
- Q4’22 production of 85% oil and 94% liquids

Free Cash Flow and Growth

- Projected to reach Free Cash Flow in 2H’23
- Ability to scale development program to support increased production growth if market conditions warrant

(1) IRR calculated using flat $90 WTI / $4 HH price deck.

HIGHPEAK ENERGY, INC.

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HIGHPEAK ENERGY, INC.

Appendix

Rig Released Wells

	4Q22		2022 FY	
	Gross	Net	Gross	Net
OP	33	31.8	113	106.5
Nonop	2	0.1	10	0.4
Total	35	31.9	123	106.8
SWD	1	1.0	4	4.0

In Progress(1)

	As of 12/31/2022	
	Gross	Net
OP	59	57.3
Nonop	6	0.3
Total	65	57.5
SWD	0	0.0

Turned in Line

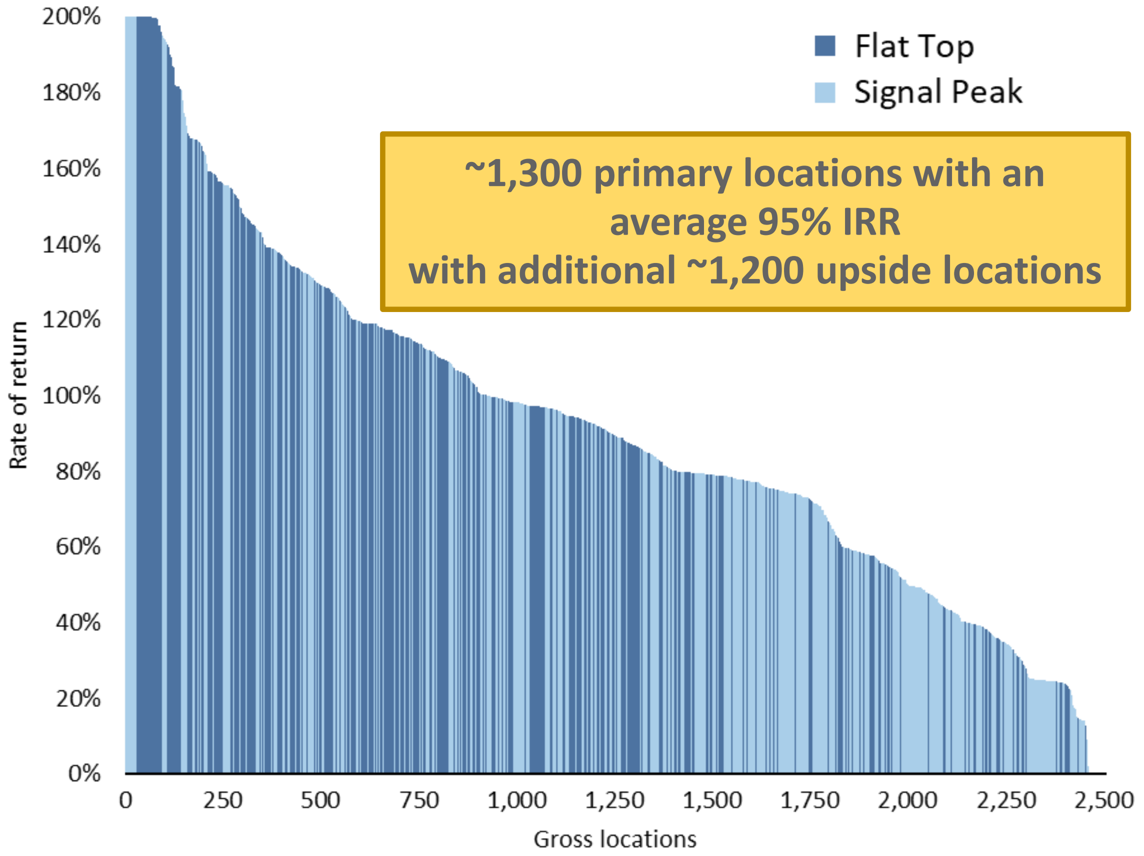
	4Q22		2022 FY	
	Gross	Net	Gross	Net
OP	25	22.4	87	78.0
Nonop	2	0.1	5	0.2
Total	27	22.4	92	78.2

(1) In Progress includes 11 gross (10.7 net) wells drilling on December 31, 2022.

HighPeak Inventory Analysis

Flat WTI/HH $90/$4

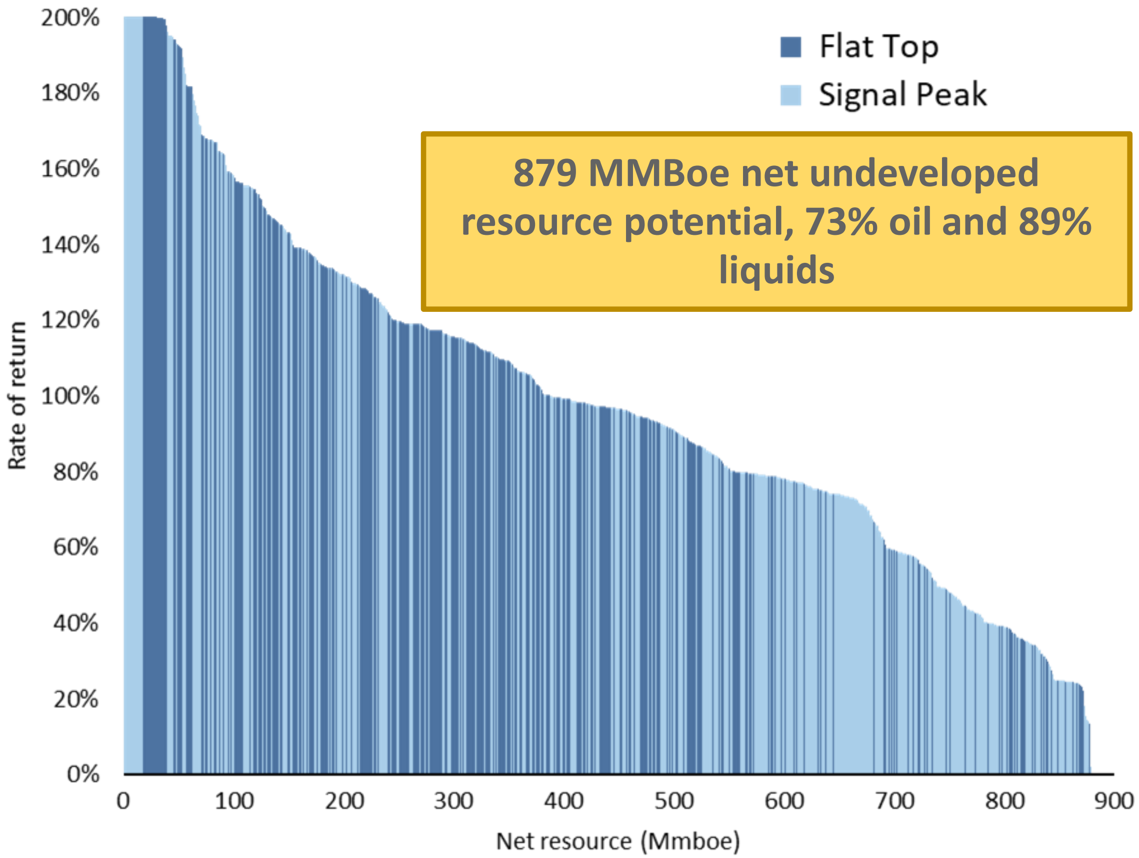
Remaining Locations



(# of wells)

	Well IRR					
	>20%	>40%	>60%	>80%	>100%	Total
Flat Top	1,067	993	928	811	567	1,095
Signal Peak	1,354	1,153	904	587	353	1,408
Total	2,421	2,146	1,832	1,398	920	2,503

Net Remaining Resource (MMBoe)



(net resource, Mmboe)

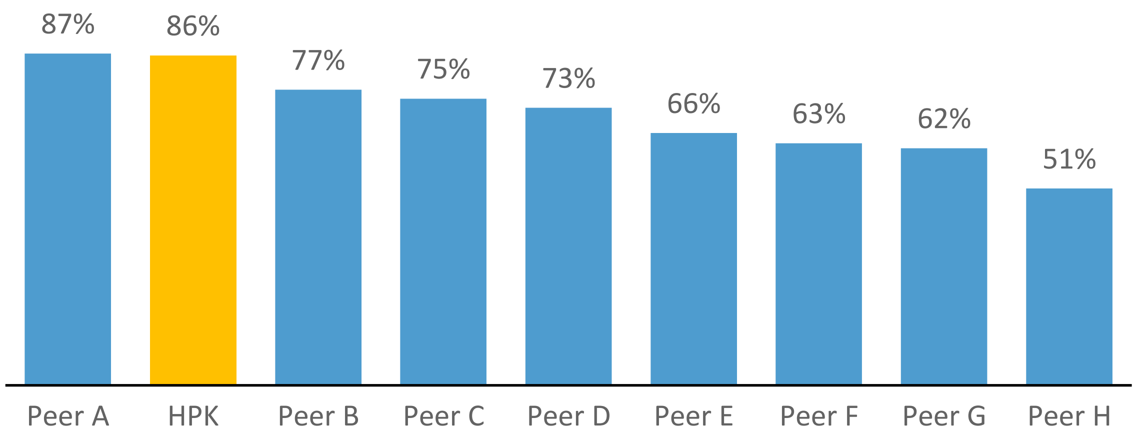
	Well IRR					
	>20%	>40%	>60%	>80%	>100%	Total
Flat Top Resource	389	361	346	316	230	391
Signal Peak Resource	484	429	347	239	159	488
Total	873	790	693	555	389	879

Source: Company year-end '22 SEC database.

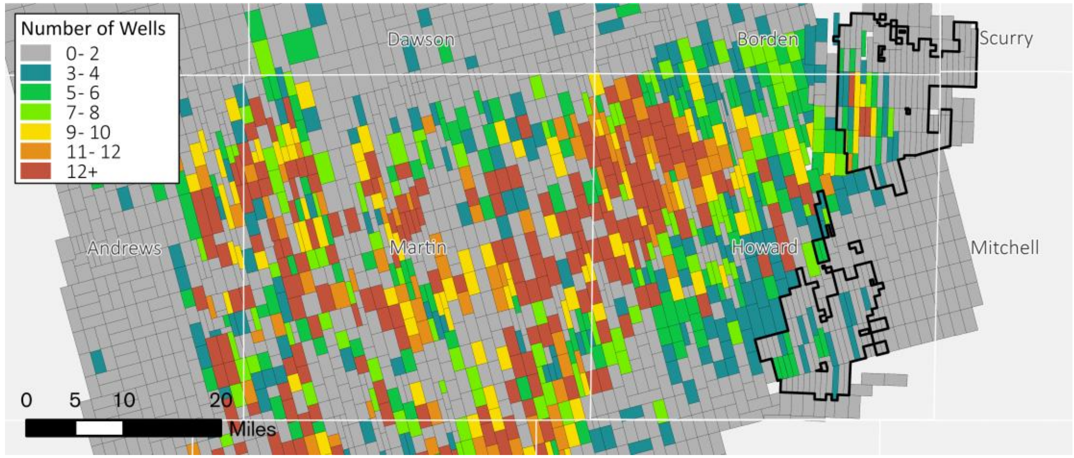
HighPeak Poised for Optimal Development on Proven Inventory

- ~88% of HPK acreage has 6 or less wells/DSU making it one of the least densely populated acreage of any mid-cap Permian public
- One of the smallest parent child risks relative to HighPeak's Permian basin peers
- Clean fairways allow for optimized full-scale pad development on delineated acreage
- Contiguous acreage with optimal lateral design to maximize capital efficiency

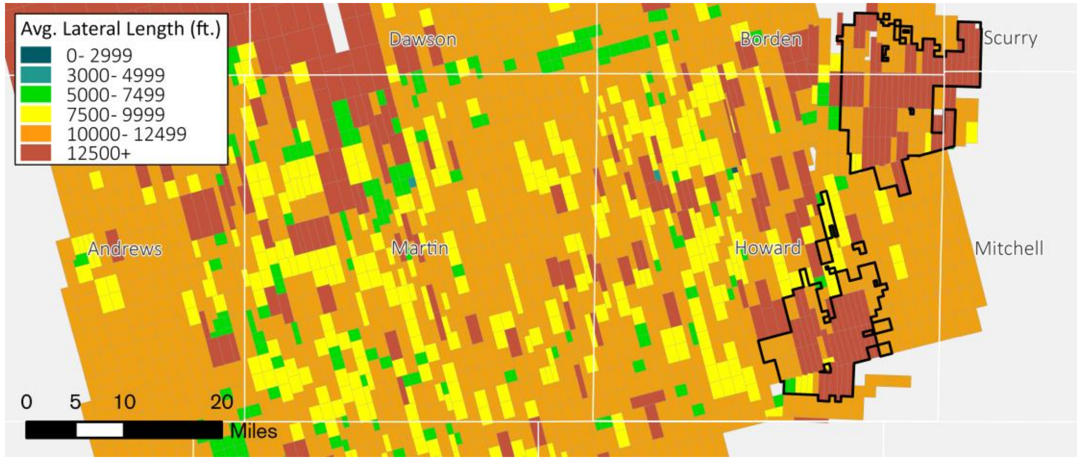
Non-child as percent of overall remaining net locations[1]



DSU well density Northern Midland[2]



DSU lateral length configuration Northern Midland



Source: Enverus.
(1) Based on May 2022 Permian Play Fundamentals report. Peers include CPE, ESTE, FANG, MTDR, PR, PXD, SM, and VTLE (LPI).
(2) Well density normalized for a 1-mile wide DSU.

Q4 2022 Summary

Production	Q4 2022
Total sales volumes (MBoe)	3,436.0
Total daily sales volumes (MBoe/d)	37.35
Oil percentage	85%
Liquids percentage	94%
Realized Pricing	
Oil per Bbl	$84.67
NGL per Bbl	$26.19
Gas per Mcf	$3.41
Total per Boe (excluding derivatives)	$75.06
Total per Boe (including derivatives)	*$76.82*
Costs (per Boe)	
LOE	$6.94
Production & Ad Valorem taxes	$3.67
G&A (Cash)	$1.93
Total cash costs	$12.54
Cash margin (excluding derivatives)	$62.52
Cash margin (including derivatives)	$64.28

Earnings	Q4 2022
Net Income ($MM)	$67.9
GAAP Earnings (per diluted share)	*$0.53*
EBITDAX ($MM)	$220.9
EBITDAX (per diluted share)	*$1.71*
Other	
Capex ($MM)(1)	$321.6
Rig Released(2) / Turn in Line	36 / 27

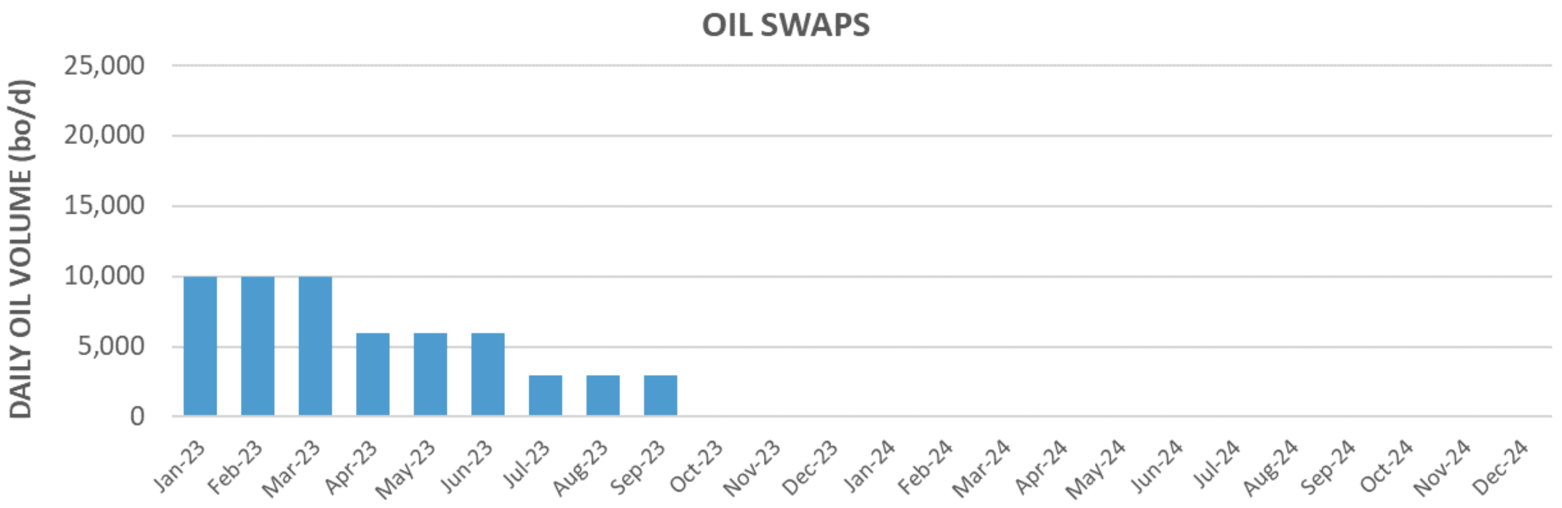
(1) Excludes acquisition capex.
(2) Rig Released includes 1 SWD.

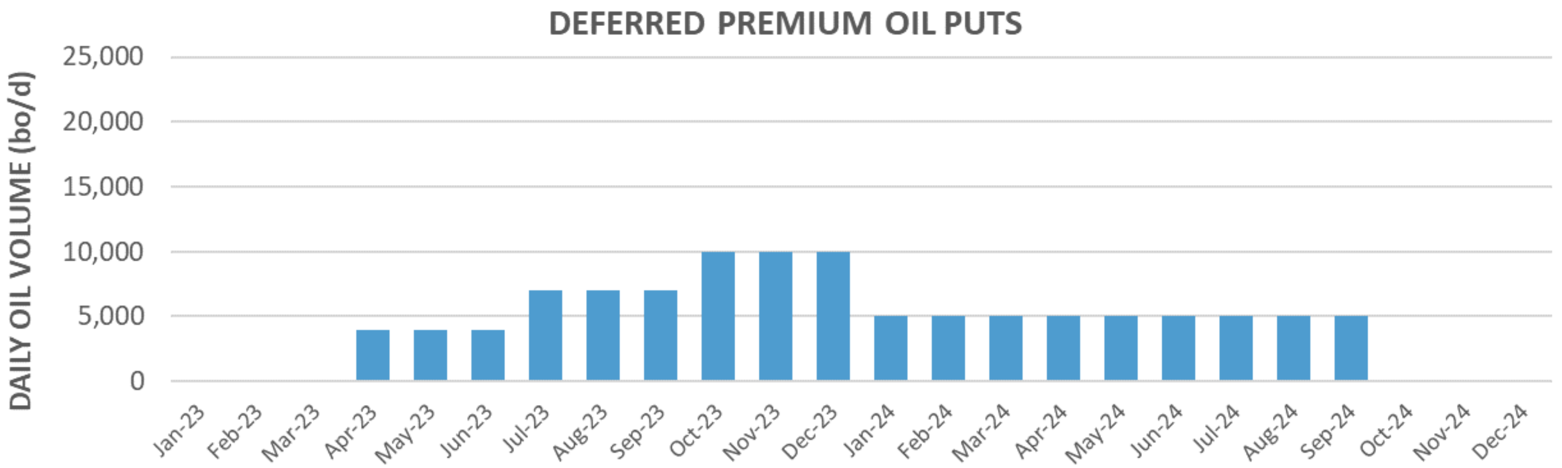
Hedges[1]

Summary

- Average oil volumes of ~4,718 Bo/d hedged in 2023 using swaps at an average price of $71.59/bbl
- Average oil volumes of ~5,282 Bo/d hedged through 2023 using puts at an average price of $58.43/bbl
  - Deferred premium cost of $5/bbl

	OIL SWAPS		OIL PUTS	
	VOL (Mbbl)	Price	VOL (Mbbl)	Price
2023/Q1	900	$73.67		
2023/Q2	546	$67.81	364	$61.05
2023/Q3	276	$72.30	644	$60.46
2023/Q4			920	$55.97
2023	**1,722**	**$71.59**	**1,928**	**$58.43**
2024/Q1			455	$51.50
2024/Q2			455	$51.50
2024/Q3			460	$51.50
2024/Q4				
2024			**1,370**	**$51.50**





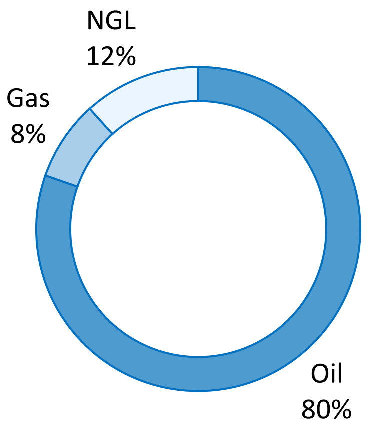
(1) Hedges as of 12/31/22.

SEC Pricing: Year-End 2022 Proved Reserves[(1)]

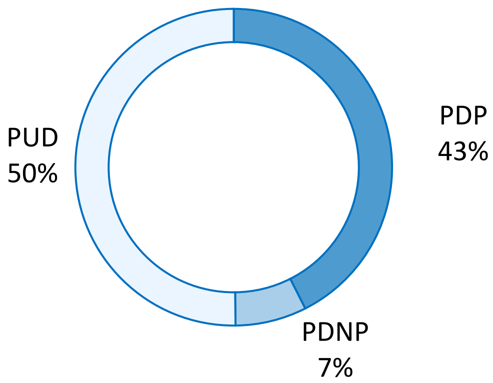
Year-End 2022 Proved Reserves

	Net Proved Reserves						
Reserve Category	Oil (MBbl)	Gas (MMcf)	NGL (MBbl)	Total (MBoe)	% of Total Proved	% Liquids	PV-10 ($MM)
Proved Developed Producing (PDP)	40,428	29,028	7,042	52,308	43%	91%	$1,947
Proved Developed Non-Producing (PDNP)	7,417	3,641	927	8,950	7%	93%	$373
Total Proved Developed Reserves	**47,845**	**32,669**	**7,968**	**61,259**	**50%**	**91%**	**$2,320**
Proved Undeveloped (PUD)	50,971	25,968	6,401	61,699	50%	93%	$1,552
Total Proved Reserves	**98,816**	**58,638**	**14,369**	**122,958**	**100%**	**92%**	**$3,872**

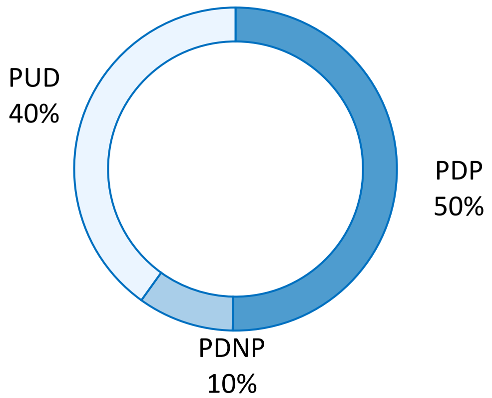
Proved Net Reserves by Commodity



Proved Net Reserves by Category



Proved PV-10 by Category



(1) Reserves per HighPeak's year-end 2022 third party reserve report prepared by Cawley Gillespie & Associates ("CGA"). Assumes effective date of 01/01/23; based on SEC pricing – average oil ($/bbl): $93.67 and average gas ($/MMBtu): $6.358.

Non-GAAP Reconciliation

Reconciliation of Net Income to EBITDAX

(in thousands)	Qtr. Ended	Qtr. Ended	Qtr. Ended	Qtr. Ended	Qtr. Ended
	31-Dec-21	30-Mar-22	30-Jun-22	30-Sep-22	31-Dec-22
Net income	$37,025	$(16,510)	$ 77,561	$107,904	$ 67,899
Interest expense	1,331	5,252	9,282	14,608	21,468
Income tax expense (benefit)	12,224	(312)	24,072	31,597	20,004
Depletion, depreciation and amortization	21,464	17,024	34,883	42,624	83,211
Accretion of discount	51	54	66	125	125
Exploration and abandonment expense	407	209	184	290	466
Stock based compensation	3,782	3,976	14,579	10,655	4,142
Derivative-related noncash activity	(3,935)	41,633	(25,191)	(38,098)	23,565
Other	40	(250)	(2)	(1)	(13)
Est. Hannathon EBITDAX contribution		23,500	19,750		
EBITDAX	**$72,389**	**$ 74,576**	**$155,184**	**$169,704**	**$220,867**
Cash G&A	3,843	1,940	2,016	1,877	6,637
Adjusted EBITDAX	**$76,232**	**$ 76,516**	**$157,200**	**$171,581**	**$227,504**

Unhedged Cash Operating Margin Reconciliation

(in thousands)	Qtr. Ended
	31-Dec-22
Oil, NGL and natural gas sales (including deducts)	$ 257,915
Less: Lease operating expenses	(23,573)
Less: Workover expenses	(278)
Less: Production & ad valorem taxes	(12,607)
Less: Cash G&A	(6,637)
Cash Margin	**$ 214,820**
Divided by: Production (Mboe)	3,436.0
Cash Margin per Boe, excluding effects of derivatives	**$62.52**
Cash Margin	**$ 214,820**
Cash G&A	6,637
Divided by: Production (Mboe)	3,436.0
Cash Operating Margin per Boe, before cash G&A and excluding effects of derivatives	**$64.45**

Non-GAAP Reconciliation

Reconciliation of Proved Reserves PV-10 to Standardized Measure

(in thousands)	As of 12/31/20	As of 12/31/21	As of 12/31/22
Reserves PV-10	**$235,490**	**$1,338,193**	**$3,872,045**
Present value of future income taxes/abandonment costs	($13,298)	($219,384)	($455,537)
Standardized measure	**$222,192**	**$1,118,809**	**$3,416,508**