DIAMONDBACK Energy

Investor Presentation

November 2020

Forward Looking Statement

Forward-Looking Statements

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. All statements, other than statements of historical fact, included in this presentation that address activities, events or developments that Diamondback Energy, Inc. (the "Company" or "Diamondback") expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "may," "estimates," "will," "anticipate," "plan," "intend," "foresee," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company's acquisitions, dispositions, drilling programs, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include the factors discussed or referenced in the Company's filings with the Securities and Exchange Commission ("SEC"), including its Forms 10-K, 10-Q and 8-K and any amendments thereto, relating to financial performance and results, the volatility of realized oil and natural gas prices and the extent and duration of price reductions and increased production by the Organization of Petroleum Exporting Countries ("OPEC") members and other oil exporting nations, the threat, occurrence, potential duration or other implications of epidemic or pandemic diseases, including the ongoing coronavirus ("COVID-19") pandemic, or any government response to such threat, occurrence or pandemic; conditions of U.S. oil and natural gas industry and the effect of U.S. energy, monetary and trade policies, U.S. and global economic conditions and political and economic developments, including the outcome of the U.S. presidential election and resulting energy and environmental policies, current economic, business or industry conditions and resulting capital restraints, prices and demand for oil and natural gas, impact of impairment charges, effects of hedging arrangements, availability of drilling equipment and personnel, levels of production; impact of reduced drilling activity, availability of sufficient capital to execute the Company's business plan, impact of compliance with legislation and regulations, successful results from the Company's identified drilling locations, the Company's ability to replace reserves and efficiently develop and exploit its current reserves, the Company's ability to successfully identify, complete and integrate acquisitions of properties or businesses, and other important factors that could cause actual results to differ materially from those projected.

Any forward-looking statement speaks only as of the date on which such statement is made, and Diamondback 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. Readers are cautioned not to place undue reliance on these forward-looking statements that speak only as of the date hereof.

The presentation also contains the Company's updated capital expenditure and production guidance for 2020 and certain forward-looking information with respect to 2021. The actual levels of production, capital expenditures, expenses and other estimates may be higher or lower than these estimates due to, among other things, uncertainty in drilling schedules, changes in market demand and unanticipated delays in production. These estimates are based on numerous assumptions, including assumptions related to number of wells drilled, average spud to release times, rig count, and production rates for wells placed on production. All or any of these assumptions may not prove to be accurate, which could result in actual results differing materially from estimates. If any of the rigs currently being utilized or intended to be utilized becomes unavailable for any reason, and the Company is not able to secure a replacement on a timely basis, we may not be able to drill, complete and place on production the expected number of wells. Similarly, average spud to release times may not be maintained in 2020. No assurance can be made that new wells will produce in line with historic performance, or that existing wells will continue to produce in line with expectations. Our ability to fund our 2020 and future capital budgets is subject to numerous risks and uncertainties, including volatility in commodity prices and the potential for unanticipated increases in costs associated with drilling, production and transportation. In addition, our production estimate assumes there will not be any new federal, state or local regulation of portions of the energy industry in which we operate, or an interpretation of existing regulation, that will be materially adverse to our business. For additional discussion of the factors that may cause us not to achieve our production estimates, see the Company's filings with the SEC, including its forms 10-K, 10-Q and 8-K and any amendments thereto. We do not undertake any obligation to release publicly the results of any future revisions we may make to this prospective data or to update this prospective data to reflect events or circumstances after the date of this presentation. Therefore, you are cautioned not to place undue reliance on this information.

Non-GAAP Financial Measures

Consolidated Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Consolidated Adjusted EBITDA as net income (loss) plus non-cash (gain) loss on derivative instruments, net, interest expense, net, depreciation, depletion and amortization expense, impairment of oil and natural gas properties, non-cash equity based compensation expense, capitalized equity-based compensation expense, asset retirement obligation accretion expense, loss from equity method investments, loss on damaged assets, gain (loss) on revaluation of investment, loss on extinguishment of debt and income tax (benefit) adjusted for non-controlling interest in net income (loss). Consolidated Adjusted EBITDA is not a measure of net income (loss) as determined by United States' generally accepted accounting principles, or GAAP. Management believes Consolidated Adjusted EBITDA is useful because the measure allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We add the items listed above to net income (loss) in arriving at Consolidated Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Consolidated Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Consolidated Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets. Our computation of Consolidated Adjusted EBITDA may not be comparable to other similarly titled measures of other companies or to such measures in our revolving credit facility and the indenture governing our senior notes. For a reconciliation of Consolidated Adjusted EBITDA to net income (loss), and other non-GAAP financial measures, please refer to filings we make with the SEC.

Oil and Gas Reserves

The SEC generally permits oil and 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. The Company discloses only estimated proved reserves in its filings with the SEC. The Company's estimated proved reserves (including those of its consolidated subsidiaries) as of December 31, 2019 referenced in this presentation were prepared by Ryder Scott Company, L.P., an independent engineering firm, and comply with definitions promulgated by the SEC. Additional information on the Company's estimated proved reserves is contained in the Company's filings with the SEC. This presentation also contains the Company's internal estimates of its potential drilling locations, which may prove to be incorrect in a number of material ways. Actual number of locations that may be drilled may differ substantially.

Diamondback Energy: Leading Pure-play Permian Operator

Large Cap Permian pure-play E&P:

- >347,000 net Midland and Delaware basin acres(1)
- >12,300 gross (>8,100 net) horizontal locations(1)

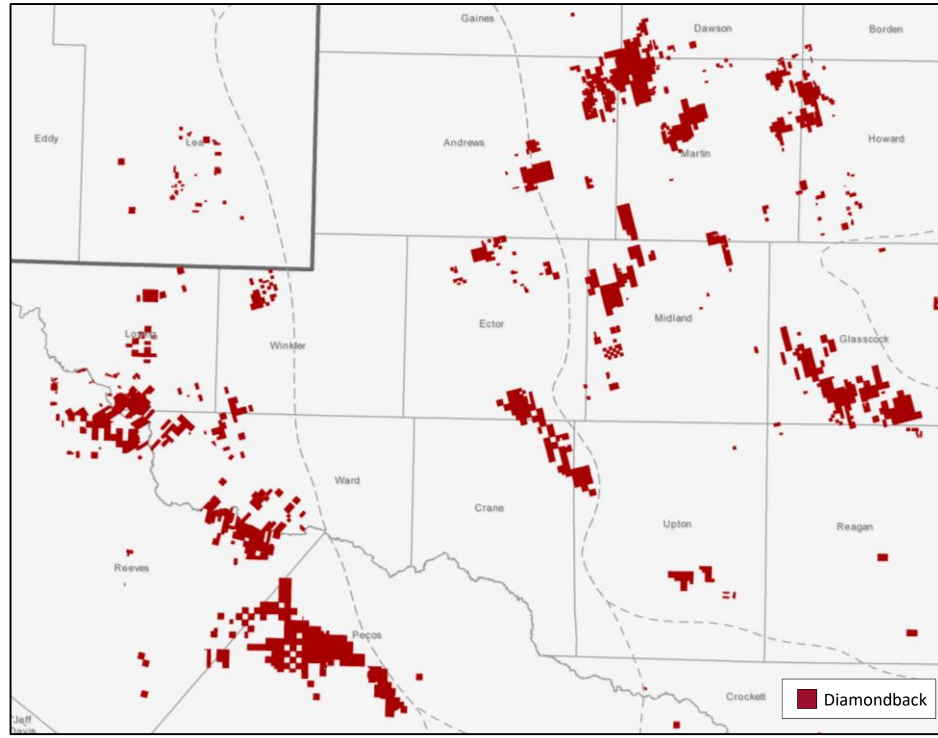
Low Cost Structure and Capital Flexibility:

- Generated >$150 million of Free Cash Flow ("FCF") in Q3 2020, with industry-leading cash operating costs of $7.61 per boe(2)
- Reduced consolidated net debt by $136 million in Q3 2020
- Significant backlog of drilled but uncompleted ("DUC") wells provides enhanced capital efficiency and flexibility for the remainder of 2020 and 2021
- Expect to maintain expected Q4 2020 oil production with 25% - 35% less capital than 2020 budget in 2021
- Targeting 2021 reinvestment rate of ~70% assuming WTI oil prices of $40/Bbl with significant Free Cash Flow(2)
- Flexibility to reduce capital further should commodity prices weaken

Significant Liquidity and Capital Return:

- >$2.0 billion of standalone liquidity as of September 30(3)
- >$3.0 billion of consolidated liquidity
- $191 million maturity in September 2021; no other material term debt maturities until 2024
- Maintaining $1.50 per share annual dividend(4)

Diamondback Acreage Map



Diamondback Market Snapshot

NASDAQ Symbol: FANG

Market Cap: $4,101 million

Net Debt: $5,797 million

Enterprise Value: $11,015 million

Share Count: 158 million

2020 Annual Dividend: $1.50 (5.8% current yield)(4)

Source: Company data, public filings, and Bloomberg. Financial data as of 9/30/2020. Market data as of 10/30/2020.

(1) Net acreage excludes exploratory, conventional and Quinn Ranch. Net locations internal company estimates as of 12/31/2019.

(2) FCF defined as operating cash flow before changes in working capital less cash CAPEX. Reinvestment rate calculated as cash CAPEX divided by pre-dividend cash flow from operations before changes in working capital. See slides 6-7 for more detail.

(3) Excludes Viper and Rattler.

(4) Yield based on 10/30/2020 closing price. Future dividends subject to the discretion and approval of the Board of Directors.

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Diamondback: Investment Highlights

Q3 2020 Highlights

- Generated $153 million of FCF in Q3 2020[1]
- Q3 2020 oil production of 170.0 Mbo/d (287.3 Mboe/d)
- Q3 2020 cash operating costs of $7.61 per boe; including cash G&A of $0.42 per boe
- Q3 2020 dividend of $0.375 / share; payable November 19, 2020
- Reduced flaring to 0.5% of net production in Q3 2020, down 74% year over year

2020 Guidance

- Q4 2020 production guidance of 170 – 175 Mbo/d (280 – 290 Mboe/d)
- Lowering 2020 LOE / G&A unit guidance by a combined $0.40 per boe at the midpoint; implies FY 2020 cash cost savings of over $43 million versus prior guidance
- Current Midland Basin D,C&E costs of $510 - $530 per Ft.; down $215 per Ft. from 2019
- Current Delaware Basin D,C&E costs of $700 - $850 per Ft.; down $315 per Ft. from 2019

2021 Investment Framework

- Expect to exit 2020 with 110 – 140 drilled but uncompleted ("DUC") wells; expect to maintain estimated Q4 2020 oil production with 25% - 35% less capital than 2020 budget
- Expect to generate over $525 million of pre-dividend Free Cash Flow in 2021, with a reinvestment rate of ~70% assuming $40/Bbl WTI oil prices[1]
- Current 2021 hedges provide downside protection for >50% of expected 2021 oil production at a weighted average price of $38.18 per barrel[2]
- Free Cash Flow in excess of dividend to be used towards debt reduction

Significant Liquidity

- Standalone liquidity of >$2.0 billion with $68 million net cash position[3]
- Consolidated net debt down $136 million quarter over quarter from Q2 2020
- Repurchased all $10 million in principal amount of 7.35% medium-term notes due 2027
- $191 million of Senior Notes maturing September 2021; no other maturities before 2024

Source: Company data and filings. Financial data as of 9/30/2020 unless otherwise noted.

(1) Free Cash Flow ("FCF") defined as operating cash flow before changes in working capital less cash CAPEX. Reinvestment rate defined as cash CAPEX divided by pre-dividend cash flow from operations before changes in working capital. See slides 6-7 for more detail.

(2) As of 10/30/2020. Calculated as the average hedged volumes divided by the midpoint of Q4 2020 production guidance of 170 – 175 Mbo/d; excludes basis and roll hedges.

(3) Excludes Viper and Rattler.

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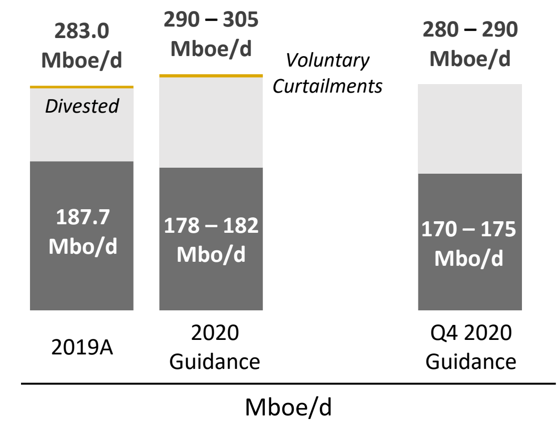
Overview of 2020 Guidance and Capital Budget

2020 Activity and Guidance Midpoints vs 2019

	2019A	Change	Current 2020 Guidance
Oil Production *Net Mbo/d*	188	-4%	180
Net Lateral Feet *TIL Net Ft. (1,000's)*	2,774	-40%	1,665
Capital Budget *$MM*[1]	$2,921	-37%	$1,850
LOE *$ / Boe*	$4.74	-14%	$4.10
Midland Basin D,C&E Well Costs *$ / TIL Lateral Ft.*[2]	$738	-30%	$520
Delaware Basin D,C&E Well Costs *$ / TIL Lateral Ft.*[2]	$1,093	-29%	$775

2020 Production and Activity Outlook

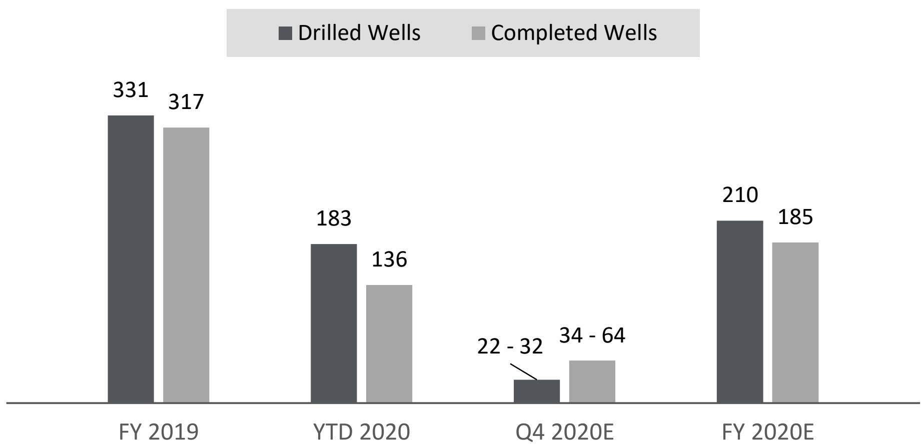


205 – 215
Gross operated wells drilled

170 – 200
Gross operated wells TIL

110 – 140
Gross DUC's at YE 2020

2020 Gross Operated Activity Summary (Guidance Midpoint)



Source: Company data, filings and estimates. Note: 2019 production included ~6.5 Mboe/d divested on 7/1/2019; estimated 2020 production net of ~16.1 Mboe/d of voluntary curtailments during Q2 2020.

(1) Capital budget includes spending for operated drill, complete and equip ("D,C&E"), non-operated properties and capital workovers, midstream and infrastructure; excludes long-haul pipeline investments and acquisitions.

(2) Well costs assume gross Rattler costs. See note 1 on slide 8 for additional detail.

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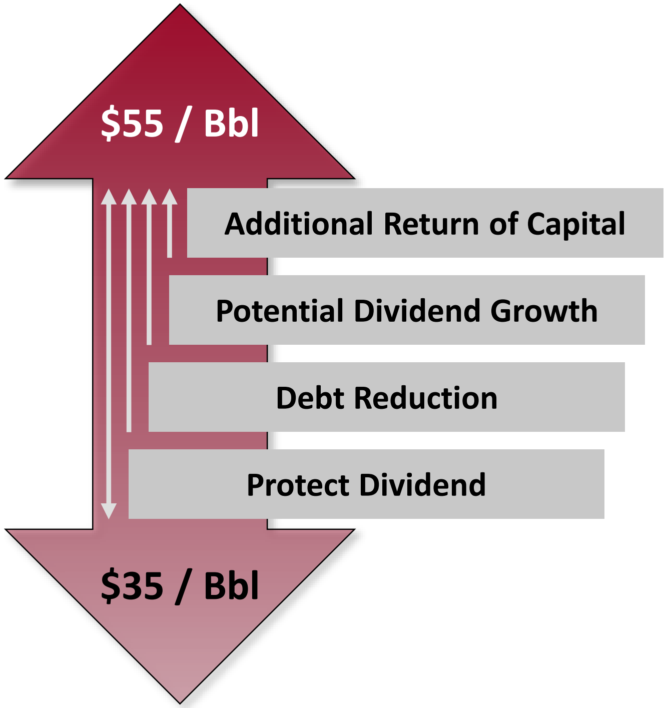
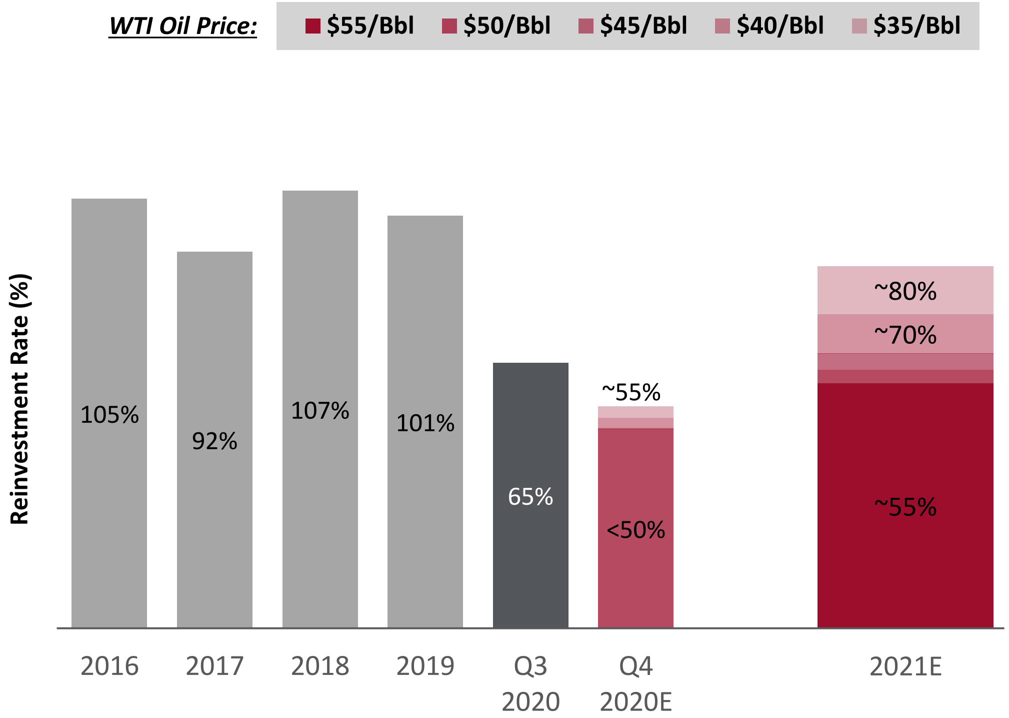
Current Investment Framework

- Diamondback has the size, scale, balance sheet, asset quality and cost structure to weather a prolonged downturn and thrive in the inevitable upcycle
- Diamondback's investment framework and capital allocation philosophy at current oil prices remain very simple and have not changed: protect our base dividend, spend maintenance capital to hold oil production flat, and use excess Free Cash Flow to pay down debt
- If commodity prices weaken for a sustained period of time, Diamondback will cut activity further

Investment Framework



Historical and Future Reinvestment Rates (%)(1)



Source: Company data, filings and estimates. Note: All Q4 2020E / 2021E scenarios incorporate identical activity levels, capital spending, production, respectively; assumes current cash operating costs, well costs and incorporate current hedges.
(1) Reinvestment rate calculated as cash CAPEX (defined below) divided by pre-dividend cash flow from operations before changes in working capital. See slide 7 for additional detail.
(2) Defined as capital spending for operated D,C&E, non-operated properties and capital workovers, midstream and infrastructure; excludes long-haul pipeline investments.

2021 Free Cash Flow Sensitivity

- Diamondback believes it can maintain expected Q4 2020 oil production with 25% - 35% less capital than 2020 budget
- Diamondback expects to generate over $525 million of pre-dividend free cash flow at $40/Bbl
- Protecting dividend and maintenance capital with forward expected cash flow remains capital allocation priority, with any potential tailwinds from increasing commodity prices to be used towards debt reduction

Illustrative 2021E Consolidated Free Cash Flow at Various WTI Oil Prices ($MM)(1)

FY 2021 Assumptions

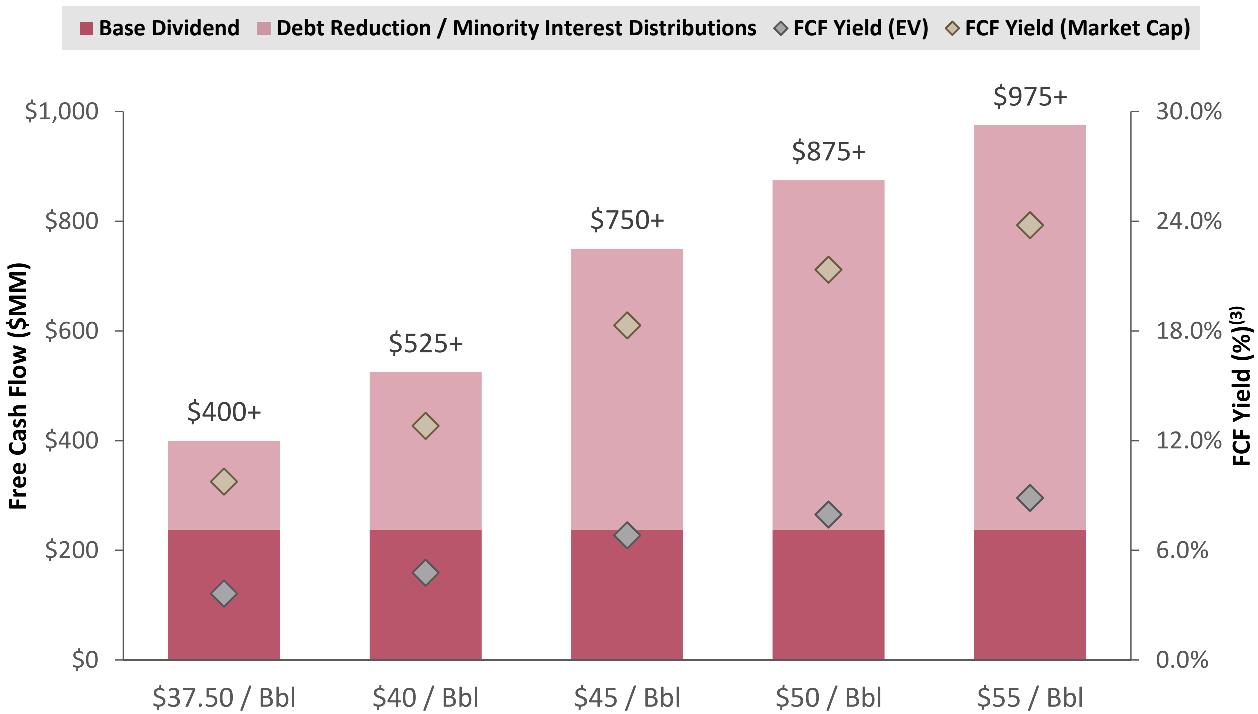
170 - 175 Mbo/d
Oil Production

~30% Reduction
2021 CAPEX vs. 2020 Guidance(2)

~95%
% of WTI Realized ($/Bbl)

$11/Bbl / $2/Mcf
Unhedged NGL / Gas Prices

$1.50 / Share
Annual Shareholder Dividend



Source: Company data, filings and estimates. Note: All 2021E scenarios incorporate identical activity levels, capital spending, production, respectively; assumes current cash operating costs, well costs and incorporate current hedges.
(1) Free cash flow defined as operating cash flow before changes in working capital less cash CAPEX (defined below).
(2) Relative to FY 2020 guidance range. Defined as capital spending for operated D,C&E, non-operated properties and capital workovers, midstream and infrastructure; excludes long-haul pipeline investments and acquisitions.
(3) Free cash flow yield calculated as free cash flow divided by FANG's enterprise value ("EV") and FANG's market capitalization ("Market Cap") as of 10/30/2020, respectively.

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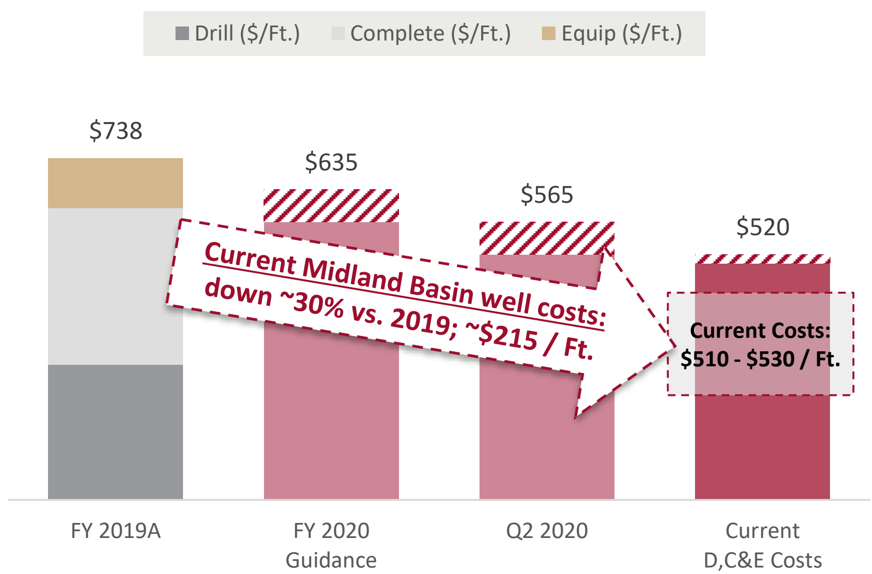
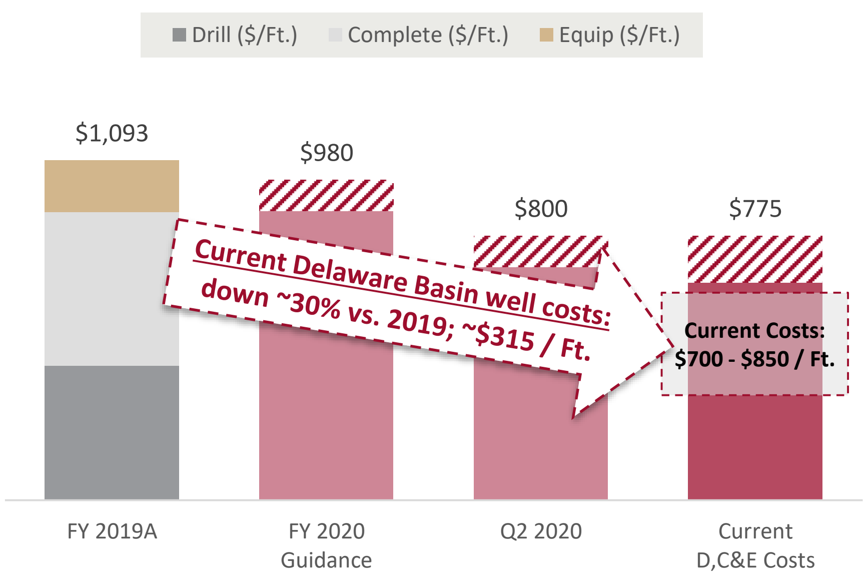
Significant Reduction to Capital Costs

- Diamondback has realized significant capital cost savings through a combination of internal optimization and service cost concessions:
  - Midland Basin: ~$215 / Ft. savings versus 2019 (~30%); Delaware Basin: ~$315 / Ft. savings versus 2019 (~30%)
- Current Midland Basin D,C&E costs between $510 - $530 per lateral foot (~$450 per foot D&C)
- Current Delaware Basin D,C&E costs between $700 - $850 per lateral foot ($600 - $700 per foot D&C)
- Continue to aggressively pursue additional cost reductions and efficiency improvements

Gross Midland Basin D,C&E Well Costs ($ / Ft.)(1)



Gross Delaware Basin D,C&E Well Costs ($ / Ft.)(1)



Diamondback continues to make significant reductions to capital costs per lateral foot while increasing development efficiencies across its acreage

Source: Company filings, management data and estimates.
(1) Well costs assume gross Rattler costs. Net benefit of Rattler margins would result in approximately $25/Ft. of extra savings in the Midland Basin and approximately $40/Ft. of extra savings in the Delaware Basin.

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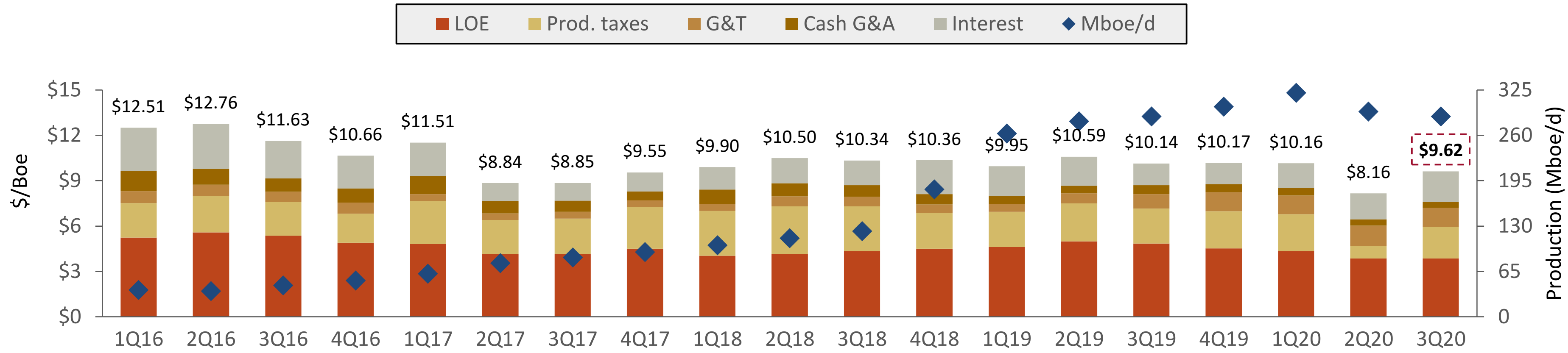
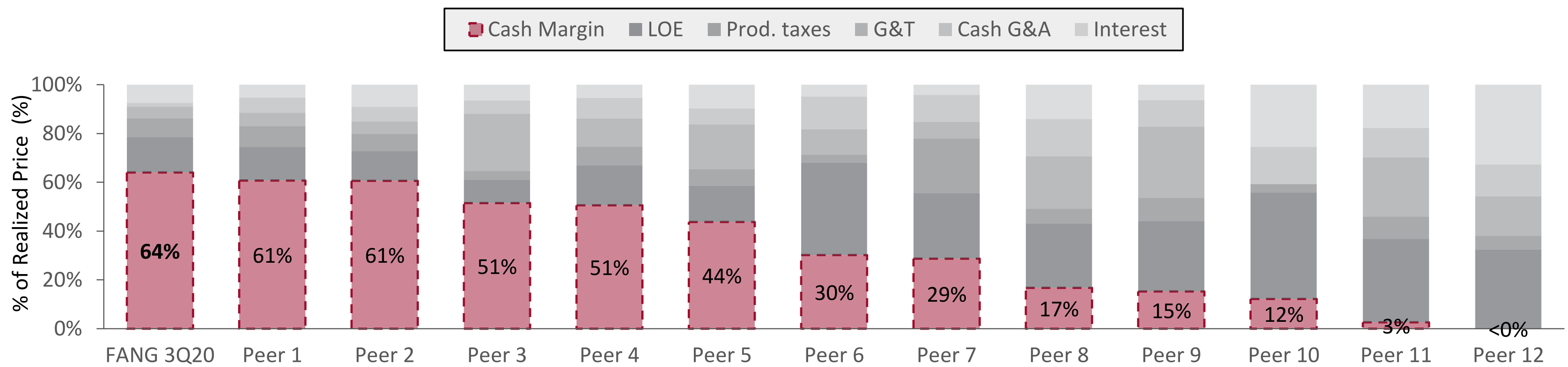
Peer-Leading Cash Margins and Operating Costs

Diamondback Cash Operating Costs Including Interest Over Time ($ / Boe)(1)



Cash Margins and Operating Costs versus Extended Peer Group (% of Unhedged Realized Price)(1)(2)



Peer leading cash operating costs and a low interest burden allow Diamondback to maintain high cash margins in a weak commodity price environment

Source: Company data and latest peer filings as of 10/30/2020. Extended peers include CXO, PE, OVV, PXD, DVN, APA, XEC, MRO, EOG, HES, WPX and CLR.

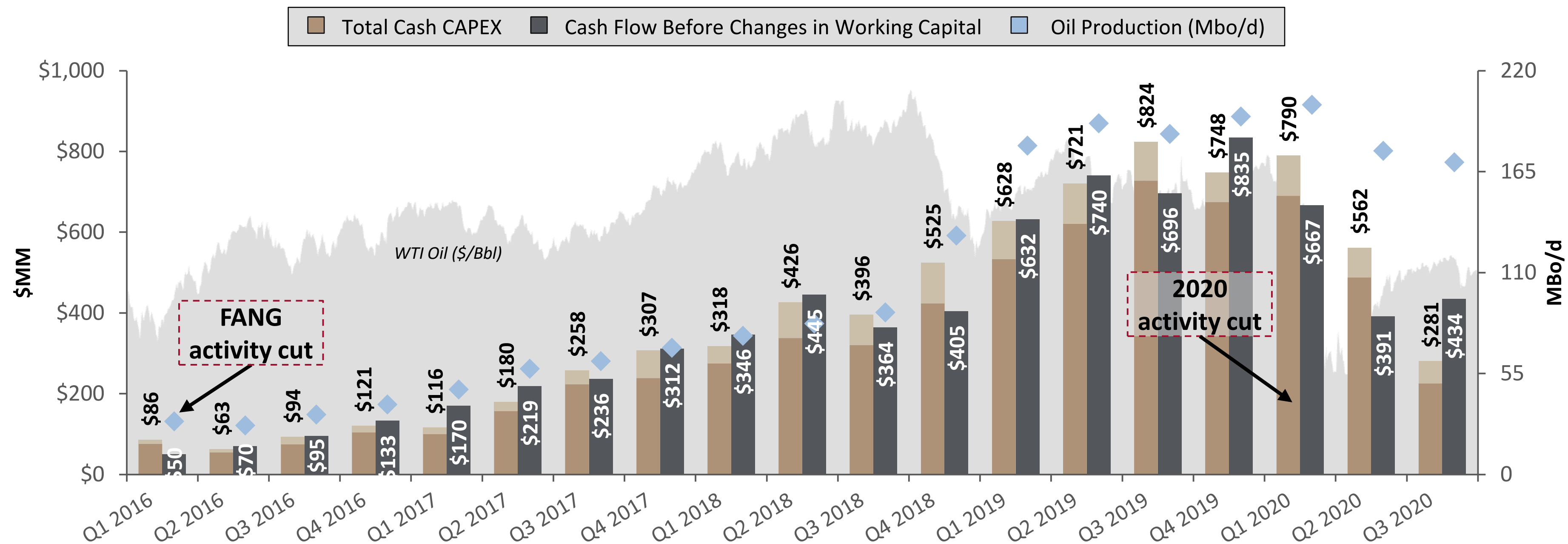
(1) Cash operating costs including interest calculated as the sum of LOE, G&T, production taxes, cash G&A expense and interest expense per boe.

(2) Unhedged cash margins calculated as the sum of unhedged realized price per boe less cash operating costs including interest divided by unhedged realized price per boe.

Track Record of Aligning Development with Commodity Prices

- Diamondback has a track record of achieving robust production growth while spending within cash flow, with a willingness and demonstrated ability to adjust activity levels quickly to react to challenging market conditions
- Current 2020 plan implies >35% reduction to operated activity versus original 2020 plan; >70% of remaining activity focused on lower cost development in the Midland Basin
- Expect to continue to consistently generate Free Cash Flow at current forward commodity prices(1)

Cash Flow / Cash CAPEX by Quarter Since 2016(1)



As a result of Diamondback's immediate and dramatic reduction in activity following unprecedented commodity price weakness in the first half of 2020, Diamondback generated over $150 million of Free Cash Flow in Q3 2020

Source: Company data, filings and estimates.
(1) Free Cash Flow defined as operating cash flow before changes in working capital less cash CAPEX for operated D,C&E, non-operated properties and capital workovers, midstream and infrastructure; excludes long-haul pipeline investments and acquisitions.

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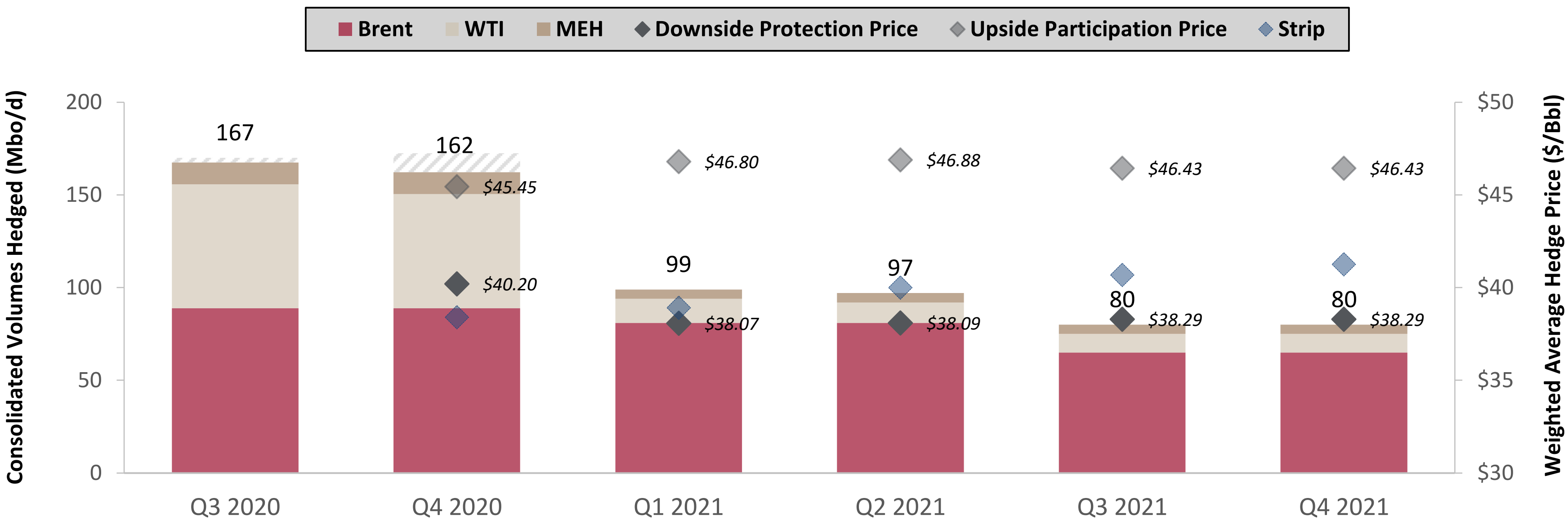
Current Hedges Maximize Downside Protection

Q4 Crude Oil Hedges	**~95%** Q4 2020 Hedge Protection(1)	**~100% Hedged** Midland / WTL Basis Exposure	**120,000 Bo/d** WTI Roll Hedges
2021 Crude Oil Hedges	**>50%** FY 2021 Hedge Protection(1)	**~97% of Hedges** Swaps / 2-Way Collars (FY 2021)	**~90% of Hedges** Upside Participation (FY 2021)(2)

Consolidated Oil Hedges (Mbo/d)(3)



Diamondback proactively restructured hedges, with downside protection on ~95% of expected remaining 2020 oil production and over 50% of expected 2021 oil production(1)

Source: Company data, filings and estimates and Bloomberg as of 10/30/2020.
(1) Based on management expectations and Q4 2020 production guidance of 170 – 175 Mbo/d.
(2) Based on consolidated 2021 oil hedges relative to NYMEX strip pricing as of 10/30/2020.
(3) Excludes basis / roll swaps and calls. See slides 17-18 for additional detail.

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Midland Basin Inventory and Development Strategy

Diamondback Midland Basin Inventory:

- >7,000 gross (~4,970 net) horizontal locations with an average lateral length of ~8,300 feet
- Primary zones: >3,300 net locations (MS, LS, WCA and WCB); total net lateral footage up 19% from YE 2018[1]
- Diamondback has moved to co-development of more economic zones together, particularly in the Midland Basin, but has not changed inter-lateral spacing assumptions within each zone
- Inter-lateral and vertical spacing between zones varies by major development area

Midland Basin Development Strategy:

- Development has moved to incorporate more economic zones completed simultaneously, or co-development
- As acreage position has grown and zones such as the MS and WCB have been successfully tested, more activity has been added to the development plan
- 2020 activity plan focused on simultaneous development of economic zones that meet return thresholds
- If co-development is not necessary, Diamondback will develop the highest rate of return zone first

Midland Basin Economic Locations at Various Oil Prices[2]

Oil Price	Gross Economic Locations
$35 / Bbl	3,258
$40 / Bbl	4,772
$45 / Bbl	5,667
$50 / Bbl	6,219

Gross (Net) Midland Basin Locations by Zone / Lateral

	5,000'+	7,500'+	10,000'+	Total	Avg. Lateral
MS	212 (89)	341 (252)	598 (479)	**1,151 (820)**	*8,500'*
LS	305 (137)	346 (243)	580 (473)	**1,231 (853)**	*8,200'*
WCA	296 (128)	338 (239)	571 (459)	**1,205 (826)**	*8,200'*
WCB	286 (121)	342 (247)	585 (469)	**1,213 (837)**	*8,200'*
Other[3]	472 (219)	571 (430)	1,194 (985)	**2,237 (1,635)**	*8,400'*
Total	**1,571 (694)**	**1,938 (1,411)**	**3,528 (2,865)**	**7,037 (4,971)**	***8,300'***

Diamondback has consistently maintained conservative spacing assumptions, preferring an "at least" strategy to a "best case scenario" strategy

Source: Company data, filings and estimates. Note: locations based on internal company estimates as of 12/31/2019; excludes Quinn Ranch.
(1) Primary zones include Jo Mill / Middle Spraberry ("MS"), Lower Spraberry ("LS"), Wolfcamp A ("WCA") and Wolfcamp B ("WCB").
(2) Defined as gross locations that can generate at least a 10% rate of return. Assumes current well costs, 25% of WTI NGL pricing and $0/Mcf gas prices.
(3) Other zones comprised of Wolfcamp D, Wolfcamp C, Clearfork and Barnett intervals.

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Delaware Basin Inventory and Development Strategy

Diamondback Delaware Basin Inventory:

- >5,200 gross (3,170 net) horizontal locations with an average lateral length of ~7,600 feet
- Primary zones: >2,500 net locations (2BS, 3BS, WCA and WCB); total net lateral footage up 5% from YE 2018[(1)]
- Successfully traded majority of operated New Mexico acreage in the Northern Delaware Basin for operated Texas acreage in both Midland / Delaware basin; <0.1% of current net acreage exposed to federal land

Delaware Basin Development Strategy:

- Primarily focused on WCA development, which remains highest rate of return zone in the Delaware Basin
- Other zones continue to attract some capital, such as the 2BS in Pecos County, 3BS in ReWard and WCB in Vermejo
- 2020 activity plan focused primarily on WCA and simultaneous development of economic zones that meet return thresholds

Delaware Basin Economic Locations at Various Oil Prices[(2)]

Oil Price	Gross Economic Locations
$35 / Bbl	1,666
$40 / Bbl	2,408
$45 / Bbl	2,842
$50 / Bbl	3,452

Gross (Net) Delaware Basin Locations by Zone / Lateral

	5,000'+	7,500'+	10,000'+	Total	Avg. Lateral
2BS	340 (219)	253 (175)	364 (235)	**957 (629)**	*7,600'*
3BS	420 (257)	290 (178)	467 (287)	**1,177 (722)**	*7,700'*
WCA	343 (194)	254 (157)	347 (215)	**944 (566)**	*7,600'*
WCB	346 (189)	274 (186)	430 (284)	**1,050 (659)**	*7,800'*
Other[(3)]	510 (241)	310 (151)	325 (201)	**1,145 (594)**	*7,100'*
Total	**1,959 (1,101)**	**1,381 (846)**	**1,933 (1,223)**	**5,273 (3,170)**	***7,600'***

Diamondback has consistently maintained conservative spacing assumptions, preferring an "at least" strategy to a "best case scenario" strategy

Source: Company data, filings and estimates. Note: locations based on internal company estimates as of 12/31/2019.
(1) Primary zones include Second Bone Spring ("2BS"), Third Bone Spring ("3BS"), Wolfcamp A ("WCA") and Wolfcamp B ("WCB")
(2) Defined as gross locations that can generate at least a 10% rate of return. Assumes current well costs, 25% of WTI NGL pricing and $0/Mcf gas prices.
(3) Other zones primarily comprised of the 1st Bone Spring and Wolfcamp C intervals.

Oil Takeaway Solutions

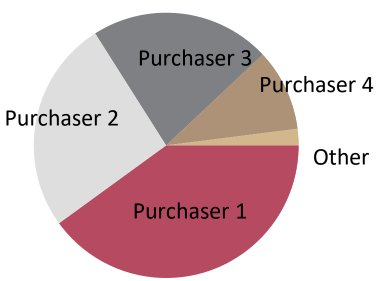
Oil Purchase Contracts:

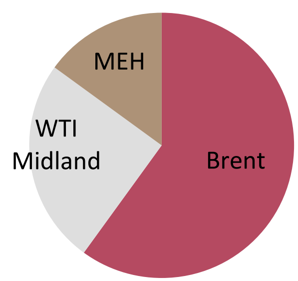
- Diamondback's oil production is purchased under long term purchase agreements with four large, well-funded counterparties
- Every major operating area has a long term oil purchase agreement and is dedicated to a long haul pipeline
- Long-term agreements and associated physical pipeline space provide insurance in times of uncertainty

Obligations and Pricing Exposure:

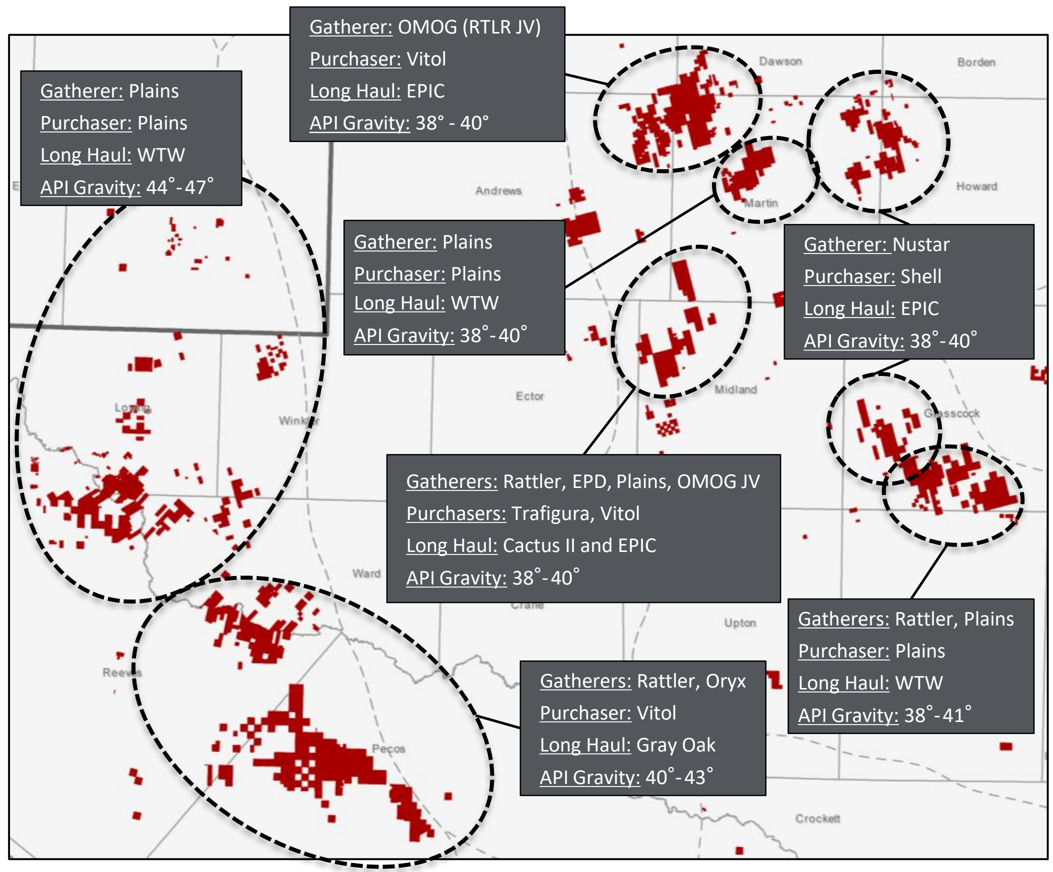
- Take or pay obligations to pipelines and firm sales in 2020 cover 125,000 gross bo/d
  - Increases to 175,000 gross bo/d with the in-service date of the Wink to Webster pipeline
- Expects to receive Brent pricing for ~60% of Q4 2020 production; Brent (~60%), Midland (~25%) and MEH (~15%) in 2021

Unhedged Oil Exposure by Purchaser and Price





Oil Takeaway Solutions



Diamondback's oil marketing agreements provide long-term flow assurance to the most liquid markets as well as minimize local basis exposure

Source: Company filings, management data and estimates.

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Capital Structure and Liquidity

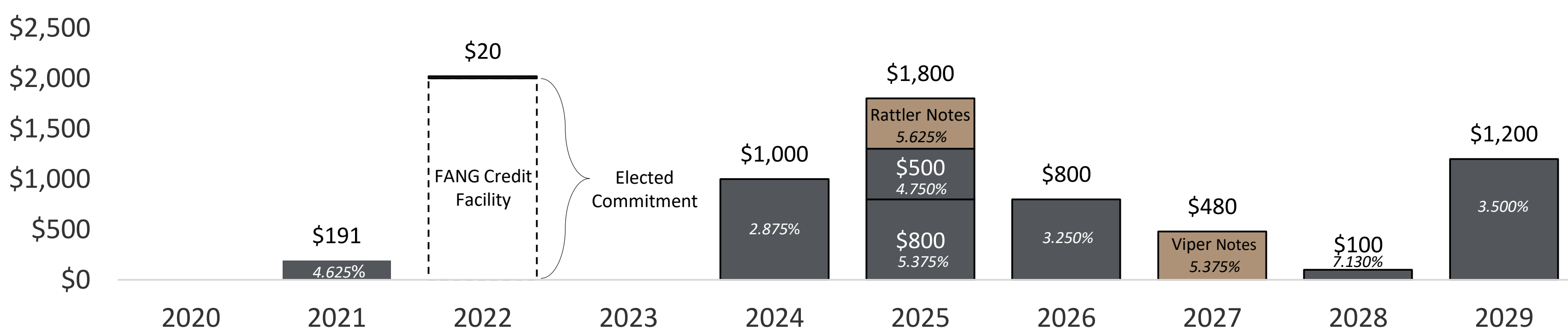
- As of September 30, 2020, FANG had no outstanding borrowings under its credit facility with standalone liquidity of over $2.0 billion(1)
- Consolidated net debt down $136 million from June 30, 2020; Consolidated total liquidity of over $3.0 billion
- In August 2020, Diamondback repurchased all $10 million in principal amount of the outstanding 7.35% medium-term Energen notes due 2027 for $12.3 million
- Future Free Cash Flow in excess of the dividend will be used to reduce debt

FANG's Liquidity and Capitalization ($MM)

FANG's Consolidated Capitalization	9/30/2020
Cash and cash equivalents	$92
FANG's Revolving Credit Facility	$0
VNOM's Revolving Credit Facility	127
RTLR's Revolving Credit Facility	85
Senior Notes	5,591
DrillCo Agreement	86
Total Debt	***$5,889***
Net Debt	***$5,797***

FANG's Standalone Liquidity	9/30/2020
Cash(1)	$68
Elected commitment amount	2,000
Liquidity	***$2,068***

FANG's Debt Maturity Profile ($MM)



Source: Company Filings, Management data and Estimates.
(1) Excludes Viper and Rattler.

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Updated 2020 Guidance

- Immediately responded to unprecedented decline in oil prices; updated 2020 plan implies >35% reduction in CAPEX and activity from original 2020 plan
- D,C&E CAPEX budget of $1,565 – $1,630 million; expect to complete 170 – 200 gross horizontal wells with an average lateral length of ~10,000 feet
- Anticipated total infrastructure and midstream capital expenditures of $235 – $270 million
- Lowered LOE and G&A unit guidance by a combined $0.40 per boe at the midpoint of each guidance range; implies cash operating cost savings of over $43 million for 2020

Diamondback 2020 Capital Activity Guidance	
Gross (net) horizontal wells completed	170 – 200 (153 – 180)
Average completed lateral length (ft.)	~10,000’
Midland Basin net lateral feet (%)	~60%
Delaware Basin net lateral feet (%)	~40%

Updated November 2020	Diamondback	Viper
Net Production – Mboe/d	290.0 – 305.0	26.00 – 26.50
Oil Production – Mbo/d	178.0 – 182.0	⇧ 15.75 – 16.00
Unit Costs ($/boe)		
Lease Operating Expenses	$4.00 – $4.20 ⇩	
Gathering & Transportation	$1.25 – $1.35	
Cash G&A	$0.45 – $0.55 ⇩	$0.60 – $0.80
Non-Cash Equity Based Compensation	$0.30 – $0.40 ⇩	$0.10 – $0.25
D,D&A	$11.00 – $13.00 ⇩	$9.50 – $11.00
Interest Expense (net)	$1.75 – $1.95 ⇧	$3.25 – $3.50
Production and Ad Valorem Taxes (% of Revenue)(1)	7% – 8%	7% – 8%
Corporate Tax Rate (% of Pre-tax Income)	23%	

Diamondback Capex Budget ($MM)	
D,C&E and Non-Operated Properties	$1,565 – $1,630
Midstream (ex. long-haul pipeline investments)	$125 – $150
Infrastructure	$110 – $120
Total 2020 Capital Budget	**$1,800 – $1,900**

Source: Company filings, management data and estimates. Note: Based on 2020 guidance provided on 11/2/2020, which is subject to numerous assumptions and risks. See the disclaimer at the beginning of this presentation.
(1) Includes production taxes of 4.6% for crude oil and 7.5% for natural gas and NGLs and ad valorem taxes.

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Current Hedge Summary: Oil

Consolidated Crude Oil Hedges (Bbl/day, $/Bbl)						
Crude Oil Hedges	**Q4 2020**	**Q1 2021**	**Q2 2021**	**Q3 2021**	**Q4 2021**	**FY 2022**
Swaps - WTI	**11,000**	**–**	**–**	**–**	**–**	**–**
	$43.47	–	–	–	–	–
Swaps - MEH	**4,000**	**5,000**	**5,000**	**5,000**	**5,000**	**–**
	$61.95	$37.78	$37.78	$37.78	$37.78	–
Swaps - Brent[1]	**24,200**	**5,000**	**5,000**	**5,000**	**5,000**	**–**
	$47.62	$41.62	$41.62	$41.62	$41.62	–
Total Oil Swaps	**39,200**	**10,000**	**10,000**	**10,000**	**10,000**	**--**
Costless Collars - WTI	**45,779**	**13,000**	**11,000**	**10,000**	**10,000**	**–**
Floor / Ceiling	$35.92 / $42.29	$31.62 / $43.31	$30.64 / $43.41	$30.00 / $43.05	$30.00 / $43.05	–
Costless Collars - MEH	**4,000**	**–**	**–**	**–**	**–**	**–**
Floor / Ceiling	$39.00 / $49.00	–	–	–	–	–
Costless Collars - Brent	**64,710**	**76,000**	**76,000**	**60,000**	**60,000**	**–**
Floor / Ceiling	$37.59 / $45.63	$38.96 / $48.33	$38.96 / $48.33	$39.43 / $48.12	$39.43 / $48.12	–
Total Costless Collars	**114,489**	**89,000**	**87,000**	**70,000**	**70,000**	**--**
Puts - WTI	**4,700**	**–**	**–**	**–**	**–**	**–**
	$46.51	–	–	–	–	–
Calls - WTI[2]	**8,000**	**–**	**–**	**–**	**–**	**–**
	$45.00	–	–	–	–	–
Short Puts - Brent	**–**	**–**	**–**	**–**	**–**	**5,000**
	–	–	–	–	–	$35.00
Total Puts / Calls	**12,700**	**--**	**--**	**--**	**--**	**5,000**
Put Spreads - MEH	**3,800**	**–**	**–**	**–**	**–**	**–**
Short Put / Long Put	$25.00 / $50.00	–	–	–	–	–
Total Put Spreads	**3,800**	**--**	**--**	**--**	**--**	**--**
Total Crude Oil Hedges	**170,189**	**99,000**	**97,000**	**80,000**	**80,000**	**5,000**

Source: Company data as of 10/30/2020.
(1) 1H 2021 Brent swaps include 5,000 Bo/d whereby the counterparty has the right to extend the hedge into the second half of 2021 at an average price of $51/Bbl.
(2) Includes a deferred premium at a weighted-average price of $1.89/Bbl and a strike price of $45/Bbl.

Current Hedge Summary: Oil Basis, NGL's and Natural Gas

Consolidated Oil Basis / Natural Gas Liquids Hedges (Bbl/day, $/Bbl)

Crude Oil Hedges	Q4 2020
Basis Swaps - WTI	45,087
	($1.33)
Basis Swaps - WTL	8,000
	($1.31)
Total Basis Swaps	**53,087**
Roll Swaps - WTI	120,000
	($1.05)
Total Roll Swaps	**120,000**

Natural Gas Liquids Hedges	Q4 2020
Swaps - Mont Belvieu Ethane	7,000
	$8.43
Swaps - Mont Belvieu Propane	5,000
	$21.76
Total Swaps	**12,000**

Consolidated Natural Gas Hedges (Mmbtu/day, $/Mmbtu)

Natural Gas Hedges	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	FY 2022
Swaps - Henry Hub	60,000	200,000	200,000	200,000	200,000	–
	$2.48	$2.65	$2.65	$2.65	$2.65	–
Swaps - Waha[(1)] *Fixed Price*	90,000	–	–	–	–	–
	$1.58	–	–	–	–	–
Total Swaps	**150,000**	**200,000**	**200,000**	**200,000**	**200,000**	**–**
Basis Swaps - Waha	145,000	230,000	230,000	230,000	230,000	100,000
	($1.57)	($0.69)	($0.69)	($0.69)	($0.69)	($0.42)
Total Basis Swaps	**145,000**	**230,000**	**230,000**	**230,000**	**230,000**	**100,000**

Source: Company data as of 10/30/2020.
(1) Remaining 2020 fixed price Waha swaps exclude additional 30,000 Mcf/d of hedges exercisable at $1.70/Mcf at option of counterparty.

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Differential Per Share Metrics and Cost Structure

Return On and Return Of Capital

Significant Resource Potential

Conservative Financial Management

Strategic Acquisitions and Execution

Efficient Conversion of Resource to Cash Flow

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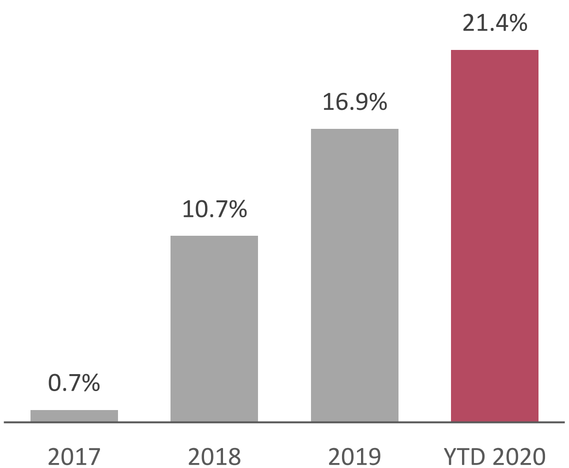
APPENDIX

Environmental, Social and Governance ("ESG")

- Diamondback is deeply committed to the safe and responsible development of its resources
- As our organization has grown to be in a leadership position in the Permian Basin, we continue to believe we have a responsibility to minimize our environmental impact across our operating footprint
- Corporate responsibility initiatives center on a dozen key areas: risk management, energy intensity, global climate change, emissions, waste and spills, water use, business ethics, compliance, diversity and inclusion, health and safety, training and education, and community engagement
- 2020 Corporate Responsibility Report available at www.diamondbackenergy.com/about/sustainability

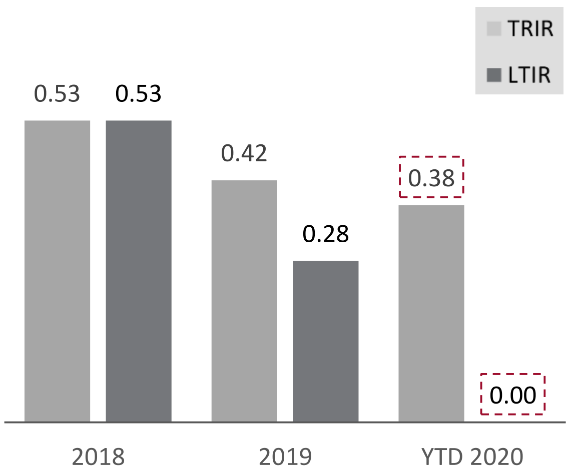
Water Recycling (% of Produced)

Water recycling up 100% since 2018



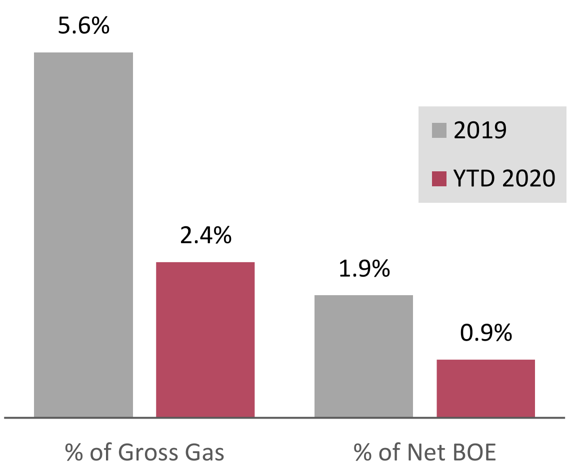
Workplace Safety (TRIR / LTIR)

TRIR down ~28% since 2018



Flaring (% of Production)

Flaring down >50% since 2019



Source: Company data and filings.

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Recent Changes to ESG and Compensation

- Diamondback seeks to expand its best in class track record on both disclosure and performance as it relates to sustainable long-term development of its natural resources
- 2020 Proxy Report available at www.diamondbackenergy.com

Recent Changes to ESG and Compensation	
Dedicated ESG Oversight	◆ Formed Safety, Sustainability and Corporate Responsibility Committee of the Board of Directors in the fourth quarter of 2019
Proxy Access	◆ Adopted Proxy Access in Q4 2019
Change of Control	◆ Replaced executive employment agreements with a severance and change of control plan consistent with current market practice
Long-term Incentive Compensation ("LTI")	◆ Added an absolute total shareholder return ("TSR") modifier to LTI: ◊ Reduces payouts upon negative performance period TSR ◊ No modification upon achieving a performance period annual TSR of 0-15% ◊ Includes multiplier upon achieving a performance period annual TSR >15%
Short-term Incentive Compensation ("STI")	◆ Updated annual metrics to include an ESG component with 15% weighting ◆ ESG component to be determined by meeting or exceeding key environmental and safety metrics including flaring, GHG emissions, recycled water, oil spill control and Total Recordable Incident Rate ◆ Existing metrics unchanged from 2019 (ROACE, D,C&E/Ft. well costs and per boe PD F&D costs, LOE and Cash G&A)

Source: Company data and filings.

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Build-out of Midstream Assets Through Rattler Midstream

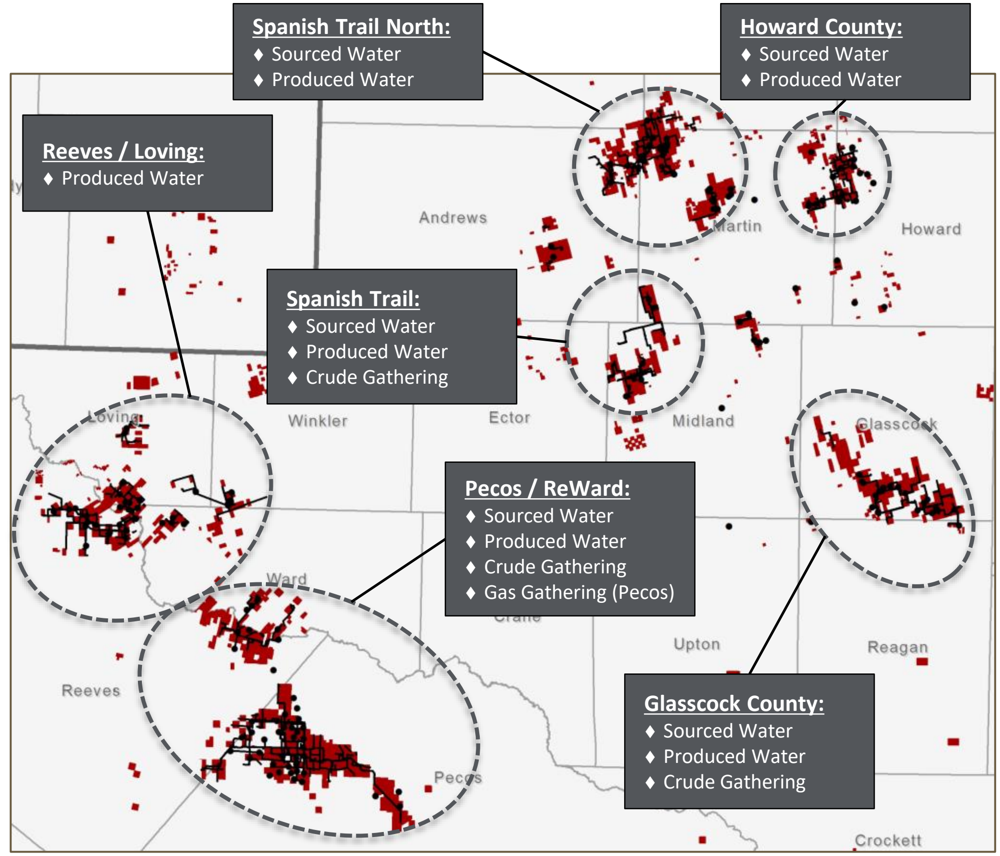
Rattler Midstream:

- Publicly-traded midstream subsidiary (NASDAQ: RTLR) created by Diamondback
- Interests fully aligned with upstream operations:
  - Assets located in all seven core operating areas
  - Midstream services key to Diamondback's low-cost operations
  - Close coordination and development visibility allows efficient and timely midstream build-out
  - Vehicle for participation in non-upstream investment opportunities such as long-haul pipelines
- 2020E Distribution: $1.16 / unit (19.8% yield)(1)

Rattler Capacity Overview

Fee Stream	Midland	Delaware
Produced Water – Bbl/d	1,822,000	1,482,000
Sourced Water – Bbl/d	455,000	120,000
Crude Oil – Bbl/d	65,000	210,000
Natural Gas – Mcf/d	--	170,000(2)
Total	**>2,340,000**	**>1,980,000**

Rattler Midstream Asset Map



Rattler secures FANG's access to vital midstream services and supports FANG's low-cost operations via improving realizations and lower LOE

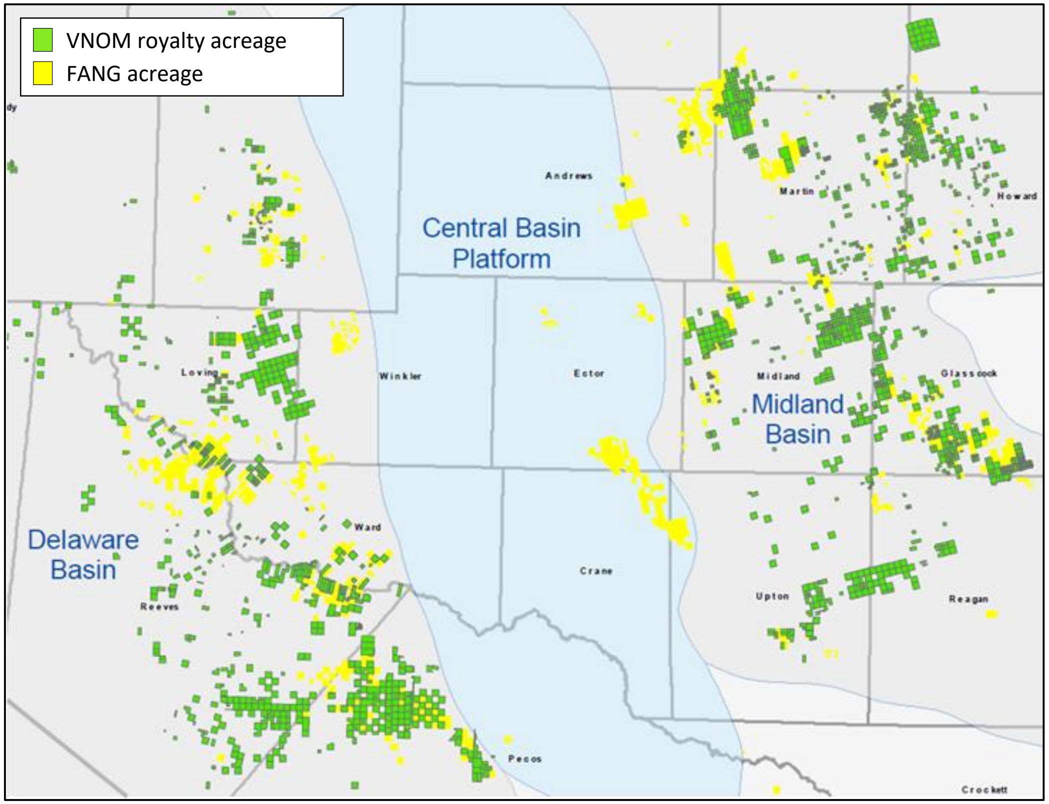
Source: Company filings, management data and estimates.
(1) Based on Rattler's 2020 guidance provided on 08/05/2020. Yield based on RTLR's closing price as of 10/30/2020.
(2) 151,000 Mcf/d compression capacity.

Viper Update

Viper Energy Partners:

- Publicly-traded mineral and royalty subsidiary (NASDAQ: VNOM) created by Diamondback
  - Focused on owning and acquiring minerals and royalty interests in the Permian Basin, with a primary focus on Diamondback-operated acreage
- 24,696 net royalty acres, ~51% of which are operated by Diamondback
- Diamondback incentivized to focus development on Viper's acreage when possible due to improved consolidated returns
  - 38 of Diamondback's 41 Q3 2020 completions on Viper's acreage, in which Viper owned a roughly 10% average NRI
- Q3 2020 average oil production of 15.8 Mbo/d; generated $0.21 / unit in distributable cash flow
- Outside of Diamondback operating almost 60% of Viper's current oil production, Viper has diversified exposure to other competent operators within the Permian Basin and Eagle Ford Shale

Viper Mineral and Royalty Assets



Viper's Mineral and Royalty Interests Provide Perpetual Ownership Exposure to High Margin, Largely Undeveloped Assets and Lower Diamondback's Consolidated Breakevens

Source: Partnership data and filings. Data as of 9/30/2020.

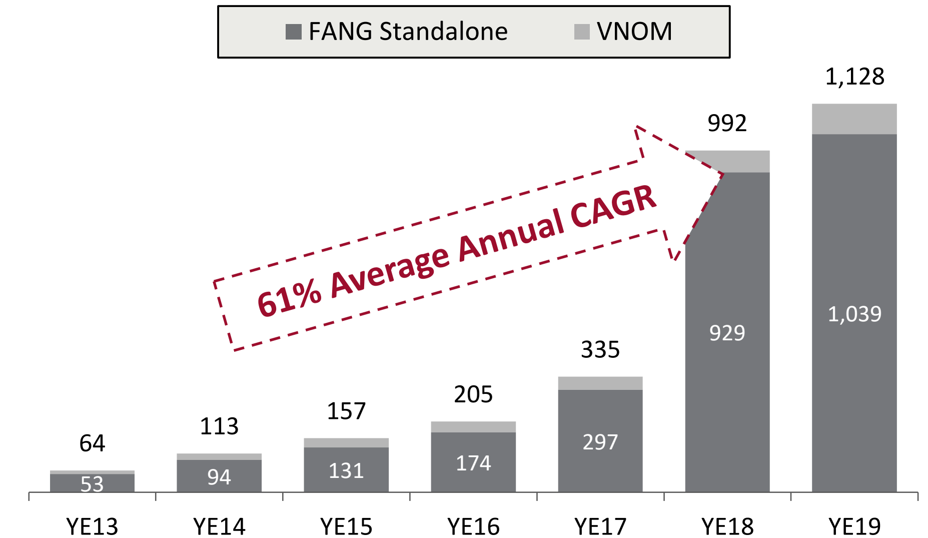
High Growth, Oil Weighted Reserves

- YE19 proved reserves increased 14% y/y to 1,128 MMBoe (711 MMBo, 67% PDP)
- PDP reserves of 760 MMBoe, up 18% y/y; PDP oil reserves of 457 MMBo, up 13% y/y
- Oil comprised 63% of total proved reserves on 3-stream basis; ~69% of total on 2-stream basis
- Consolidated proved developed F&D for 2019 was $10.87/boe with drill bit F&D of $11.11

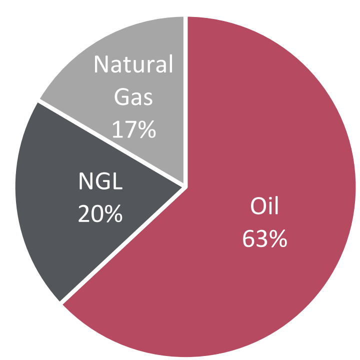
F&D Costs

($/boe)	2017	2018	2019
Proved Developed F&D(2)	$9.09	$10.44	$10.87
Drill Bit F&D(3)	$7.22	$7.28	$11.11
Reserve Replacement(4)	549%	1,479%	231%
Organic Reserve Replacement(5)	443%	457%	250%

Total Reserve Growth (MMBoe) (1)

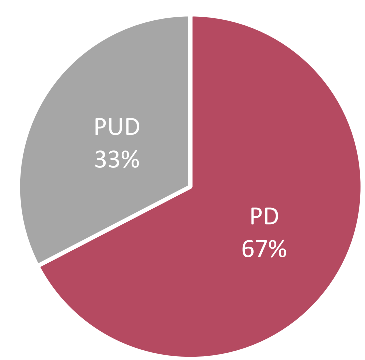


1P Reserves – By Commodity



1,128 MMBOE

1P Reserves – By Category



1,128 MMBOE

Source: Company Filings, Management Data and Estimates.
(1) Historical FANG reserves per independent reserve report prepared by Ryder Scott as of 12/31/2019.
(2) PD F&D costs are defined as exploration and development costs divided by the sum of reserves associated with transfers from proved undeveloped reserves at YE2018 including any associated revisions in 2019 and extensions and discoveries placed on production during 2019.
(3) Drill bit F&D costs are defined as the exploration and development costs divided by the sum of extensions, discoveries and recoveries.
(4) Defined as the sum of extensions, discoveries, revisions, and purchases, divided by annual production.
(5) Defined as the sum of extensions, discoveries, and revisions, divided by annual production.

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