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and deemed filed pursuant to Rule 14a-12
under the Securities Exchange Act of 1934, as amended
Subject Company: Energen Corporation
(Commission File No. 001-07810)
Date: November 7, 2018

Forward Looking Statement

FORWARD LOOKING STATEMENT AND OTHER IMPORTANT INFORMATION FOR INVESTORS AND STOCKHOLDERS

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, 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, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas, availability of drilling equipment and personnel, 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.

Forward-looking statements included in this presentation also involve certain risks and uncertainties discussed or referenced in Diamondback's 424(b)(3) prospectus filed with the SEC on October 25, 2018 relating to Diamondback's pending merger with Energen Corporation ("Energen"), which contains, among other things, additional risk factors relating to the pending merger that could cause the results to differ materially from those expected by the management of Diamondback or Energen. These include the expected timing and likelihood of completion of the pending merger, including the ability to successfully integrate the businesses, the occurrence of any event, change or other circumstances that could give rise to the termination of the merger agreement, the possibility that stockholders of Diamondback may not approve the issuance of new shares of common stock in the pending merger or that shareholders of Energen may not approve the merger agreement, the risk that the parties may not be able to satisfy the conditions to the pending merger in a timely manner or at all, risks related to disruption of management time from ongoing business operations due to the pending merger, the risk that any announcements relating to the pending merger could have adverse effects on the market price of Diamondback's common stock or Energen's common stock, the risk of any unexpected costs or expenses resulting from the pending merger, the risk of litigation relating to the pending merger, the risk that the pending merger have an adverse effect on the ability of Diamondback and Energen to retain customers and retain and hire key personnel and maintain relationships with their suppliers and customers and on their operating results and businesses generally, the risk the pending merger could distract management of both entities and they will incur substantial costs, the risk that problems may arise in successfully integrating the businesses of the companies, which may result in the combined company not operating as effectively and efficiently as expected, the risk that the combined company may be unable to achieve synergies or other anticipated benefits of the pending merger or it may take longer than expected to achieve those synergies or benefits and other important factors that could cause actual results to differ materially from those projected. All such factors are difficult to predict and are beyond Diamondback's or Energen's control, including those detailed in Diamondback's annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K that are available on its website at http://www.diamondbackenergy.com and on the SEC's website at http://www.sec.gov, and those detailed in Energen's annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K that are available on Energen's website at http://www.energen.com and on the SEC's website at http://www.sec.gov. All such forward-looking statements are based on assumptions that Diamondback or Energen believe to be reasonable but that may not prove to be accurate.

Any forward-looking statement speaks only as of the date on which such statement is made, and Diamondback and Energen, as may be applicable, undertake 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 2018 production guidance. The actual levels of production, capital expenditures and expenses 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 2018. 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 2018 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.

Important Information for Investors and Shareholders

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 as of December 31, 2017 contained 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.

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, income tax (benefit) provision and 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 it 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, none of which are components of Consolidated Adjusted EBITDA. Our computations of Consolidated Adjusted EBITDA may not be comparable to other similarly titled measures of other companies or to similar 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.

Non-Solicitation

This presentation may be deemed to relate to a pending merger between Diamondback and Energen and does not constitute an offer to buy or sell or the solicitation of an offer to buy or sell any securities or a solicitation of any vote or approval.

Other Important Information for Investors and Stockholders

In connection with the pending merger with Energen, Diamondback filed with the SEC a registration statement on Form S-4, as amended (Registration No. 333-227328), which registration statement was declared effective by the SEC on October 24, 2018 and includes a joint proxy statement of Diamondback and Energen and also constitutes a prospectus of Diamondback ("the joint proxy statement/prospectus"). Each of Diamondback and Energen also filed and may in the future file other relevant documents with the SEC regarding the pending merger. No offering of securities shall be made except by means of a prospectus meeting the requirements of Section 10 of the U.S. Securities Act of 1933, as amended. A definitive joint proxy statement/prospectus of for Diamondback and/or Energen was mailed to stockholders of Diamondback and shareholders of Energen on October 26, 2018.

INVESTORS AND SECURITY HOLDERS OF DIAMONDBACK AND ENERGEN ARE URGED TO READ THE REGISTRATION STATEMENT, JOINT PROXY STATEMENT/PROSPECTUS AND OTHER DOCUMENTS THAT WERE PREVIOUSLY FILED AND MAY IN THE FUTURE BE FILED BY EITHER DIAMONDBACK OR ENERGEN WITH THE SEC CAREFULLY AND IN THEIR ENTIRETY BECAUSE THEY CONTAIN IMPORTANT INFORMATION ABOUT THE PENDING MERGER.

Investors and security holders can obtain free copies of these documents and other documents containing important information about Diamondback and Energen through the website maintained by the SEC at http://www.sec.gov. Copies of the documents filed with the SEC by Diamondback are available free of charge on Diamondback's website at http://www.diamondbackenergy.com or by contacting Diamondback's Investor Relations Department by email at IR@Diamondbackenergy.com, alawlis@diamondbackenergy.com, or by phone at 432-221-7467. Copies of the documents filed with the SEC by Energen are available free of charge on Energen website at http://www.energen.com or by phone at 205-326-2634.

Diamondback, Energen and certain of their respective directors and executive officers may be deemed to be participants in the solicitation of proxies in respect of the pending merger. Information about the directors and executive officers of Energen is set forth in Energen's proxy statement for its 2018 annual meeting of shareholders, which was filed with the SEC on March 22, 2018. Information about the directors and executive officers of Diamondback is set forth in its proxy statement for its 2018 annual meeting of shareholders, which was filed with the SEC on April 27, 2018. These documents can be obtained free of charge from the sources indicated above.

Other information regarding the participants in the proxy solicitations and a description of their direct and indirect interests, by security holdings or otherwise, is contained in the joint proxy statement/prospectus and other relevant materials filed with the SEC on October 25, 2018. Investors should read the joint proxy statement/prospectus carefully before making any voting or investment decisions. You may obtain free copies of these documents from Diamondback or Energen using the sources indicated above.

Diamondback Energy: Leading Pure-play Permian Operator

Permian pure-play with >394,000 pro forma net acres

- ~7,200 net horizontal locations
- Industry leading corporate returns, growth within cash flow and pro forma Tier 1 Inventory depth

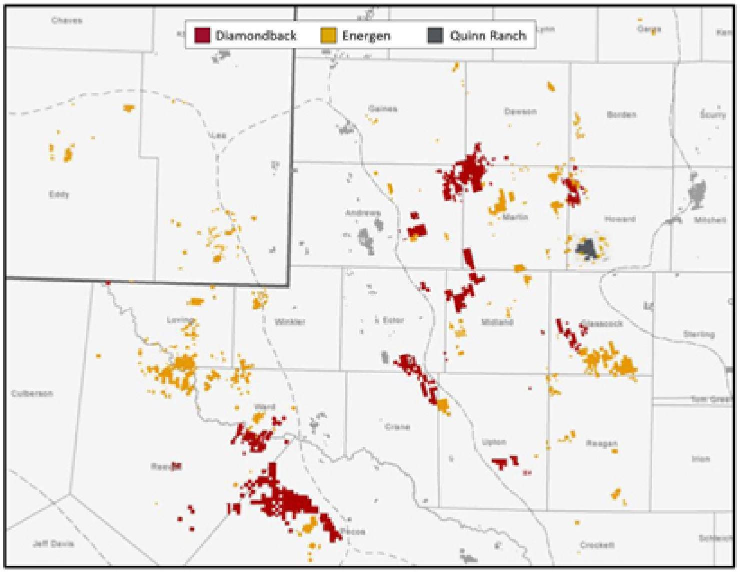
Industry leading growth profile and execution

- Targeting 50% annual production growth in 2018; 170 - 175 gross horizontal completions with an average lateral length of ~9,300 feet
- 2018 Plan – Maximize corporate-level returns through organic growth within cash flow
- Peer-leading cash margins and capital costs per completed lateral foot

Announced Pending Acquisition of Energen Corporation

- Shareholder meetings to vote on the previously announced transaction scheduled for November 27th; deal expected to close shortly thereafter pending shareholder approvals
- Pro Forma Capital Strategy:
  - Significant multi-year growth within cash flow and increasing return of capital program
  - Immediate focus on value enhancement from primary and secondary synergies
  - Enact "grow and prune" strategy to high-grade capital allocation

Diamondback Pro Forma Acreage Map



Pro Forma Inventory Overview[1]

	DIAMONDBACK	ENERGEN	DIAMONDBACK
Enterprise Value ($bn)[1]	$16.3	$8.1	**$24.4**
Net Permian Acres[2]	216,000	178,000	**394,000**
Tier One Permian Acres[3]	174,000	89,000	**263,000**
Tier One Permian Acres (incl. Quinn)[3]	174,000	99,000	**273,000**
Net Locations	3,260	3,901	**7,162**

Source: Company data, public filings, and FactSet. Market data as of 11/6/2018.
(1) Gives effect to Spanish Trail North acquisitions that closed 10/31/2018.
(2) Midland and Delaware only. Energen acreage includes 10,000 Quinn Ranch net acres.
(3) IRR greater than 50% at $60 WTI in at least one zone.

DIAMONDBACK Energy

Diamondback: Investment Highlights

Q3 Highlights	◆ Q3 2018 production of 123.0 Mboe/d (72% oil), up 9% q/q and 45% year over year ◆ Realized cash margins of over 81% in Q3 2018; Q3 annualized ROACE of 11.3% ◆ <u>Update on announced Energen merger:</u> Received regulatory approval; shareholders to vote by November 27th with deal expected to close shortly thereafter pending approval ◆ Core Permian footprint – >394,000 pro forma net acres with ~7,200 net horizontal locations across the Midland and Delaware basins[1]
Accretive Midland Basin Acquisitions	◆ Acquired ~29,100 net acres in Northwest Martin and Northeast Andrews counties ("Spanish Trail North") from multiple sellers; transactions closed October 31st ◆ Includes 3,646 net adjacent acres with current production of ~3,500 boe/d[2] and ORRI increasing NRI by 1% across majority of Ajax acreage ◆ >450 net potential locations; 285 locations across three zones with estimated IRR's >100% ◆ Accretive on NAV, acreage, top quartile inventory and 2019 financial metrics
Midstream Update	◆ Increased Gray Oak volume commitment to 100,000 bo/d; increases total commitment on new long-haul pipelines to 200,000 bo/d (50% take or pay) ◆ Rattler Midstream exercising right to acquire 10% equity interest in Gray Oak Pipeline, subject to certain closing conditions ◆ <u>2019:</u> >100,000 gross bo/d at fixed discount to Gulf Coast pricing (MEH and Brent); remainder of production covered via term sales agreements ◆ <u>2020+:</u> 225,000 bo/d of FT to Gulf Coast
Industry-Leading Growth, Capital Efficiency and Cost Structure	◆ Full year 2018 production guidance implies 50% y/y growth at midpoint within cash flow ◆ Cash flow positive YTD through Q3 2018, as well as for the past 15 quarters in aggregate ◆ Net debt to Q3 2018 Annualized Adjusted EBITDA of 1.2x[3] ◆ Quarterly dividend of $0.125/share payable on November 26, 2018

Source: Company data and filings. Financial data as of 9/30/2018 unless otherwise noted.
(1) Net acreage and net locations based in on internal company estimates pro forma for the pending Energen acquisition.
(2) Ext. estimated net production as of 11/6/2018.
(3) Excludes cash from Viper. Does not take into account the Spanish Trail North acquisitions that closed on 10/31/2018. Net debt to Q3 2018 annualized Adjusted EBITDA is net debt as of 9/30/2018 divided by annualized Adjusted EBITDA for the three months ended 9/30/2018. See the disclaimers at the beginning of this presentation.

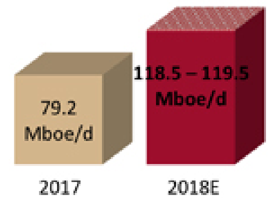
Third Quarter Execution and 2018 Activity Overview

Year Over Year Execution

	Change	Q3 2017	Q3 2018
Daily Production	+45%	85,029	122,975
Cash Costs (% of $/Boe)	-4%	20%	19%
Cash Margins ($/Boe)[1]	+24%	$30.58	$37.89
Adjusted EBITDA	+60%	$232	$372
Adjusted EPS	+27%	$1.33	$1.67
ROACE[2]	+20%	9.5%	11.3%

2018 Production and Activity Outlook

Targeting 50% y/y production growth within cash flow



170 – 175
Gross operated completions

12+
Average operated hz. rigs

~9,300'
Average lateral length

2018 Capital Budget

Diamondback 2018 Capital Activity	
Midland Basin D,C&E per Foot	$760 – $810
Delaware Basin D,C&E per Foot	$1,175 – $1,225
Diamondback Capex Budget ($MM)	
D,C&E and Non-Operated Properties	$1,250 – 1,300
Infrastructure	$250 – $275
Total 2018 Capital Budget	$1,500 – $1,575

Source: Company data, filings and estimates.
(1) Cash margins calculated as realized price per boe less LOE, gathering and transportation, production taxes and cash G&A expenses.
(2) Return on Average Capital Employed ("ROACE") calculated as consolidated annualized EBIT divided by average total assets less cash for current and prior period less average current liabilities for current and prior period.

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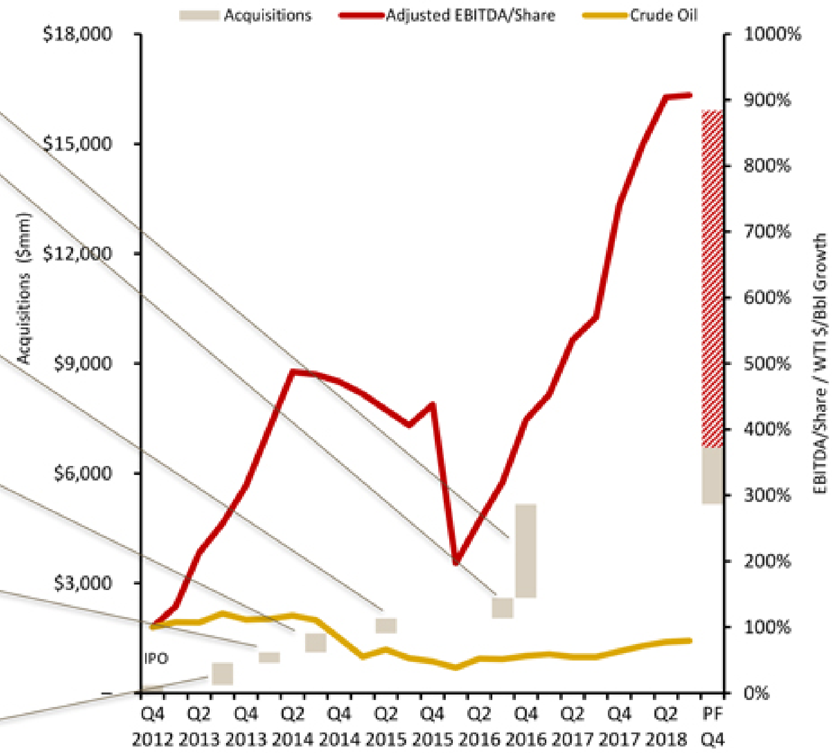
Acquisition Track Record and Subsequent Per Share Value Creation

Value Creation to Shareholders[1]

Normalized Growth	EBITDA/share	EPS	WTI Crude
Pecos $2.55 billion	100%	61%	34%
Reeves / Ward $560 million	184%	209%	55%
NW Howard $404 million	111%	307%	20%
Glasscock / Midland $524 million	88%	174%	-29%
SW Martin $188 million	126%	215%	-30%
NW Martin / Viper $605 million	253%	377%	-34%

FANG Acquisitions and EBITDA/Share Growth Since IPO[2]



FANG has grown EBITDA/share over 800% since IPO with oil prices down 21% over same period

Source: Company data and filings. Acquisition prices as of the date announced. Note: NW Martin / Viper acquisitions are combined as both transactions were completed in Q3 2013.
(1) Reflects Adjusted EBITDA/share and adjusted EPS performance relative to WTI price per barrel. Performance period benchmarked to the quarter each acquisition closed.
(2) Cumulative quarterly Adjusted EBITDA/share relative to average quarterly WTI price per barrel since Q4 2012.

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Substantial Pro Forma Economic Inventory

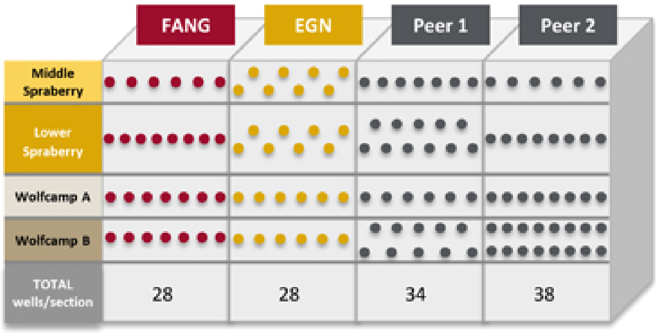
Net Midland Basin Location by Zone / Lateral[1]

	5,000'+	7,500'+	10,000'+	Total	Avg. Lateral
MS	162	264	317	**743**	*8,100'*
LS	260	394	424	**1,078**	*7,900'*
WCA	209	249	344	**802**	*7,900'*
WCB	194	242	307	**744**	*7,900'*
Other	126	372	342	**840**	*8,100'*
Total	**952**	**1,521**	**1,734**	**4,207**	***8,000'***

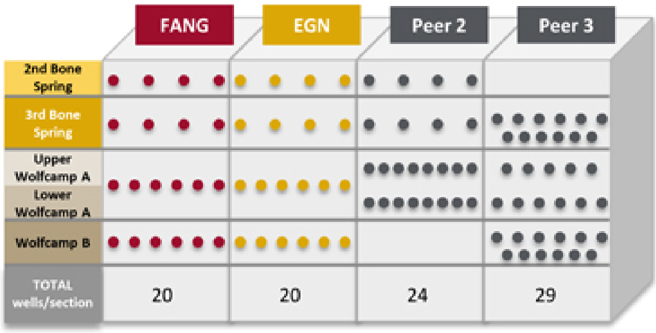
Net Delaware Basin Locations by Zone / Lateral

	5,000'+	7,500'+	10,000'+	Total	Avg. Lateral
2BS	107	92	97	**296**	*7,300'*
3BS	222	155	163	**540**	*7,100'*
WCA	326	270	249	**845**	*7,100'*
WCB	358	286	306	**951**	*7,400'*
Other	151	73	98	**323**	*6,800'*
Total	**1,165**	**877**	**913**	**2,955**	***7,100'***

Midland Basin Premium Zone Spacing Assumptions vs. Peers[2]



Delaware Basin Premium Zone Spacing Assumptions vs. Peers[2]



Conservative spacing assumptions and depth of Tier One, long lateral inventory to drive capital efficient growth

Source: Company data, filings and estimates.
(1) Includes Ajax and ExL transactions that closed on 10/31/2018 and pro forma for the Energen merger as announced of 8/14/2018.
(2) Midland peers include QEP and PE. Delaware peers include PE and JAG.

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Multiple Acquisitions Create Spanish Trail North

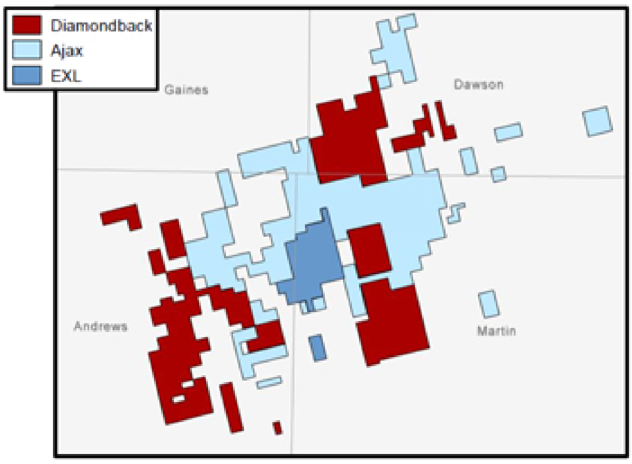
Overview of Acquisitions (Closed 10/31/2018):

- $1.21B cash consideration and 2.58MM FANG shares
- 29,139 net acres (~25,000 in Martin / Andrews counties)
- >450 net potential locations; 285 in 3 zones with estimated IRRs >100% (top quartile of FANG's current inventory)
  - Average lateral length of ~9,300 feet
- ExL bolt-on acquisition adds >3,600 net surface acres within core prospectivity windows for WCA, MS and LS
  - ~3,500 boe/d of estimated current net production[1]

Strategic Rationale / Synergies:

- ~6,500 acres adjacent to existing acreage
- Shared infrastructure assets (Rattler Midstream):
  - 40 Mb/d of SWD gathering lines and disposal capacity; growing to 60 Mb/d by Q4 2018
  - 45 Mb/d of existing fresh water production
  - 20 miles of fresh water / SWD gathering lines
  - >700 acres of surface
- Acreage >75% NRI opportunity for VNOM dropdown
- Acreage HBP allows for efficient development with 12+ well multi-zone pads
- Accretive on NAV, acreage, top quartile inventory and 2019 financial metrics

Spanish Trail North Acreage Map



Net Potential Acquisition Locations By Zone / Lateral

	5,000'+	7,500'+	10,000'+	Total	Avg. Lateral
MS	9	58	53	**120**	*9,042'*
LS	8	52	56	**115**	*9,255'*
WCA	9	46	52	**107**	*9,394'*
WCB	9	47	53	**109**	*9,409'*
Total	**35**	**203**	**214**	**452**	***9,268'***

Source: Company data, filings and estimates and data from the Sellers.
(1) Estimated daily net production for ExL acquisition as of 11/6/2018.

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Spanish Trail North: Prolific Well Results Across Three Proven Zones

2 — UL Comanche Unit A4144 4
EXL Petroleum
IP30/1k': 145 boe/d (93% oil)

3 — UL Comanche Unit A4144 5
EXL Petroleum
IP30/1k': 157 boe/d (91% oil)

4 — UL Comanche Unit A4144 6
EXL Petroleum
IP30/1k': 196 boe/d (95% oil)

5 — Vineyard Hz B Unit 0601WA
Ajax Resources
IP30/1k': 174 boe/d (93% oil)

1 — UL Comanche Unit A4144 2
EXL Petroleum
IP30/1k': 190 boe/d (93% oil)

A — Vineyard Hz O Unit 1701LS
Ajax Resources
IP30/1k': 129 boe/d (92% oil)

B — University 6-40 Unit 105LS
Ajax Resources
IP30/1k': 160 boe/d (92% oil)

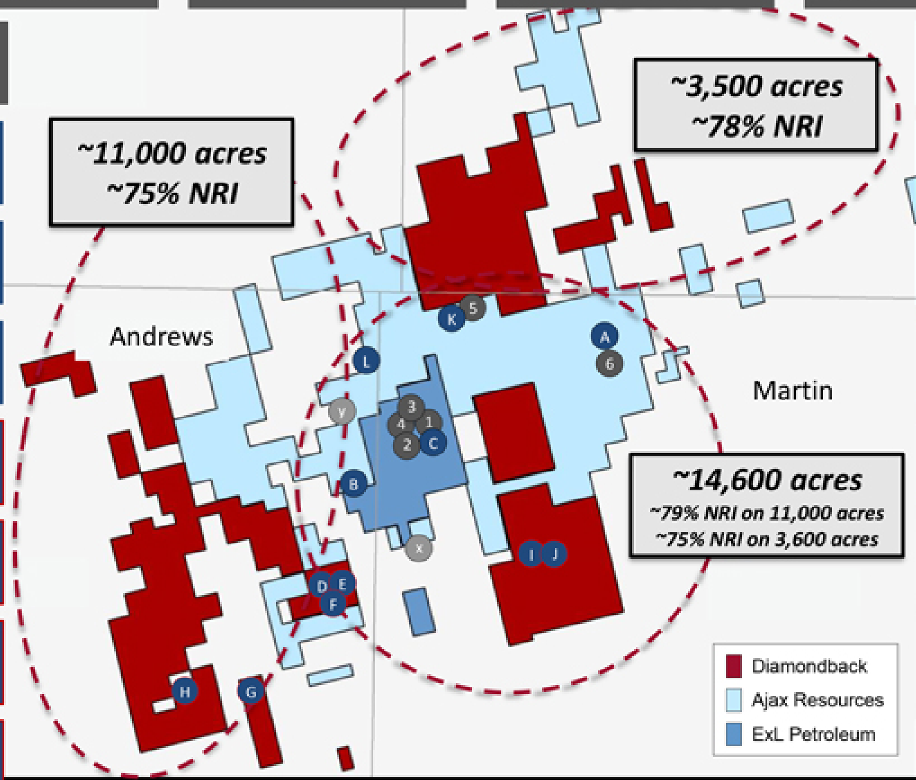
C — UL Comanche Unit A4144 1
EXL Petroleum
IP30/1k': 152 boe/d (91% oil)

D — UL Mason East Unit 3LS
Diamondback
IP30/1k': 115 boe/d (90% oil)

E — UL Mason East Unit 5LS
Diamondback
IP30/1k': 113 boe/d (91% oil)

F — UL Mason East Unit 4LS
Diamondback
IP30/1k': 124 boe/d (90% oil)

G — UL Carpenter 7- 20 4LS
Diamondback
IP30/1k': 139 boe/d (88% oil)



H — UL Tawny Unit 8-12 1LS
Diamondback
IP30/1k': 147 boe/d (91% oil)

I — Mabee Breedlove 4001LS
Diamondback
IP30/1k': 159 boe/d (88% oil)

J — Mabee Breedlove 4003LS
Diamondback
IP30/1k': 171 boe/d (88% oil)

K — Vineyard Hz B Unit 0601LS
Ajax Resources
IP30/1k': 108 boe/d (93% oil)

L — University 6-16 26 27 101LS
Ajax Resources
IP30/1k': 122 boe/d (93% oil)

X — UL MS Hz Blk 6 Unit 4106
EnergyQuest II
IP30/1k': 149 boe/d (90% oil)

Y — UL MS Hz Blk 6 Unit 3107
Ajax Resources
IP30/1k': 135 boe/d (91% oil)

6 — Vineyard Hz O Unit 1701WA
Ajax Resources
IP30/1k': 132 boe/d (92% oil)

Middle Spraberry | Lower Spraberry | Wolfcamp A

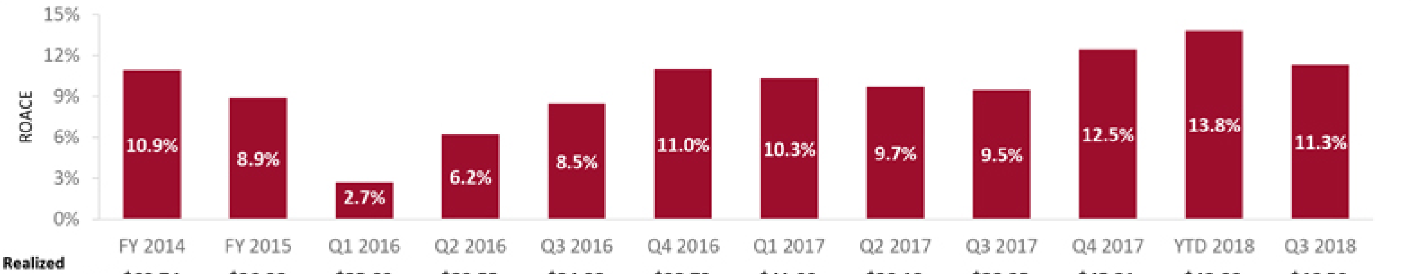
Source: Management data and estimates and data from the Sellers.

DIAMONDBACK Energy

Corporate Level Full-Cycle Economics and Returns Matter

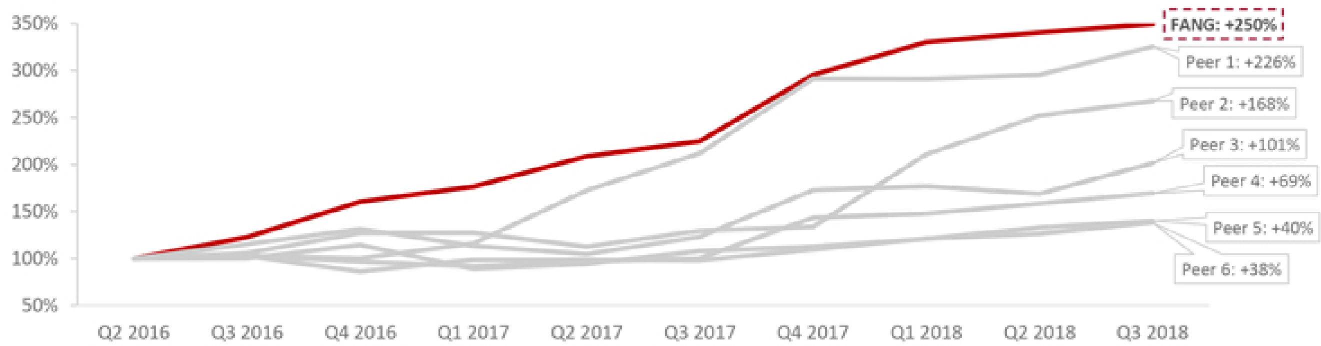
- Diamondback's cost structure and disciplined approach to investment facilitates greater per share EBITDA and earnings growth, and is reflected in an industry-leading ROACE

Return on Average Capital Employed ("ROACE") Over Time(1)



	FY 2014	FY 2015	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017	YTD 2018	Q3 2018
Realized Price ($/Boe)	$69.74	$36.98	$25.09	$33.55	$34.39	$38.72	$41.93	$38.18	$38.25	$45.31	$49.00	$46.59
Adjusted EPS	$2.24	$1.81	$0.02	$0.26	$0.54	$0.90	$1.04	$1.25	$1.33	$1.56	$4.90	$1.67

Normalized Adjusted EBITDA/share Growth Versus Peers

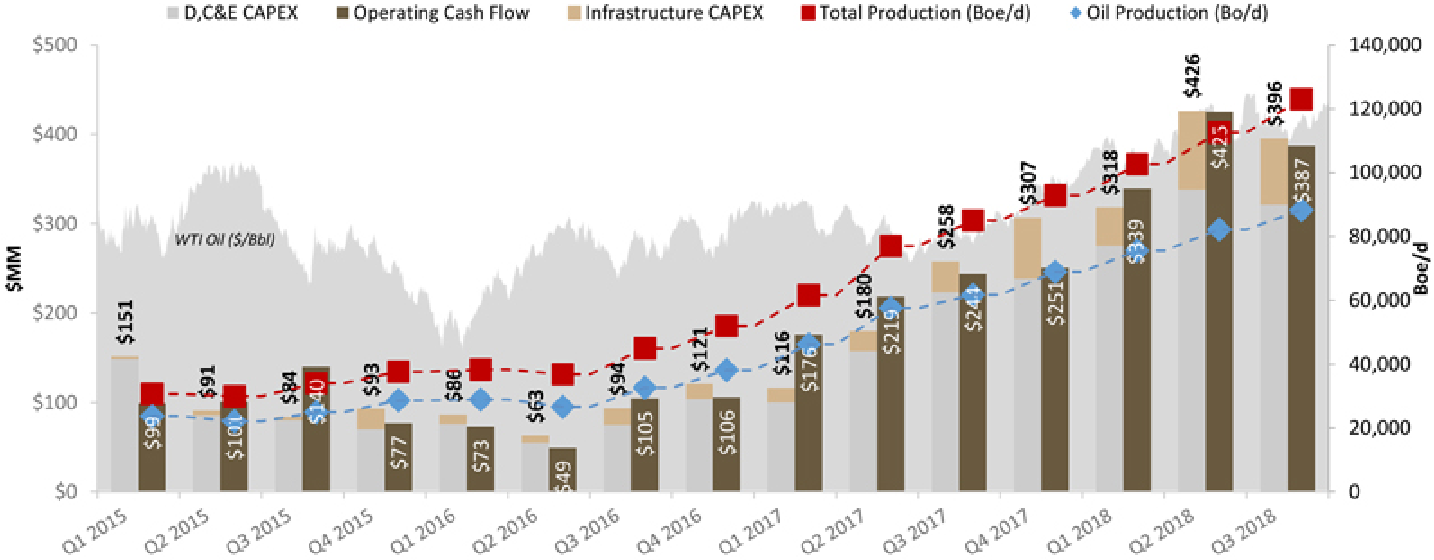


Source: Company data, Bloomberg and latest peer filings as of 11/6/2018. Peers include EGN, PE, PXD, CPE, LPI and CXO.

(1) Return on Average Capital Employed ("ROACE") calculated as consolidated annualized EBIT divided by average total assets less cash for current and prior period less average current liabilities for current and prior period. In this presentation, the Company defines Consolidated EBIT as Consolidated Adjusted EBITDA before depreciation, depletion and amortization. For a definition and reconciliation of Consolidated Adjusted EBITDA, see "Froward Looking Statements" included in this presentation, and filings the Company makes with the SEC, including its form 10-k.

Consistent Capital Discipline and Growth Within Cash Flow

- FANG has a track record of achieving robust production growth while spending within cash flow
- Cumulative cash flow has more than offset D,C&E and Infrastructure spending since the beginning of 2015
- Asset base can support differential growth within cash flow and increasing return of capital program



Since Q1 2017, FANG has generated $39 million in free cash flow, while doubling production

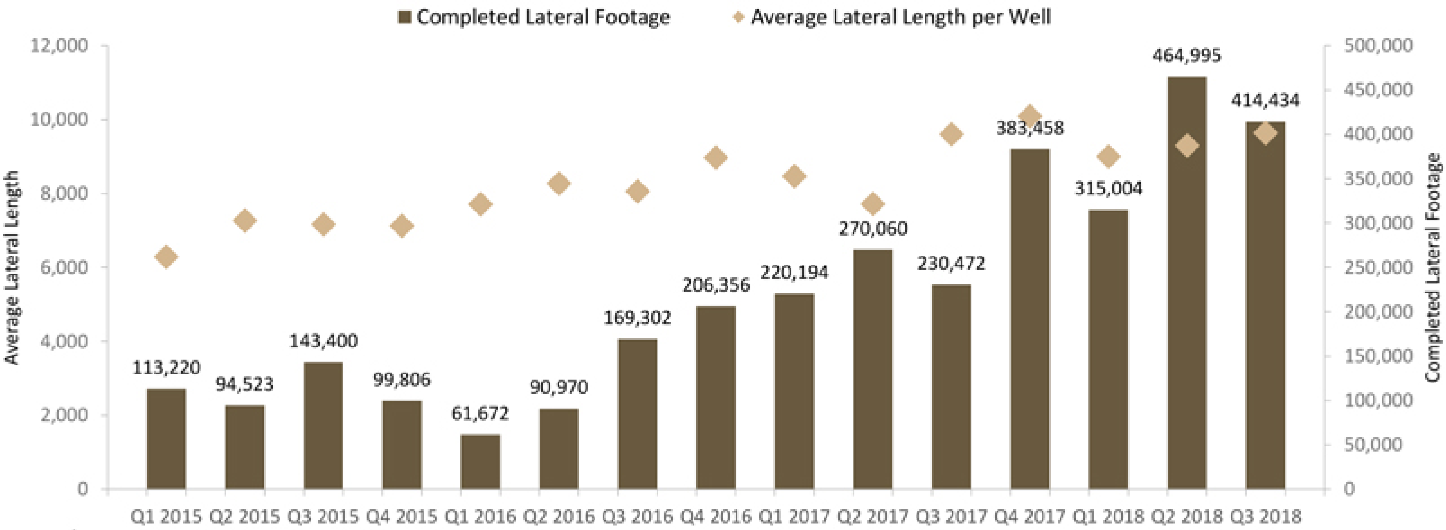
Source: Company filings, management data and estimates.

DIAMONDBACK Energy

Balanced, Capital Efficient Development

- Completing an average ~1,400 lateral feet per day per completion crew in the Midland Basin
- Completing an average of ~900 feet per day in the Delaware Basin

Completed Lateral Footage by Quarter



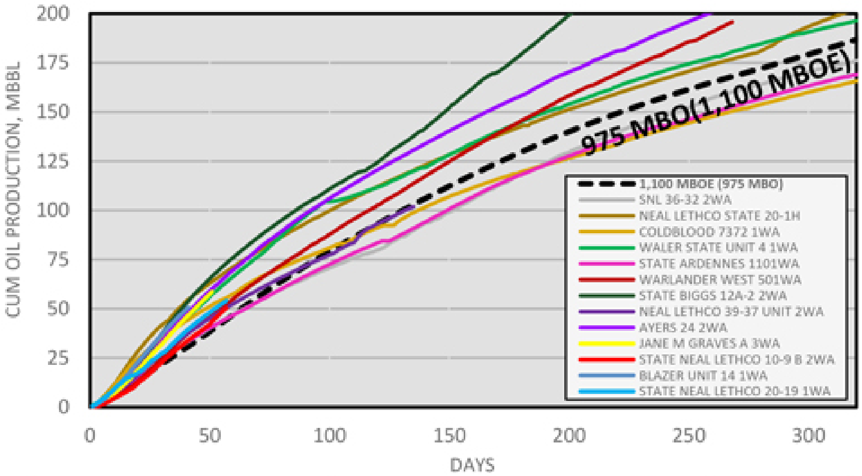
	Q1 2015	Q2 2015	Q3 2015	Q4 2015	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Q2 2018	Q3 2018
Drilled / Completed wells	15 / 18	11 / 13	21 / 20	17 / 14	16 / 8	15 / 11	17 / 21	25 / 23	28 / 26	34 / 35	42 / 24	46 / 38	41 / 35	53 / 50	40 / 43

FANG continues to maximize long-lateral efficient pad development across its acreage

Source: Company filings, management data and estimates.

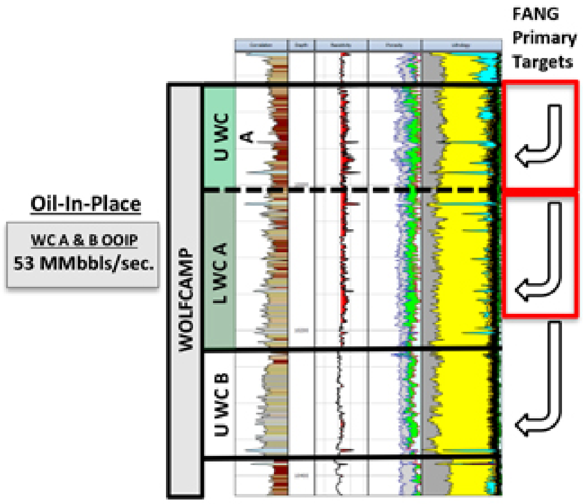
Southern Delaware Basin Wolfcamp A Update

Southern Delaware WCA Performance – Normalized to 7,500' (Mbo)



WELL	COUNTY	TARGET	IP30 (Boe/d / 1k')	% Oil
NOKOTA 19 DODT 1WA/2WA	Reeves	WCA	292[1]	74%
NEAL LETHCO A 17-18 1WA	Pecos	WCA	229	89%
NEAL LETHCO 10-9 B 2WA	Pecos	WCA	173	80%
JANE GRAVES A 3WA	Reeves	WCA	217	81%
BLAZER UNIT 14 1WA	Reeves	WCA	221	82%
NEAL LETHCO 39-37 UNIT 2WA	Pecos	L WCA	159	84%
STATE BIGGS 12A-2 2WA	Pecos	L WCA	226	91%
AYERS 24 2WA	Reeves	WCA	226	82%
WARLANDER 501 WA	Reeves	WCA	186	80%

Central Type Log and Landing Targets



- High-graded landing zones through integration of captured core and log data; continue to receive high-res 3-D seismic data
- Well results confirming geologic assessment of rock quality

Source: Company filings, management data and estimates.
(1) Reflects average peak-24 hour IP rate as of 11/6/2018.

Near Term and Long Term Solutions for Permian Oil Takeaway

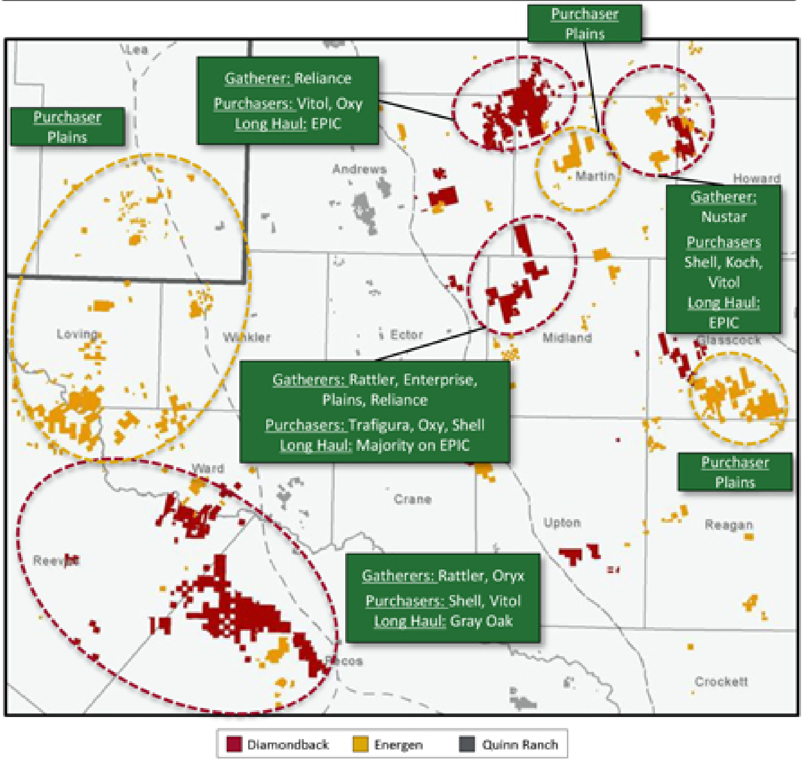
Diamondback:

- Volume-weighted average transport cost to Midland market: $1.00 - $1.25/Bbl (ex-Rattler)
- Firm to Midland market on all barrels (ample reserved space on in-basin gathering systems)
- 2019: FT agreements cover >100,000 gross bo/d at fixed discount Gulf Coast pricing (Brent, MEH)
  - Gulf Coast differentials weakest Q4 2018 and Q1 2019, improving through remainder of 2019
  - Term sales agreements cover remainder of barrels
- Long term: 225,000 bo/d of FT to Gulf Coast markets
  - 100,000 bo/d on EPIC for Midland Basin barrels
  - 100,000 bo/d on Gray Oak for Delaware Basin barrels
  - 50% take or pay
  - "Wellhead to water" solutions

Energen:

- Production supported by Basin-wide flow assurance with 85% of oil production on pipe
- Multi-year term purchasing contracts in place at Midland market prices
- Hedging mitigates exposure to basis differentials
  - ~50,000 net Bo/d of 2019 oil production hedged at ($5.13)/Bbl as of November 2018

Pro Forma In Basin Oil Takeaway



Gray Oak and EPIC pipeline commitments and joint ventures provide Diamondback with "wellhead to water" solutions for the majority of projected standalone production for years to come, removing Midland market risk

Source: Company filings, management data and estimates.

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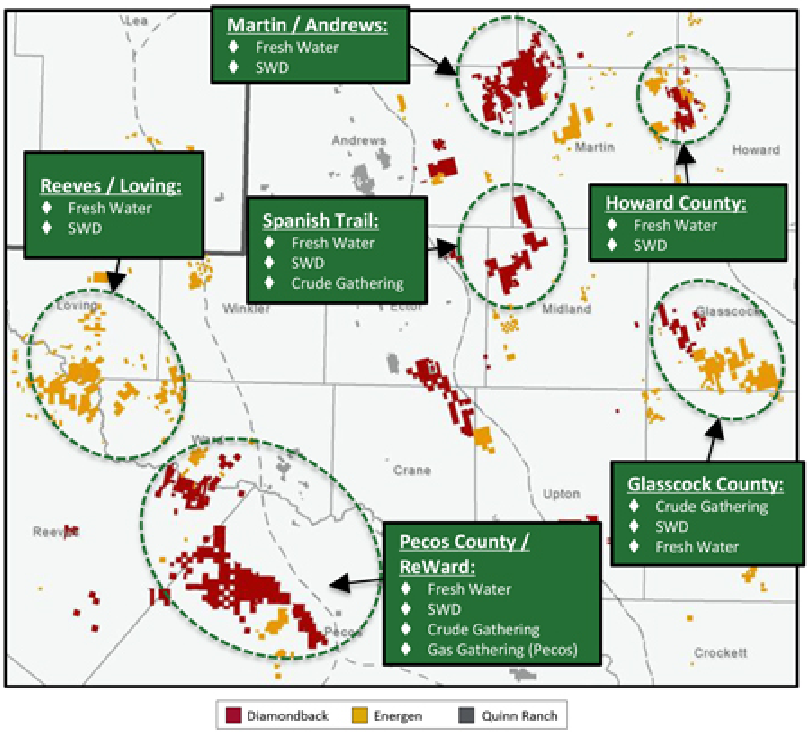
Build-out of Midstream Assets Through Rattler Midstream

Rattler Midstream:

- Wholly-owned midstream subsidiary created by Diamondback
- Interests fully aligned with upstream operations:
  - Organic growth via accelerating development
  - Assets located in all six core operating areas
  - Energen adds significant existing capacity in both the Midland and Delaware Basins
- Energen's extensive midstream assets will add critical mass for midstream value creation opportunities at Diamondback

Pro Forma Capacity Overview		
Fee Stream	Midland	Delaware
SWD – Bbl/d	744,400	809,000
Fresh Water – Bbl/d	371,200	369,500
Crude Oil – Bbl/d	90,000	176,000
Natural Gas – Mcf/d	--	150,000[1]
Total	**>1,205,600**	**>1,379,500**

Rattler Midstream Asset Map



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

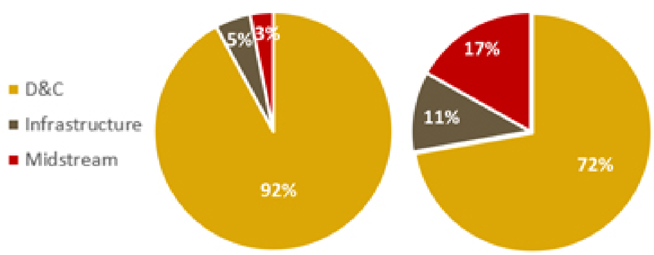
Source: Company filings, management data and estimates.
(1) Excludes 36,000 Mcf/d compression capacity.

Infrastructure Development Ahead of Continued Acceleration

- >100,000 net Delaware Basin acres acquired in 2016 with minimal infrastructure in place
- Building out infrastructure, retaining 100% ownership of assets with 100% utilization
- Assets being set up for efficient, large scale development which is critical for capital efficient growth
- Over time, total infrastructure spend to trend to <10% of total capital like Midland Basin

Capital Spend Breakdown

Midland Basin | Delaware Basin



Infrastructure & Midstream as percent of total CAPEX:	~8% of total capital	~28% of total capital

2018 YTD Infrastructure Capital Spend

Total Infrastructure & Midstream ~$205MM

- **Batteries & Electricity (40%)**
  Midland: ~15%
  Delaware: ~25%
  - **Pecos:** 120 mW substation → ~$60k / well monthly savings for each ESP
  - **ReWard:** 30 mW substation → ~$60k / well monthly savings for each ESP
- **Midstream (60%)**
  Midland: ~10%
  Delaware: ~50%
  - **Oil Gathering:** 216,000 bo/d capacity
  - **Gas Gathering:** 150,000 mcf/d capacity → Improves realizations
  - **SWD:** 589,000 bbl/d capacity
  - **Fresh Water:** 740,700 bbl/d capacity → Reduces LOE

Source: Company filings, management data and estimates.

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Capital Structure and Liquidity

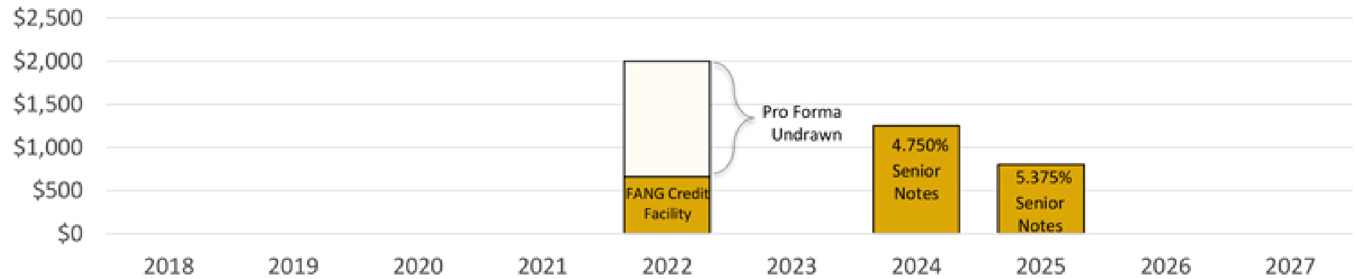
- Net Debt to Q3 2018 Annualized Adjusted EBITDA of 1.2x(1); continue to target leverage below 2.0x
- In September 2018, FANG issued $750 million of tack-on 4.750% Senior Notes; proceeds used to pay down revolver and to fund a portion of the Ajax acquisition
- In October 2018, FANG's borrowing base was increased to $2.65 billion; FANG elected to increase its commitment to $2.0 billion from $1.0 billion previously
- Pro forma for the Ajax and ExL transactions, FANG had standalone liquidity of over $1.3 billion as of September 30, 2018

FANG's Liquidity and Capitalization(2)

FANG's Consolidated Capitalization	9/30/2018	Pro Forma
($MM)		
Cash and cash equivalents	$508	17
FANG's Revolving Credit Facility	-	659
VNOM's Revolving Credit Facility	297	297
4.750% Senior Notes Due 2024	1,250	1,250
5.375% Senior Notes Due 2025	800	800
Total Debt	***$2,347***	***$3,005***

FANG's Standalone Liquidity	9/30/2018	Pro Forma
Cash(1)	$492	-
Elected commitment amount	1,000	2,000
FANG borrowing base	2,000	2,650
Liquidity	***$1,492***	***$1,341***

FANG's Debt Maturity Profile ($MM)



Source: Company Filings, Management data and Estimates.
(1) As of 9/30/2018. Excludes cash from Viper. Does not take into account the Spanish Trail North acquisitions that closed on 10/31/2018.
(2) Pro forma liquidity reflects the remaining cash portion of the Spanish Trail North acquisitions that closed on 10/31/2018 as well as its increased borrowing capacity following its Fall 2018 redetermination of its revolving credit facility.

DIAMONDBACK Energy

Updated 2018 Guidance

- Targeting annual production growth of 50% within cash flow in 2018
- 2018 D,C&E CAPEX budget of $1,250 – $1,300 million from a 12+ average rig program; anticipate running 14 horizontal rigs in Q4 2018
- Anticipated infrastructure capital expenditures of $250 - $275 million
- Expect to complete 170 – 175 gross horizontal wells with an average lateral length of ~9,300 feet
- Targeting annual production growth of over 50% for Viper Energy Partners in 2018
- 2018 capital budget will target estimated operating cash flow and drilling rigs will be added or dropped accordingly

	Diamondback Energy, Inc.	Viper Energy Partners LP
Net Production – Mboe/d	118.5 – 119.5	16.75 – 17.25
Oil Production – (% of Net Production)	72% - 74%	69% – 73%
Unit Costs ($/boe)		
Lease Operating Expenses	$3.75 – $4.50	n/a
Gathering & Transportation	$0.25 – $0.75	$0.20 – $0.40
Cash G&A	Under $1.00	$0.75 – $1.25
Non-Cash Equity Based Compensation	$0.50 – $1.00	$0.50 – $0.75
DD&A	$11.00 – $14.00	$8.00 – $11.00
Interest Expense (net)	$1.00 – $2.00	
Production and Ad Valorem Taxes (% of Revenue)[1]	7.0%	7.0%
Corporate Tax Rate	20% - 23%	n/a
Diamondback 2018 Capital Activity		
Gross (Net) Horizontal Wells Completed	170 – 175 (146 – 154)	
Midland Basin D,C&E per Foot	$760 – $810	
Delaware Basin D,C&E per Foot	$1,175 – $1,225	
Diamondback Capex Budget ($MM)		
2018 Capital Budget	$1,500 – $1,575	

Source: Company filings, management data and estimates.
Note: Based on updated 2018 guidance provided on 11/6/2018, 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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Energy
Differential Growth Within Cash Flow
Return On and Return Of Capital
Significant Resource Potential
Conservative Financial Management
Strategic Acquisitions
Efficient Conversion of Resource to Cash Flow

APPENDIX

Current Hedge Summary

	Crude Oil (Bbls/day, $/Bbl)				
	Q4 2018	**Q1 2019**	**Q2 2019**	**Q3 2019**	**Q4 2019**
Swaps - WTI	**26,000**	**7,000**	**4,000**	**4,000**	**3,000**
	$51.27	$55.29	$51.86	$51.59	$49.82
Swaps - MEH	**7,000**	**7,000**	**4,000**	**2,000**	**1,000**
	$71.06	$69.65	$74.64	$75.65	$75.74
Swaps - Brent	**10,000**	**5,000**	**2,000**	**2,000**	**2,000**
	$62.51	$72.82	$75.43	$74.95	$74.45
Basis Swaps - WTI	**15,000**	**3,000**	–	–	–
	($0.88)	($9.42)	–	–	–
Three Way Collars - WTI	–	**10,000**	**10,000**	–	–
Floor / Ceiling	–	$55.00 / $70.76	$55.00 / $69.71	–	–
Three Way Collars - MEH	**7,000**	**7,000**	**4,000**	–	–
Floor / Ceiling	$66.43 / $78.82	$66.43 / $77.56	$67.50 / $77.68	–	–
Three Way Collars - Brent	–	**8,000**	**8,000**	**4,000**	**2,000**
Floor / Ceiling	–	$65.00 / $81.25	$65.00 / $81.25	$65.00 / $84.58	$65.00 / $87.90

	Natural Gas (Mmbtu/day, $/Mmbtu)				
	Q4 2018	**Q1 2019**	**Q2 2019**	**Q3 2019**	**Q4 2019**
Swaps	**20,000**	–	–	–	–
	$3.07	–	–	–	–

Source: Company data as of 11/6/2018.
(1) Sub floors for three way collars are priced $10/Bbl below the respective floor price for each period.

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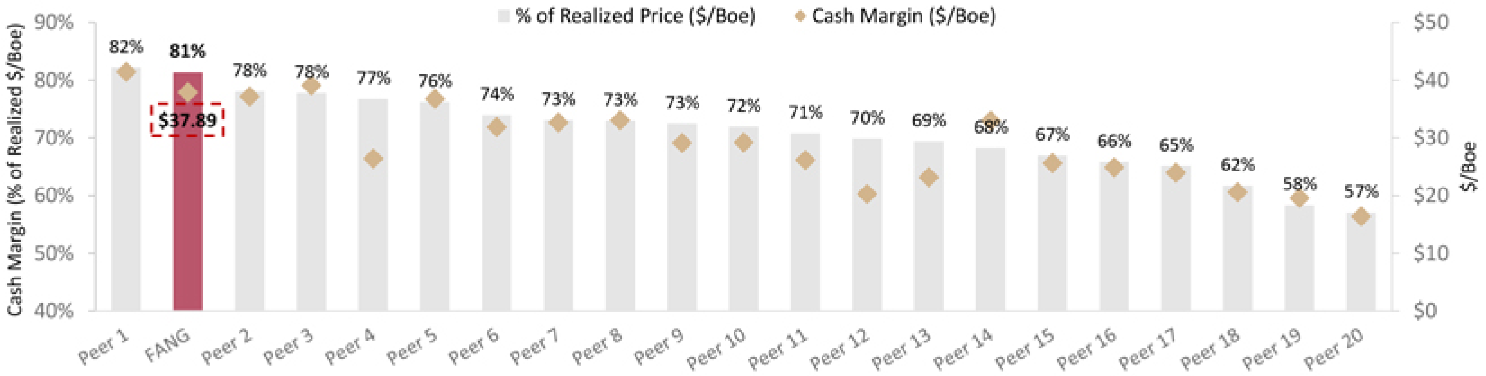
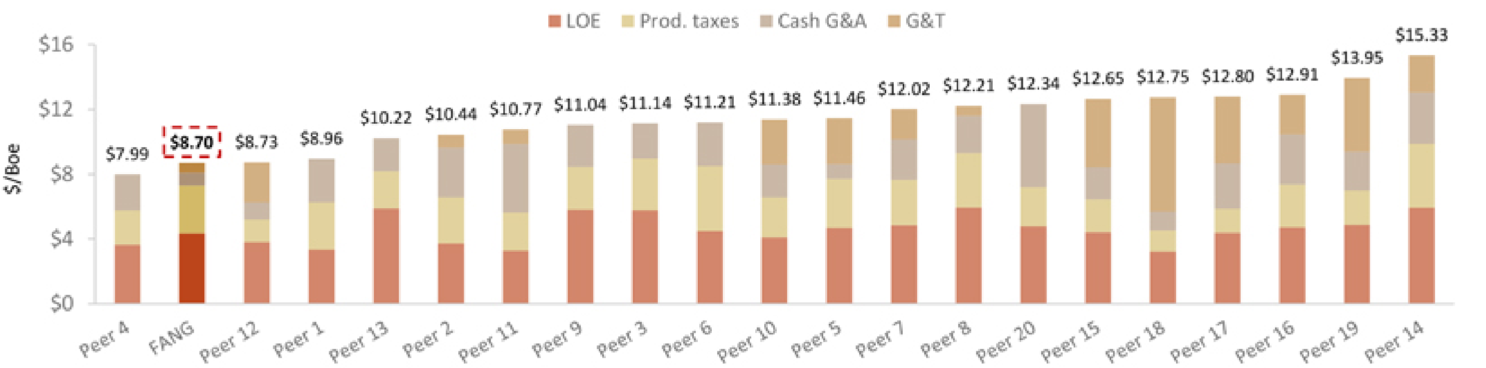
Peer-Leading Cash Margins and Operating Costs

Q3 2018 Cash Margins Versus Extended Peer Group ($/Boe)(1)



Q3 2018 Cash Operating Costs Versus Extended Peer Group ($/Boe)(2)



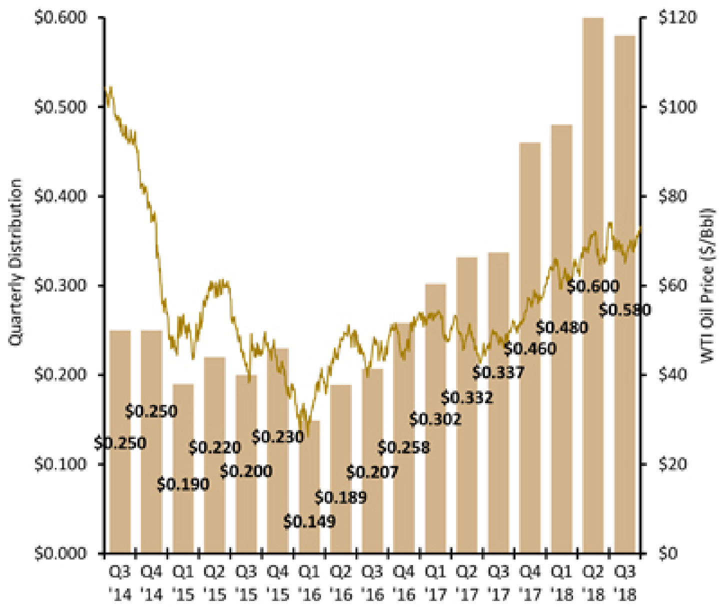
Source: Company and latest peer filings as of 11/6/2018. Extended peers include JAG, PE, CPE, LPI, EOG, MTDR, PXD, CXO, EGN, CDEV, PDCE, XEC, REN, WPX, SM, QEP, NBL, ECA, DVN and AREX.
(1) Cash margins calculated as realized price per boe less LOE, gathering and transportation, production taxes and cash G&A expenses per boe.
(2) Cash operating costs calculated as the sum of LOE, gathering and transportation, production taxes and cash G&A expenses per boe.

DIAMONDBACK Energy

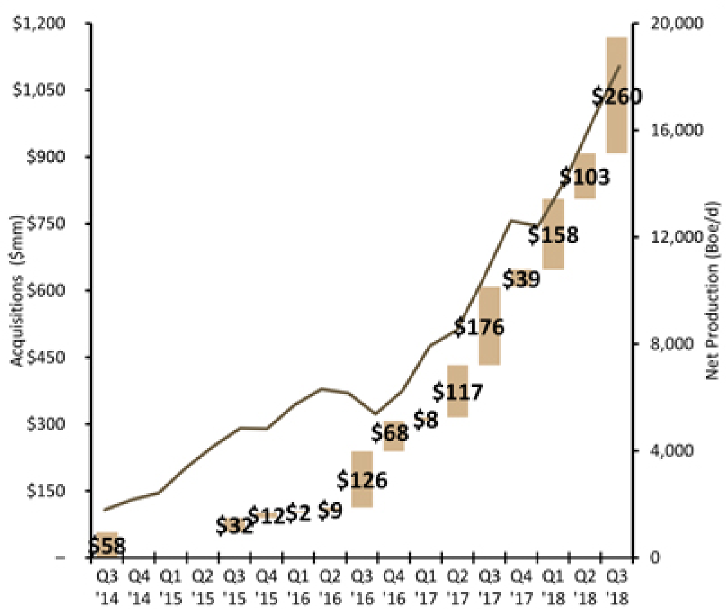
Viper Update

- Q3 2018 cash distribution of $0.580 per unit, up 72% over Q3 2017
- Organic growth on legacy assets provide consistent volume and distribution growth
- Focused on mineral acquisitions in oil-weighted basins with high visibility towards active development
- Robust acquisition activity: 65 deals closed YTD through Q3 2018, adding 4,348 net royalty acres for a total of $521 million; increases asset base to 13,908 net royalty acres (38% FANG-operated)

Distributions Have Tripled In Last Nine Quarters



Production Growth and Acquisitions Since IPO



Source: Company data and filings.

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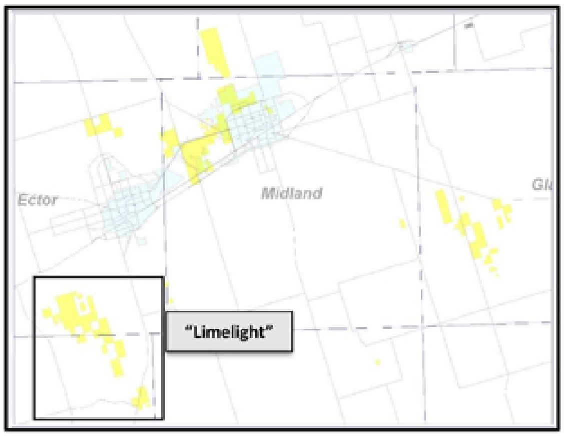
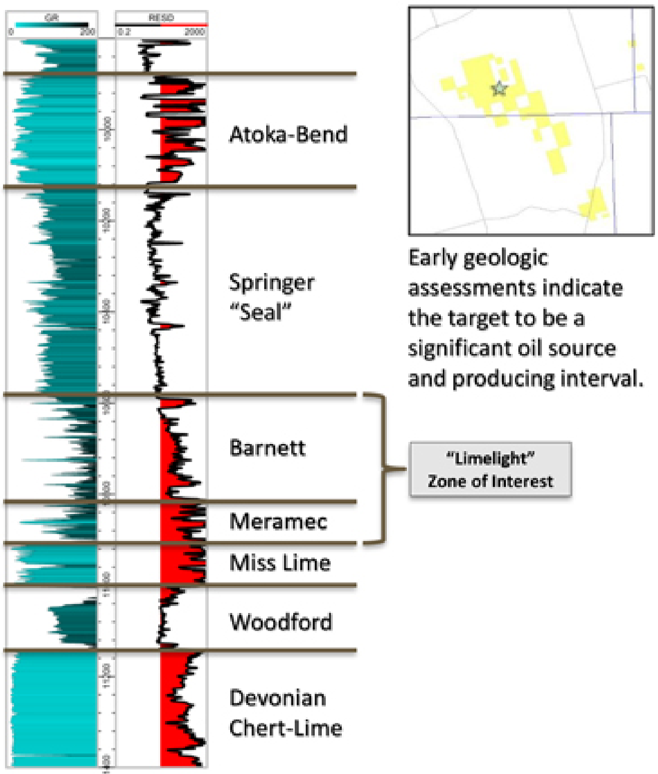
"Limelight" Prospect – Emerging Mississippian Oil Potential

Diamondback "Limelight" Acreage Map



- ~22,000 acres acquired at low entry cost
- Mississippian Barnett (Springer-Chester equiv.) and Meramec are prospective on "terrace" structures along the Central Basin Platform and Midland Basin boundary, at depths where maturation is within peak oil window
- Analogous to recent successful Mississippian horizontal activity in Andrews County
- Plan to begin initial appraisal of acreage in 2019

"Limelight" Type Log



Early geologic assessments indicate the target to be a significant oil source and producing interval.

Stratigraphic and geochemical characteristics are comparable to Andrews County Barnett/Meramec

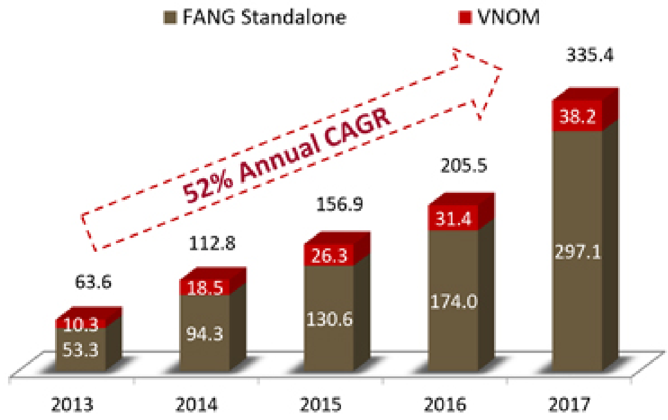
Source: Company filings, management data and estimates.

DIAMONDBACK Energy

High Growth, Oil Weighted Reserves

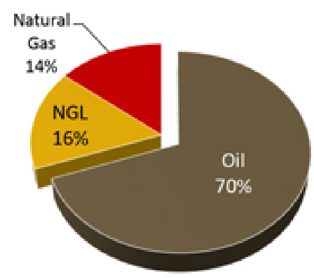
- 2017 total proved reserves increased 63% y/y to 335.4 MMboe
- FANG standalone reserves increased 71% y/y to 297.1 MMboe
- 62% proved developed; conservatively booked
- Proved developed F&D for 2017 was $9.09/Boe

Total Reserves Growth (MMboe) (1)

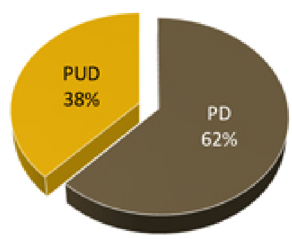


F&D Costs				
($/boe)	2014	2015	2016	2017
Drill Bit F&D(2)	$11.09	$5.51	$6.31	$7.22
Reserve Replacement(3)	793%	465%	409%	549%
Organic Reserve Replacement(4)	626%	422%	380%	443%

1P Reserves – By Commodity



1P Reserves – By Category



335.4 MMBOE

Source: Company Filings, Management Data and Estimates.
(1) Historical FANG reserves per independent reserve report prepared by Ryder Scott as of 12/31/2017.
(2) Defined as exploration and development costs divided by the sum of extensions and discoveries and revisions. 2014 F&D excludes 6.2 MMboe of revisions due to vertical PUD downgrades. 2015 F&D excludes 14.6 MMboe of revisions due to vertical and horizontal PUD downgrades.
(3) Defined as the sum of extensions, discoveries, revisions, and purchases, divided by annual production.
(4) Defined as the sum of extensions, discoveries, and revisions, divided by annual production.

DIAMONDBACK Energy

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