DIAMONDBACK Energy

Investor Presentation

May 2015

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 drilling program, 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, risks 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.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

The presentation contains the Company's estimated 2015 production, capital expenditures, expenses and other matters. 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 2015. 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 finance our 2015 capital budget 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 2015 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.

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, 2014 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.

This presentation contains estimates of the Company's proved reserves and potential drilling locations, including reserves and drilling locations from the Company's 2015 acquisitions. Proved reserves attributable to the Company's 2015 acquisitions are based on internal estimates and have not been reviewed by the Company's independent reserve engineers. As a result, the assumptions on which the Company's internal estimates of proved reserves and potential drilling locations included in this presentation may prove to be incorrect in a number of material ways. Actual quantities that may ultimately be produced and the actual number of locations that may be drilled may differ substantially.

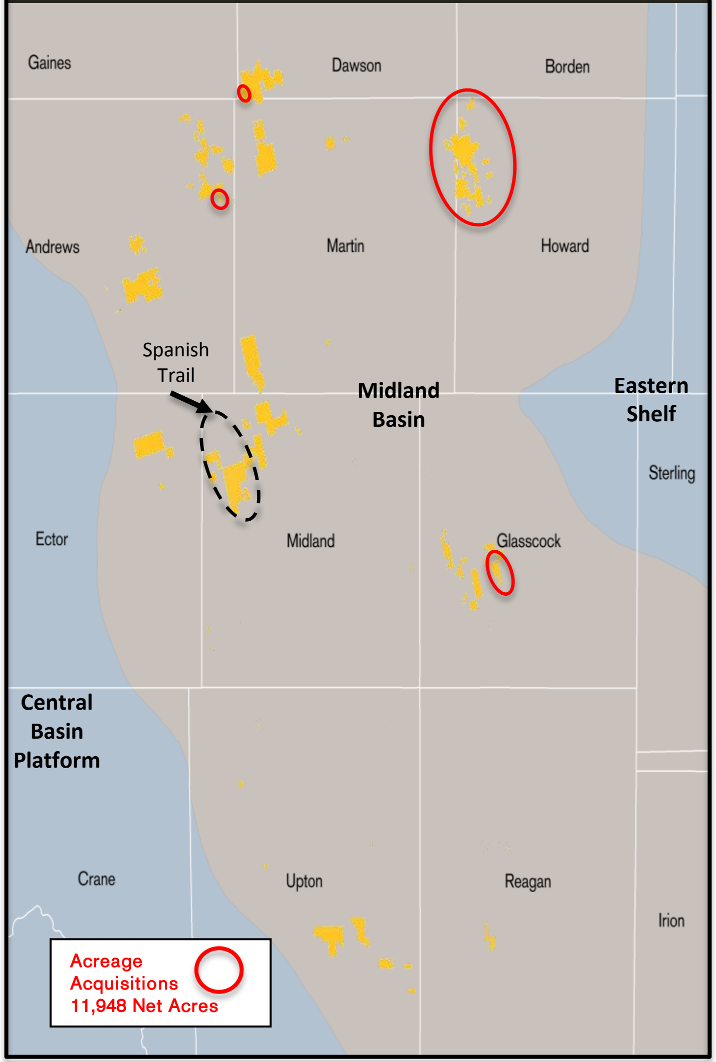
Non-GAAP Financial Measures

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 Adjusted EBITDA as net income (loss) plus gain/loss on derivative instruments, interest expense, depreciation, depletion and amortization, impairment of oil and gas properties, non-cash equity based compensation less capitalized equity-based compensation expense, asset retirement obligation accretion expense, and income tax provisions. Adjusted EBITDA is not a measure of net income (loss) as determined by United States' generally accepted accounting principles, or GAAP. Management believes 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 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. 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 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 Adjusted EBITDA. Our computations of 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 Adjusted EBITDA to net income (loss), please refer to the appendix to this presentation and to filings we make with the SEC.

Diamondback Energy Overview

- **High Returns in Current WTI Environment**
  - At $60 WTI with recalibrated service costs and operating efficiencies the Company expects to generate comparable returns as when WTI was $75[1]
    - 60% IRR at $60 Bbl WTI[1]
  - Increasing 2015E production guidance range 11% to 29.0 - 31.0 Mboe/d while staying within previous capex guidance
  - Have begun completing backlog of wells driven by service cost reductions
  - Increasing from 3 to 5 horizontal rigs in 2H’15 to bring NAV forward
- **Track Record of Capital Discipline, Stockholder Returns, Accretive Acquisitions and Maintaining a Strong Balance Sheet**
  - Peer-leading drill and complete times translate to lower well costs and higher returns[2]
  - History of higher cash margins and lower OpEx than peers[2]
  - Strong balance sheet with low net debt to 1Q’15 annualized Adjusted EBITDA[3] of 1.3x – supports increased activity
- **Viper Energy Partners Drives Significant Free Cash Flow**
  - ~$1.6 BN market capitalization[4]; Diamondback owns 88%
  - Ownership of underlying minerals significantly improves rates of return
- **Key Statistics**
  - Midland Basin pure-play with ~89,200 pro forma net acres[5]
  - Market capitalization of $4.7 BN and enterprise value of $5.5 BN[6]
  - 1Q’15 production of 30.6 Mboe/d, up 705% since IPO
  - Pro forma proved reserves[7]: 117.2 MMBOE (60% PD), up 84% y/y

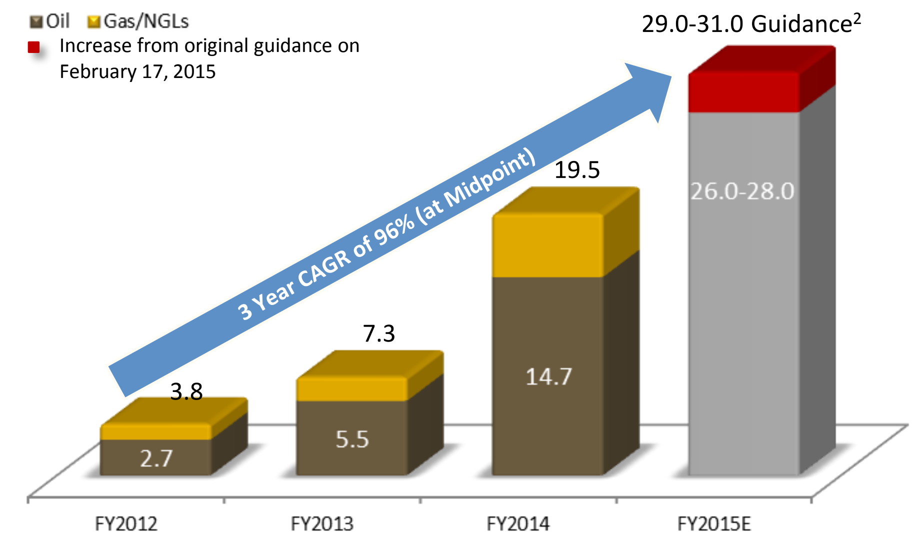
Diamondback Energy Acreage



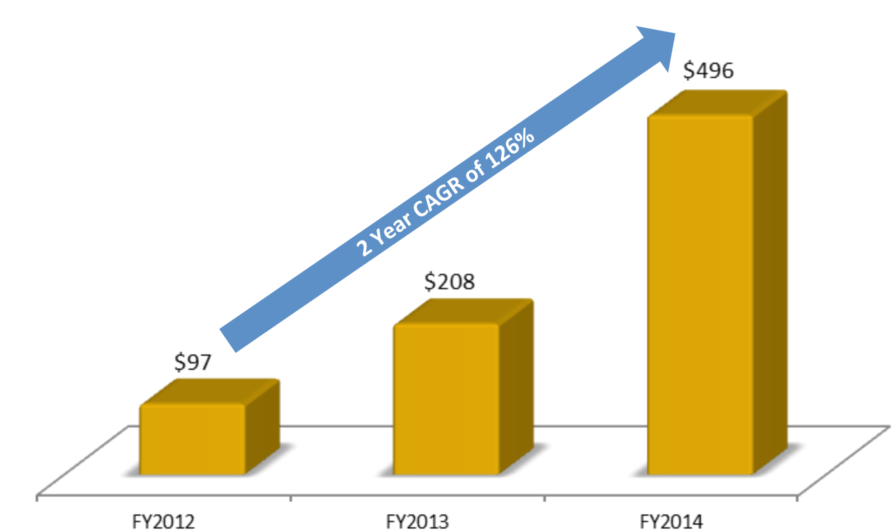
(1) $60 WTI returns assume realized prices of $56.50 oil, $3.40 gas, $14 NGLs. Based on 7500’ lateral and average EUR of 800 Mboe. Peak well cost of ~$7.8 MM and assumes ~23% cost reduction. (2) Peers include CXO, LPI, PE, PXD, and RSPP. (3) Annualized Adjusted EBITDA is Adjusted EBITDA for the three months ended March 31, 2015 multiplied by four. Actual Adjusted EBITDA for 2015 will depend on many factors and may differ from Annualized Adjusted EBITDA. See the disclaimers at the beginning of this presentation. (4) Based on closing price on May 5, 2015. (5) Pro forma net acreage number accounts for both recent and pending announced acquisitions. (6) Market data based on 59.0MM shares outstanding and $79.76 closing share price on May 5, 2015. Cash, debt and noncontrolling interest as of 1Q15 10-Q. (7) Includes YE2014 standalone reserves plus May 2015 announced acquisition proved developed reserves estimates prepared internally by the Company and subject to numerous assumptions and risks. Substantially all of these acquisitions remain pending and there can be no assurance that they will be completed on the anticipated terms or at all.

A Growth Story

Average Daily Net Production (Mboe/d)[1]



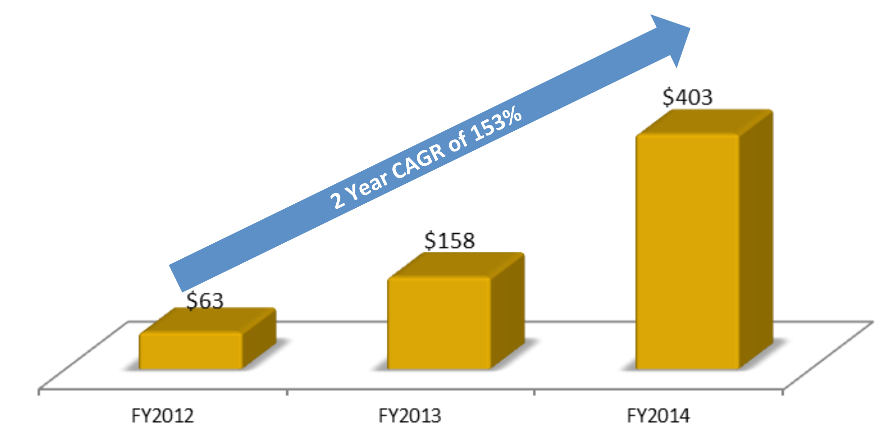
Revenue Growth[1] ($ in MMs)



Key Highlights

- Shift to horizontal development in late 2012 driving accelerated growth
- Leader in delivering horizontal value with over 140 operated horizontal wells drilled
- Grew production volumes 148% and 166% y/y in 2013 and 2014, respectively
- 2015E volumes forecasted to increase nearly 54% y/y[2]

Adjusted EBITDA Growth[1] ($ in MMs)



(1) 2012 numbers reflect pro forma information of Diamondback and its subsidiaries and includes the Permian Basin interests of Gulfport acquired in October 2012 as if those interests had been acquired by Diamondback on January 1, 2012. (2) Based on midpoint of updated 2015 production guidance announced May 6, 2015, which guidance is subject to numerous assumptions and risks. See the disclaimer at the beginning of this presentation.

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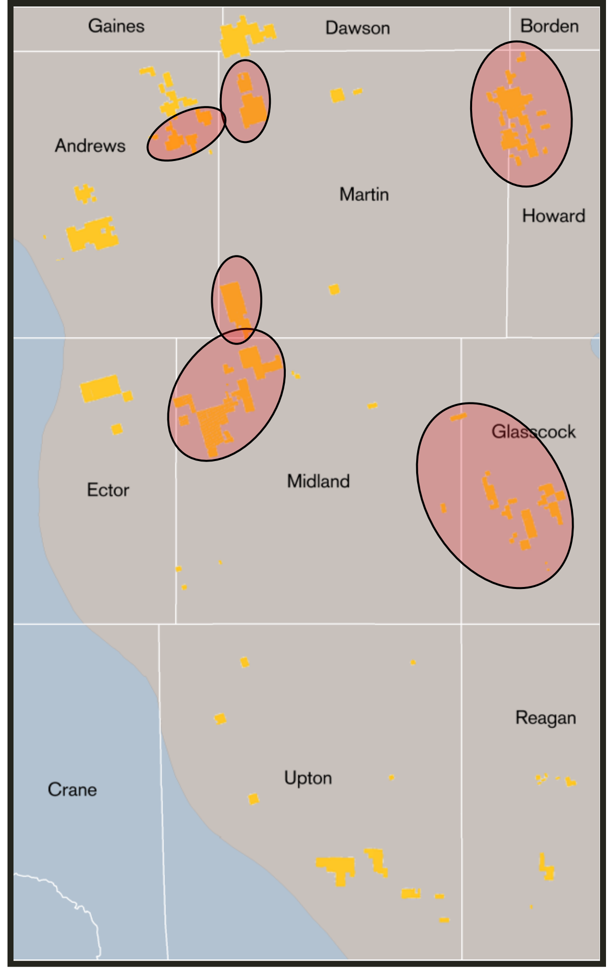
Significance of the Lower Spraberry

- **New horizontal development target in formation considered marginally economic for decades**
- **Positive tests across acreage base**
- **~1 MMboe EUR in Midland County, ~0.7 MMboe in Glasscock, and ~0.8 MMboe in Martin, Howard, and Andrews based on management estimates and Ryder Scott PUD values in respective areas.**

PV-10 Upside from Lower Spraberry[1]

Area	Net locations[2] (660 ft)	(500 ft)	PV-10 at $70/bbl Oil (660 ft)	(500 ft)	PV-10 at $90/bbl Oil (660 ft)	(500 ft)
Spanish Trail[3]	58	74	$1.04 bn	$1.30 bn	$1.45 bn	$1.81 bn
Other Midland	51	64	$0.44 bn	$0.55 bn	$0.66 bn	$0.82 bn
SW Martin	44	55	$0.29 bn	$0.36 bn	$0.44 bn	$0.55 bn
NW Martin / NE Andrews	71	89	$0.45 bn	$0.56 bn	$0.70 bn	$0.87 bn
NW Howard	82	102	$0.56 bn	$0.70 bn	$0.85 bn	$1.06 bn
Glasscock	62	77	$0.31 bn	$0.39 bn	$0.51 bn	$0.64 bn
Total	**368**	**461**	**$3.09 bn**	**$3.86 bn**	**$4.61 bn**	**$5.75 bn**

Acreage Map



Acreage included in inventory/PV-10 calculation

(1) Based on Lower Spraberry potential in areas identified only. Assumes 990 mboe EURs in Midland County, 700 mboe in Glasscock County and 810 mboe in other areas. $70/bbl oil case assumes $7.0 mm well cost for a 7,500' lateral while $90/bbl case assumes that improved oil price would cause service costs to increase to $7.5 mm for a 7,500' lateral. PV values assume development over the next five years. (2) Net locations are normalized to an equivalent 7,500' lateral. Spanish Trail location count does not include 25 net mineral interest locations at 660' spacing and 32 net mineral interest locations at 500' spacing (normalized to 7,500' laterals and 25% royalty interest). (3) Includes mineral value

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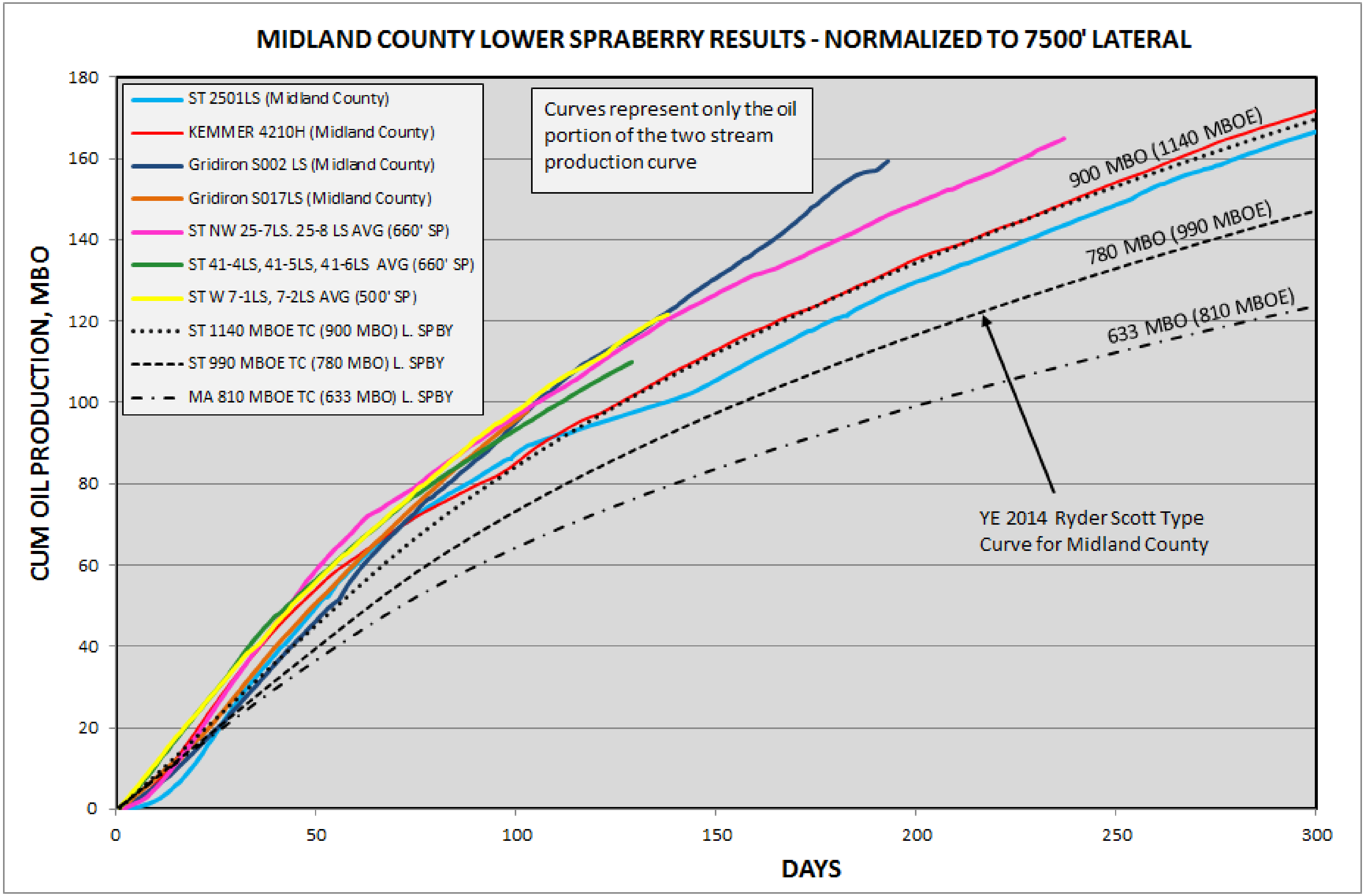
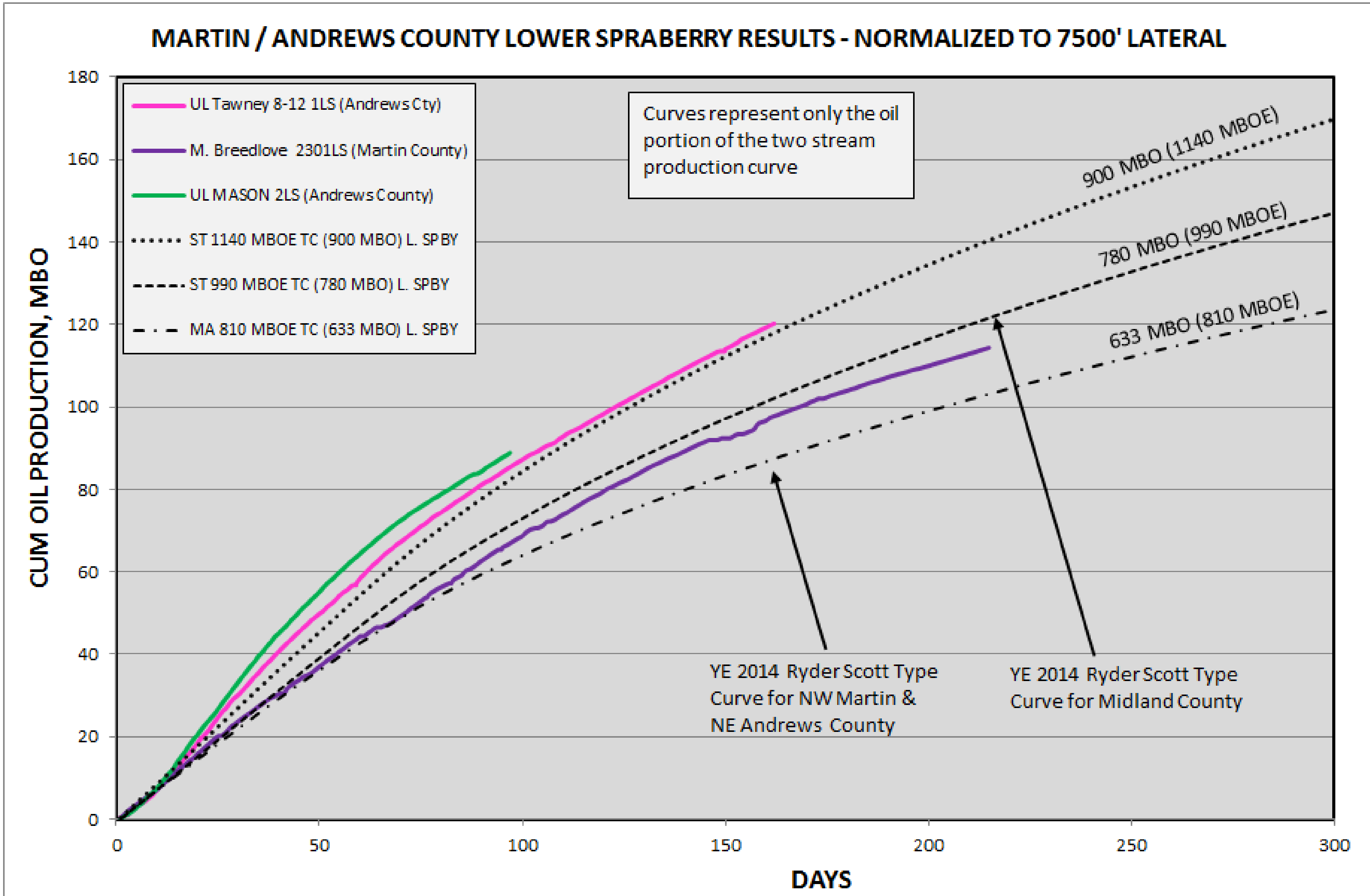
Lower Spraberry Performance – Midland



Note: Daily production normalized for operational shut-ins. Type curves based on normalized 7,500' laterals; actual lateral lengths vary.

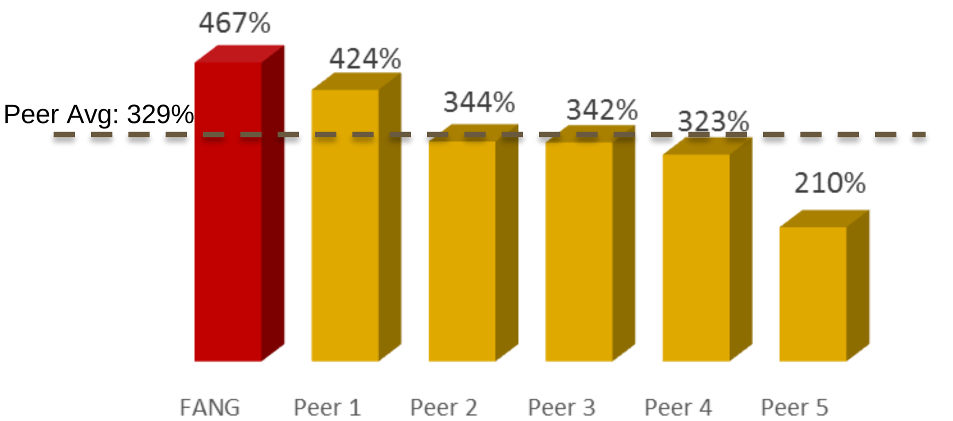
Lower Spraberry Performance – Martin and Andrews



Note: Daily production normalized for operational shut-ins. Type curves based on normalized 7,500' laterals; actual lateral lengths vary.

Peer Leading Capital Efficiency, Conservative Leverage & Attractive Valuation

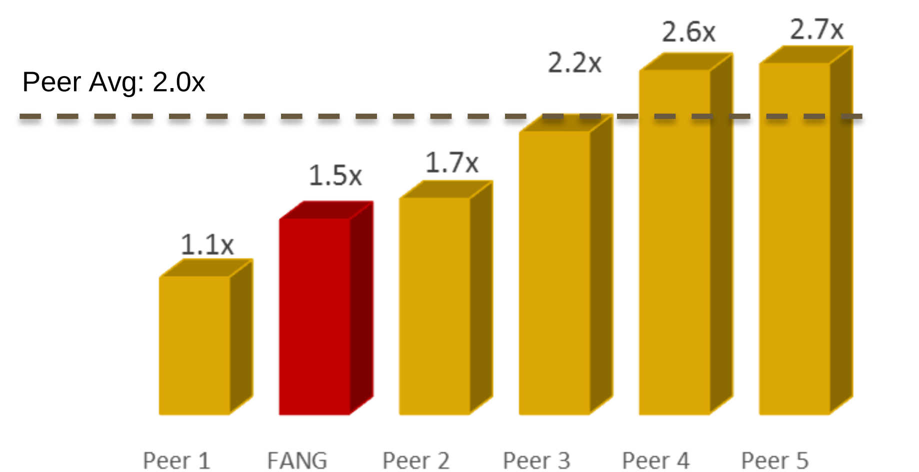
FY2014 Recycle Ratio[1]



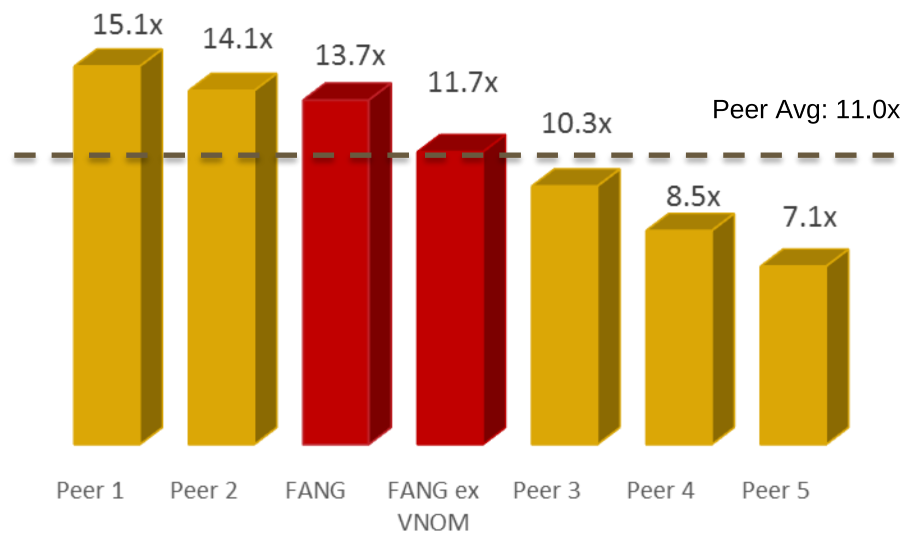
Key Highlights

- Peer leading cash margins and F&D costs drive differential recycle ratio
- FANG has a strong balance sheet with $370MM of liquidity and low total debt of 1.5x to 2014 Adjusted EBITDA
- Excluding Viper, Diamondback trades at an attractive valuation versus best in class Permian peers

Debt to FY2014 Adjusted EBITDA[2,3]



EV/2014 Adjusted EBITDA Comparison to Permian Peers[2,4]



Source: Company and peer filings. (1) Calculated by dividing 2014 adjusted EBITDA by 3-year average 1-year F&D costs. Peers include CXO, LPI, PE, PXD and RSPP. (2) Peers include CXO, LPI, PE, PXD, and RSPP. (3) Peer debt metrics are pro forma for all equity and debt offerings in 2015. (4) Enterprise value calculated as of May 5, 2015. VNOM is fully consolidated into FANG's EV and EBITDA. FANG ex VNOM is calculated by subtracting VNOM's EV and 2014 EBITDA from FANG's. All EVs pro forma for all debt and equity offerings in 2015.

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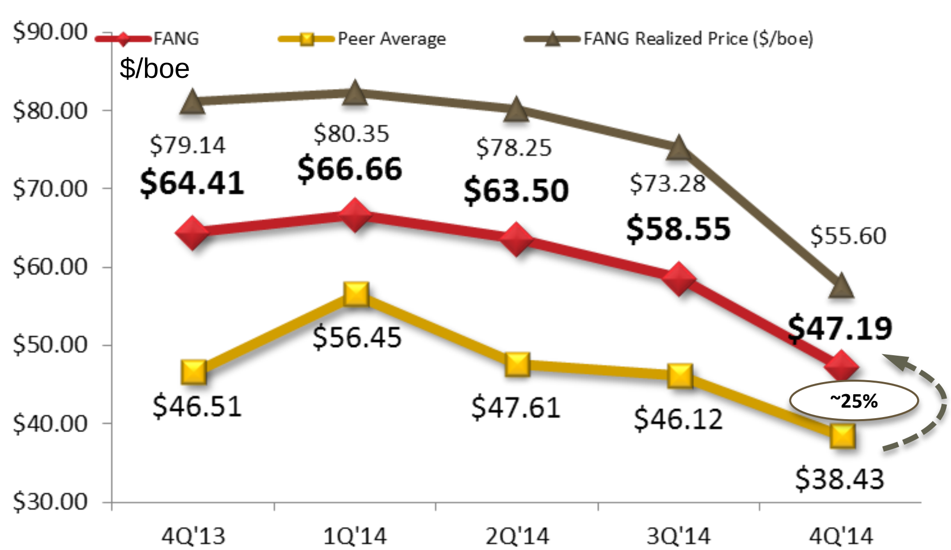
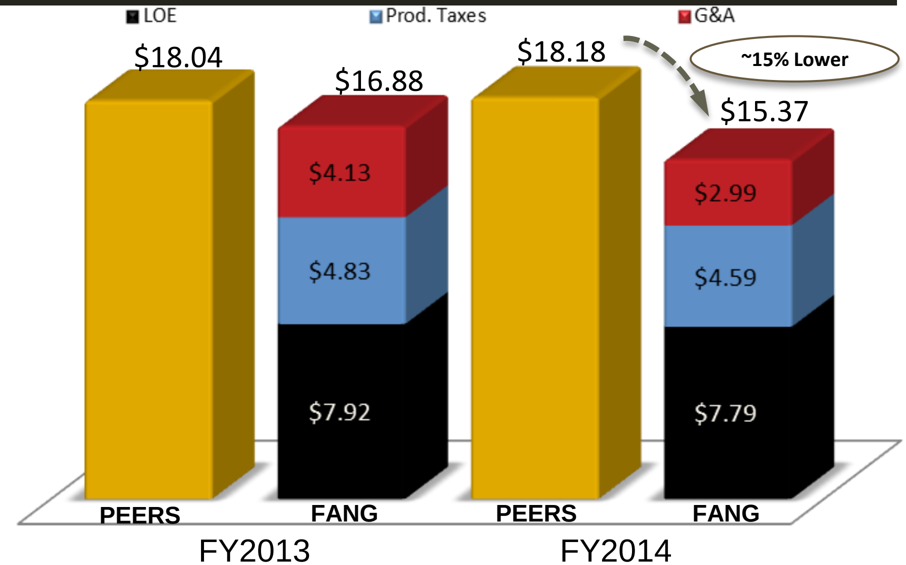
Peer Leading Cash Margins

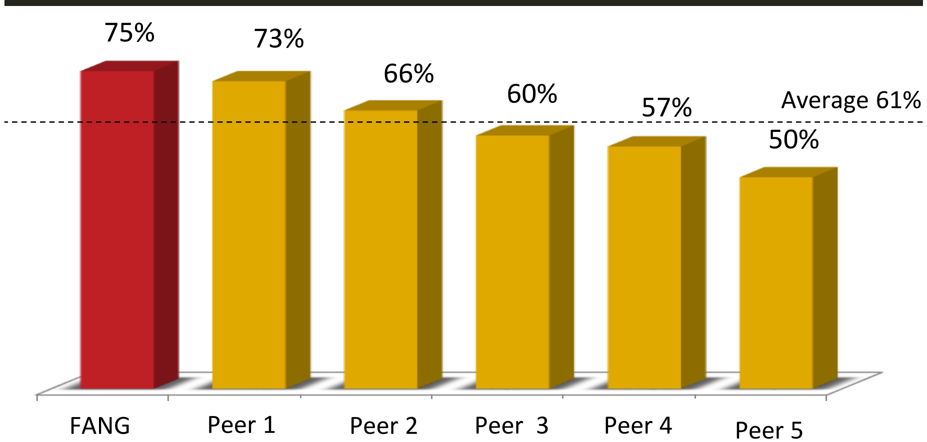
Cash Margins Have Consistently Exceeded Peers[1,2]



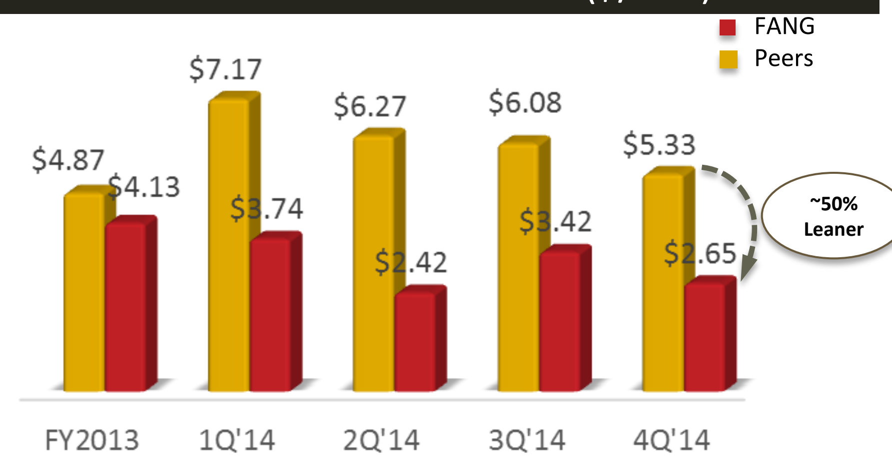
FANG Operating Expenses Below Peers[1] ($/boe)



FANG Percent Oil Greater than Peers[1,3]



FANG G&A Below Peers[1,4] ($/boe)



Source: Company and peer filings, Management Data and Estimates. (1) Peers include CXO, LPI, PE, PXD and RSPP. (2) Cash margin represents publicly reported EBITDA divided by BOE production for the period. Cash margins do not include PE or RSPP prior to 2Q'14, as 2Q was the first time they reported publicly. (3) Represents 4Q'14 reported production percentage of oil. (4) Peer G&A expense averages do not include PE prior to 2Q'14.

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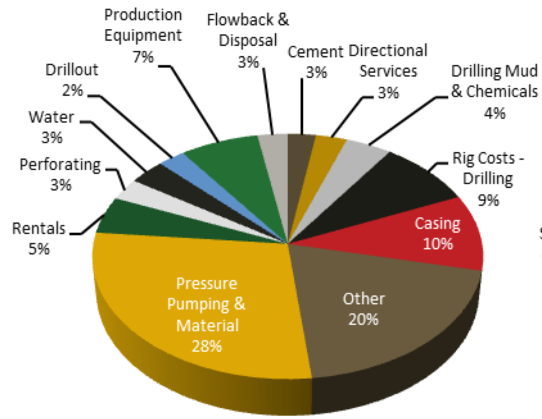
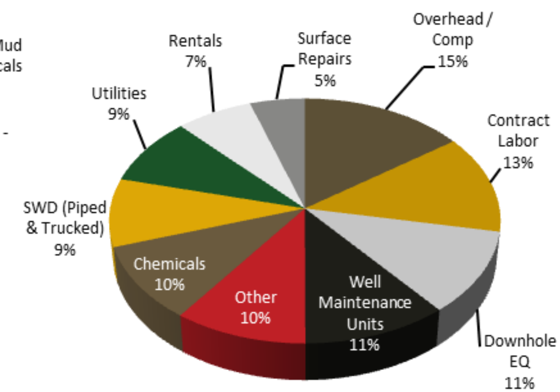
Diamondback Has Reduced Costs in Current Commodity Environment

- **Cooperation with service cost providers has led to further reductions in AFEs**
  - Leading-edge AFEs are down 20-30% from 2014 peak
  - Company continues to pursue incremental cost reductions and continued efficiency improvements

Breakdown of Current Costs[1]



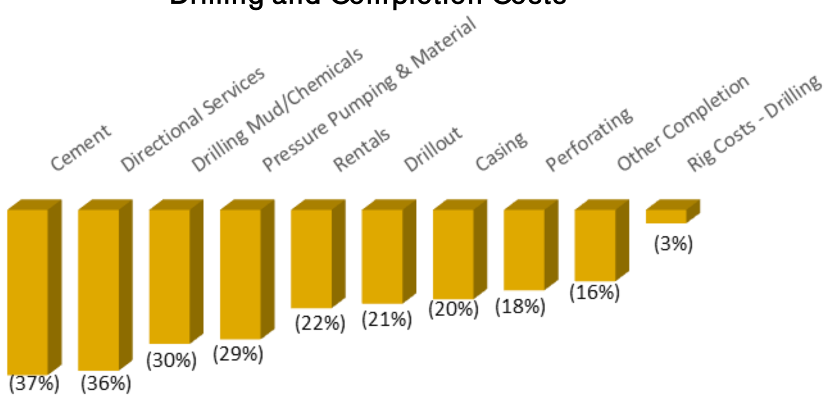
Drilling and Completion Costs



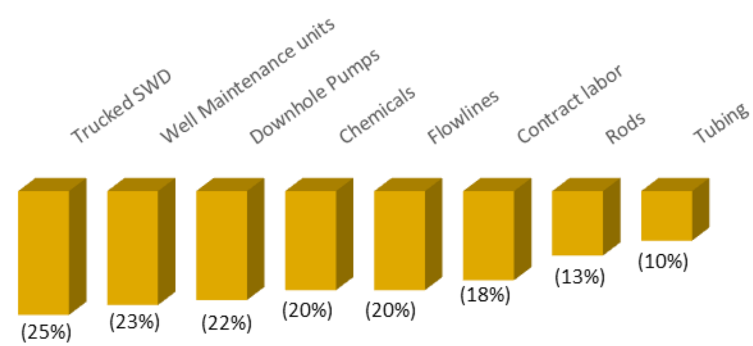
Lease Operating Expenses

Current Realized Cost Reductions

Drilling and Completion Costs



Lease Operating Expenses



At $60 WTI with recalibrated service costs and operating efficiencies the Company expects to generate comparable returns as when WTI was $75[2]

(1) Artificial lift and intangibles included in production equipment sector. (2) $60 WTI returns assume realized prices of $56.50 oil, $3.40 gas, $14 NGLs. Based on 7500' lateral and average EUR of 800 Mboe. Peak well cost of ~$7.8 MM and assumes ~23% cost reduction.

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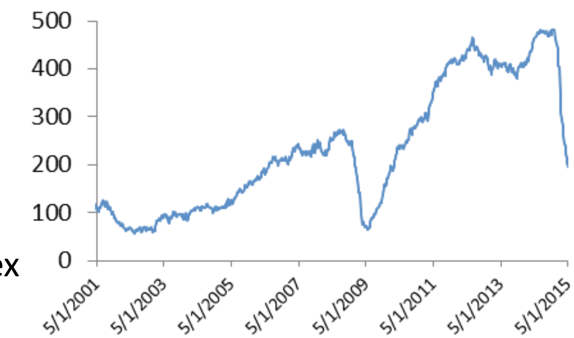
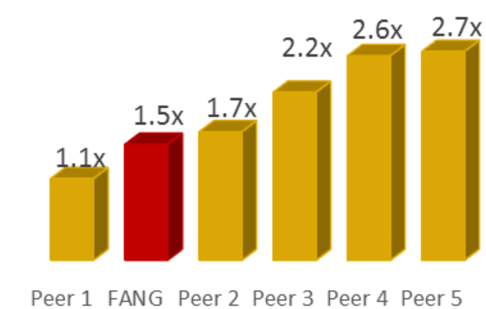
2015: Capital Discipline Remains Key

- **Responding to Market Conditions with 2015 Production and Capex Guidance**
  - At $60 WTI with recalibrated service costs and operating efficiencies the Company expects to generate comparable returns as when WTI was $75[1]
  - Have begun completing wells drilled in 2014 due to meaningful decrease in pressure pumping costs
  - Increased 2015 production guidance represents nearly 54% growth at the midpoint as compared to 2014 production
    - 2015E production guidance increased 11% while staying within previous capex guidance
- **Strong Balance Sheet**
  - Company remains focused on financial strength and flexibility
  - Liquidity of $370 MM with low net debt to 1Q'15 annualized Adjusted EBITDA of 1.3x
  - 88% ownership in Viper offers additional liquidity and/or ability to finance growth
  - Borrowing base anticipated to be $725 MM in spring 2015 redetermination, but Company to limit its commitment amount to $500 MM
  - Balance sheet supports increased activity levels
  - On April 13, 2015, S&P raised Diamondback's corporate credit rating to B+ from B and revised its outlook to stable from positive
- **Consistent Track Record of Focus on Rates of Return**
  - Switched focus from vertical to horizontal drilling in 2012
  - History of accretive acquisitions with minimal drilling obligations
  - Purchase of mineral acres

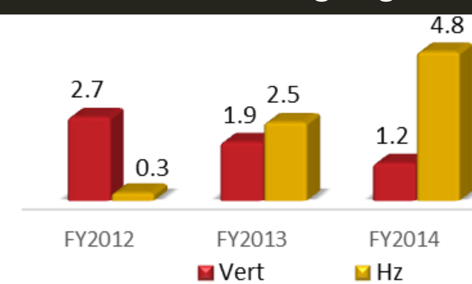
Permian Rig Count[2]



Debt to FY2014 Adjusted EBITDA[3]



Diamondback Avg. Rig Count



(1) $60 WTI returns assume realized prices of $56.50 oil, $3.40 gas, $14 NGLs. Based on 7500' lateral and average EUR of 800 Mboe. Peak well cost of ~$7.8 MM and assumes ~23% cost reduction. (2) Source: Baker Hughes Rig Count for TX Districts 7B, 7C, 8, and 8A as of May 1, 2015. (3) Peers include CXO, LPI, PE, PXD and RSPP.

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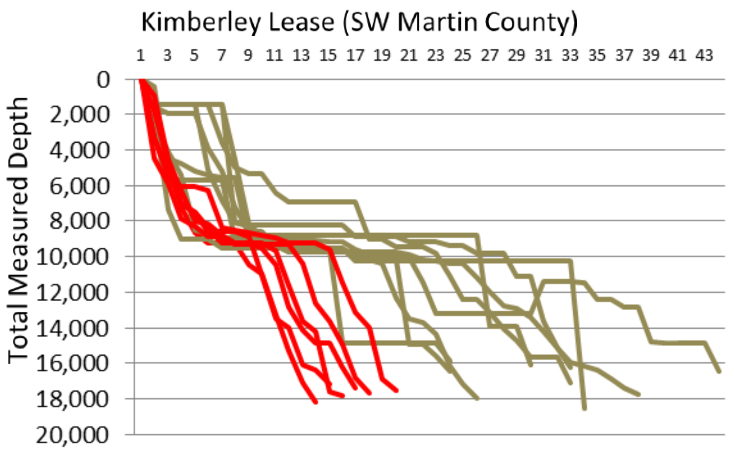
Horizontal Execution – Peer Leading Performance Drives Lower Well Costs and Higher Returns

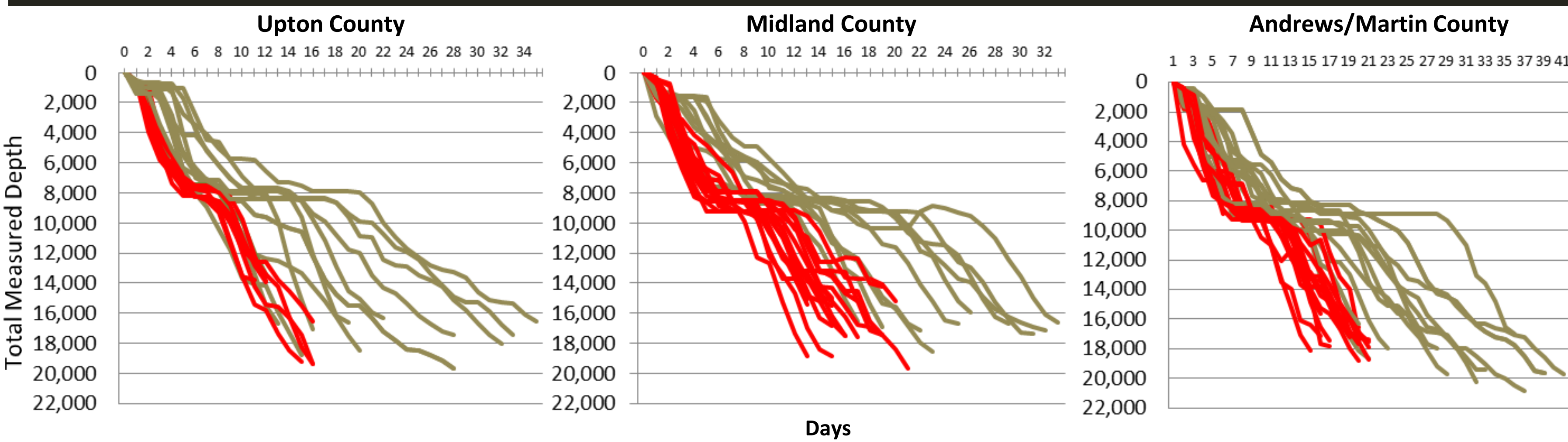
Days vs Depth Hz[1]

Diamondback **Peers**



- **Faster drilling times lead to lower well costs and higher rates of return**
- **Leading edge two-well pad in Midland County with an average lateral of ~10,000' (average ~19,000' measured depth) drilled in 31 days from spud of first well to TD of second**
    - Includes one well drilled in less than 12 days
- **On the Kimberly asset acquired in February 2014, FANG has decreased drilling times from 20 days to 12 days**
    - Average of 16 days compared to peer average of 32 days

Days vs Depth Hz[1] **Diamondback** **Peers**



Source: Company filings, management data and estimates. (1) ~7,500' laterals.

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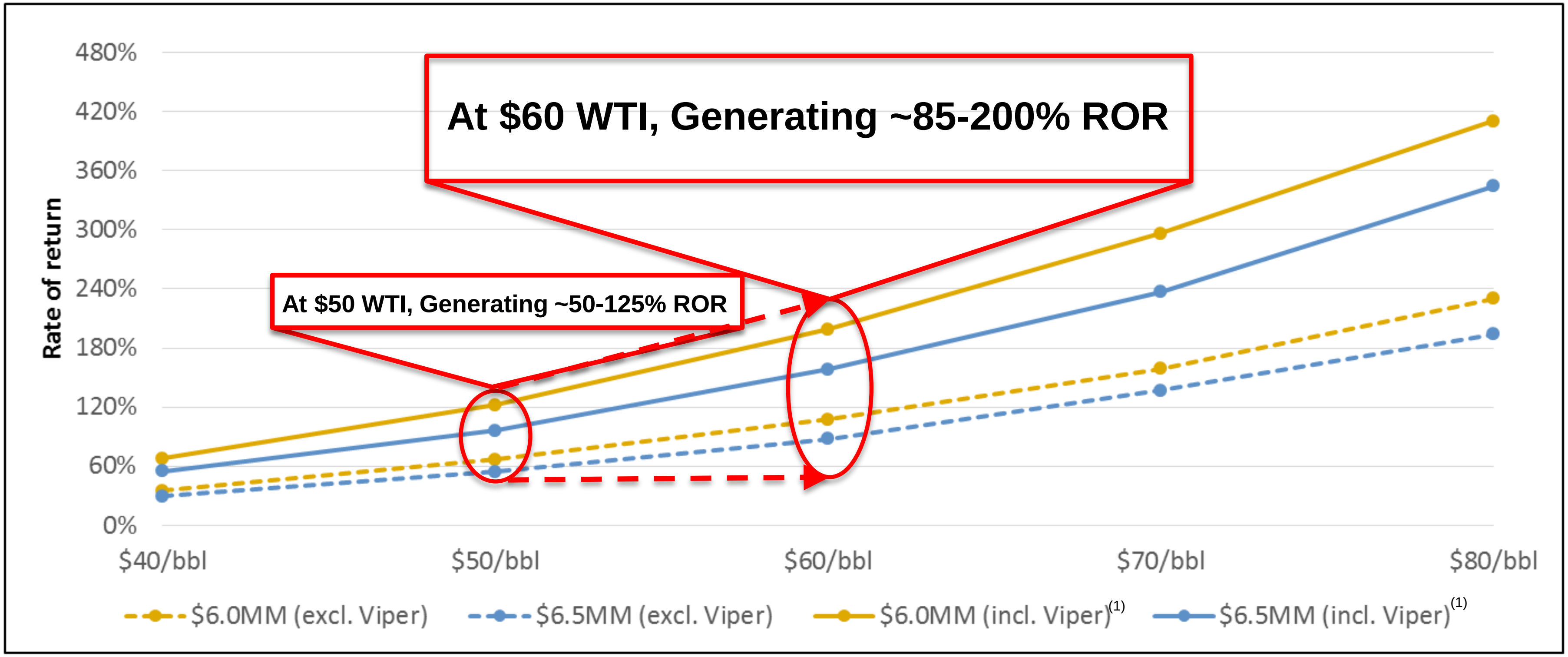
Resilient Lower Spraberry Economics in Spanish Trail

Spanish Trail Lower Spraberry Economics



- **Spanish Trail Lower Spraberry EUR increased by Ryder Scott to 990 Mboe from 650 Mboe**
- **65-75% of activity in Spanish Trail this year will target the Lower Spraberry**
- **Viper ownership significantly increases rates of return**
- **Breakeven prices below $30/bbl WTI**

Note: $60 WTI returns assume realized prices of $56.50 oil, $3.40 gas, $14 NGLs. Based on 7500' lateral and average EUR of 800 Mboe. Peak well cost of ~$7.8 MM and assumes ~23% cost reduction. (1) Represents additional ROR related to 88% ownership of Viper which owns mineral interests underlying acreage operated by FANG.

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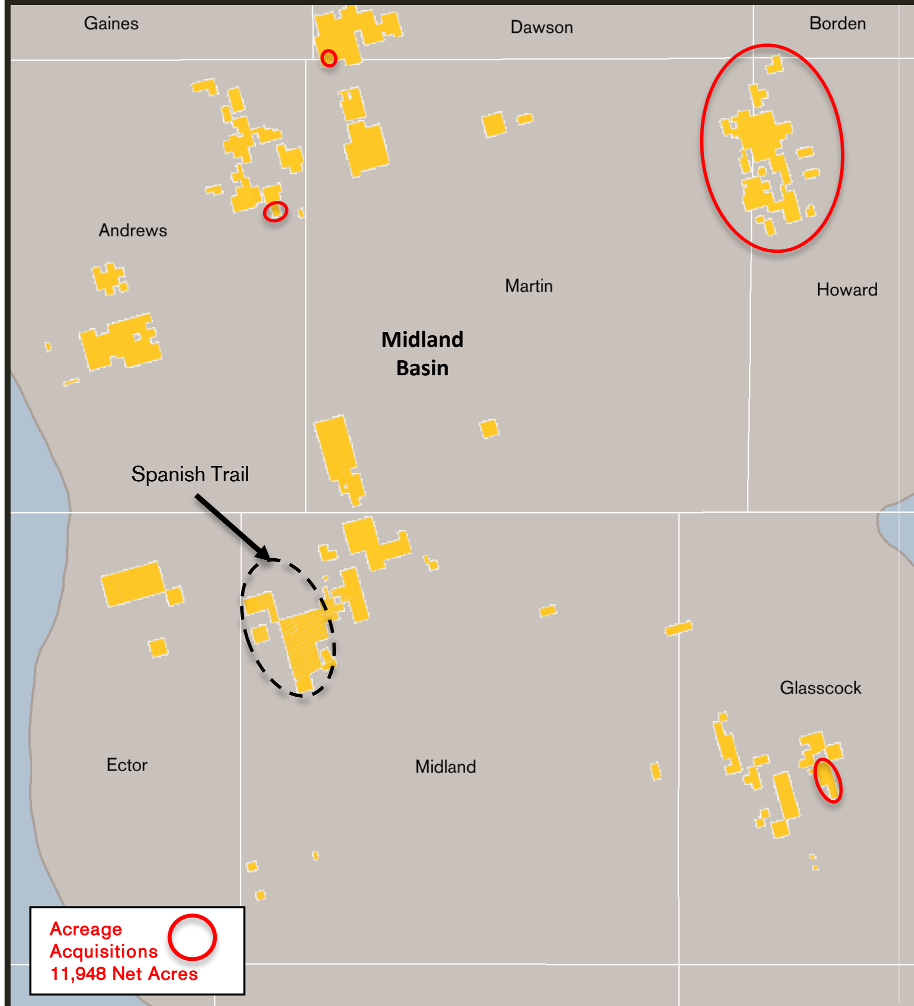
Adding Acreage in the Core of the Northern Midland Basin

- Recently acquired or signed agreements to acquire 11,948 net acres mostly in NW Howard County for ~$438MM
  - Production of 2.5 MBOEPD[1] from 120 gross wells and 4.3 MMBOE of proved developed reserves[2]
  - 232 net identified potential horizontal drilling locations with an average lateral length of 8,357'[3]
  - Includes salt water disposal facilities in Howard Co.
- Management believes acreage is in top quartile of FANG's existing acreage portfolio based on well results in immediate proximity
- Management believes 3 horizontal zones are de-risked – Lower Spraberry, Wolfcamp B and Wolfcamp A with upside potential from Middle Spraberry
- Includes a ~1.5% average overriding royalty interest on 12,890 gross acres which has been offered to VNOM for ~$33.7 million subject to board approval by conflict committee[4]

	Acreage	Net Potential Locations[5]				
County	Net	L Spra	WC B	WC A	M Spra	Total
Howard / Martin	10,098	71	71	71	TBD	214
Glasscock	1,252	6	1	6	TBD	13
Martin / Dawson	342	2	–	–	TBD	2
Andrews	256	2	–	–	2	3
Total	11,948	81	73	77	2	232

Acquisition Acreage Map



(1) Represents production from properties subject to acquisition announced in May 2015. Acquisition production is for April 2015 and is based on data provided by sellers and has not been verified by the Company. Actual production from acquired wells may vary materially. (2) Acquisition reserve estimates are based solely on management's internal evaluation and interpretation of reserve information and of other information provided to management in the course of due diligence review of the acquired properties. Such estimates have not been reviewed by the Company's independent reserve engineers and are subject to numerous assumptions and risks, including those discussed above. (3) Based on well spacing of 660 feet. (4) There can be no assurance that this transaction will be completed on these terms or at all. (5) Based on management internal estimates.

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Compelling Acquisitions to Add Attractive Horizontal Inventory

Accretive to stockholders

- Expected to be accretive on net asset value, production, acreage and on 2016 earnings valuation metrics
- Attractive acquisition price of ~$23,845 per adjusted[2] net acre and ~$2.05 per Boe[3]
- Significant value from exposure to mostly undeveloped 11,948 net acres in core of Northern Midland Basin
- Attractive well economics

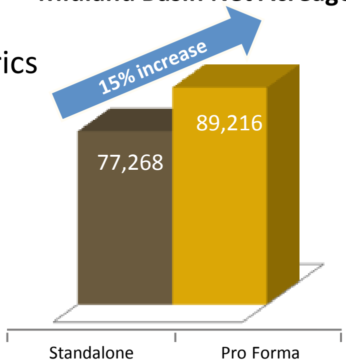
Expands scope of core Midland Basin assets

- Management believes acreage is in the top quartile of FANG's existing acreage portfolio – compares favorably to Spanish Trail
- Provides meaningful increase in oil-rich net acreage expanding 15% to 89,216 net acres
- 2 dedicated horizontal rigs expected to be added in second half of 2015
- 83% HBP through vertical and horizontal wells, providing optionality on when to develop

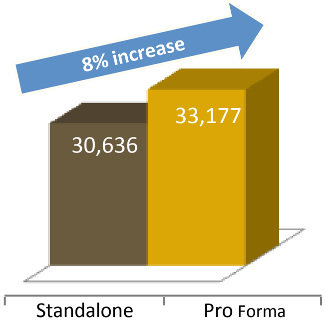
Additive to concentrated horizontal story

- Complementary acreage blocks with strong horizontal delineation potential
- Largely contiguous acreage allows for efficient infrastructure installation and ~42% locations to be ~10,000' laterals
- Management believes 3 horizontal zones are de-risked – Lower Spraberry, Wolfcamp B and Wolfcamp A with additional development potential from Middle Spraberry
- Acreage in close proximity to strong Encana (Athlon), Energen and private operator horizontal well results
- 93% operated with high working interest (75%)
- 3D seismic data available to geosteer horizontal wells

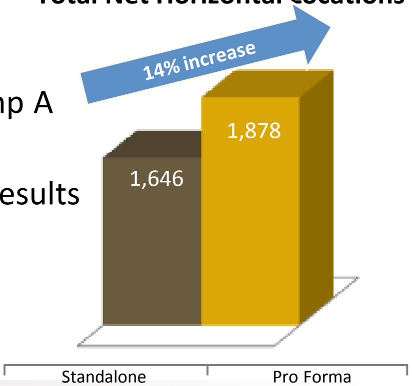
Midland Basin Net Acreage



Current Net Production (BOEPD)[1]



Total Net Horizontal Locations



(1) Represents Company average daily production for 1Q'15. Pro forma includes 2.5 MBOEPD of production from announced acquisitions in May 2015. Acquisition production is for April 2015 and is based on data provided by seller and has not been verified by the Company. Actual production from acquired wells may vary materially. (2) Purchase price adjusted for production valued at $45,000 per Boe/d, $4.9 million for salt water disposal system, and $33.7 million for VNOM drop-down, subject to board approval by conflicts committee. (3) Assumes 232 net locations at 800 Mboe per location and 75% NRI.

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Acquisition Acreage is Central to Some of the Best Well Results in the Midland Basin

Wright 44-41 3H
Element
IP30: 929 Boepd (91% oil)
EUR : 815 MBOE
Lateral Length: 6727’

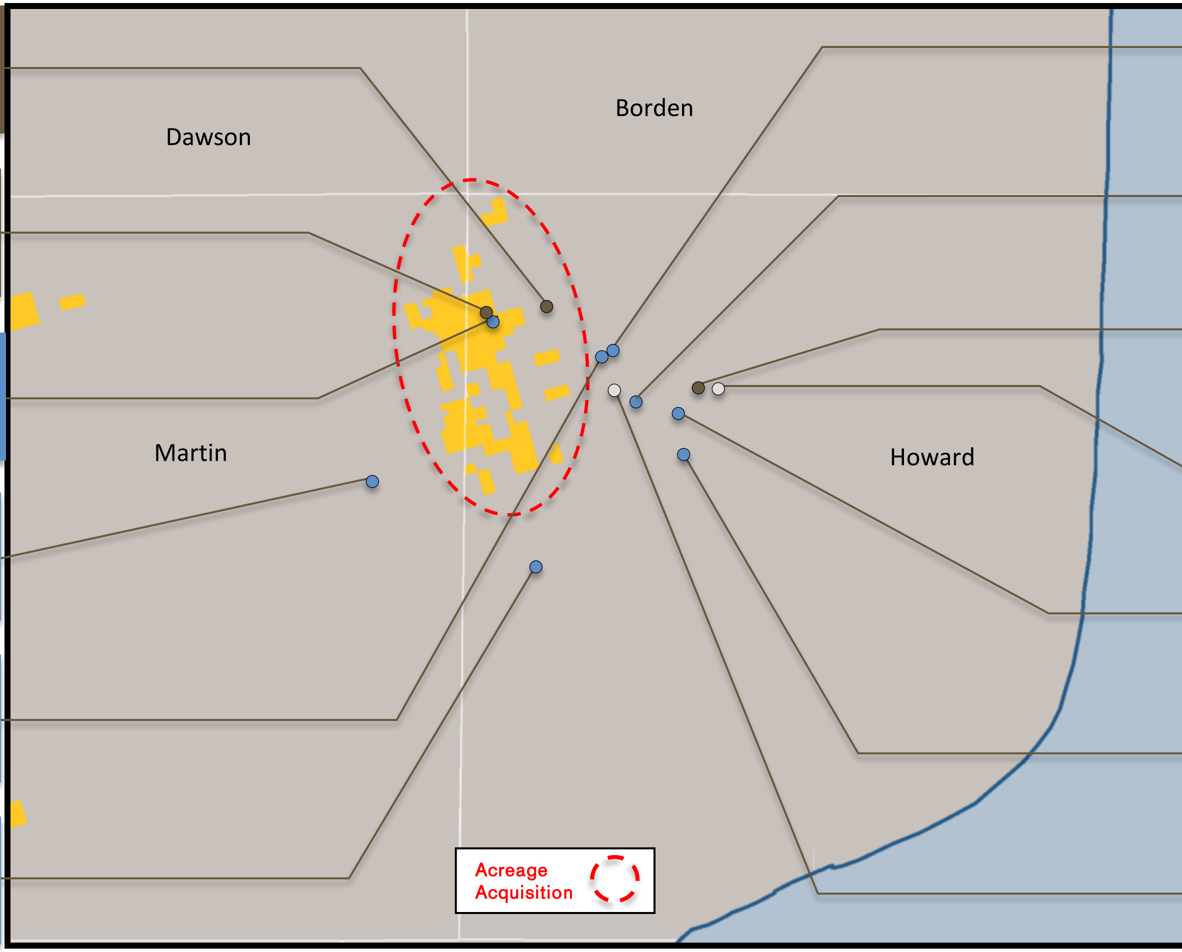
Smith SN 48-37 501H
Energen
Well recently completed
Lateral Length: ~7000’

Smith SN 48–37 101H
Energen
IP30: 770 Boepd (92% oil)
EUR: 827 MBOE
Lateral Length: 6930’

Wilbanks SN 16–15 101H
Energen
IP30: 582 Boepd (90% oil)
EUR: 852 MBOE
Lateral Length: 6930’

Wolf-McCann Unit 10-15 2H
Element
IP30: 1020 Boepd (91% oil)
EUR: 884 MBOE
Lateral Length: 6995’

Hendrix 1H
Occidental
IP30: 832 Boepd (88% oil)
EUR: 622 MBOE
Lateral Length: 4514’



Gardner Unit 15-10 2H
Element
IP30: 724 Boepd (91% oil)
EUR: 802 MBOE
Lateral Length: 7020’

SFH Unit 23 1H
Element
IP30: 670 Boepd (89% oil)
EUR: 766 MBOE
Lateral Length: 7268’

Hamlin 19-30 1H
Tall City
IP30: 1144 Boepd (89% oil)
EUR: 1088 MBOE
Lateral Length: 7012’

Hamlin 20-29 1H
Tall City
IP30: 742 Boepd (91% oil)
EUR: 686 MBOE
Lateral Length: 6513’

Garret Snell B 36-25 4H
Element
IP30: 559 Boepd (90% oil)
EUR: 773 MBOE
Lateral Length: 9200’

Garret Reed Unit 37-48 4H
Element
IP30: 886 Boepd (91% oil)
EUR: 955 MBOE
Lateral Length: 7295’

Hamlin 15-22 3H
Element
IP30: 498 Boepd (88% oil)
EUR: 673 MBOE
Lateral Length: 7005’

Lower Spraberry | Wolfcamp A | Wolfcamp B

More de-risked than any previous Diamondback acquisition

Source: DrillingInfo. Note: All EURs and 30-day rates are two-stream. EURs and IPs are FANG’s interpretation of data normalized for a 7,500 foot lateral

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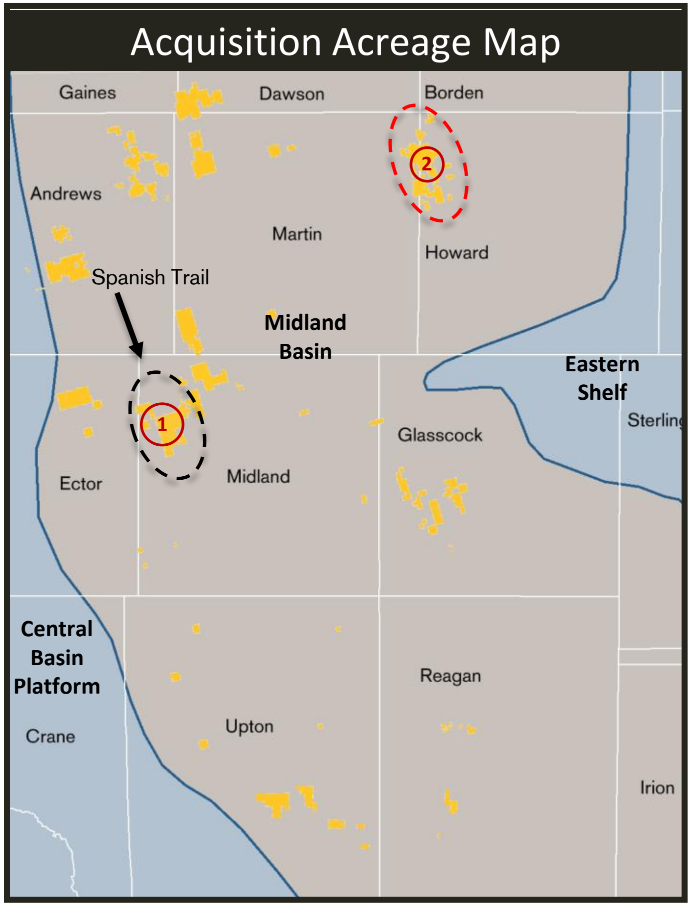
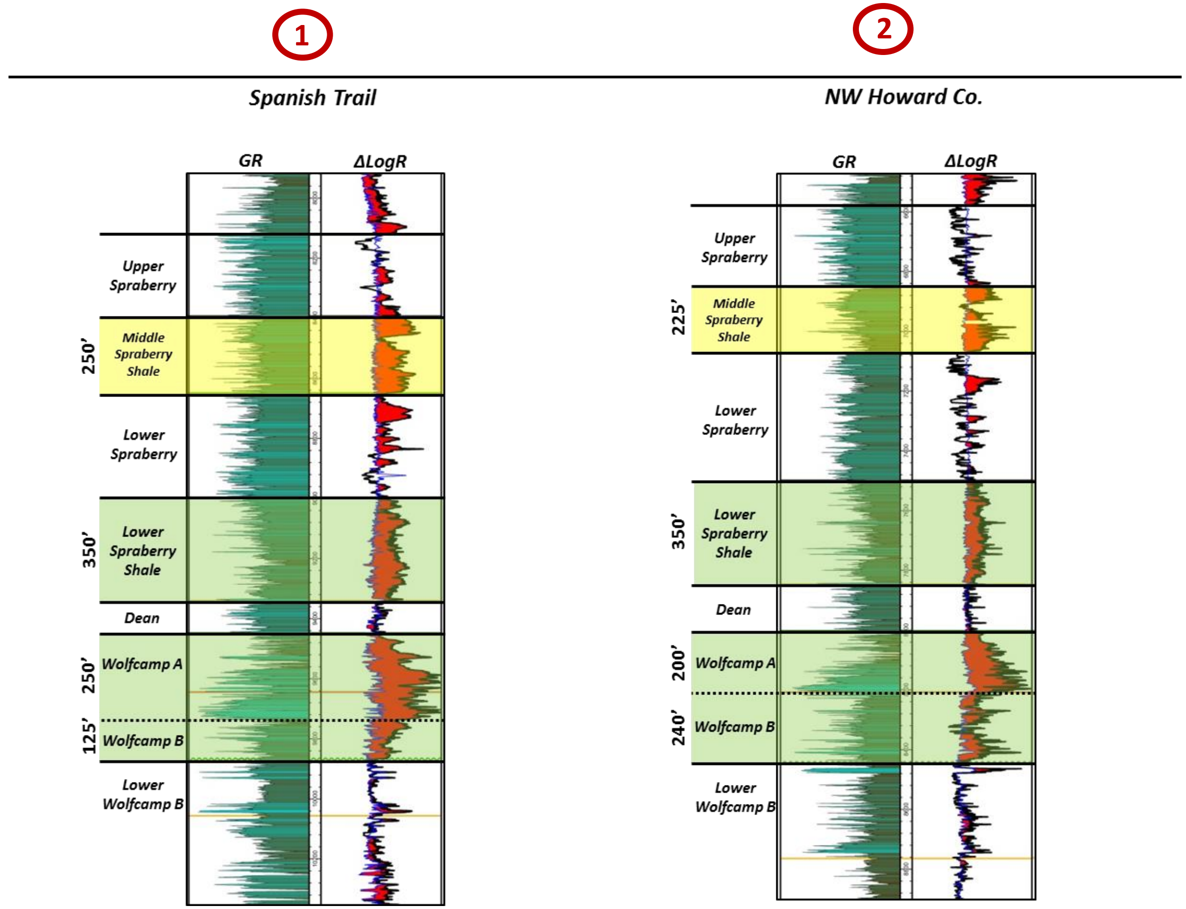
Comparison to Spanish Trail





- Petrophysical analysis of the Lower Spraberry, Wolfcamp B and Wolfcamp A shales in NW Howard County results in similar unconventional reservoir quality as type wells in FANG's Spanish Trail. These results have been validated by core data.
- Unvalued upside in Middle Spraberry which is currently being validated in Spanish Trail

Acquisition acreage in Howard County original oil in place appears to be the same or better than Spanish Trail

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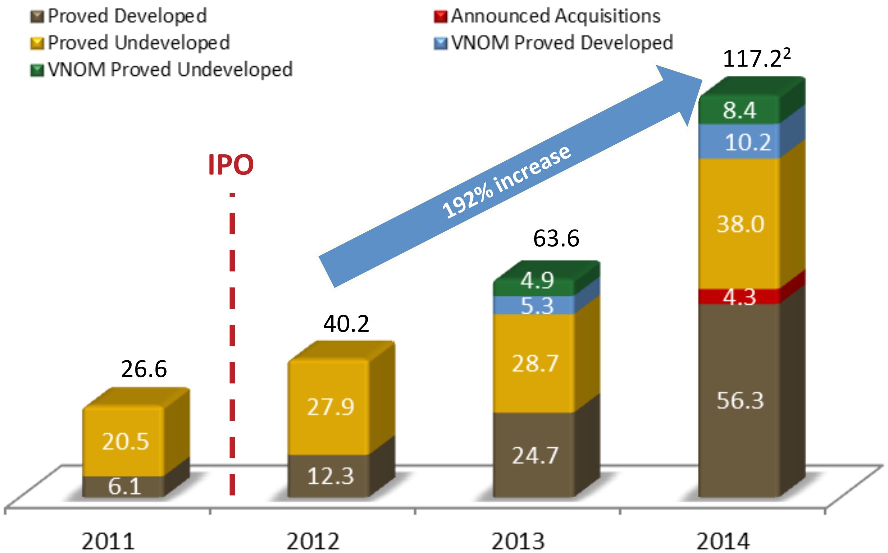
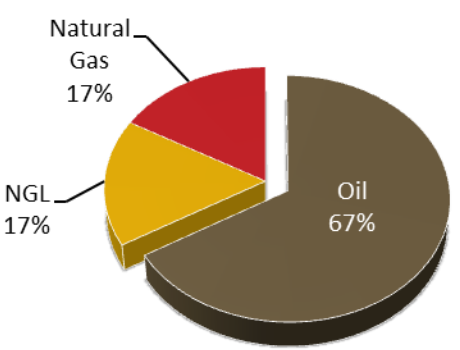
Diamondback Energy – Reserves Summary

Total Reserves Growth[1] (MMboe)

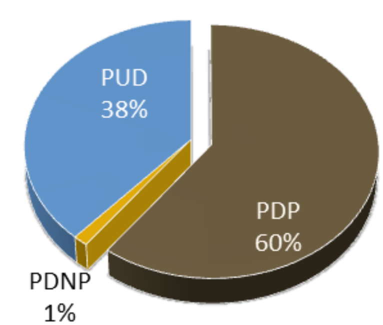


Pro forma 1P Reserves – By Commodity



117.2 MMBOE

Pro forma 1P Reserves[2] – By Category



117.2 MMBOE

- **Proved Reserves Represent Over a Decade of Reserve Life[3]**
  - Pro forma 2014 total proved reserves increased 84% y/y to 117.2 MMboe
  - Diamondback's pro forma standalone proved reserves increased 85% y/y to 98.6 MMboe
  - Diamondback's pro forma standalone proved developed reserves increased 136% to 70.8 MMboe

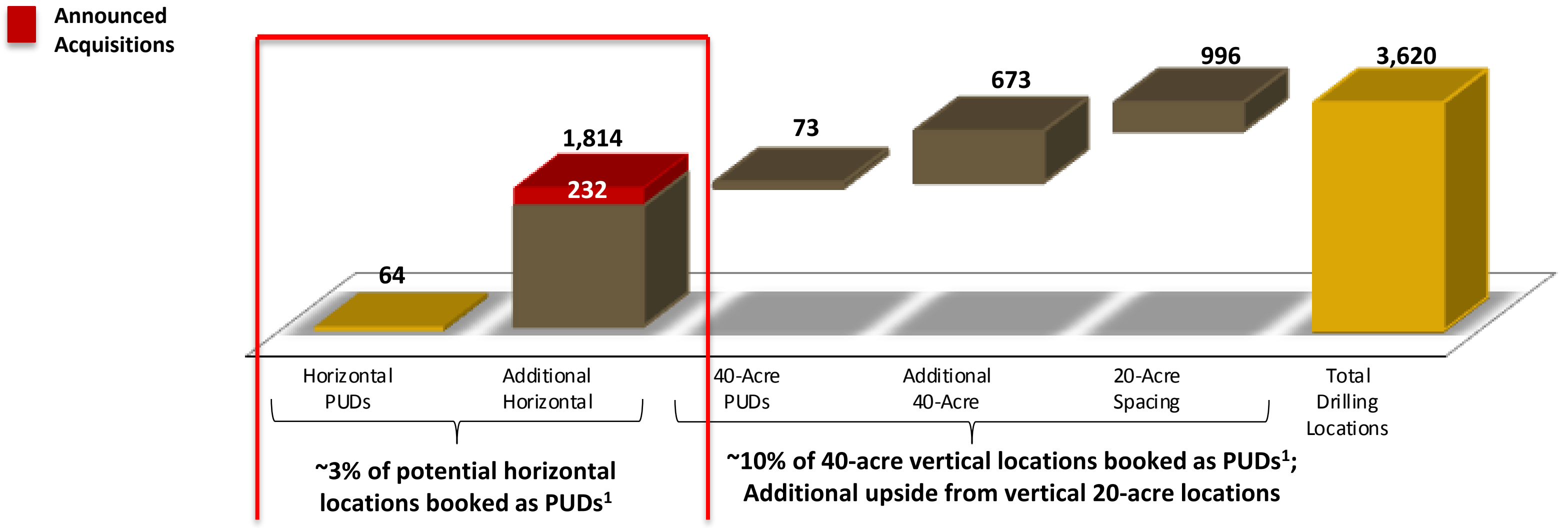
F&D Costs

($/boe)	2013	2014
Drill Bit F&D[4]	$14.46	$11.09
Reserve Replacement[5]	975%	793%
Organic Reserve Replacement[6]	573%	626%

(1) 2011-2012 reserves pro forma for acquisition of Permian Basin assets in connection with the Company's IPO. (2) Historical FANG reserves per independent reserve report prepared by Ryder Scott as of 12/31/14 (calculated as of 12/31/14 using SEC pricing of $87.15/bbl and $4.85/Mcf), plus management's estimate of reserves for the acquisitions announced in May 2015. (3) Based on midpoint of 2015 production guidance (4) Defined as exploration and development costs divided by the sum of extensions and discoveries and revisions. 2013 F&D excludes negative revisions of 7.9 MMBoe for vertical PUD downgrades and 0.3 MMBoe of positive revisions due to higher product pricing. 2014 F&D excludes 6.2 MMboe of revisions due to vertical PUD downgrades. (5) Defined as the sum of extensions, discoveries, revisions, and purchases, divided by annual production (6) Defined as the sum of extensions, discoveries, and revisions, divided by annual production

Robust Multi-year Inventory

Identified Net Potential Drilling Locations



Horizontal Potential (excluding minerals)[2]

Horizontal Target	Wolfcamp B	Lower Spraberry	Middle Spraberry	Clearfork	Wolfcamp A	Wolfcamp C	Cline	Total
Locations (gross / net)	594/405	625/428	332/252	250/206	501/342	47/38	283/207	**2,632 / 1,878**
EUR / Well (Mboe)	550 – 650	725 – 825	500 – 600	350 – 450	500 – 600	350 – 450	400 – 500	**530 – 630**
Average Lateral Length[3]	7,190’	7,160’	6,590’	6,470’	7,190’	5,550’	6,500’	**6,940’**

Estimated EURs for potential drilling locations are normalized to 7,500’ in lateral length. Actual lateral length varies depending on numerous factors, including the lease geometry, anticipated characteristics and permitted spacing. The actual average lateral length for the Company’s potential drilling locations is currently less than 7,500’. Estimated EUR ranges based on 84 Wolfcamp B, 17 Lower Spraberry, 2 Middle Spraberry, 3 Wolfcamp A, 2 Clearfork, and 2 Cline wells that Diamondback and/or Viper own an interest in and are in the 2014 Ryder Scott PDP Report and various geological and engineering assumptions made by management using company and public data sources. Potential drilling locations and EUR ranges are management estimates and may change materially over time as the Company and offset operators drill initial and/or additional wells in each target zone.

Source: Company Filings, Management Data and Estimates. Management estimates as of 12/31/14. (1) PUDs based on Ryder Scott prepared estimates as of 12/31/2014. (2) 64 of the net horizontal locations are booked as PUDs. (3) Lateral lengths vary from ~5,000’ to 10,000’ depending on lease geometry and other considerations.

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Financial Overview

Liquidity and Financial Profile

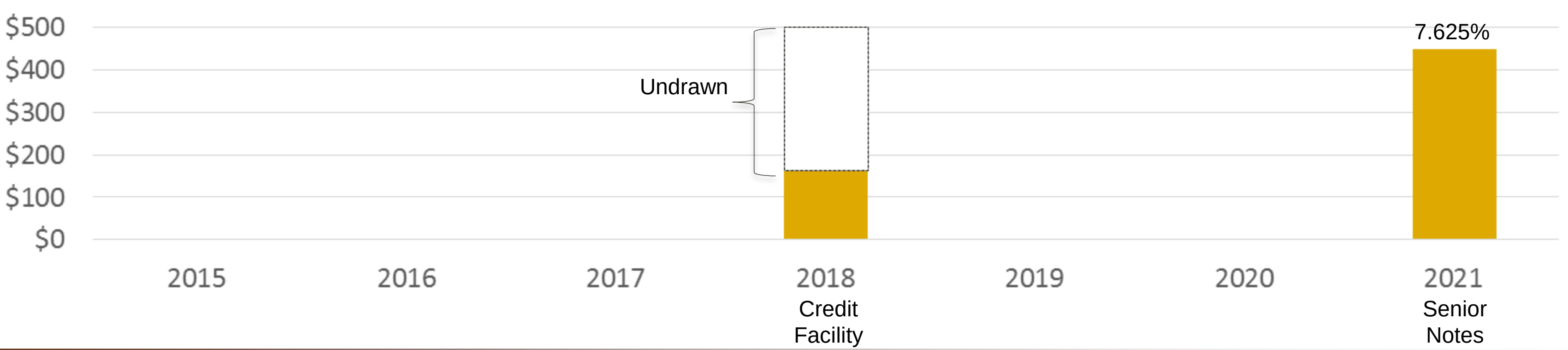
FANG's Liquidity and Capitalization

FANG's Capitalization as of 3/31/15	
($MM)	
Cash and cash equivalents	$32
Revolving Credit Facility	$162
7.625% Senior Notes Due 2021	$450
Total Debt	***$612***
Net Debt	**$580**

FANG's Liquidity as of 3/31/15	
Cash	$32
Borrowing Base	$500
Less: Borrowings	($162)
Liquidity	**$370**

- **Net Debt to annualized 1Q'15 Adjusted EBITDA of 1.3x[1]**
- **Strong balance sheet with the ability to use its 88% ownership stake in Viper Energy Partners for further liquidity**
- **Borrowing base anticipated to be $725 MM in Spring 2015 redetermination, but Company to limit its commitment amount to $500 MM**
- **Based on Spring 2015 redetermination, the agent lender has recommended that VNOM's borrowing base be increased to $175 MM, but increase remains subject to lender approval**
- **On April 13, 2015, S&P raised Diamondback's corporate credit rating to B+ from B and revised its outlook to stable from positive**

FANG's Debt Maturity ($MM)



Source: Company Filings, Management Data and Estimates. (1) Annualized Adjusted EBITDA is Adjusted EBITDA for the three months ended March 31, 2015 multiplied by four. Actual Adjusted EBITDA for 2015 will depend on many factors and may differ from Annualized Adjusted EBITDA. See the disclaimers at the beginning of this presentation.

Diamondback Energy – Hedging

Hedging[1]

Oil Swaps 2015	Average Bbls Per Day	Average Price Per Bbl
First Quarter 15 – LLS	6,344	$95.57
First Quarter 15 – WTI	5,000	$84.10
First Quarter 15 – Brent	1,000	$88.83
Second Quarter 15 – LLS	3,330	$91.89
Second Quarter 15 – WTI	5,000	$84.10
Second Quarter 15 – Brent	2,000	$88.78

Oil Swaps 2015	Average Bbls Per Day	Average Price Per Bbl
Third Quarter 15 – LLS	3,000	$90.99
Third Quarter 15 – WTI	5,000	$84.10
Third Quarter 15 – Brent	2,000	$88.78
Fourth Quarter 15 – LLS	3,000	$90.99
Fourth Quarter 15 – WTI	5,000	$84.10
Fourth Quarter 15 – Brent	2,000	$88.78
2015 Average	**10,660**	**$88.14**

- **Nearly 11 Mbbl/d of production hedged at an average price of ~$88/bbl**
- **Hedges are all straight swaps not subject to any floors**

(1) 2015 hedging includes a combination of LLS, Brent, and WTI hedges.

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Diamondback Energy – Updated 2015 Guidance[1]

	Diamondback Energy, Inc.	Viper Energy Partners LP
Net Production – Mboe/d[1]	29.0 – 31.0	4.6 – 5.0
Unit Costs ($/boe)		
Lease Operating Expenses	$7.00 – $8.00	$0.00
Cash G&A	$1.00 – $2.00	$1.00 – $2.00
Non-Cash Equity Based Compensation	$1.00 – $2.00	$2.00 – $3.00
DD&A	$20.00 – $22.00	$20.00 – $22.00
Production and Ad Valorem Taxes (% of Revenue)[2]	7.1%	7.5%
($ - million)		
Gross Horizontal Well Costs[3]	$6.2 – $6.7	n/a
Gross Horizontal Wells Drilled & Completed	55 – 65	n/a
Interest Expense	$40 – $50	n/a

Diamondback Capex Budget ($ - million)	
Horizontal Drilling and Completion	$285 – $315
Infrastructure	$20 – $30
Non-op and Other	$20 – $30
2015 Capital Budget	**$325 – $375**
Net Carry In[4]	$75
2015 Capital Spend	**$400 – $450**

- **Increasing 2015E production guidance range 11% to 29.0 – 31.0 Mboe/d**
  - Viper production guidance increase of 10% at the midpoint
- **No increase from previous capex budget guidance**
- **As a reminder, Viper incurs no LOE or capital expenditures**

(1) Based on 2015 updated guidance provided on May 6, 2015, which guidance is subject to numerous assumptions and risks. See the disclaimer at the beginning of this presentation. (2) Includes production taxes of 4.6% for crude oil and 7.5% for natural gas and NGLs and ad valorem taxes. (3) Assumes a 7,500' average lateral length. (4) Capital from projects in 2014 carried into 2015 net of capital for projects in 2015 carried into 2016.

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In Conclusion

Diamondback Energy is a low-cost operator in one of the highest return basins.

Stockholder Return Growth

Opportunistic and Accretive Acquisitions

- Complementary acreage additions
- Midland Basin focused
- Maintain operations excellence

Conservative Financial Structure

- Efficient capital allocation
- Debt/Adjusted EBITDA < 2X

Focus on Rates of Return

- Switched focus to horizontal drilling in late 2012
- History of accretive acquisitions
- Purchase of mineral acres

Execute on Development Plan

- Continued D&C cost reduction
- Continued focus on cost structure (LOE & G&A)
- Aggressive development of minerals

DIAMONDBACK
Energy

APPENDIX

Attractive Acquisition and Development Economics – Announced Acquisitions

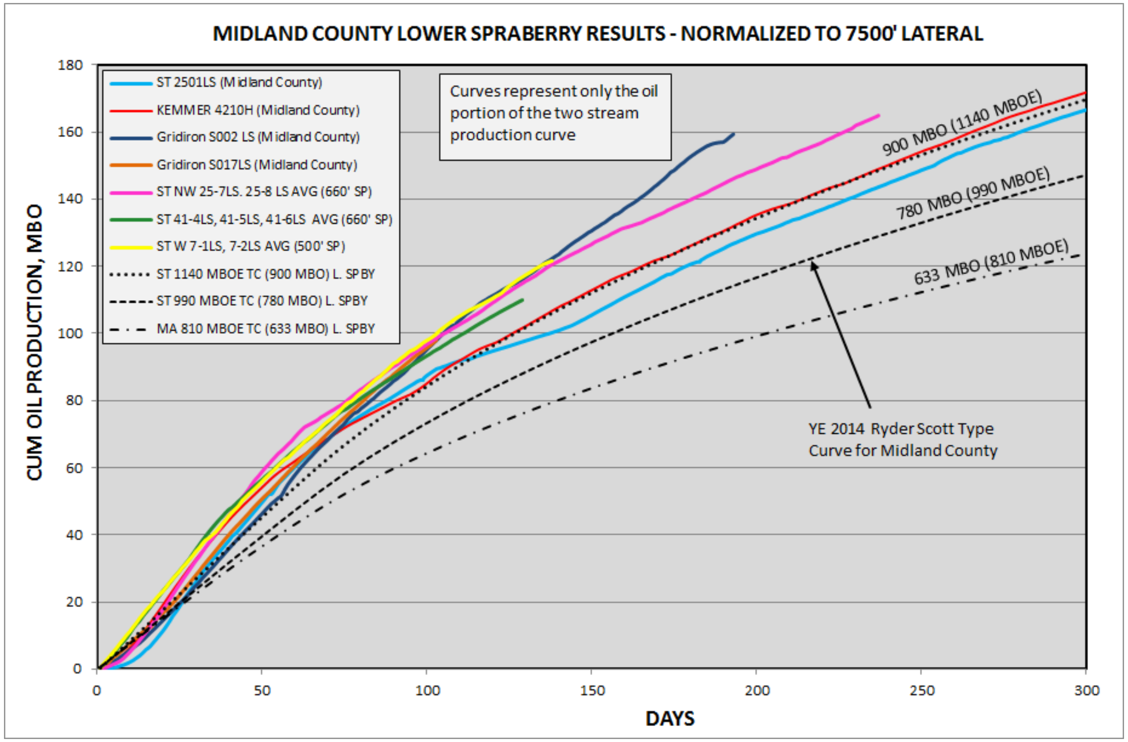
- **Management believes acreage is in top quartile of FANG's existing acreage portfolio based on well results in immediate proximity**
  - Believe 3 horizontal zones are de-risked – Lower Spraberry, Wolfcamp B and Wolfcamp A with upside potential from Middle Spraberry
- **Attractive acquisition price of ~$23,845 per adjusted(1) net acre and ~$2.05 per Boe(2)**
- **Total acquisition, D&C and LOE cost of ~$20 per Boe provides attractive economics even at low commodity prices**

Diamondback Announced Acquisitions	
Price per acre ($ / net acre) (1)	$23,845
Net acres	11,948
Illustrative acreage purchase price ($ MM) (1)	$285
Locations (assumes 3 zones)	232
Avg EUR (Mboe) per location	800
Illustrative Net Revenue Interest	75%
Acquisition Cost ($ / Boe) (2)	**$2.05**
D&C cost per well ($ MM) (3)	$6.5
D&C per Boe ($ / Boe)	**$10.83**
LOE per Boe ($ / Boe) (3)	**$7.00**
Total Acquisition, D&C and LOE Cost ($ / Boe)	**$19.88**

(1) FANG purchase price adjusted for current production valued at $45 per Mboe/d, ~$33.7MM for ORRI to be dropped down to VNOM subject to board approval by Conflicts Committee and $4.9mm for salt water disposal facility. (2) Assumes 232 net locations at 800 Mboe per location and 75% NRI. (3) Based on FANG public guidance range.

DIAMONDBACK Energy

Lower Spraberry Type Curve & Economics at $60 Oil



Midland County Type Curve Economics

EUR, 2 Stream Mboe	990
Peak 30 day IP, boe/d	1,030
Oil %, 2 stream basis	79%
D & C Cost, $MM	$6.0
ROR, %	104%
ROR,% with minerals	190%(1)
PV10, $MM	$9.3
PV10 with minerals, $MM	$13.5

45+% Uplift

ROR Sensitivity

EUR Mboe

Well Cost $MM	650	810	990	1,200
$5.5	49%	76%	129%	208%
$6.0	39%	61%	104%	169%
$6.5	33%	50%	86%	140%
$7.0	27%	43%	74%	118%

Note: Based on $60/BBL WTI ($56.50/BBL realized price). Realized gas and NGL pricing is $3.40/Mcf and $14/Bbl. Daily production normalized for operational shut-ins. Type curves based on normalized 7,500' laterals; actual lateral lengths vary. (1) Represents additional ROR related to mineral interests underlying acreage owned by Viper and operated by FANG.

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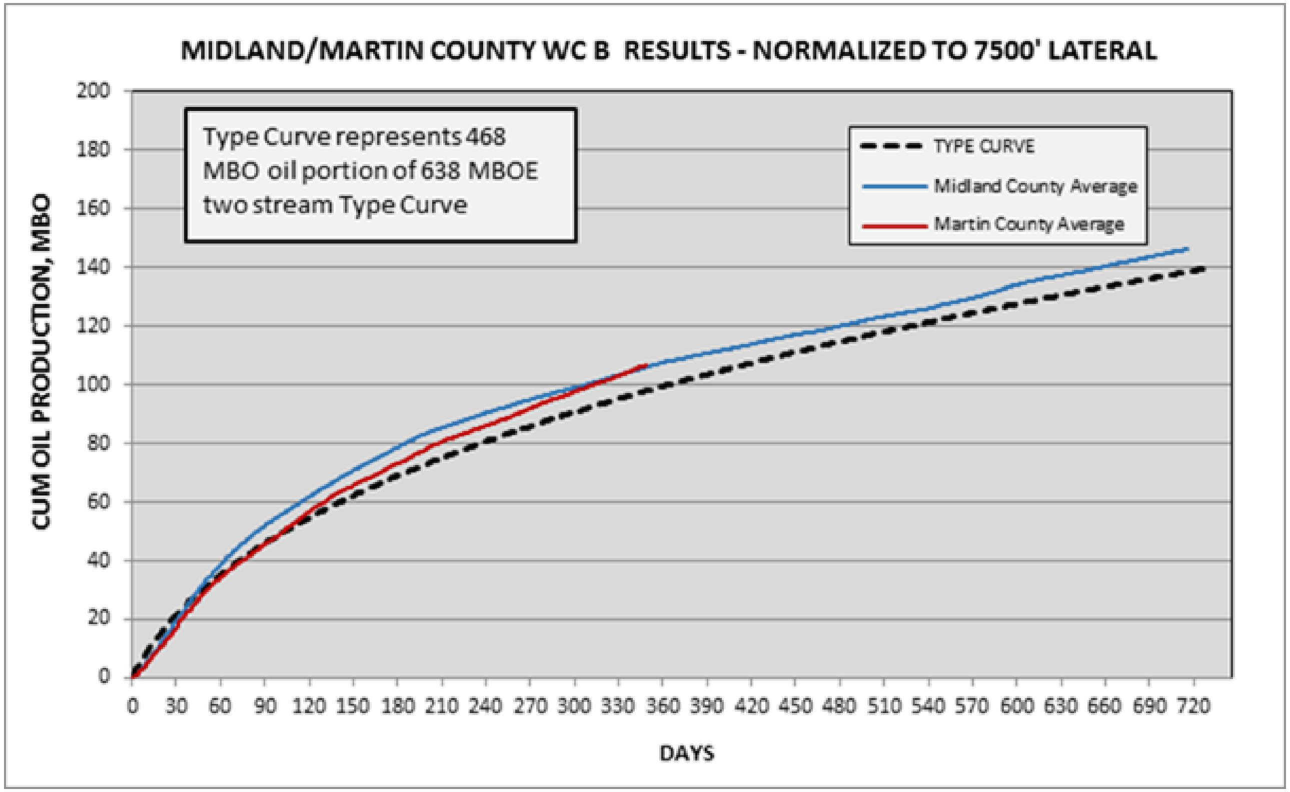
Midland County Wolfcamp B Type Curve & Economics at $60 Oil



Type Curve Economics

EUR, 2 Stream Mboe	*638*
Peak 30 day IP, boe/d	*808*
Oil %, 2 stream basis	*76%*
D & C Cost, $MM	*$6.0*
ROR, %	*32%*
ROR, % with minerals	*59%* (1)
PV10, $MM	*$3.4*
PV10 with minerals, $MM	*$6.0*

~76% Uplift

ROR Sensitivity

EUR Mboe

Well Cost $MM	600	638	700	750
$5.5	34%	40%	50%	60%
$6.0	28%	32%	41%	48%
$6.5	23%	29%	34%	40%
$7.0	19%	22%	28%	33%

Note: Based on $60/BBL WTI ($56.50/BBL realized price). Realized gas and NGL pricing is $3.40/Mcf and $14/Bbl. Daily production normalized for operational shut-ins. Type curves based on normalized 7,500' laterals; actual lateral lengths vary. Excludes Wolcott 253 1H in north central Martin County. (1) Represents additional ROR related to mineral interests underlying acreage owned by Viper and operated by FANG.

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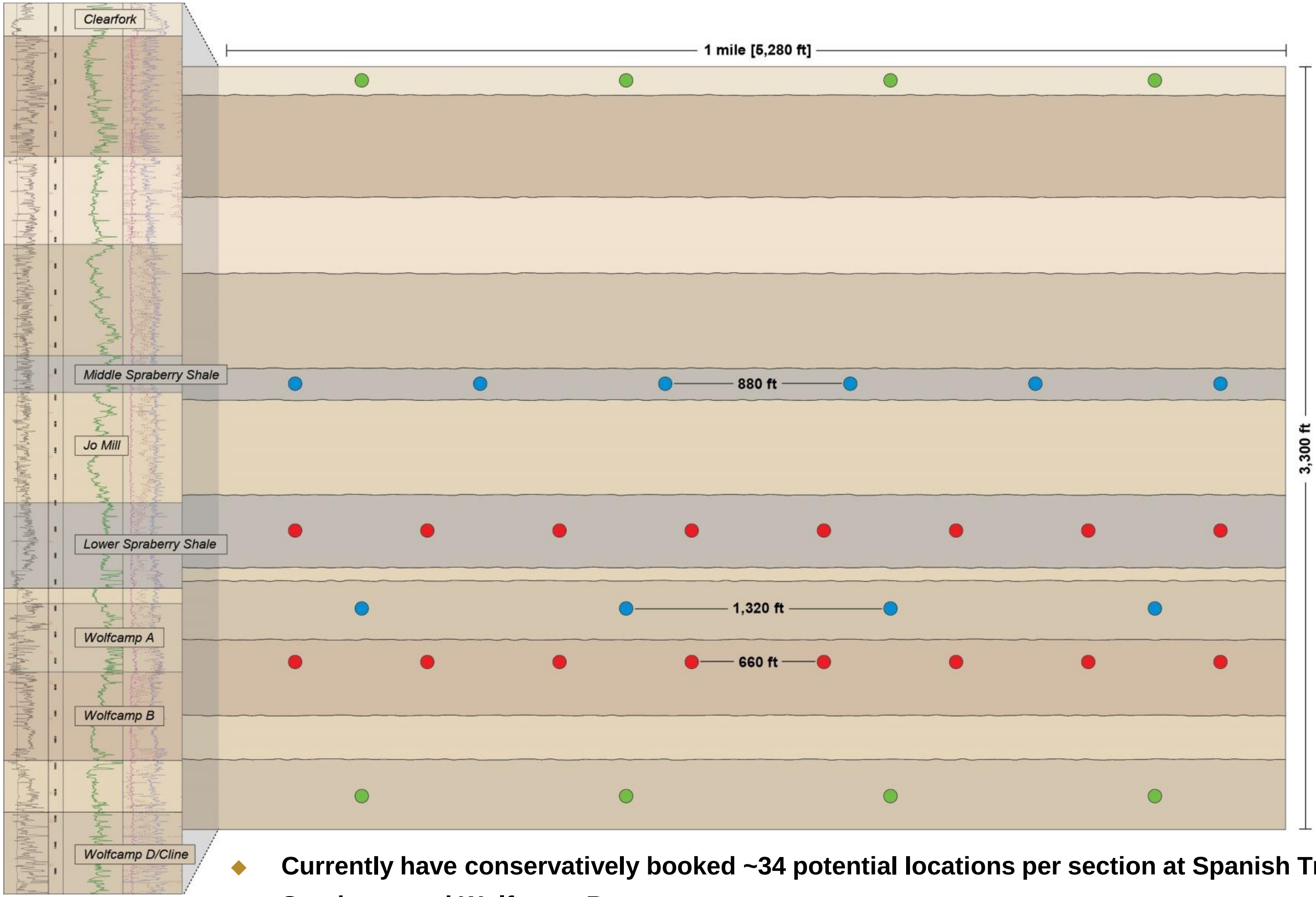
Downspacing and Stacked Pay Potential in Spanish Trail



Upside Potential

Increase from 6 to 8 per section

Increase from 8 to 10 per section

Increase from 4 to 8 per section

- **Could see upside from downspacing and delineation of other zones**

- **Currently have conservatively booked ~34 potential locations per section at Spanish Trail, 16 in Lower Spraberry and Wolfcamp B**

Active Development | Future Development | Contingent Targets

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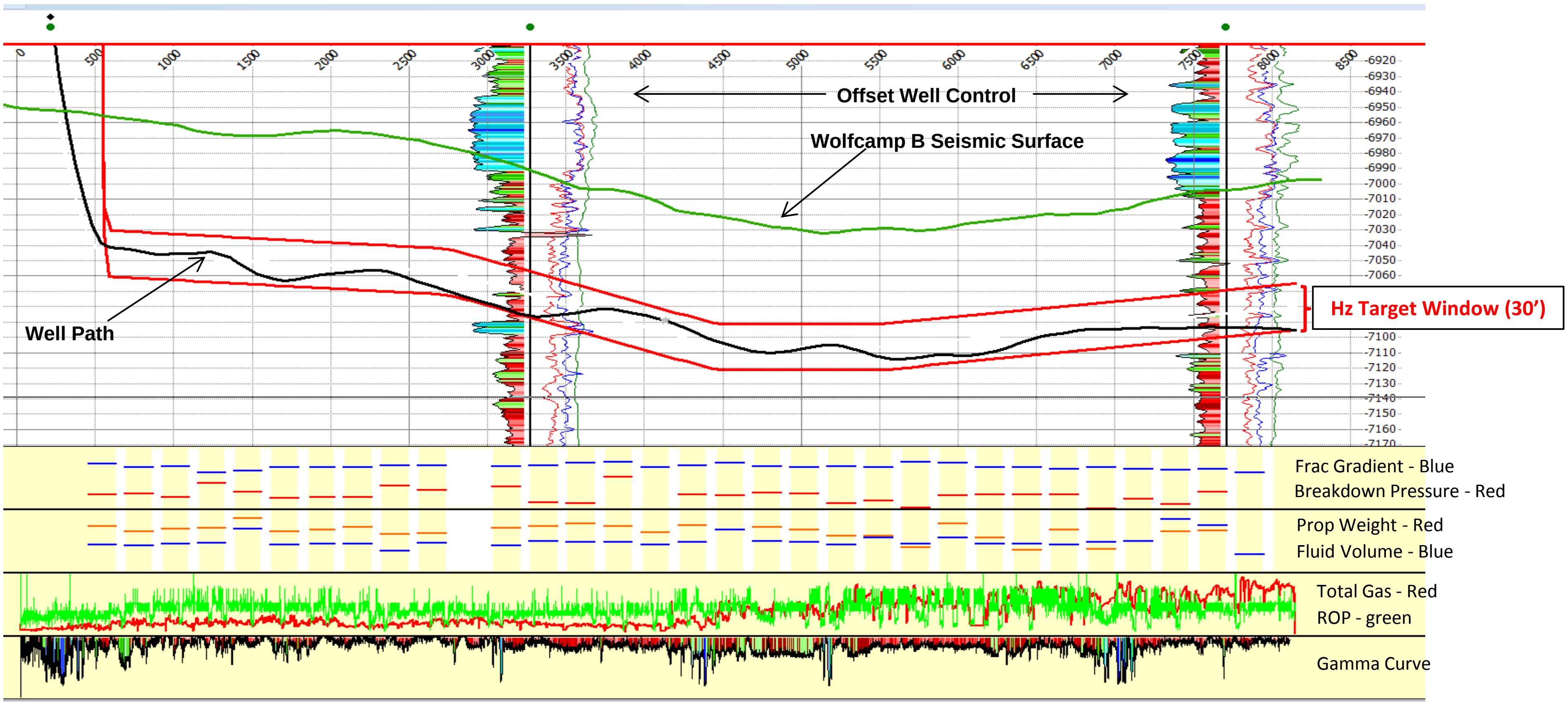
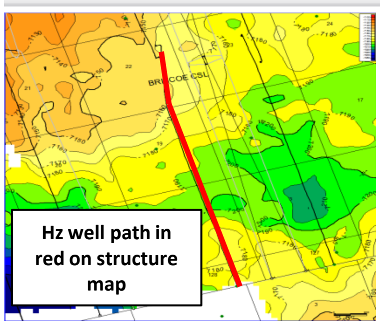
Superior Geosteering & Hydraulic Fracturing





Geosteering

- All offset wells are used to aid in steering lateral, typically within 10' of target
- Diamondback has or is currently acquiring 3D seismic on >90% of its assets; this data is incorporated into the well plan
- Evaluate results to optimize lateral landing target for future wells

Hydraulic Fracturing

- Slickwater prop transportation
- Over 1,700 Hz stages pumped by FANG since IPO- decades of experience in other basins
- Post frac analysis, frac data is evaluated to determine job effectiveness

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Viper Energy Partners – Landmark IPO of Mineral Interests

- **September 2013 - acquired 14,804 gross acres of minerals in the core of the Northern Midland Basin**
  - Non-traditional investment for an E&P company, unique opportunity with Diamondback now operating approximately 43% of Viper's acreage
- **Diamondback creates a variable MLP structure for minerals**
  - Direct mineral ownership in the heart of the Midland Basin from "tombstone to granite"
    - No maintenance capex, direct operating expense, IDRs, minimum distributions or hedges
  - Organic growth from horizontal development of multiple benches
  - Opportunity to acquire additional mineral/royalty interests on accretive basis
- **June 2014 IPO of minerals - Viper Energy Partners LP (NASDAQ: VNOM)**
  - Diamondback sells 7.5% stake, raises $138MM, retains ~92.5% ownership of Viper and controls the general partner
- **Viper Energy Partners today**
  - $1.6 billion market capitalization, current price ~$20 per unit[1]
  - Diamondback currently owns ~88% of this limited partnership
- **Poised for Continued Growth**
  - Basic premise of being a vehicle to collect mineral revenue and distribute in a tax efficient way has not changed
  - Believe that current weakness in crude could provide opportunities for expansion as royalty checks decline
    - Viper has an early mover advantage as a publicly traded company with low cost of capital
    - Could use equity to make accretive acquisitions in a tax-advantaged way that allows mineral owners geographic diversification and helps facilitate efficient generational wealth transfer

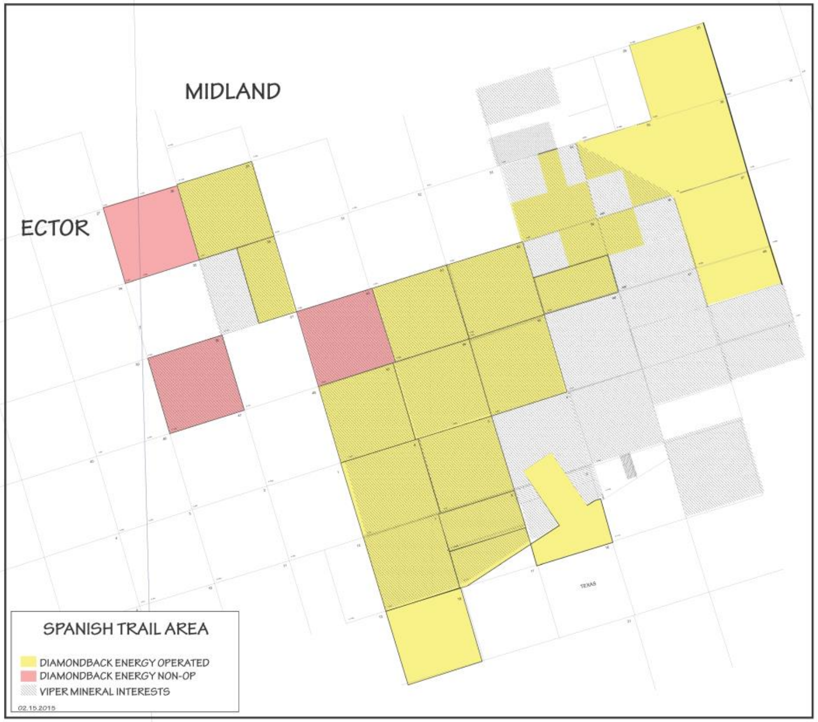
Note: At the time of the acquisition, Diamondback operated approximately 50%. Source: Company filings, management data and estimates. (1) $20.12 closing price on 5/5/2015.

Development of Viper Energy's Spanish Trail is Well Underway

Operators Incentivized to Drill

- 21.4% average revenue interest in 15,460 gross acres in Midland County known as Spanish Trail
  - Viper does not pay direct LOE or capital expenditures
  - FANG and RSPP currently have 3 horizontal rigs in total focused on Spanish Trail development
  - Since mid-2014 RSPP has completed nine horizontal wells and has drilled or is in the process of drilling or completing seven more at Spanish Trail
    - RSPP's recent completions target the Wolfcamp B, Wolfcamp A and Lower Spraberry
    - Viper owns a 12.5-25% royalty in these wells
  - Core focus area for both FANG and RSPP
- Growth funded by operators with strong incentives to drill
- 1Q'15 production of 4.8 Mboe/d (up 16% q/q)

Two Dedicated Hz Drillers



- As of 5/1/2015 gross producing horizontal wells of 48 Wolfcamp B, 16 Lower Spraberry, and 3 Middle Spraberry on Spanish Trail acreage and 2 Wolfcamp A on Delaware acreage

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EBITDA Reconciliation

($ in thousands)	2013	2014	1Q15
Net income (loss)	$54,587	$195,971	$6,439
Change in the fair value of open non-hedge derivative instruments, net	(5,346)	(117,109)	25,206
Interest expense	8,059	34,515	10,497
Depreciation, depletion and amortization	66,597	170,005	59,677
Non-cash stock-based compensation expense	2,724	14,253	7,063
Capitalized stock-based compensation expense	(972)	(4,437)	(2,139)
Asset retirement obligation accretion expense	201	467	170
Income tax provision	31,754	108,985	3,370
Adjusted EBITDA	**$157,604**	**$402,650**	**$110,283**
(Gain) loss on settlement of non-hedge derivative instruments, net	7,218	(10,430)	(43,560)
Further Adjusted EBITDA	**$164,822**	**$392,220**	**$66,723**

Source: Company Filings. Financial data as of 3/31/15.

DIAMONDBACK Energy

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