

# **DIAMONDBACK** Energy



**Investor Presentation  
November 2013**

# 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”) 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, 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 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 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. In this communication, the Company may use the term “unproved reserves” which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. “Unproved reserves” refers to the Company’s internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. Unproved reserves may not constitute reserves within the meaning of the Society of Petroleum Engineer’s Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities that may be ultimately recovered from the Company’s interests may differ substantially. Factors affecting ultimate recovery include the scope of the Company’s ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves may change significantly as development of the Company’s core assets provide additional data. In addition, the Company’s production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

This presentation contains guidance regarding our estimated future production, capital expenditures, expenses and other matters. This guidance is based on certain assumptions and analyses made by the Company and is affected by such factors as market demand for oil and natural gas, commodity price volatility and the Company’s actual drilling program, which will be directly affected by the availability of capital, drilling and production costs, developmental drilling tests and results, commodity prices, availability of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals, field spacing rules and actual drilling results. This guidance is speculative by its nature and, accordingly, is subject to great risk of not being actually realized by the Company. For additional information, we refer you to the Company’s Annual Report on Form 10-K for the year ended December 31, 2012, the Quarterly Reports on Form 10-Q for the three months ended March 31, 2013, June 30, 2013 and September 30, 2013.

# Presenters

## **Travis Stice** *Chief Executive Officer*

- ◇ Chief Executive Officer since January 2012
  - ◇ President and Chief Operating Officer from April 2011 to January 2012
- ◇ Apache Corporation – Permian Basin Production Manager
- ◇ Laredo Petroleum – Vice President, Permian Basin
- ◇ ConocoPhillips – Development Manager, Mid-Continent Business Unit
- ◇ Burlington Resources – General Manager of Engineering, Operations and Business Reporting, Mid-Continent Division
- ◇ Over 28 years of experience with 15 years focused in the Permian

## **Tracy Dick** *Chief Financial Officer*

- ◇ Chief Financial Officer and Senior Vice President since November 2009
  - ◇ Corporate Controller from November 2007 to November 2009
- ◇ Hiland Partners (publicly-traded MLP) – Controller / Tax Director
- ◇ Over 20 years of accounting experience, including over 9 years of public company experience in both audit and tax areas

## **Russell Pantermuehl** *VP Reservoir Engineering*

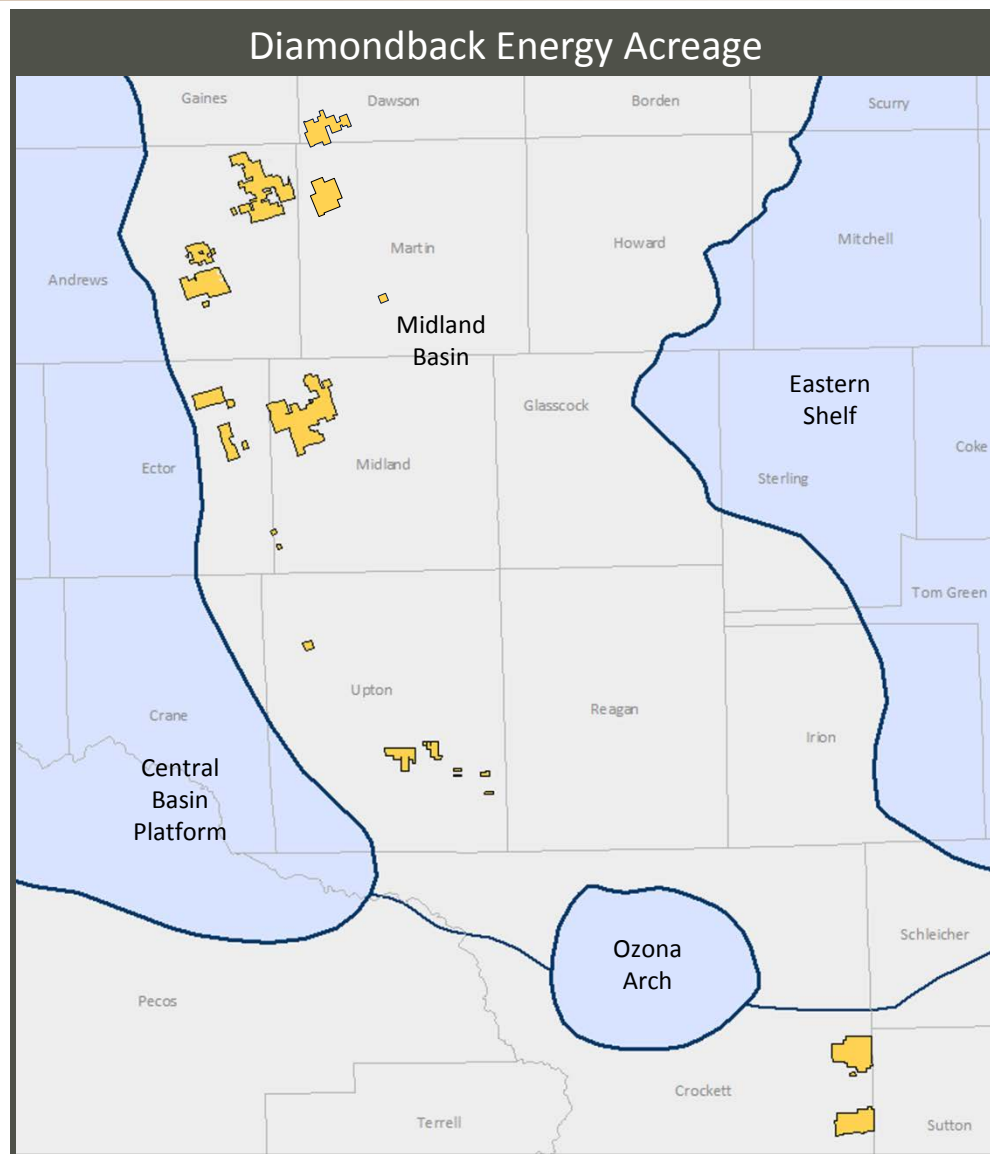
- ◇ Vice President – Reservoir Engineering since August 2011
- ◇ Concho Resources – Wolfberry Reservoir Engineering Supervisor
- ◇ ConocoPhillips – Reservoir Engineering Advisor
- ◇ Burlington Resources – Reservoir Engineering Advisor
- ◇ Over 32 years of experience with 16 years focused in the Permian

# Diamondback Overview

- ◇ Independent E&P focused on Permian Basin and headquartered in Midland, Texas
- ◇ Completed IPO on October 17, 2012 (share price increased ~204% since IPO)
- ◇ Drilled or participated in 34 horizontal wells, 26 of which are producing (24 Wolfcamp B, 1 Clearfork, 1 Middle Spraberry)
  - ◇ Diamondback is the operator of 23 of the 26 producing wells
  - ◇ Results to date have been at or above the type curves
- ◇ Acquired mineral interests under ~15,000 gross (~12,500 net) acres in Midland County in September 2013 for \$440 MM
- ◇ Acquired ~11,150 net acres in Midland Basin in September 2013 for \$165 MM

## Key Highlights

- ◇ Market capitalization of ~\$2.5 BN<sup>(1)</sup>
- ◇ Over 66,000 net acres; ~99% operated
  - ◇ Actively pursuing additional acreage in the basin
- ◇ Daily production of ~10,500 BOEPD<sup>(2)</sup>
- ◇ Proved reserves: 57.9 MMBOE (9/1/13)<sup>(3)</sup>
  - ◇ 65% Oil, 20% NGL, 15% Gas
  - ◇ 43.0% PDP
- ◇ Pre-tax PV-10: \$952 MM (9/1/13)<sup>(4)</sup>



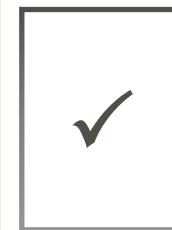
Source: Bloomberg, Ryder Scott, Company Filings, Management Data and Estimates. Market data as of November 4, 2013.

3 (1) Represents outstanding shares as of October 28, 2013. (2) Average daily production during the period October 1, 2013 – October 26, 2013. (3) Management internally prepared estimates as of 9/1/2013 pro forma for the acquisitions completed in September 2013; audited by Ryder Scott. (4) Management internally prepared estimates as of 9/1/2013 pro forma for the acquisitions completed in September 2013.

# Diamondback Continues to Deliver in 2013

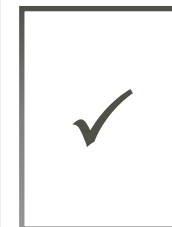
## Realizing Horizontal Development and Stacked Pay Potential

- ◇ Drilled or participated in 31 Wolfcamp B wells in Midland, Upton and Andrews Counties and 1 Clearfork well in Andrews County; participated in 1 Middle Spraberry well and 1 Lower Spraberry well in Midland County
  - ◇ Results driving production, reserve and inventory growth
- ◇ Early data suggests performance at or above type curves
- ◇ Stacked pay potential of 7 zones (Wolfcamp B, Clearfork, Middle Spraberry, Lower Spraberry, Wolfcamp A, Wolfcamp C and Cline)
- ◇ Significant tests in Middle and Lower Spraberry and Clearfork horizons
- ◇ Testing Wolfcamp B / Lower Spraberry stacked laterals with results expected in 1Q'14



## Acquisitions Driving Inventory and Cash Flow Growth

- ◇ Acquired ~11,150 net acres in Martin and Dawson Counties in September 2013 for \$165 MM
  - ◇ 307 gross identified potential horizontal drilling locations
- ◇ Acquired mineral interests under ~15,000 gross acres in Midland County in September 2013 for \$440 MM
  - ◇ No additional future capital or operating expenses required to receive run-rate cash flows



## Positioned for Successful 2014

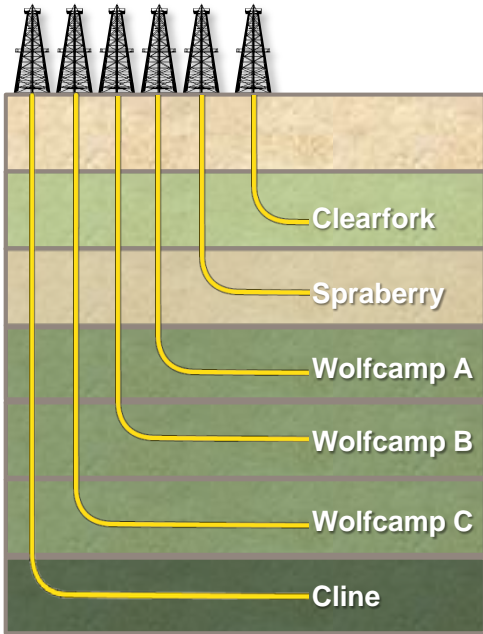
- ◇ Drilled over 38 miles of horizontal laterals since the commencement of the horizontal drilling program with among the lowest cost per lateral foot
- ◇ Reduced LOE per BOE the last four consecutive quarters, for a total reduction of \$7.91 per BOE, or 52% since 3Q'12<sup>(1)</sup>
- ◇ Attractive assets in Permian Basin with high oil content (75% oil by production) and low development costs lead to high cash margins<sup>(2)</sup> (\$69.82 per BOE)



# Stacked Pay Horizons Continue to Rewrite Potential in the Permian Basin



## Permian Peers



Middle  
Lower

3,500' of stacked pay potential

Pay Horizon	Key Metrics	Permian Peers
<b>Clearfork (Leonard)</b>	<ul style="list-style-type: none"> <li>176 gross locations</li> <li>1 well on production</li> <li>1,320' spacing</li> </ul>	<ul style="list-style-type: none"> <li>SM – 5 wells in Andrews County</li> <li>Operators: Reliance, APA</li> </ul>
<b>Spraberry<sup>(2)</sup> (Jo Mill)</b>	<ul style="list-style-type: none"> <li>180 gross locations in Middle Spraberry</li> <li>180 gross locations in Lower Spraberry</li> <li>Currently flowing back first Middle Spraberry well in Midland County</li> <li>1,320' spacing in Andrews, Martin and Dawson Counties; 880' spacing in Midland County</li> </ul>	<ul style="list-style-type: none"> <li>PXD – 8 wells in Upton County</li> <li>CPE – 54 identified locations</li> <li>3<sup>rd</sup> party completion near Midland/Ector County line</li> <li>CXO and WTI – Evaluating for development</li> </ul>
<b>Wolfcamp A</b>	<ul style="list-style-type: none"> <li>195 gross locations</li> <li>1,320' spacing</li> </ul>	<ul style="list-style-type: none"> <li>PXD – 1 well in Midland County</li> <li>WTI – 6 wells drilled out of 153 locations in Martin, Andrews, Dawson counties</li> <li>LPI – 27 wells in Glasscock and Reagan counties</li> <li>Other operators: APA, CXO, CPE, EGN, AREX</li> </ul>
<b>Wolfcamp B</b>	<ul style="list-style-type: none"> <li>309 gross locations</li> <li>24 wells on production</li> <li>7 wells in development</li> <li>880' spacing in Midland, Upton, Dawson and Martin Counties; 1,320' spacing all other counties</li> </ul>	<ul style="list-style-type: none"> <li>PXD – 4 wells in Midland, Upton and Martin counties</li> <li>AREX – 20+ wells in Crockett County</li> <li>CPE – 111 identified locations<sup>(1)</sup></li> <li>Other operators: CXO, EOG, WTI, EP Energy, AREX, DVN, LPI, SM</li> </ul>
<b>Wolfcamp C</b>	<ul style="list-style-type: none"> <li>71 gross locations</li> <li>1,320' spacing</li> </ul>	<ul style="list-style-type: none"> <li>LPI – 2 wells in Reagan County</li> <li>AREX – 700+ identified locations</li> </ul>
<b>Cline</b>	<ul style="list-style-type: none"> <li>170 gross locations</li> <li>1,320' spacing</li> </ul>	<ul style="list-style-type: none"> <li>PXD – 3 wells in Midland and Martin Counties<sup>(4)</sup></li> <li>LPI – 36 wells in Glasscock, Reagan and Howard counties</li> <li>CPE – 30 identified locations</li> <li>Other operators: RSP, APA, EGN, CVX, DVN, WTI</li> </ul>

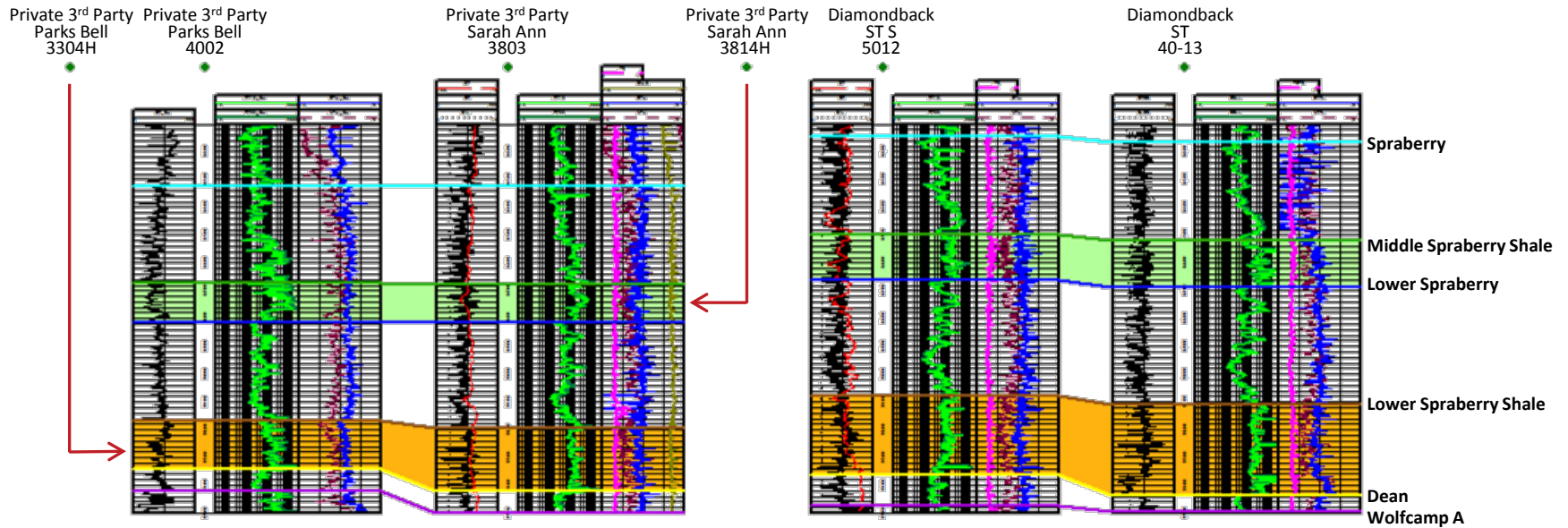
◆ Diamondback is a cost leader in developing horizontal opportunities in Midland, Upton and Andrews Counties<sup>(3)</sup>

Source: Company and Peer Filings, Management Data and Estimates.

(1) Represents upper and lower Wolfcamp B. (2) Represents Lower Spraberry for Permian Peers. (3) Based on comparison of cash margin which represents latest publicly reported EBITDA adjusted to exclude hedging gains and losses, if not already excluded, divided by BOE production for the period. (4) Represents PXD reported Wolfcamp D.

# Second Development Horizon Established in the Spraberry

## Structural Cross-Section Showing Recent Spraberry Horizontal Target Intervals in the Spanish Trail Area



### Highlights

- ◇ Middle and Lower Spraberry shale targets are continuous and increase in thickness to the east
- ◇ Early production performance similar to Wolfcamp B
- ◇ Oil in place in Lower Spraberry potentially higher than Wolfcamp B
- ◇ Oil in place in Middle Spraberry potentially similar to Wolfcamp B

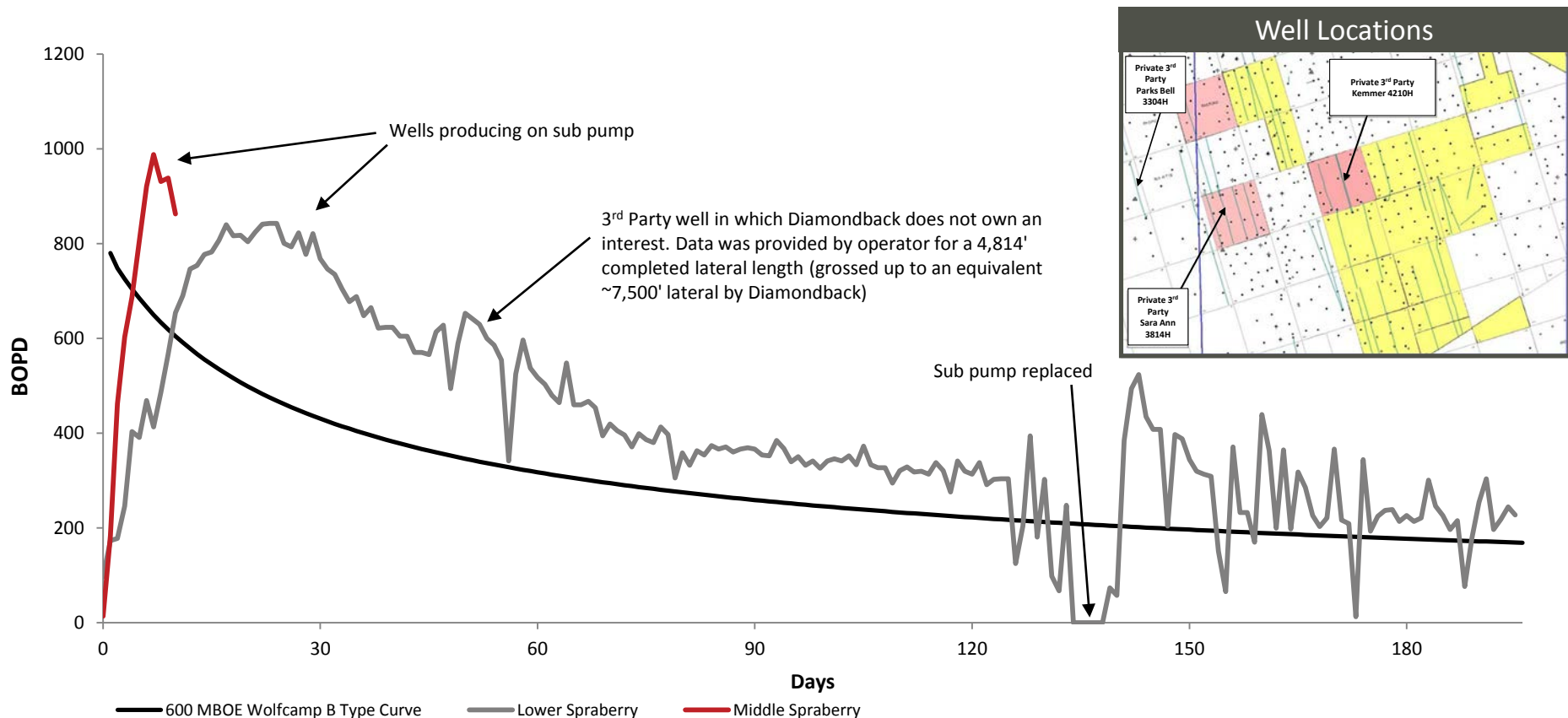
### Asset Overview



# Middle and Lower Spraberry Production Results Exceed Expectations

- ◇ All data normalized to 7,500' lateral length
- ◇ Type curve is oil portion (425 MBO) of 600 MBOE EUR projection (71% oil) reported in two stream
- ◇ Early data suggests performance at or above Wolfcamp B type curve

## Midland County Type Curve<sup>(1)</sup>

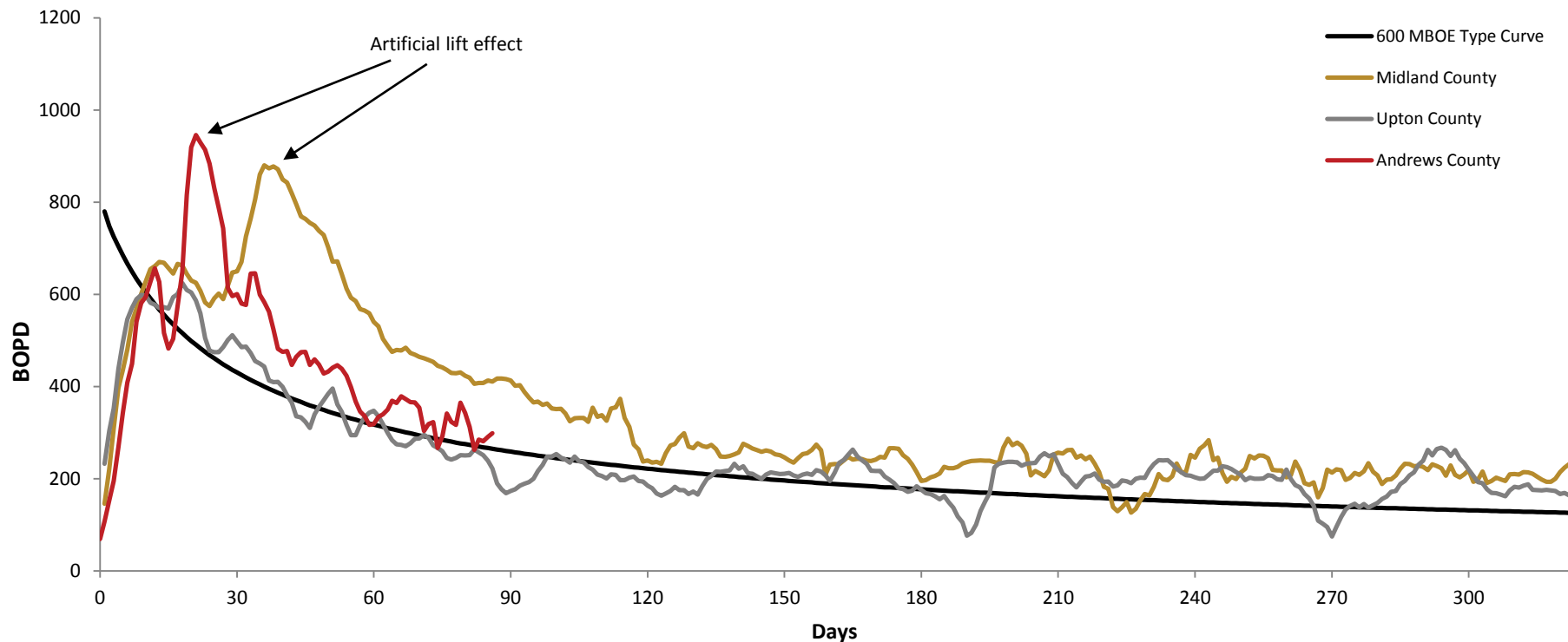


Source: Company Filings, Management Data and Estimates.  
 (1) As of November 1, 2013. Reflects averages only for actual periods.

# Horizontal Wolfcamp B Production Results

- ◇ All data normalized to 7,500' lateral length
- ◇ Type curve is oil portion (425 MBO) of 600 MBOE EUR projection (71% oil) reported in two stream
- ◇ Curves represent the average of all Diamondback interest wells in the respective counties
  - ◇ Andrews County reflects only one well
- ◇ Early data suggests performance at or above type curves

Type Curves – Area Average Results<sup>(1)</sup>



Source: Company Filings, Management Data and Estimates.  
(1) As of November 1, 2013. Reflects averages only for actual periods.

# Horizontal Wells Deliver Higher IRRs, Require Lower Development Costs and Lead to Better Capital Efficiency

## Illustrative Wolfcamp B Horizontal Well Economics (7,500')

- ◇ IRR<sup>(1)</sup>: 47%
- ◇ EUR: 600 MBOE (2 stream)
- ◇ Well Cost: \$7.0 MM
- ◇ Cost To Develop<sup>(3)</sup>: \$15.56/BOE
- ◇ NPV-10 (\$MM)<sup>(4)</sup>: \$6.6 MM (Mineral Interests add \$3.4 MM of incremental NPV-10)
- ◇ For every 100 MBOE increase in EUR the cost to develop decreases by ~\$2.25/BOE
- ◇ For every \$100K decrease in well cost the cost to develop decreases by ~\$0.22/BOE

WTI (\$ / Bbl)	NPV-10 (\$ in millions) <sup>(1)</sup>	IRR <sup>(1)</sup>	PI <sup>(5)</sup> (\$ to \$)
\$100	\$8.2	60%	1.17x
90	6.6	47%	0.94x
80	5.0	35%	0.71x

### ◇ Horizontal Inventory (Years)<sup>(6)</sup>:

	2 Rigs	4 Rigs	6 Rigs
Horizontal locations	53.4	26.7	17.8

## Illustrative Vertical Well Economics

- ◇ IRR<sup>(1)</sup>: 25%
- ◇ EUR: 133 MBOE
- ◇ Well Cost<sup>(2)</sup>: \$2.1 MM
- ◇ Cost To Develop<sup>(3)</sup>: \$21.05/BOE
- ◇ NPV-10 (\$MM)<sup>(4)</sup>: \$0.9 MM (Mineral Interests add \$0.7 MM of incremental NPV-10)

WTI (\$ / Bbl)	NPV-10 (\$ in millions) <sup>(1)</sup>	IRR <sup>(1)</sup>	PI <sup>(5)</sup> (\$ to \$)
\$100	\$1.3	33%	0.62x
90	0.9	25%	0.43x
80	0.5	19%	0.24x

### ◇ Vertical Inventory (Years)<sup>(7)</sup>:

	2 Rigs	4 Rigs	6 Rigs
40-Acre spacing	21.4	10.7	7.1
20-Acre spacing	28.2	14.1	9.4
<b>Total</b>	<b>49.6</b>	<b>24.8</b>	<b>16.5</b>

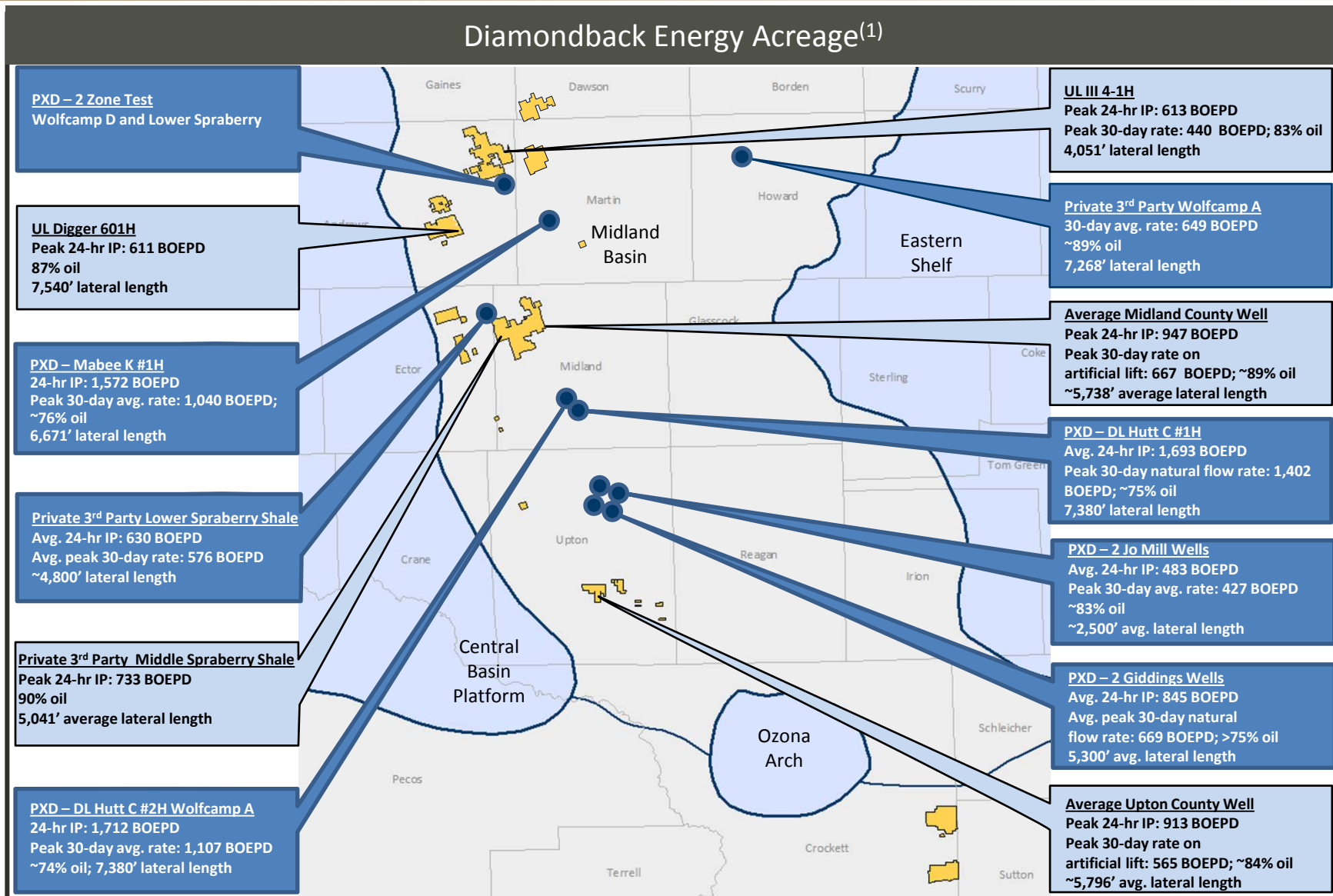
Source: Company Filings, Management Data and Estimates.

(1) Realized oil price equal to WTI less \$3.50 / Bbl. NGLs assumed 40% of WTI. Natural gas assumed \$3.50 / Mcf. Based on working interest of 100% with 75% NRI.

(2) Based on midpoint of 2014 guidance for vertical wells of \$2.0 MM to \$2.2 MM. (3) Represents costs/BOE to Company adjusted for standard Permian Basin royalty interests. (4) Based on assumed WTI price of \$90.00/Bbl. SEC pricing for 2012 was \$88.13/Bbl.

(5) Profit to investment calculated as NPV-10 to well cost. (6) Years of drilling based on 12 wells per rig per year. Based on 1,281 gross (994 net) wells. (7) Years of drilling based on 20 wells per rig per year. Based on 857 gross (800 net) wells (40-acre) and 1,128 gross (1,031 net) wells (20-acre).

# Horizontal Drilling Update

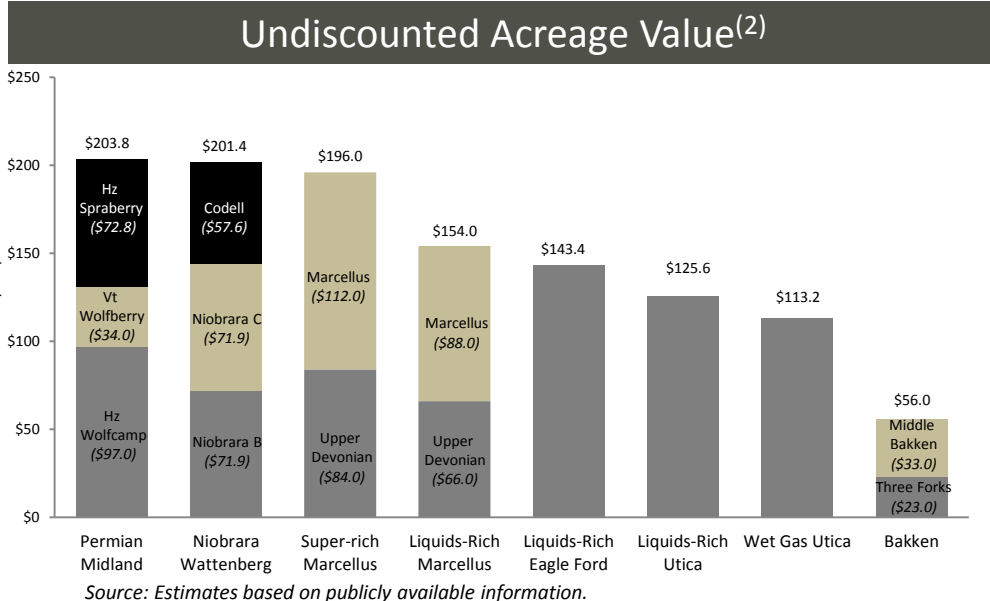


Source: Company and Peer Filings, Management Data and Estimates.  
 (1) Reflects Wolfcamp B wells, unless otherwise noted.

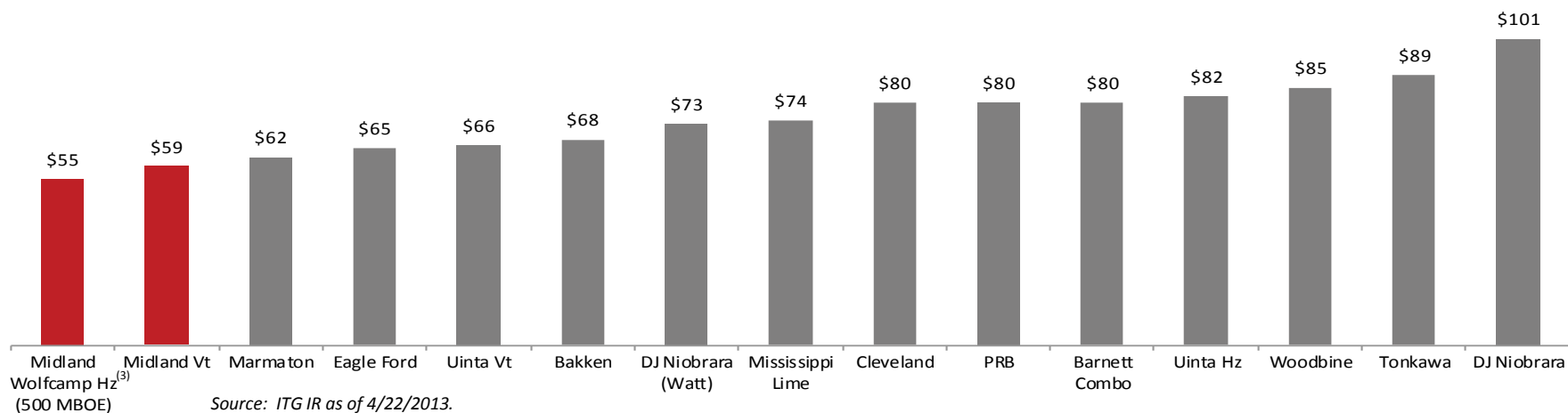
Represents Pioneer and other operator wells (Diamondback does not have any working interest in these wells)

# Permian Basin Economics – Resetting Due to Horizontal Well Results

- Not only are Permian Basin economics some of the strongest in the US, but recent horizontal well results are resetting expectations
- Additional potential exists from other horizontal targets, currently being tested by industry
- Diamondback leading the way in delivering horizontal value
- Best in class margins of public Permian peers<sup>(1)</sup>
- Provides catalyst for acceleration of horizontal inventory



## Lower 48 Plays – Pre-Tax PV-10% Break-Even Oil Prices (\$/Bbl)<sup>(3)</sup>

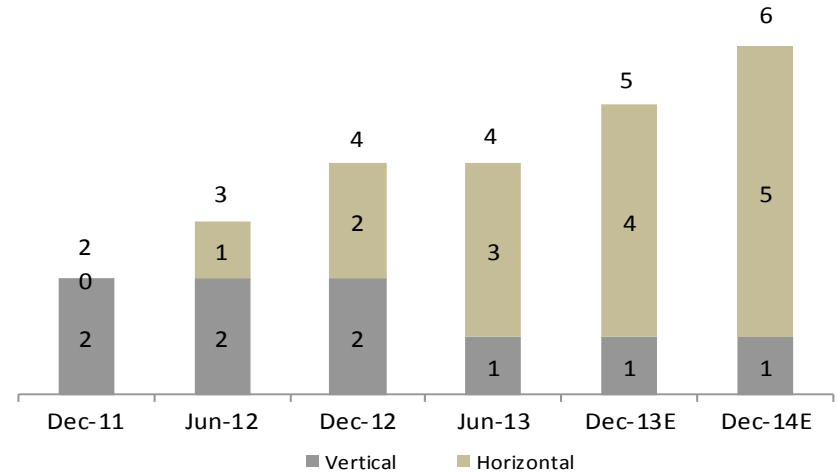


(1) Comparison reflects latest reported adjusted EBITDA/BOE production margins of peer group including ATHL, AREX, CXO, LPI and PXD. (2) 1,280 acre spacing units in the Bakken; 640 acre spacing units for all other plays. (3) Defined as threshold WTI oil price necessary to generate a 10% pre-tax rate of return. Excludes acreage costs. (4) Estimated recovery per ITG based on early PXD well performance.

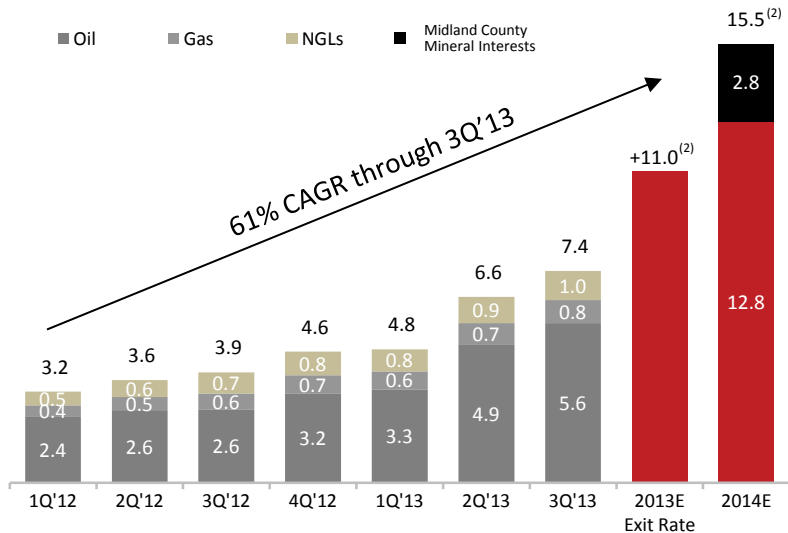
# Strong Production Growth Underway

- Leading the industry shifting from vertical to horizontal well development
- Currently operating 5 rigs (1 vertical, 4 horizontal)
- Growth further accelerated with arrival of 5<sup>th</sup> rig in 2Q'14
- 2014 production target estimated at 15,000 – 16,000<sup>(2)</sup> BOEPD based on:
  - Capex of \$425-\$475 MM<sup>(2)</sup>
  - 7,500' lateral cost of \$6.9 – \$7.4 MM<sup>(2)</sup>
  - LOE of \$6.00 – \$7.00 per BOE<sup>(2)</sup>

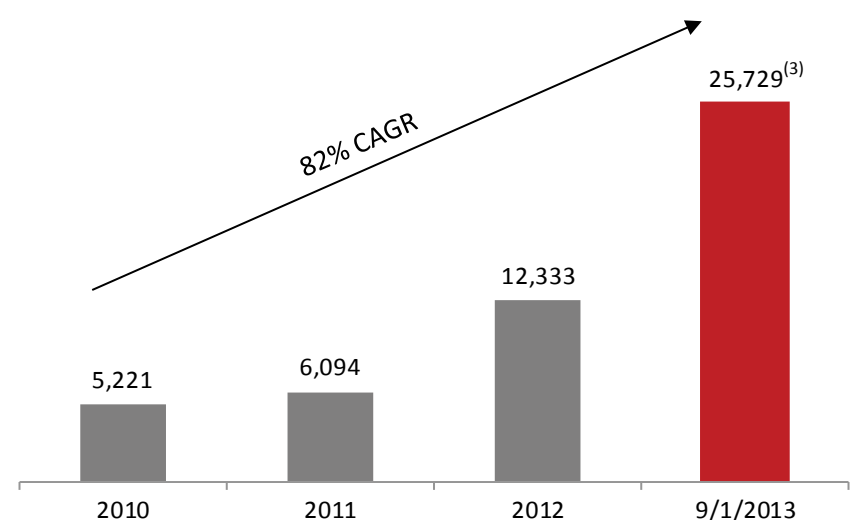
## Diamondback Rigs Over Time



## Average Daily Net Production (MBOEPD)<sup>(1)</sup>



## Proved Developed Reserve Growth (MBOE)<sup>(1)</sup>



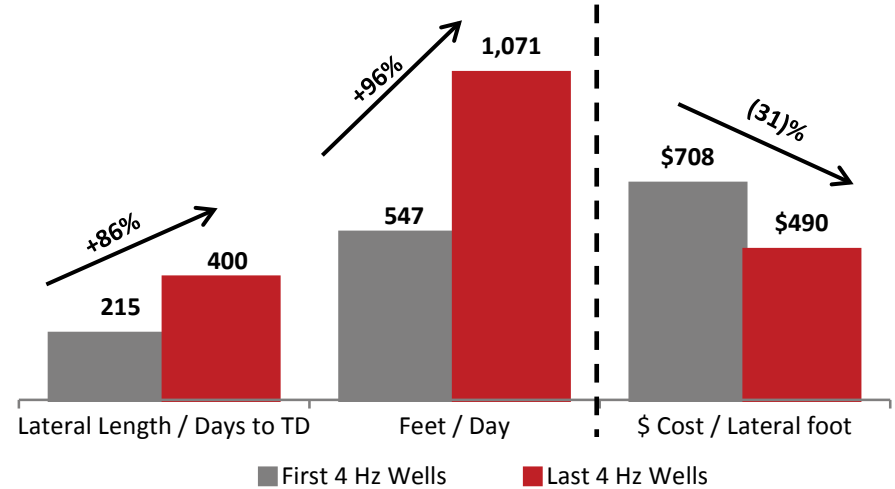
Source: Company Filings, Management Data and Estimates.

(1) 2012 numbers reflect pro forma information of Diamondback and its subsidiaries and includes the interest of Gulfport as of January 1, 2012. (2) Based on 2014 guidance published on October 23, 2013, which is subject to numerous assumptions and risks. LOE reflects reclassification of ad valorem taxes per published guidance. Midpoint of forecast shown for 2014E. See the disclaimer at the beginning of this presentation. (2) Reserves based on Management internally prepared estimates as of 9/1/2013; audited by Ryder Scott.

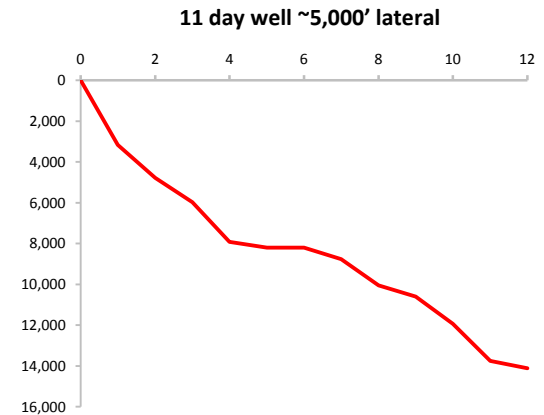
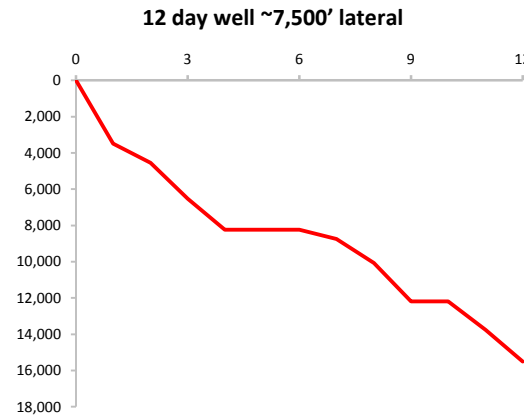
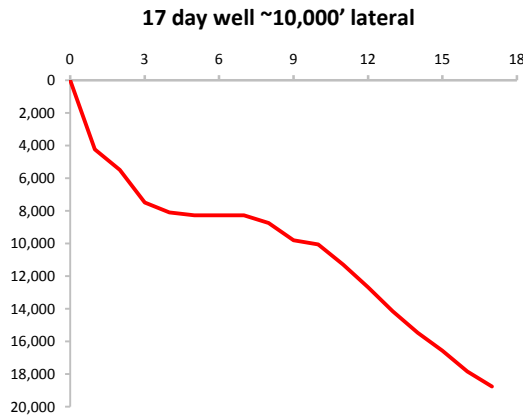
# Horizontal Execution Underway

## Horizontal Efficiency Gains

- ◇ Drilling wells faster/cheaper and decreasing cycle times leads to more wells in 2014
- ◇ 3Q'13 ~7,500' horizontals averaged 14 days to TD
- ◇ 5<sup>th</sup> horizontal rig expected in 2Q'14
- ◇ Currently running 1 vertical rig

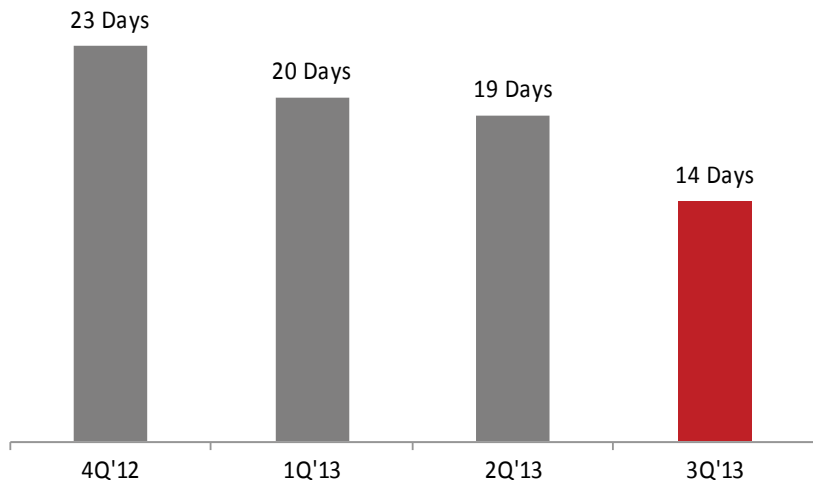


## Best Well Drilling Performance (Days vs. Depth)

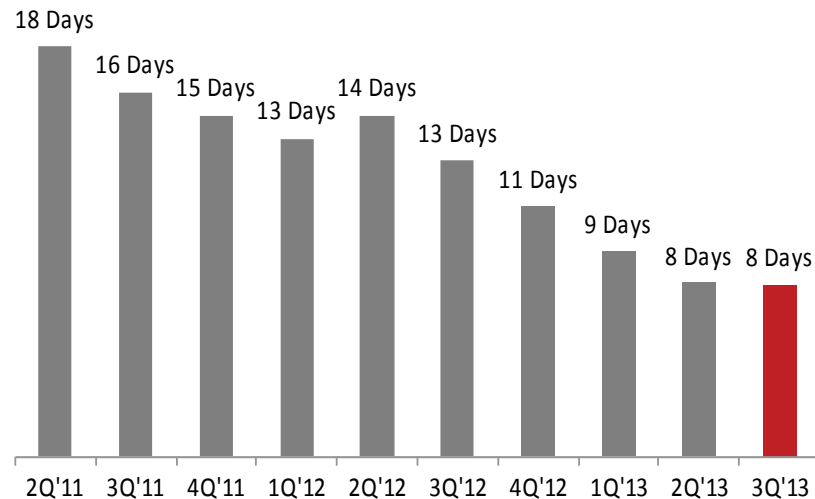


# Operational Execution Driving Positive Results

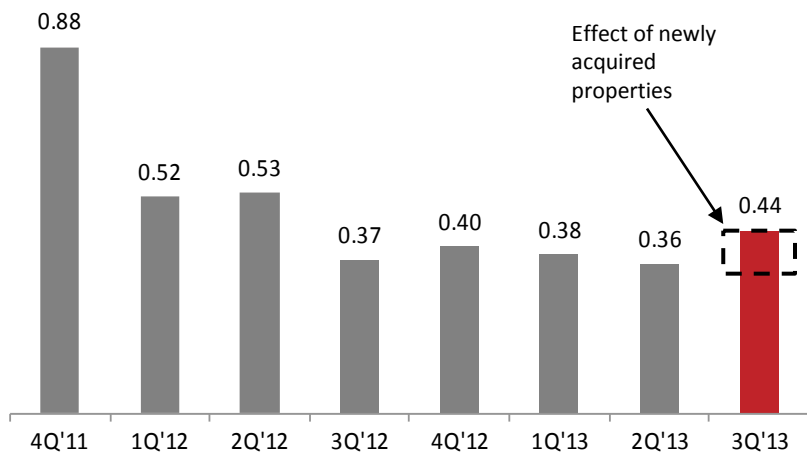
## Horizontal Well Average Spud to TD Time<sup>(1)</sup>



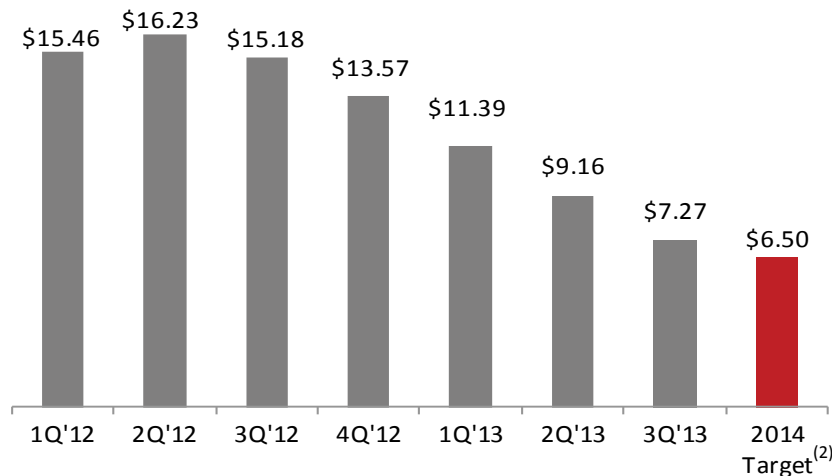
## Vertical Well Average Spud to TD Time



## Well Failure Rate %



## Quarterly LOE (per BOE)<sup>(2)</sup>

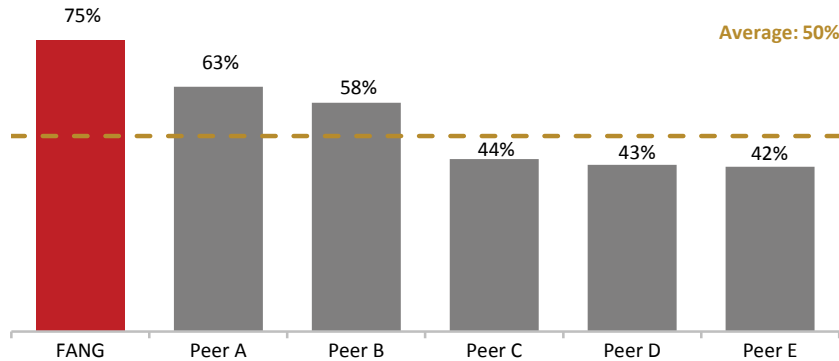


Source: Company Filings, Management Data and Estimates. Financial data and management estimates as of September 30, 2013.

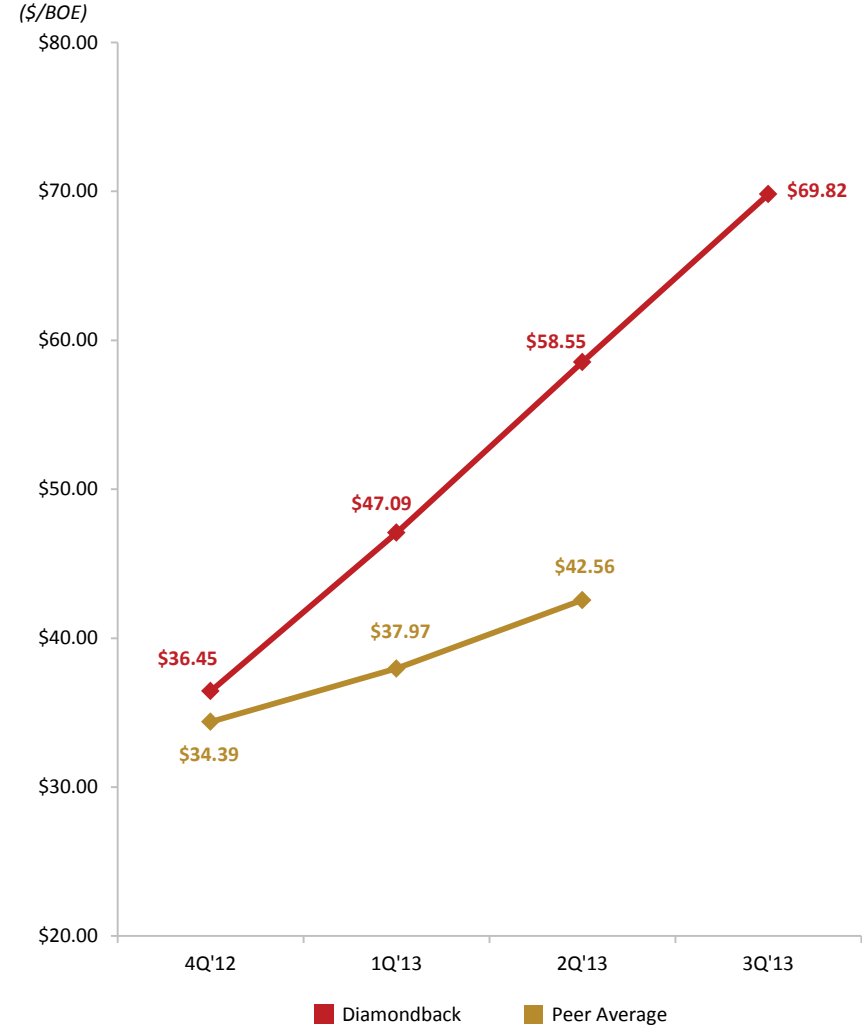
(1) Represents ~7,500' laterals only. (2) 2012 numbers reflect pro forma information of Diamondback and its subsidiaries and includes the interest of Gulfport as of January 1, 2012. Based on 2014 guidance published on October 23, 2013, which is subject to numerous assumptions and risks. Reflects reclassification of ad valorem taxes per guidance published on October 23, 2013. Midpoint of forecast shown for 2014E. See the disclaimer at the beginning of this presentation.

# Diamondback's Cash Margin Leads Public Permian Peers

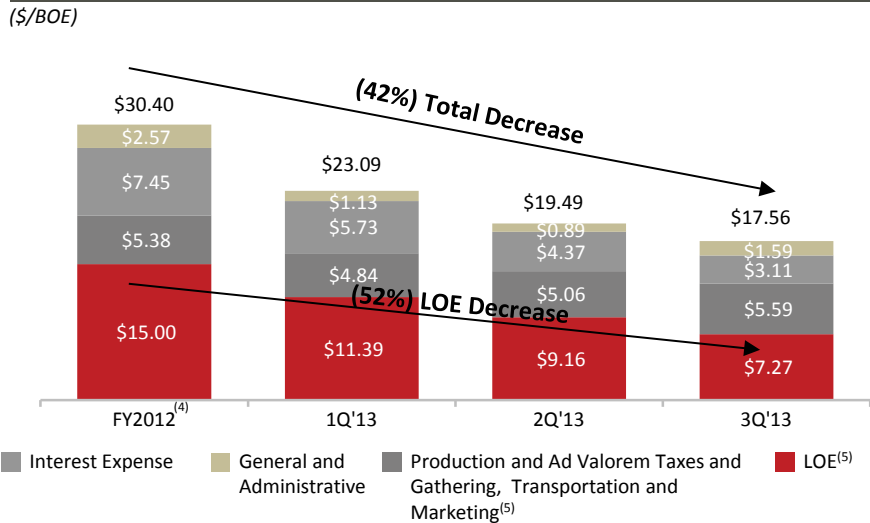
## FANG Percent Oil vs. Public Permian Peers<sup>(1)(2)</sup>



## FANG Cash Margin vs. Public Permian Peers<sup>(2)(3)</sup>



## Diamondback Expenses Over Time

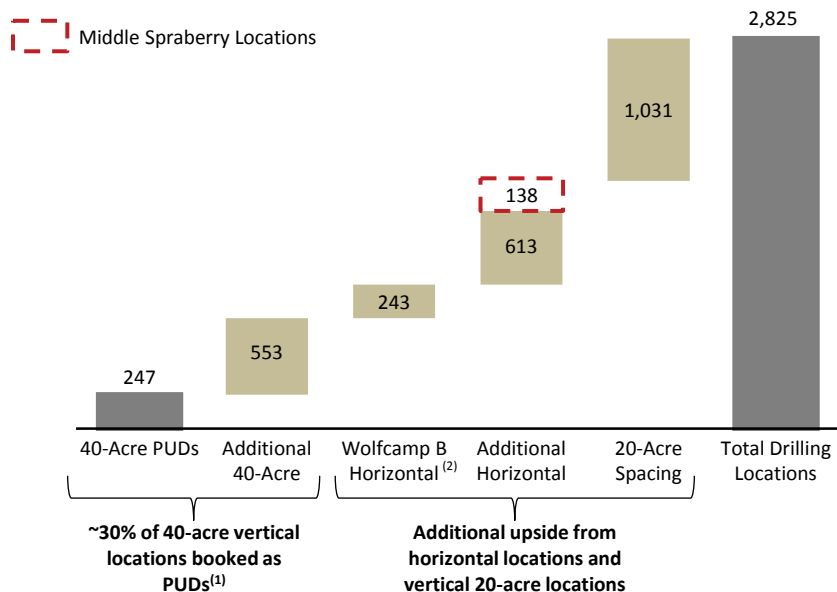


Source: Company Filings, Management Data and Estimates.

(1) Represents latest reported production percentage oil. (2) Peers include ATHL, AREX, CXO, LPI and PXD. (3) Cash margin represents publicly reported EBITDA adjusted to exclude hedging gains and losses, if not already excluded, divided by BOE production for the period. (4) 2012 numbers reflect pro forma information of Diamondback and its subsidiaries and includes the interest of Gulfport as of January 1, 2012. (5) Reflects reclassification of ad valorem taxes per guidance published on October 23, 2013.

# Multi-Year Drilling Inventory

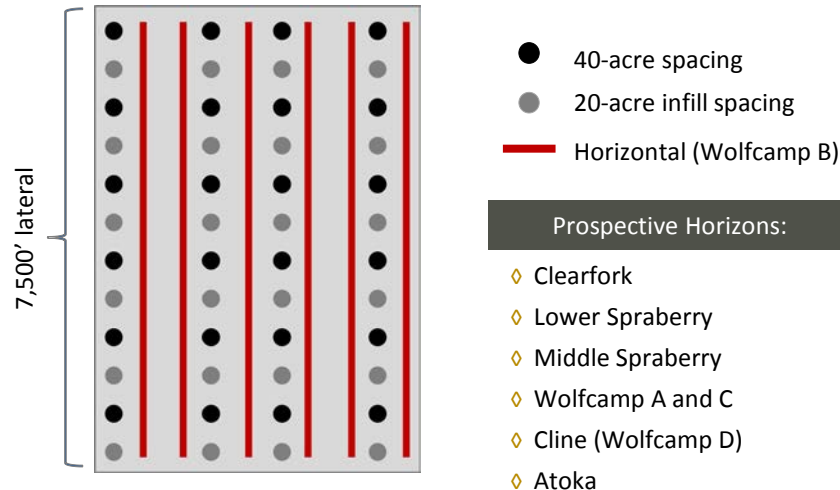
## Identified Net Potential Drilling Locations



## Horizontal Resource Potential

Horizontal Target	Wolfcamp B	Wolfcamp A	Lower Spraberry	Middle Spraberry	Cline	Clearfork	Wolfcamp C	Total
Locations (gross / net) <sup>(2)</sup>	309/243 <sup>(1)</sup>	195/150	180/138	180/138	170/128	176/138	71/59	<b>1,281/994</b>
EUR / Well (MBOE) <sup>(3)</sup>	600	500	500	500	500	400	400	<b>400 – 600</b>

## Diamondback Potential Optimized Spacing



## Horizontal Development Offers Higher Returns

Development	Wolfcamp B Horizontal Only	40-Acre Vertical Only
Wells Per Section	6	24
EUR Per Well (MBOE)	600	133
Total EUR (MBOE)	3,600	3,192
Cost (\$MM) <sup>(4)</sup>	\$42.9	\$50.4

- ◇ Horizontal development adds ~13% more production at ~\$7.5 MM lower cost
- ◇ Additional upside from stacked pay horizontal potential of 6 additional zones

Source: Company Filings, Management Data and Estimates. Management estimates as of September 30, 2013.

(1) PUDs based on management internally prepared estimates as of 9/1/2013 audited by Ryder Scott and includes 11 Wolfcamp B locations. (2) Due to lease geometry average lateral length is ~6,500'. (3) Aside from Wolfcamp B, EURs are based on management estimates based on wells drilled by other operators. The Company results may vary materially. No other locations are currently booked as PUDs in other horizons. All data based on 7,500' laterals.

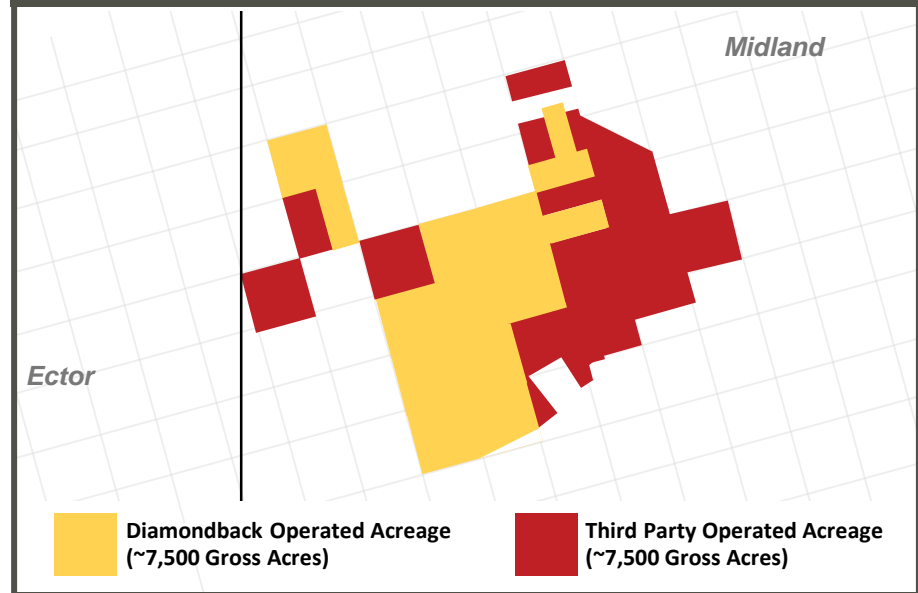
(4) Based on midpoint horizontal and vertical well costs from 2014 guidance published on October 23, 2013.

# Midland County Acquisition Adds to FANG's Production Without Additional Capex or Expenses

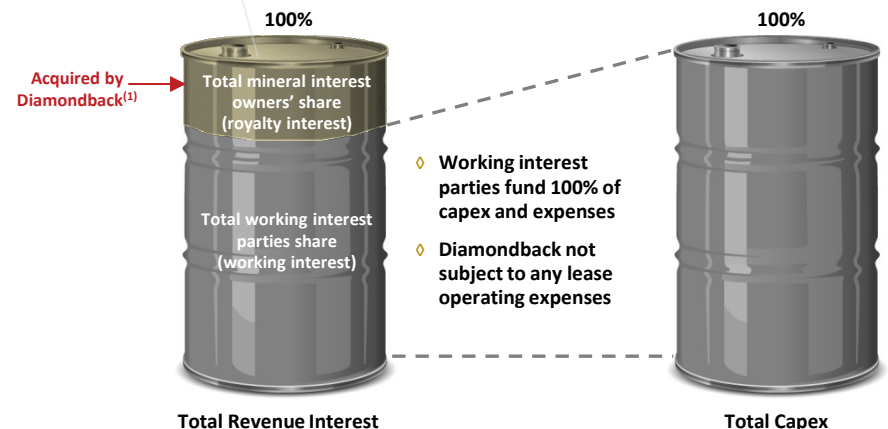
## Key Highlights

- ◇ Completed the acquisition of mineral interests under ~15,000 gross (~12,500 net) acres in Midland County in September 2013
- ◇ Entitles Diamondback to receive an average of 20% of royalty interest on all production from these ~15,000 gross acres<sup>(1)</sup>
  - ◇ Net production of 1,950 BOEPD<sup>(2)</sup> in October 2013 (30% increase since April 2013)
- ◇ Acquired free cash flow is expected to grow for the next several years
- ◇ No additional future capital or operating expenses required to receive run-rate cash flows
- ◇ Diamondback currently operates ~50% of the net acreage
- ◇ Anticipate will generate \$70 – \$80 MM of cash flow in 2014<sup>(3)</sup>

## Midland County Mineral Interest



## Illustrative Revenue Interest



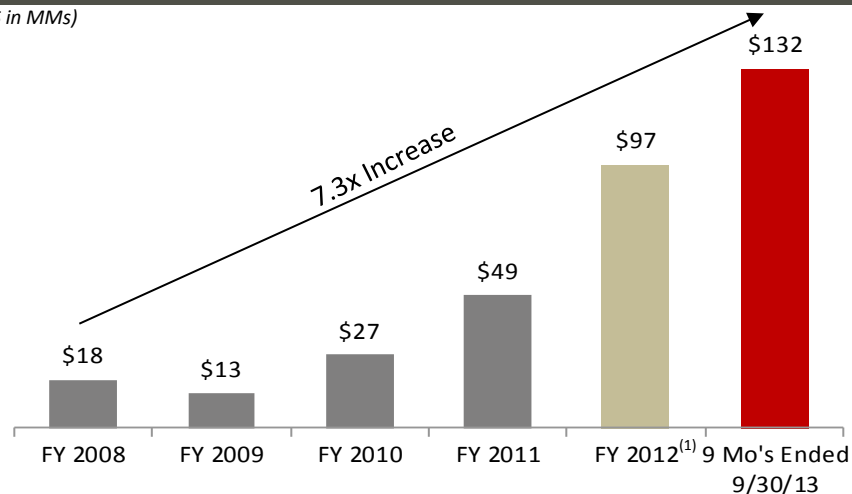
Source: Company Filings, Management Data and Estimates.

(1) Standard Permian Basin royalty interest is 25% of revenue interest. Diamondback has acquired an average of 20% royalty interest (out of 25%) across the ~15,000 gross acres. Net revenue interest equals working interest multiplied by royalty interest. (2) Per October 23, 2013 press release. (3) Subject to numerous assumptions and risks. See the disclaimer at the beginning of this presentation.

# Financial Summary

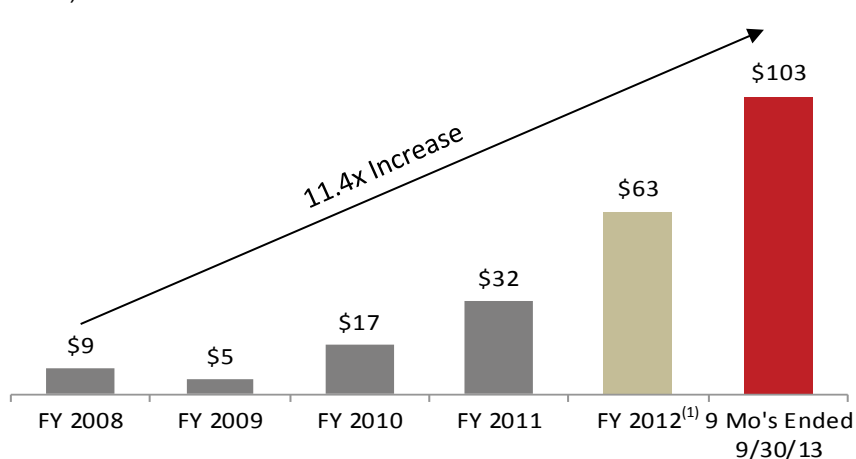
## Revenue Growth

(\$ in MM\$)



## EBITDA Growth

(\$ in MM\$)



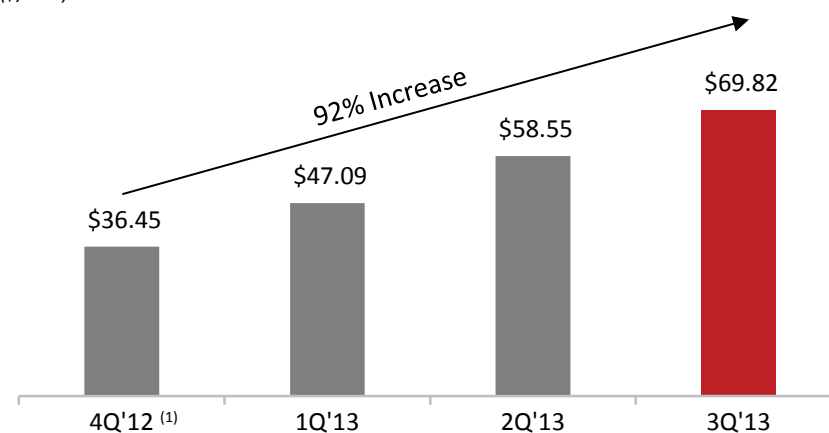
## Hedging

Management's goal is to hedge 40% - 70% of oil production

- ◇ 1,000 barrels / day at \$80.55 WTI (expires December 2013)
- ◇ 1,000 barrels / day at \$109.70 Brent (expires April 2014)
- ◇ 1,000 barrels / day at \$100.20 LLS (expires June 2014)
- ◇ 1,000 barrels / day at \$101.00 LLS (January 2014 to January 2015)

## Cash Margins (\$/BOE)<sup>(2)</sup>

(\$/BOE)

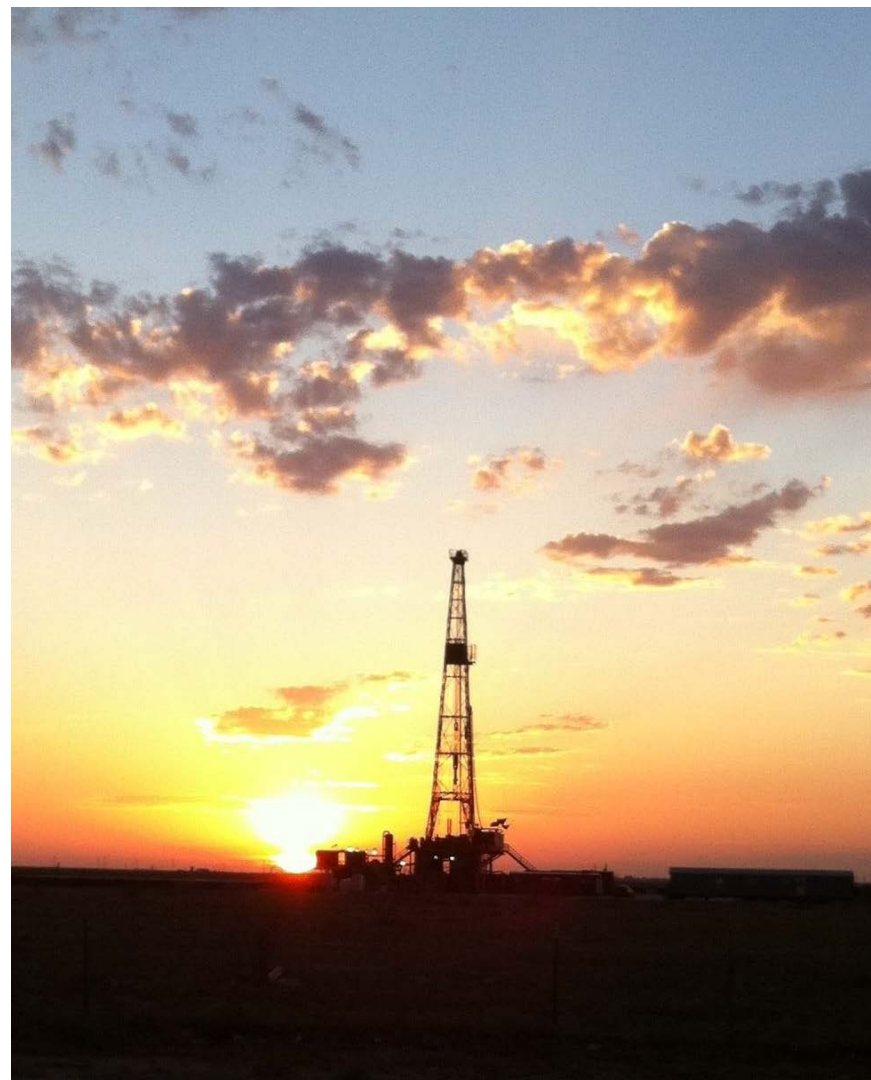


Source: Company Filings, Management Data and Estimates.

(1) 2012 numbers reflect pro forma information of Diamondback and its subsidiaries and includes the interest of Gulfport as of January 1, 2012. (2) Cash margin represents adjusted EBITDA/BOE production.

# Diamondback Guidance<sup>(1)</sup>

	Full Year 2014
<b>Production</b>	15.0 – 16.0 MBOEPD
<b>Capital Expenditures</b>	\$425 - \$475 MM
<b>Horizontal Well Costs</b>	\$6.9 - \$7.4 MM
<b>Vertical Well Costs</b>	\$2.0 - \$2.2 MM

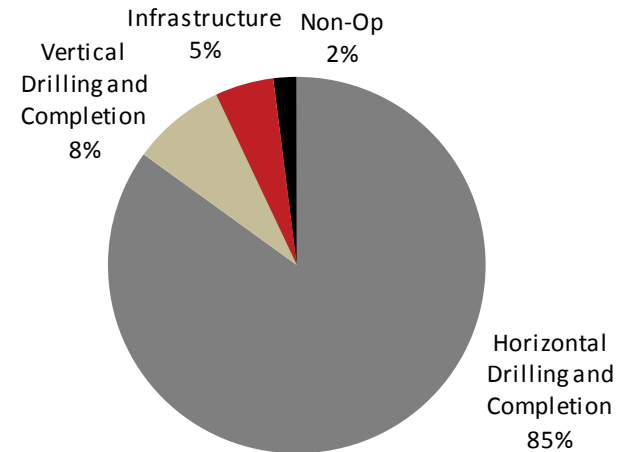


# 2014 Capital Program

## 2014E Capital Plan

- ◇ \$425 – \$475 MM capital expenditures:
  - ◇ Horizontal Drilling: 85%
    - ◇ Currently operating 4 horizontal rigs
    - ◇ Fifth horizontal rig to be added in 2Q'14
    - ◇ 65 – 75 gross operated horizontal wells expected to be drilled
    - ◇ Focus on Andrews, Martin and Dawson Counties and continue aggressive development in Midland County
  - ◇ Vertical Drilling: 8%
    - ◇ One vertical rig expected to be active during 2014
    - ◇ 20 – 25 gross operated vertical wells expected to be drilled
    - ◇ Focus on Midland County mineral interests
    - ◇ Maintaining leasehold acreage
    - ◇ Acquiring data for horizontal development
  - ◇ Infrastructure: 5%
  - ◇ Non-operated drilling: 2%

## 2014E Capital Expenditures



- ◇ Fully financed based on current liquidity, cash flow and expected growth in borrowing base over time

## In Conclusion...

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**Pure Play Exposure to the Midland Basin**

**Realizing Horizontal Development and  
Stacked Pay Potential**

**Leading Margins Driven by Low Expenses  
and High Percent Oil**

**High Return Drilling Inventory**

**Rapidly Increasing Production**

**Financial Strength and  
Strong Management**

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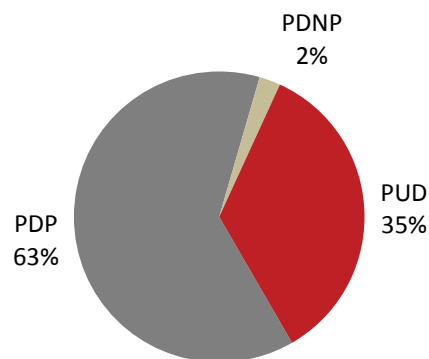
## Appendix

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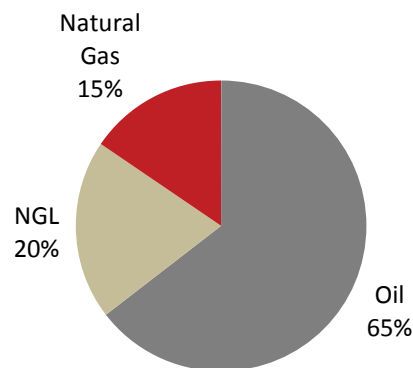
# Proved Reserves Overview (as of 9/1/2013)

- ◇ Diamondback proved reserves as of 9/1/2013, including:
  - ◇ ~2.1 MMBOE of proved reserves from completed Martin County and Dawson County acquisitions
  - ◇ ~8.6 MMBOE of proved reserves from completed Midland County acquisition
  - ◇ ~6.9 MMBOE of proved reserves from new drilling since 12/31/12
- ◇ **\$459 MM increase in PV-10% since 12/31/12 as a result of acquisitions and drilling activities**

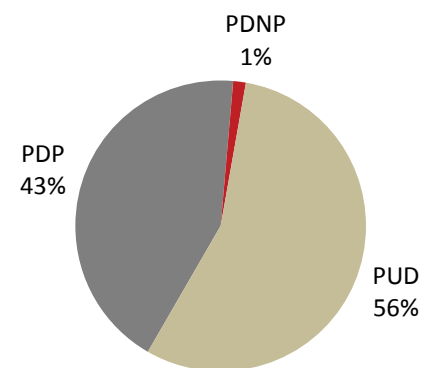
1P – PV-10%



1P – By Commodity



1P – By Category



	Net Oil (MBbls)	Net NGLs (MBbls)	Net Gas (Mmcf)	Total (MBOE)	Pre-tax PV-10% (\$MM) <sup>(1)</sup>
<b>Total reserves</b>					
PDP	15,480	5,146	25,728	24,914	\$598
PDNP	564	125	762	816	22
PUD	21,310	6,290	27,283	32,147	332
<b>Total Proved</b>	<b>37,354</b>	<b>11,561</b>	<b>53,772</b>	<b>57,876</b>	<b>\$952</b>

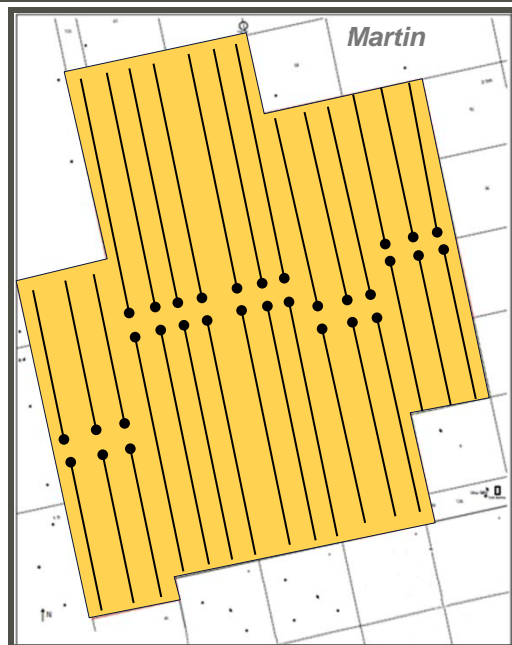
Source: Reserves based on Management internally prepared estimates as of 9/1/2013; audited by Ryder Scott.

(1) Based on management internally prepared estimates as of 9/1/2013 pro forma for the acquisitions completed in September 2013. Present value of estimated future net revenues generated from production of proved reserves, without giving effect to non-property related expenses such as G&A, debt service, income tax or DD&A; discounted at a rate of 10%.

# Midland Basin Acquisitions Add to FANG's Long Term Growth Potential

- Complementary acreage blocks with strong horizontal delineation potential

## Martin County Acreage



## Dawson and Martin County Acreage



Acreage			Ownership				
	Gross	Net	Working interest				
Acreage	4,506	4,506	<b>Net revenue interest</b>		<b>80%</b>		
Production <sup>(2)</sup>			Proved Reserves <sup>(3)</sup>				
	Gross	Net	PDP	PDNP	PUD	Total proved	
BOPD	367	293	MBBLs	805	66	–	871
MCFPD	539	431	MMCF	1,837	132	–	1,969
BOEPD	457	365	MBOE	1,112	88	–	1,199

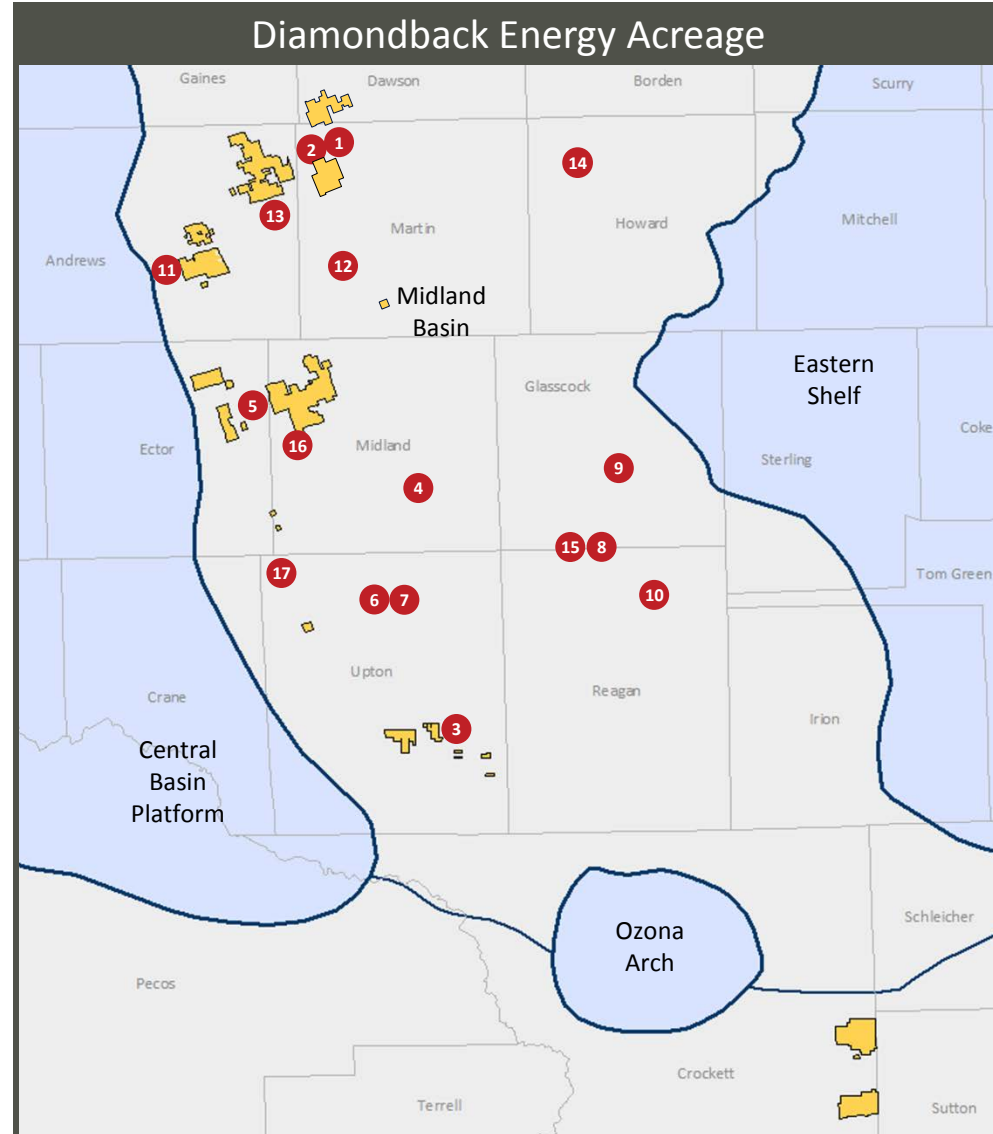
Acreage			Ownership				
	Gross	Net	Working interest				
Acreage	9,390	6,638	<b>Net revenue interest</b>		<b>77%<sup>(4)</sup></b>		
Production <sup>(2)</sup>			Proved Reserves <sup>(3)</sup>				
	Gross	Net	PDP	PDNP	PUD	Total proved	
BOPD	634	340	MBBLs	695	37	–	731
MCFPD	856	465	MMCF	1,005	49	–	1,054
BOEPD	777	417	MBOE	862	45	–	907

(1) Acquired deep rights below 10,750'. (2) Martin County acquisition for July 2013. Dawson and Martin County acquisition for June 2013. (3) Reserves based on Management internally prepared estimates as of 9/1/2013; audited by Ryder Scott. (4) Revenue interest is 77% of 70% working interest or 54% net revenue interest.

# Stacked Pay Potential Being Realized in the Permian Basin

## Permian peers have achieved successful results from horizontal wells

- 1 Wolfcamp A, W&T Offshore, Chablis 5H, 7,112' lateral, 24-hour IP of 530 BOEPD (91% oil)
- 2 Wolfcamp A, W&T Offshore, Pinotage 8H, 5,395' lateral, 24-hour IP of 457 BOEPD (96% oil)
- 3 Wolfcamp A, Callon Petroleum, Neal 341H, drilled with 3Q'13 completion
- 4 Wolfcamp A, PXD, DL Hutt C #2, ~7,380' lateral, peak 30-day average IP of 1,107 BOEPD
- 5 Lower Spraberry, private 3<sup>rd</sup> party, ~4,800' lateral, 30-day IP of 576 BOEPD
- 6 Jo Mill (Lower Spraberry), PXD, Giddings Estate 3049H, 2,628' lateral, 24-hour IP of 546 BOEPD (88% oil)
- 7 Jo Mill (Lower Spraberry), PXD, Giddings Estate 1019H, 2,178' lateral, 24-hour IP of 368 BOEPD (89% oil)
- 8 Upper Wolfcamp (Wolfcamp A), LPI, Lane Trust C/E 421HU, 7,188' lateral, 30-day IP of 1,183 BOEPD (76% oil)
- 9 Cline, LPI, Bearkat 150 5H, 7,284' lateral, 30-day IP of 835 BOEPD (74% oil)
- 10 Lower Wolfcamp (Wolfcamp C), LPI, Sugg D 106 2HL, 7,201' lateral, 30-day IP of 969 BOEPD (66% oil)
- 11 Leonard shale (Clearfork), SM Energy, University 29 Sawgrass 2H, 7,933' lateral, 24-hour IP of 492 BOEPD (85% oil)
- 12 Atoka, Reliance Energy (private), Mabee 138 801H, 4,545' lateral, 24-hour IP of 897 BOEPD (74% oil)
- 13 2 zone test, PXD, Wolfcamp D and Lower Spraberry
- 14 Wolfcamp A, private 3<sup>rd</sup> party, 7,268' lateral, 30-day average IP of 649 BOEPD (~89% oil)
- 15 Lower Wolfcamp, LPI, Lane Trust C/E 422HL, 7,571' lateral, 30-day IP of 1,217 BOEPD (79% oil)
- 16 Middle Spraberry Shale, Private 3<sup>rd</sup> party, 5,041' lateral, peak 24-hr IP 733 BOEPD (90% oil)
- 17 Wolfcamp B, SM Energy Dorcus 3035H, ~5,000' lateral, Average 30-day rate 1,226 BOEPD (82% oil)



# Management Team – Over 225 Years Combined Experience

Team	Prior Experience	Years Experience
<b>Travis Stice</b> Chief Executive Officer	 <ul style="list-style-type: none"> <li>◆ Permian Basin Production Manager of Apache Corporation</li> <li>◆ Vice President of Permian Basin for Laredo Petroleum Holdings</li> <li>◆ Development Manager of Mid-Continent Business Unit for ConocoPhillips/Burlington Resources</li> <li>◆ General Manager of Engineering, Operations and Business Reporting of Mid-Continent Division for Burlington Resources</li> </ul>	<b>28</b>
<b>Tracy Dick</b> Chief Financial Officer	 <ul style="list-style-type: none"> <li>◆ Controller / Tax Director at Hiland Partners</li> <li>◆ Over 20 years of accounting experience, including over 8 years of public company experience in both audit and tax areas</li> </ul>	<b>20</b>
<b>Russell Pantermuehl</b> Vice President of Reservoir Engineering	   <ul style="list-style-type: none"> <li>◆ Wolfberry Reservoir Engineering Supervisor for Concho Resources Inc.</li> <li>◆ Reservoir Engineering Advisor for ConocoPhillips</li> <li>◆ Reservoir Engineering Advisor for Burlington Resources</li> </ul>	<b>32</b>
<b>Paul Molnar</b> Vice President of Geoscience	   <ul style="list-style-type: none"> <li>◆ Senior District Geologist for Samson Investment Company</li> <li>◆ Asset Supervisor and Geosciences Supervisor for ConocoPhillips</li> <li>◆ Geologic Advisor for Burlington Resources</li> </ul>	<b>33</b>
<b>Michael Hollis</b> Vice President of Drilling	   <ul style="list-style-type: none"> <li>◆ Drilling Manager at Chesapeake Energy Corporation</li> <li>◆ Senior Drilling Engineer for ConocoPhillips</li> <li>◆ Drilling and Production Engineer for Burlington Resources</li> </ul>	<b>15</b>
<b>William Franklin</b> Vice President of Land	 <ul style="list-style-type: none"> <li>◆ Various land management roles with ConocoPhillips</li> </ul>	<b>37</b>
<b>Jeff White</b> Vice President of Operations	   <ul style="list-style-type: none"> <li>◆ Completion Manager for Laredo Petroleum Holdings</li> <li>◆ Staff Engineer for ConocoPhillips</li> <li>◆ Various engineering and management positions with Anadarko Petroleum</li> </ul>	<b>31</b>
<b>Randy Holder</b> Vice President, General Counsel	  <ul style="list-style-type: none"> <li>◆ General Counsel and Vice President for Great White Energy Services LLC</li> <li>◆ Mid-Continent Division Attorney for Tenneco Oil Company</li> </ul>	<b>32</b>

# EBITDA Reconciliation

(\$ in thousands)

	Year ended December 31,				Three Months Ended
	2009	2010	2011	2012 <sup>(1)</sup>	9/30/2013
<b>Reconciliation of Adjusted EBITDA to Net Income (Loss):</b>					
Net Income (Loss)	(\$2,706)	\$8,231	(\$386)	(\$29,697)	\$14,596
(Gain) Loss on Derivatives	4,068	148	13,009	(2,617)	4,910
Interest Expense	11	836	2,528	3,610	1,089
Depreciation, Depletion, Amortization	3,216	8,145	16,104	34,205	17,423
Non-Cash Equity-Based Compensation Expense	–	–	438	2,477	749
Capitalized Equity-Based Compensation Expense	–	–	–	–	(259)
Asset Retirement Obligation Accretion Expense	28	38	65	122	46
Deferred Income Tax Provision	–	–	–	54,903	9,099
<b>Adjusted EBITDA</b>	<b>\$4,617</b>	<b>\$17,398</b>	<b>\$31,758</b>	<b>\$63,003</b>	<b>\$47,653</b>

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*Houston, Texas*

## **Legal Counsel**

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*Dallas, Texas*

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