QEP RESOURCES®

3Q 2016
Operations Update

October 26, 2016

Forward-Looking Statements & Non-GAAP Financial Measures

This presentation includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can be identified by words such as “anticipates,” “believes,” “forecasts,” “plans,” “estimates,” “expects,” “should,” “will,” or other similar expressions. Such statements are based on management’s current expectations, estimates and projections, which are subject to a wide range of uncertainties and business risks. These statements are not guarantees of future performance. These forward-looking statements include statements regarding: estimated proved reserves; estimated production split among oil, gas and NGL; forecasted 2016 oil production and drilling and completion performance data; potential drilling locations; drilling program; rig activity; estimated well costs and lease operating expense; development plans; estimates of shrink and NGL yield for wells in the Permian Basin; additional compression in the Pinedale and Uinta Basins; and estimated rig count and stacked pay potential in the Permian Basin.

Actual results may differ materially from those included in the forward-looking statements due to a number of factors, including, but not limited to: disruptions of QEP's ongoing business, distraction of management and employees, increased expenses and adversely affected results of operations from organizational modifications due to the 2016 Permian Acquisition; the risk that expected efficiencies from the transaction may not be fully realized; the availability and cost of capital; changes in local, regional, national and global demand for natural gas, oil and NGL; natural gas, NGL and oil prices; strength of the U.S. dollar; impact of Brexit; changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning the environment, climate change, greenhouse gas or other emissions, natural resources, and fish and wildlife, hydraulic fracturing, water use and drilling and completion techniques, as well as the risk of legal proceedings arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures; elimination of federal income tax deductions for oil and gas exploration and development; drilling results; liquidity constraints; availability of refining and storage capacities; shortages or increased costs of oilfield equipment, services and personnel; operating risks such as unexpected drilling conditions; weather conditions; changes in maintenance and construction costs and possible inflationary pressures; permitting delays; outcome of contingences such as legal proceedings; actions taken by third-party operators, processors and transporters; demand for oil and natural gas storage and transportation services; technological advances affecting energy supply and consumption; competition from the same and alternative sources of energy; natural disasters; large customer defaults; operating in ethane recovery or rejection mode; and the other risks discussed in the Company’s periodic filings with the Securities and Exchange Commission (SEC), including the Risk Factors section of QEP’s Annual Report on Form 10-K for the year ended December 31, 2015 (the “2015 Form 10-K”), and Quarterly Report on Form 10-Q for the quarter ended September 30, 2016. QEP undertakes no obligation to publicly correct or update the forward-looking statements in this presentation, in other documents, or on its website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or through reliable technology to be economically and legally producible at specific prices and existing economic and operating conditions. The SEC permits optional disclosure of probable and possible reserves calculated in accordance with SEC guidelines; however, QEP has made no such disclosures in its filings with the SEC. “Estimated net recoverable resources” refers to QEP’s internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques and are not proved, probable or possible reserves within the meaning of the rules of the SEC. Estimates of net recoverable resources are by their nature more speculative than estimates of proved reserves and, accordingly, are subject to substantially more risks of actually being realized. Actual quantities of natural gas, oil and NGL that may be ultimately recovered from QEP’s interests may differ substantially from the estimates contained in this presentation. Factors affecting ultimate recovery include the scope of QEP’s drilling program, which will be directly affected by the availability of capital; oil, gas and NGL prices; drilling and production costs; availability of drilling services and equipment; drilling results; geological and mechanical factors affecting recovery rates; lease expirations; transportation constraints; changes in local, regional, national and global demand for natural gas, oil and NGL; changes in, adoption of and compliance with laws and regulations; regulatory approvals; and other factors. Investors are urged to consider carefully the disclosures and risk factors about QEP’s reserves in the 2015 Form 10-K and other reports on file with the SEC.

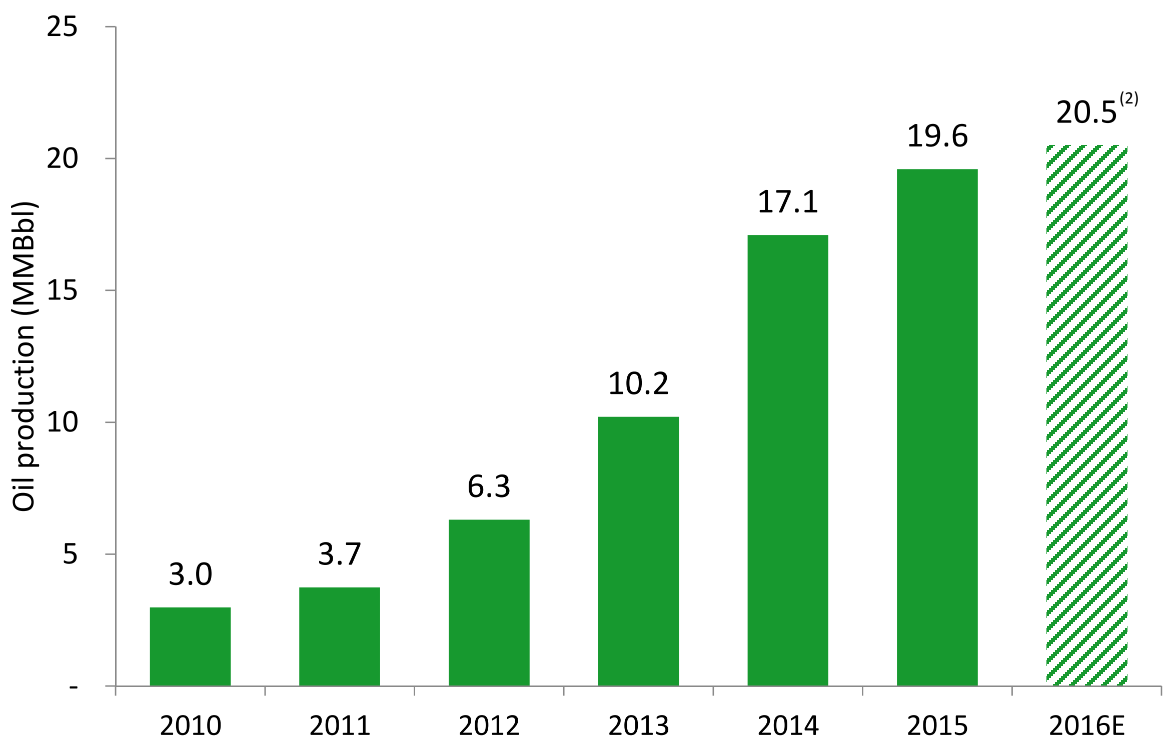
QEP refers to Adjusted EBITDA, Adjusted Net Income (Loss) and other non-GAAP financial measures that management believes are good tools to assess QEP’s operating results. For definitions of these terms and reconciliations to the most directly comparable GAAP measures, see the recent earnings press release and SEC filings at the Company’s website at www.qepres.com under “Investor Relations.”

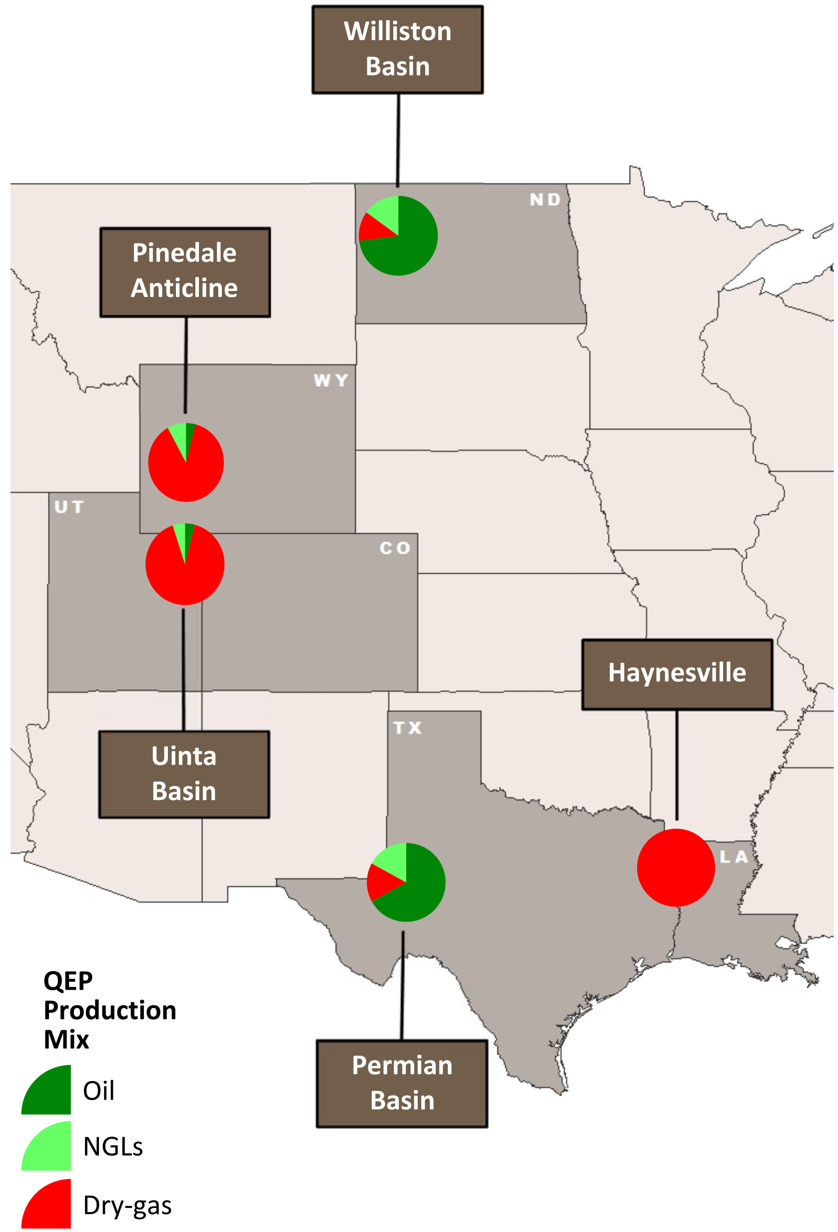
QEP at a Glance

Profile

2016 YTD production	253 Bcfe
% crude oil production	37%
Total proved reserves[(1)]	3,620 Bcfe
Total net acreage[(1)]	1,270,000

Executing on a Transition to Oil

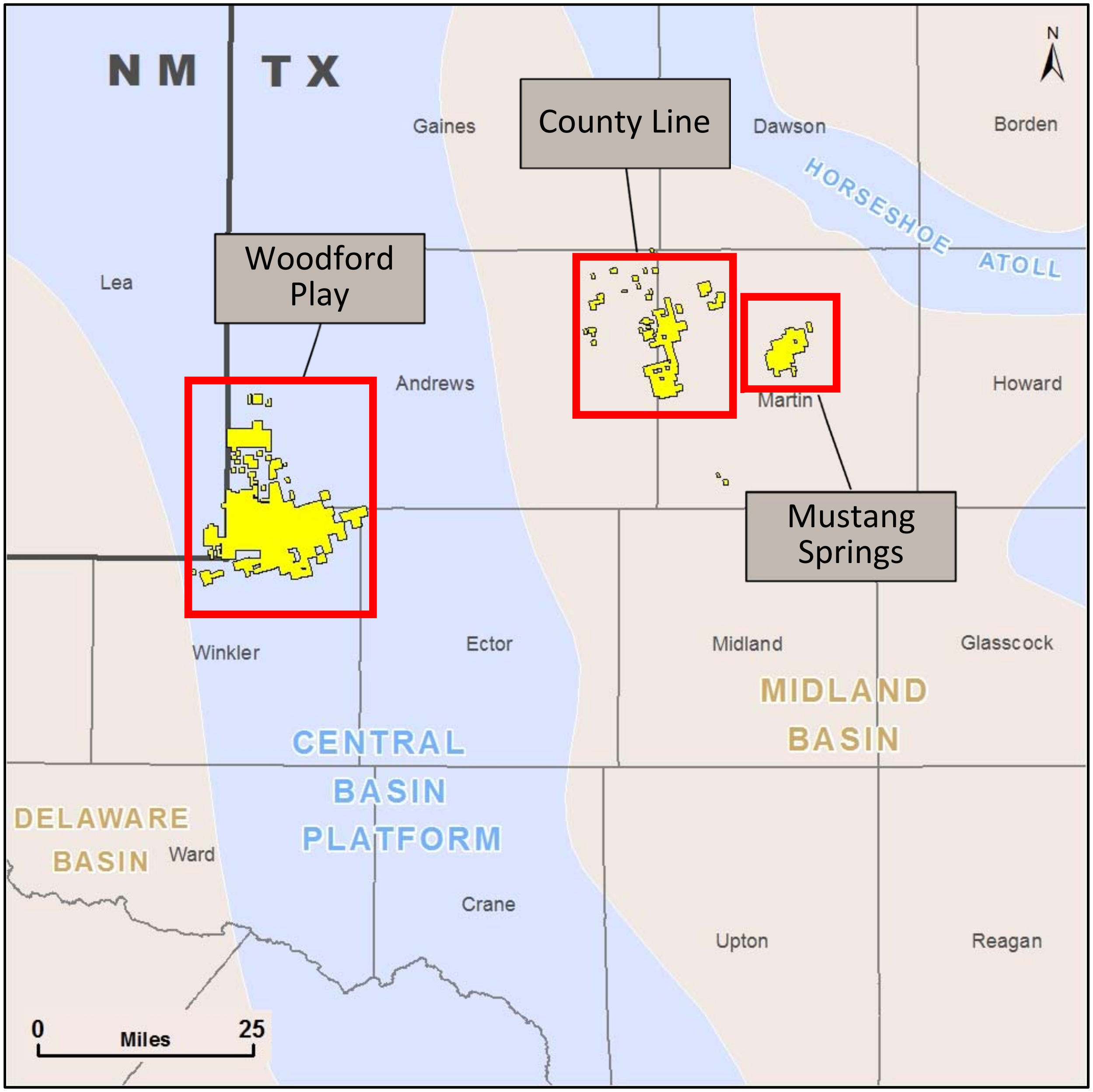




(1) Estimated as of December 31, 2015
(2) 2016E represents guidance as of October 26, 2016

Permian Basin

AGE	FORMATION
PENN.	Canyon
	Strawn
MISS.	Barnett
	Miss. Lime
DEVONIAN	Woodford
	Thirtyone
	Wristen



As of 10/19/2016

AGE	FORMATION
PERMIAN	Leonard
	U. Spraberry
	M. Spraberry
	L. Spraberry
	Spraberry Sh.
	Dean
	Wolfcamp A
	Wolfcamp B
	Wolfcamp C
PENN.	Wolfcamp D
	Strawn

QEP Acreage

Permian Basin Overview

3Q 2016 Program Highlights

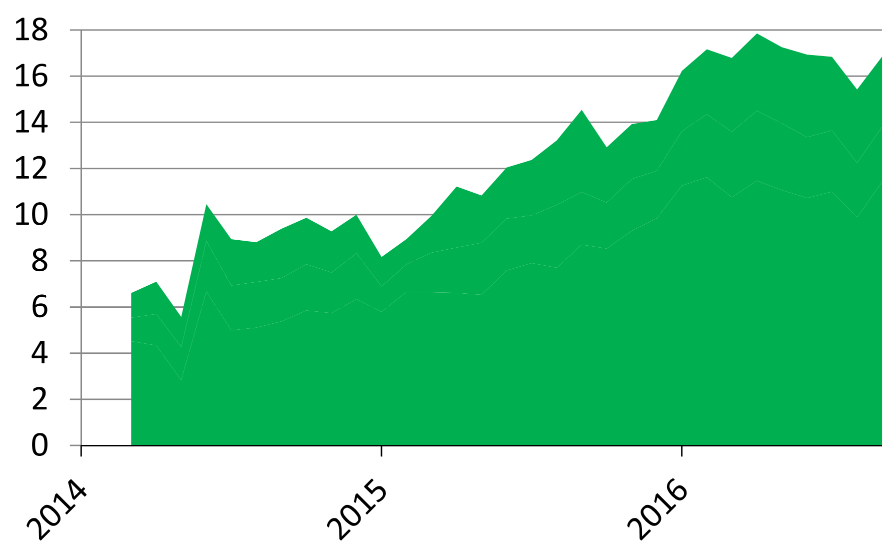
- Completed initial "wine-rack" geometry well density test targeting the "A" and "C" benches of the Spraberry Shale
  - Average 24-hour IP for eight wells 1,291 Boed
- Completed five horizontal wells in the Spraberry Shale
- LOE costs continue to trend lower
- Peak quarterly production of 18.1 Mboed

Profile [1]

Net acres	74,400
Gross operated producing wells	491
Average WI/average NRI	95/71%
Proved reserves (MMboe)/% liquids[2]	138 / 87%
Production Split – oil/gas/NGL	66/16/18%
Current rig count	3

[1] As of September 30, 2016 for Permian Basin and newly acquired properties on October 19, 2016
[2] As of December 31, 2015, SEC pricing, for Permian Basin and internal estimate on new acquisition

Net Production - Mboed



Gross Well Cost (AFE)

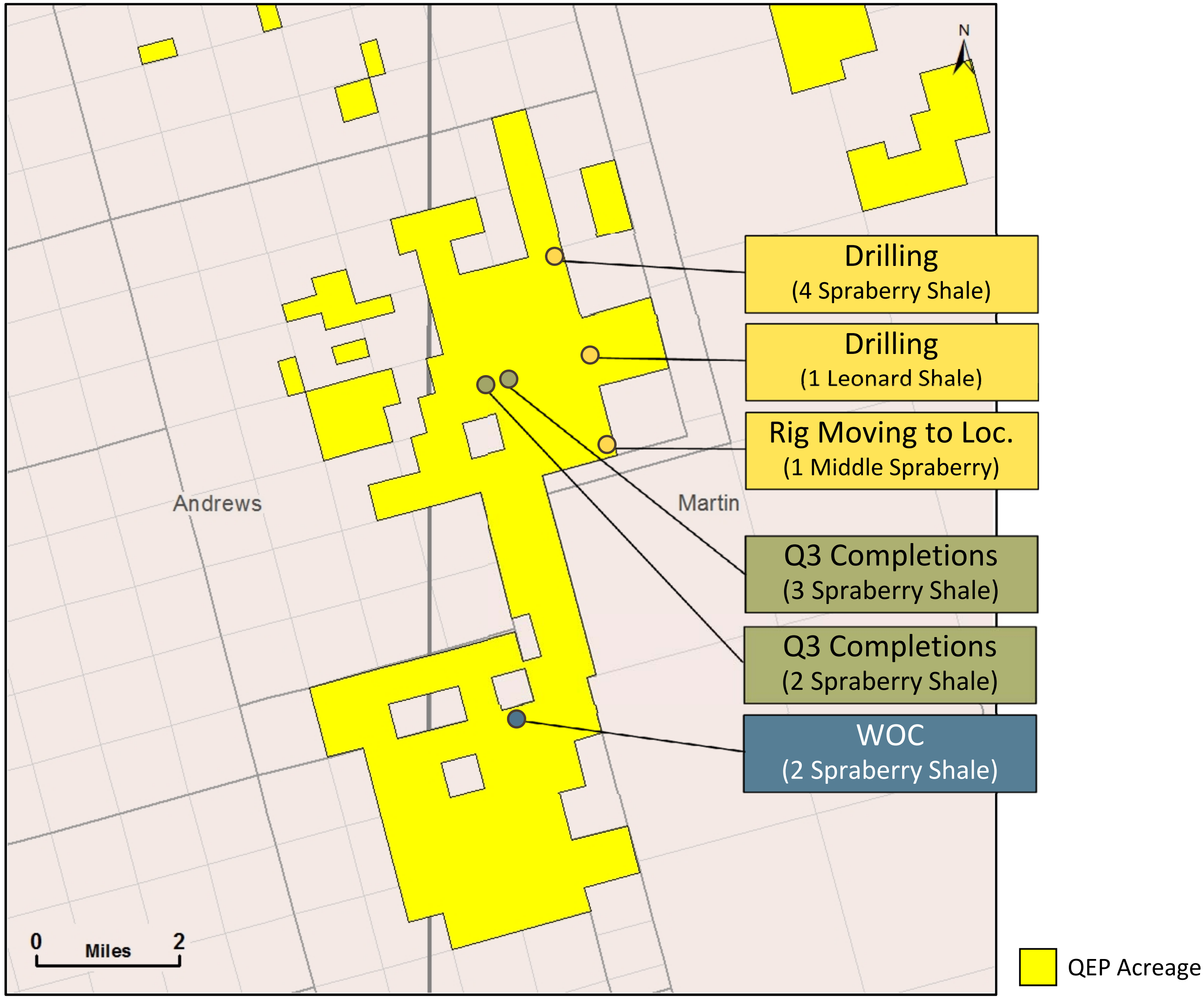
- Drill & complete: $4.9 MM (horizontal)
  - 7,500-ft. lateral, 32 stage "Plug & Perf" design
- Facilities & artificial lift: $0.7 MM

Permian Basin – Drilling & Completion Performance (1)

(1)Spraberry Shale wells only
(2)Represents average actual location and drilling costs
(3)Represents average actual completion costs which includes stimulation costs only

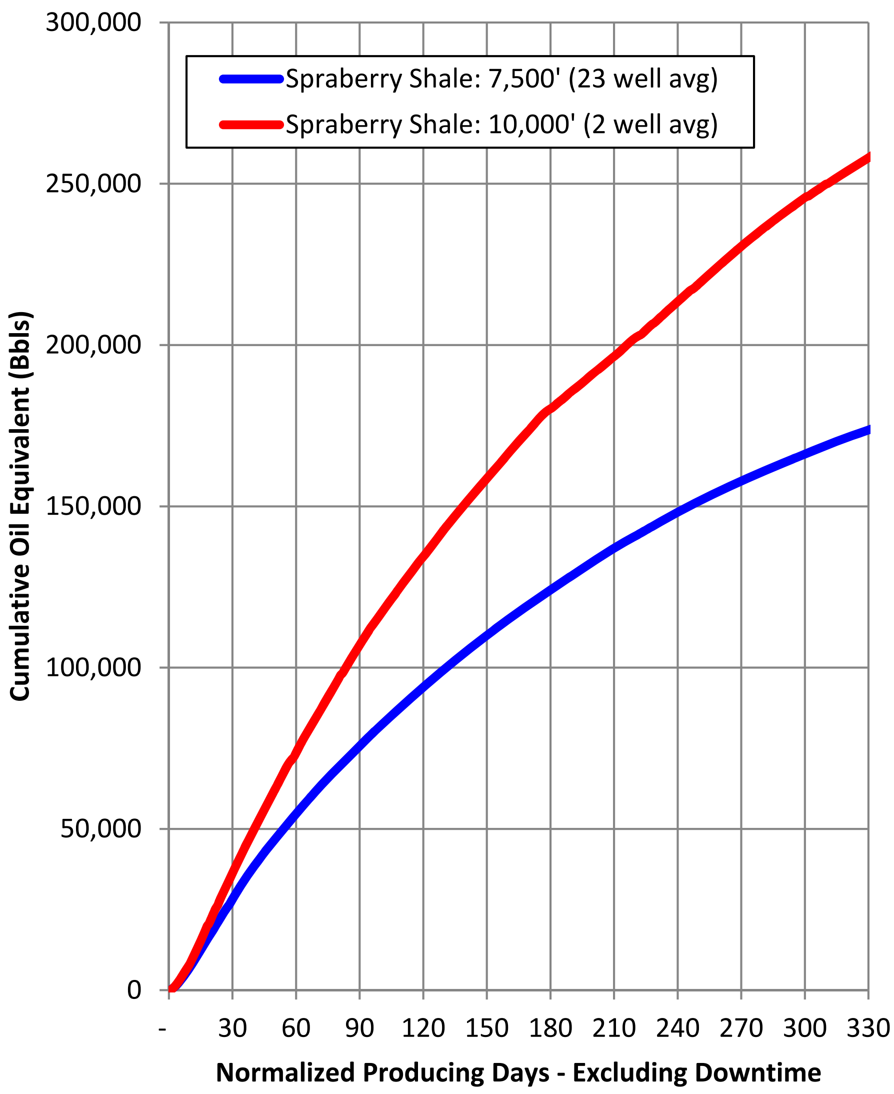
Permian Basin Activity – *County Line*

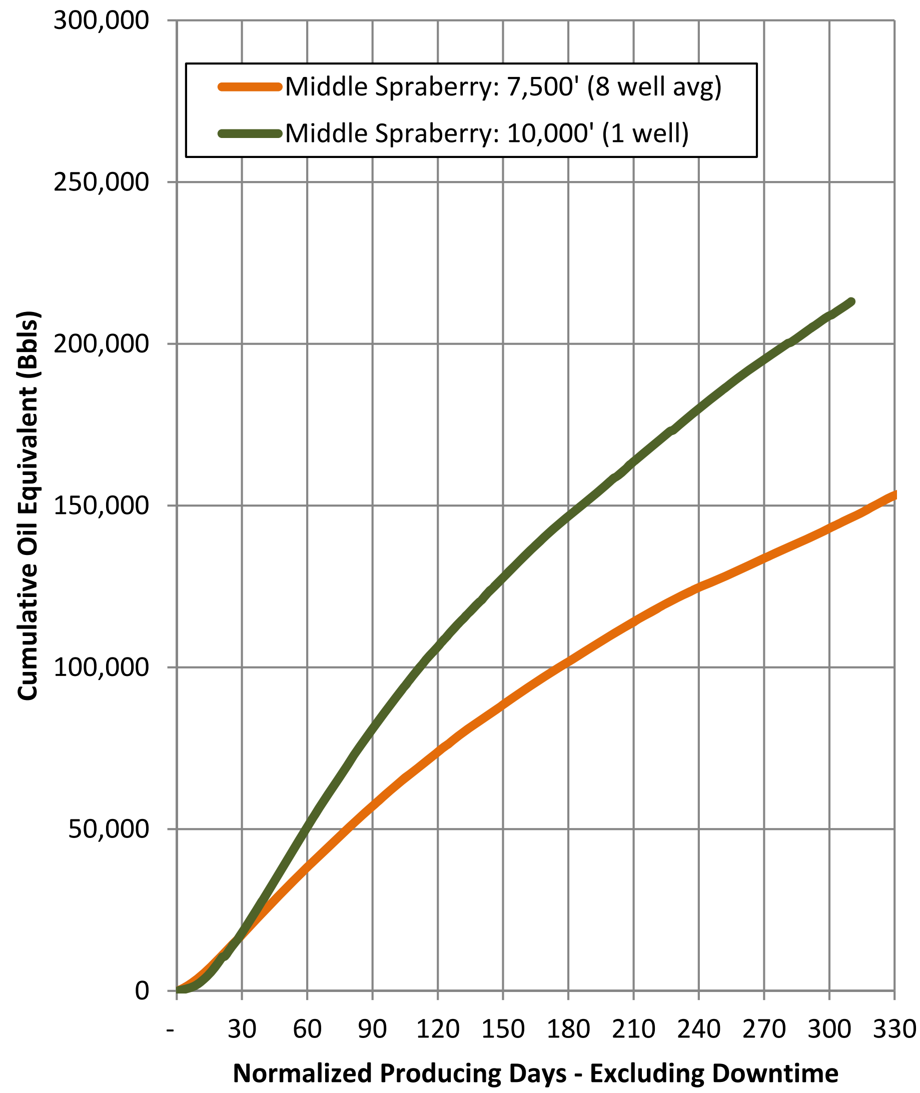
- **Net Acres: ~20,000**
- **Rig Count: 3 horizontal**
- **Completions: 5**
  - **Spraberry Shale**
- **WOC: 2**
  - **Spraberry Shale**
- **Drilling: 5**
  - **Spraberry Shale (4)**
  - **Leonard Shale (1)**



As of 9/30/2016

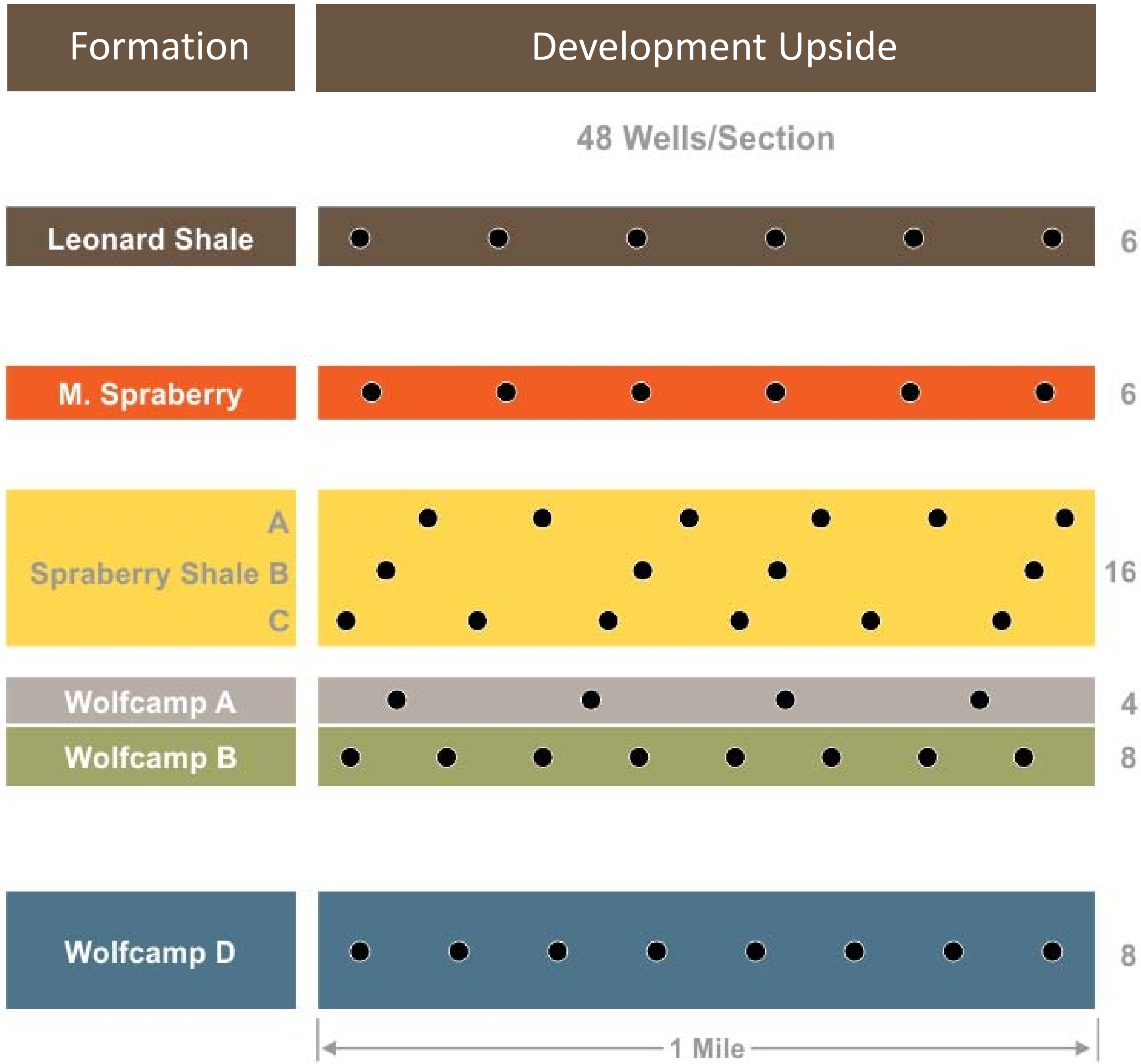
Permian Basin – Horizontal Well Performance – *County Line*





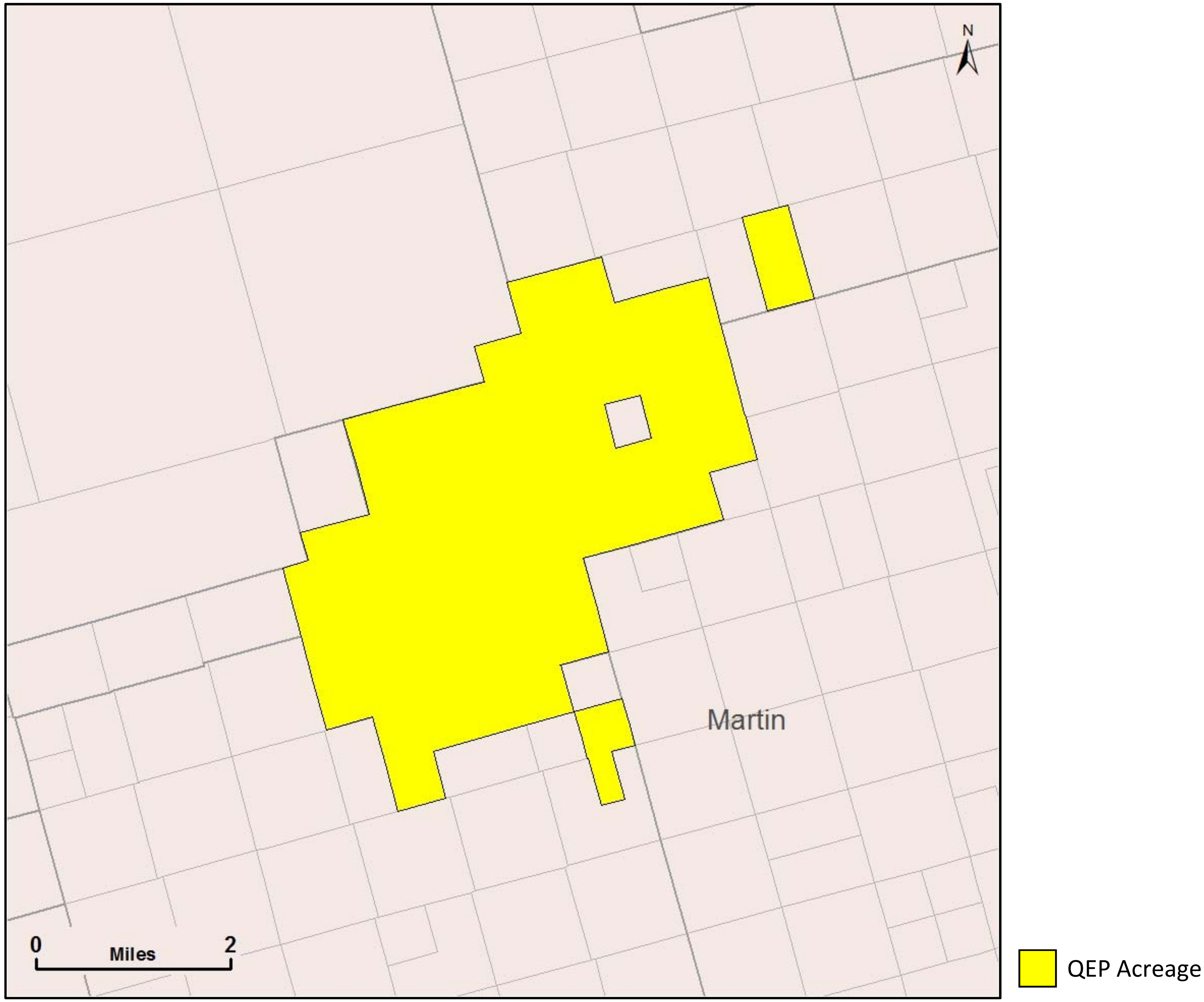
* Production figures are post processing and assume an average shrink (loss of heat content due to extraction of liquids and fuel gas) of 29%, and NGL yield of 138 Bbl/MMcf
* Production is grouped into bins based on lateral length and curves are not normalized

Stacked Pay Potential – *County Line (unrisked)*



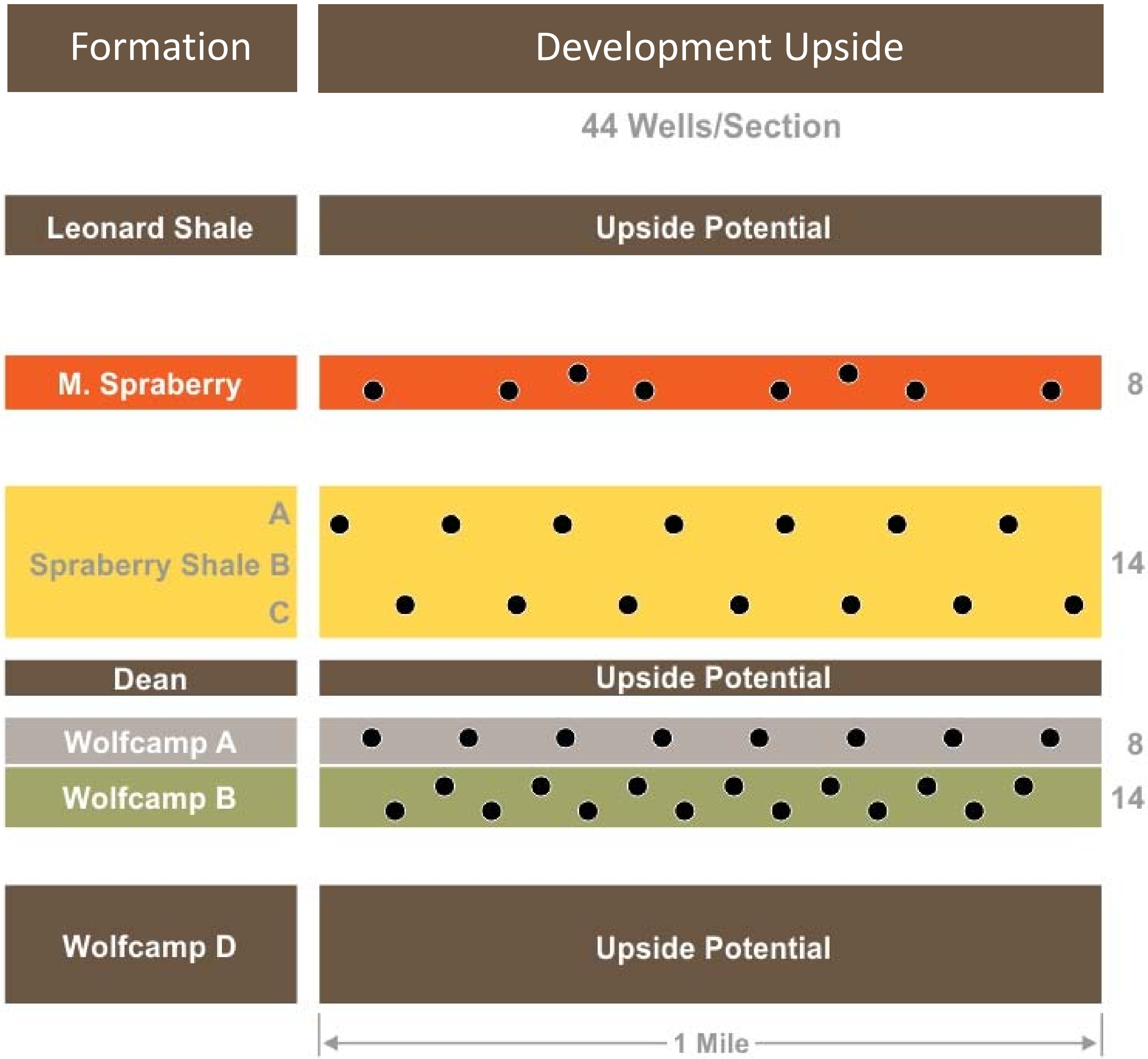
Permian Basin – *Mustang Springs*

- **Acquisition closed October 19, 2016**
- **Net Acres: ~9,400**
- **Rig Count: 0**
  - **Two rigs expected to arrive on acreage in 4Q 2016, from County Line**

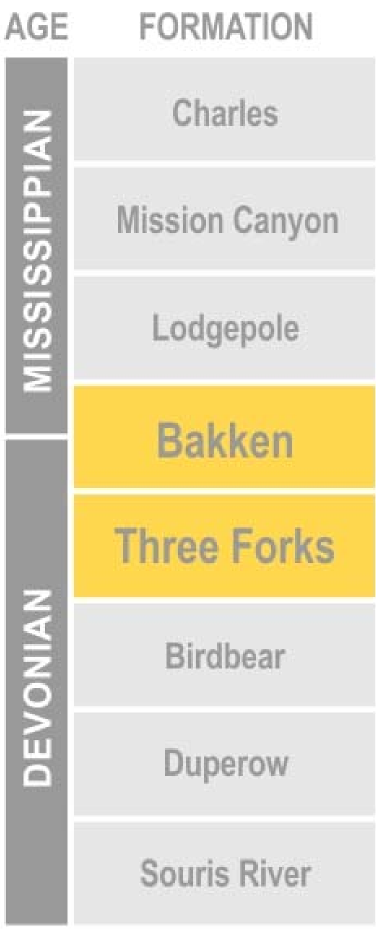


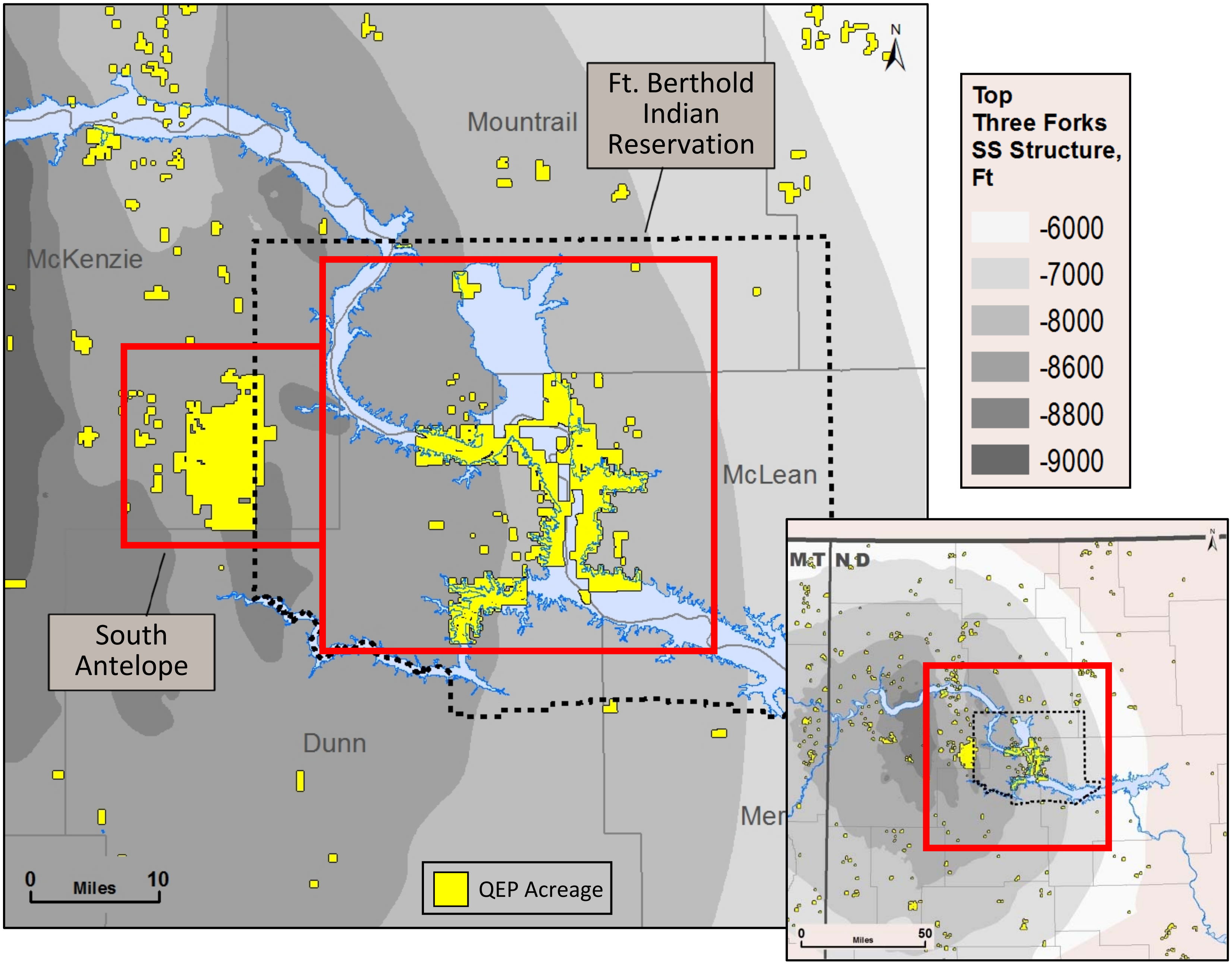
As of 10/19/2016

Stacked Pay Potential – *Mustang Springs (unrisked)*



Williston Basin





Williston Basin Overview

3Q 2016 Program Highlights

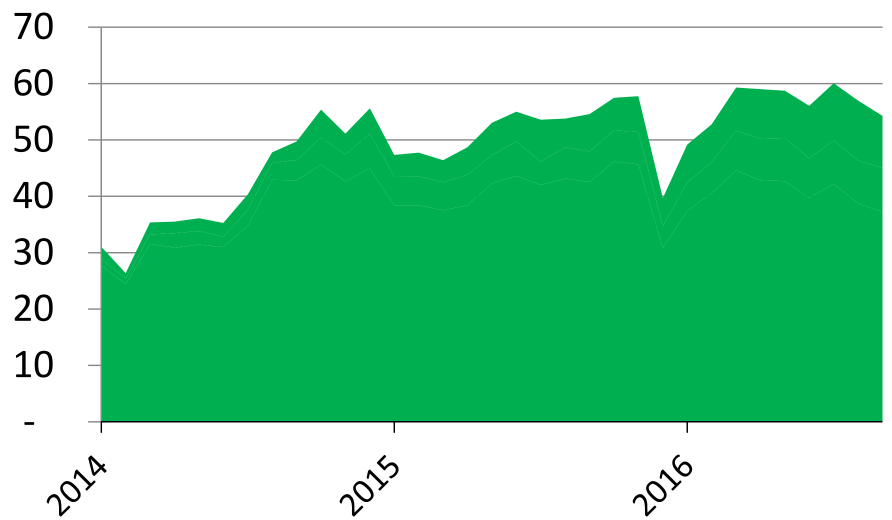
- Completed two 2nd bench wells and one 3rd bench well in South Antelope
  - 2nd Bench 24-hour IP of 2,871 Boed
- Completed three wells at Ft. Berthold utilizing modern completion design
  - 49 stages, sliding sleeve, 1,000 lbs. of proppant per foot
  - Average peak 24-hour IP of 1,380 Boed

Profile[1]

Net acres	117,000
Gross operated producing wells	340
Average WI/average NRI	87/69%
Proved reserves (MMboe)/% liquids[2]	181 / 86%
Production Split – oil/gas/NGL	73/12/15%
Current rig count	1

[1] As of September 30, 2016
[2] As of December 31, 2015, SEC Pricing

Net Production - Mboed



Gross Well Cost (AFE)

South Antelope

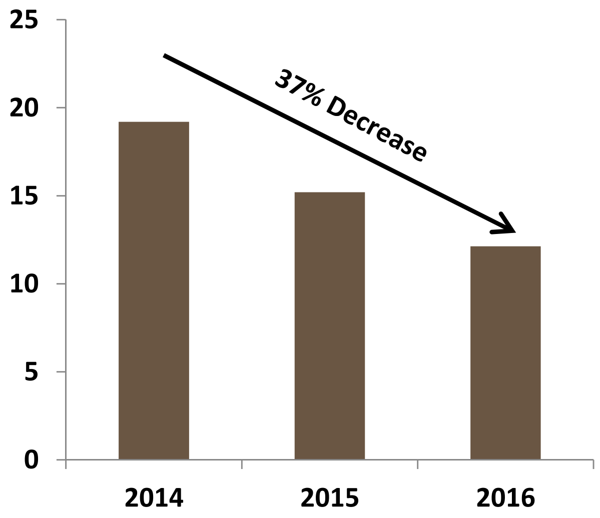
- Drill & complete: $5.5 MM (horizontal)
  - 10,000-ft lateral, 50 stage “Plug & Perf” design
- Facilities & artificial lift: $0.8 MM

Fort Berthold

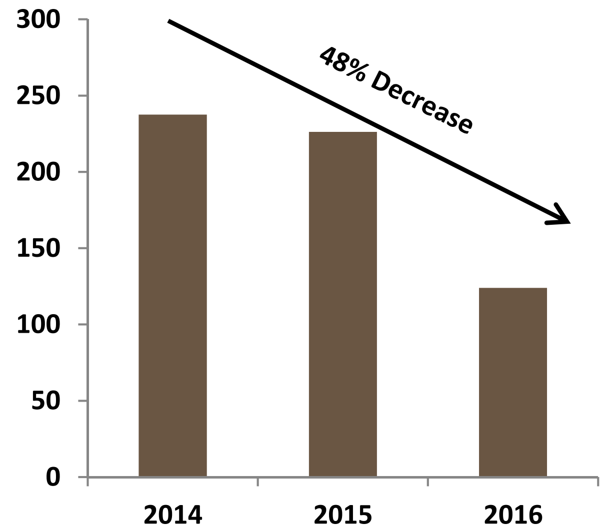
- Drill & complete: $6.0 MM (horizontal)
  - 10,000-ft. lateral, 50 stage “Plug & Perf” design
- Facilities & artificial lift: $1.1 MM

Williston Basin – Drilling & Completion Performance(1)

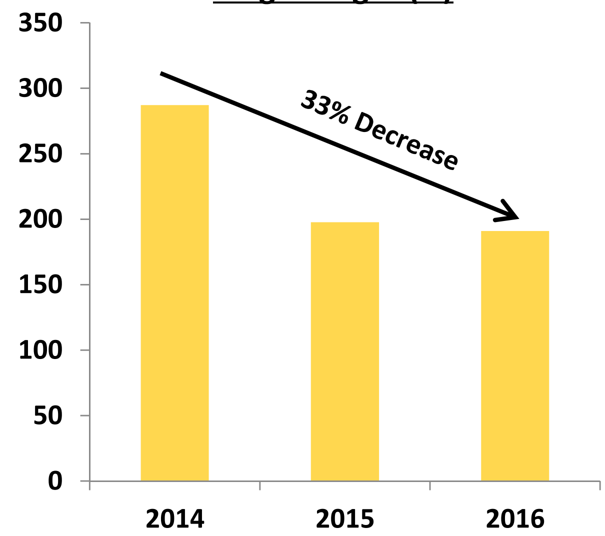
Spud to TD (Days)



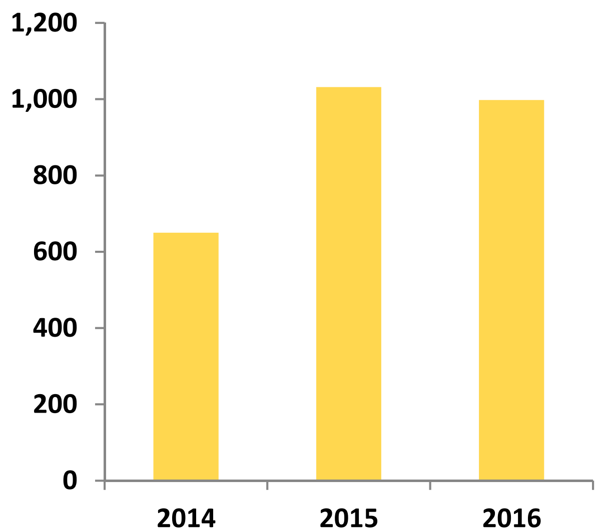
Drilling Cost ($/ft) (2)



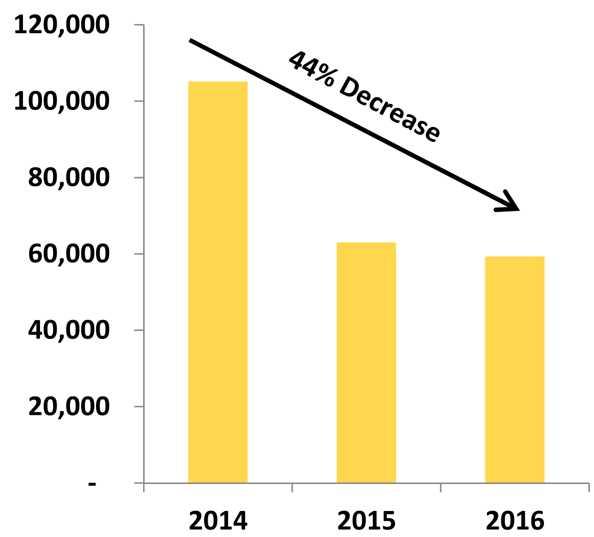
Stage Length (ft)



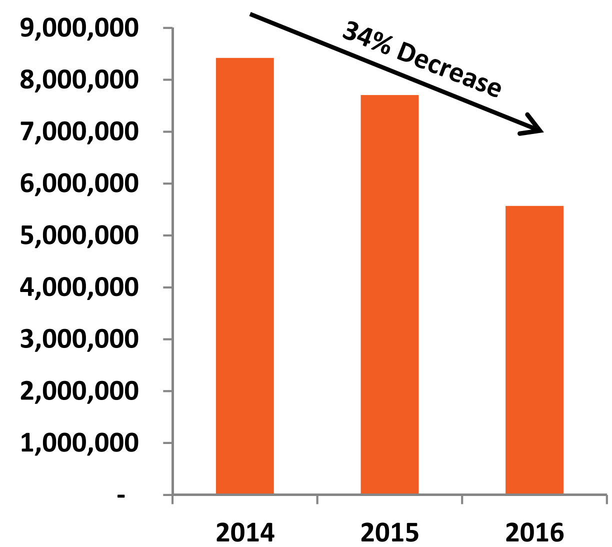
Proppant / ft. (lbs.)



Completion Cost / Stage ($)(3)



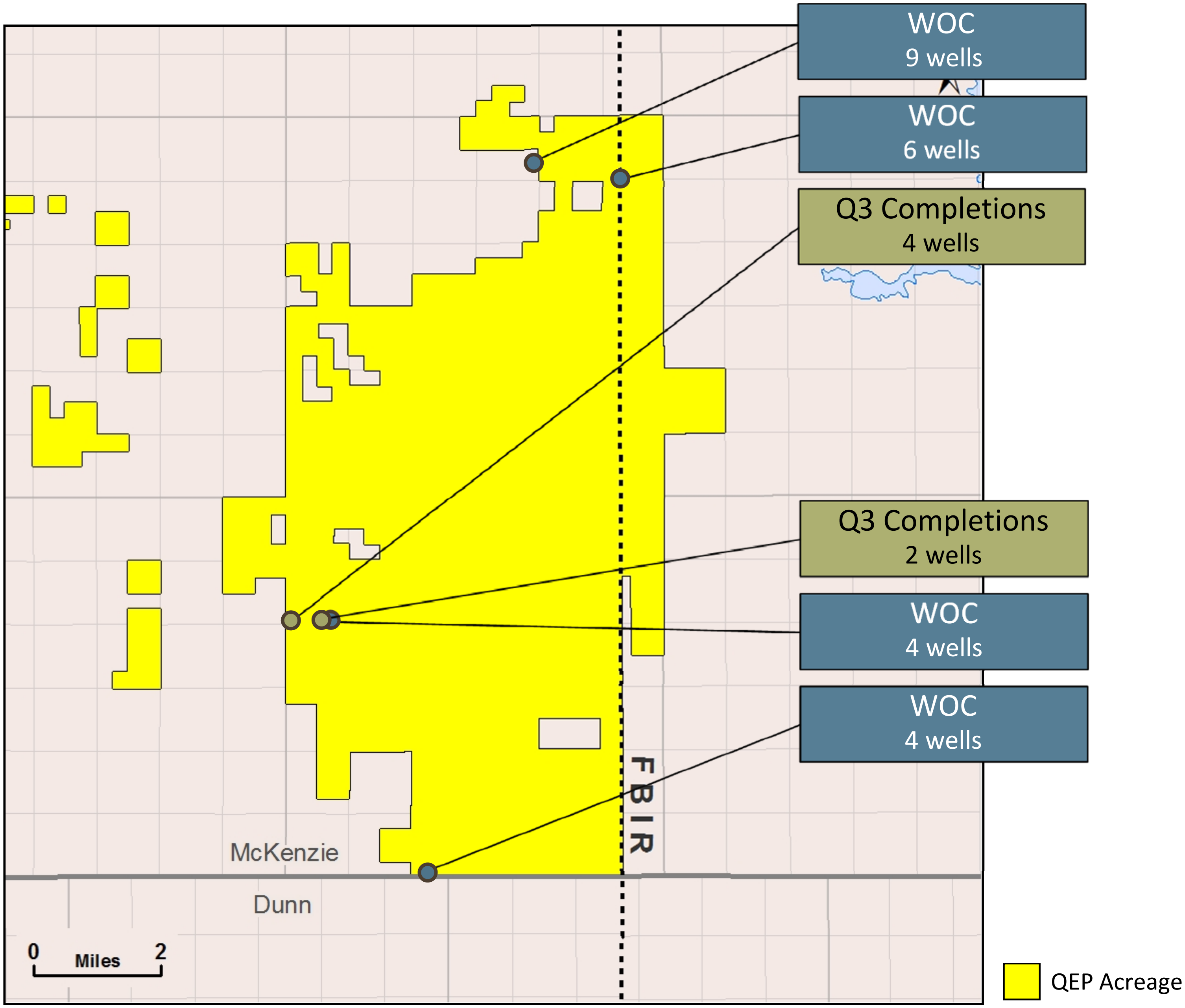
D&C Cost ($)(2,3)



(1)South Antelope wells only
(2)Represents average actual location and drilling costs
(3)Represents average actual completion costs which includes stimulation costs only

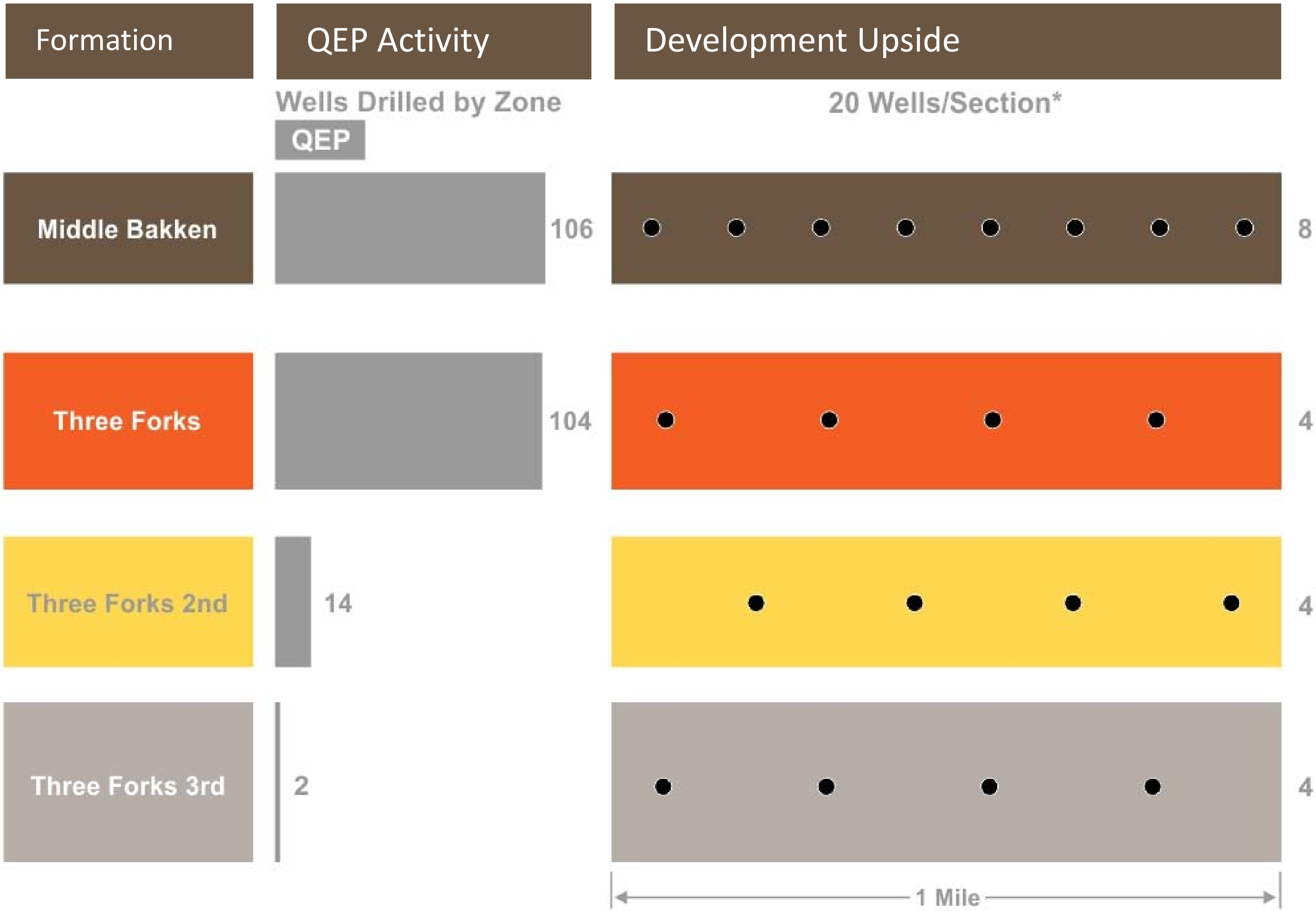
Williston Basin Activity – *South Antelope*

- **Net Acres: ~30,500**
- **Rig Count: 0**
- **Completions: 6**
  - **Middle Bakken (2)**
  - **TF 1 (1)**
  - **TF 2 (2)**
  - **TF 3 (1)**
- **WOC: 23**
  - **Middle Bakken (11)**
  - **TF 1 (4)**
  - **TF 2 (5)**
  - **TF 3 (3)**
- **Drilling: 0**



As of 9/30/2016

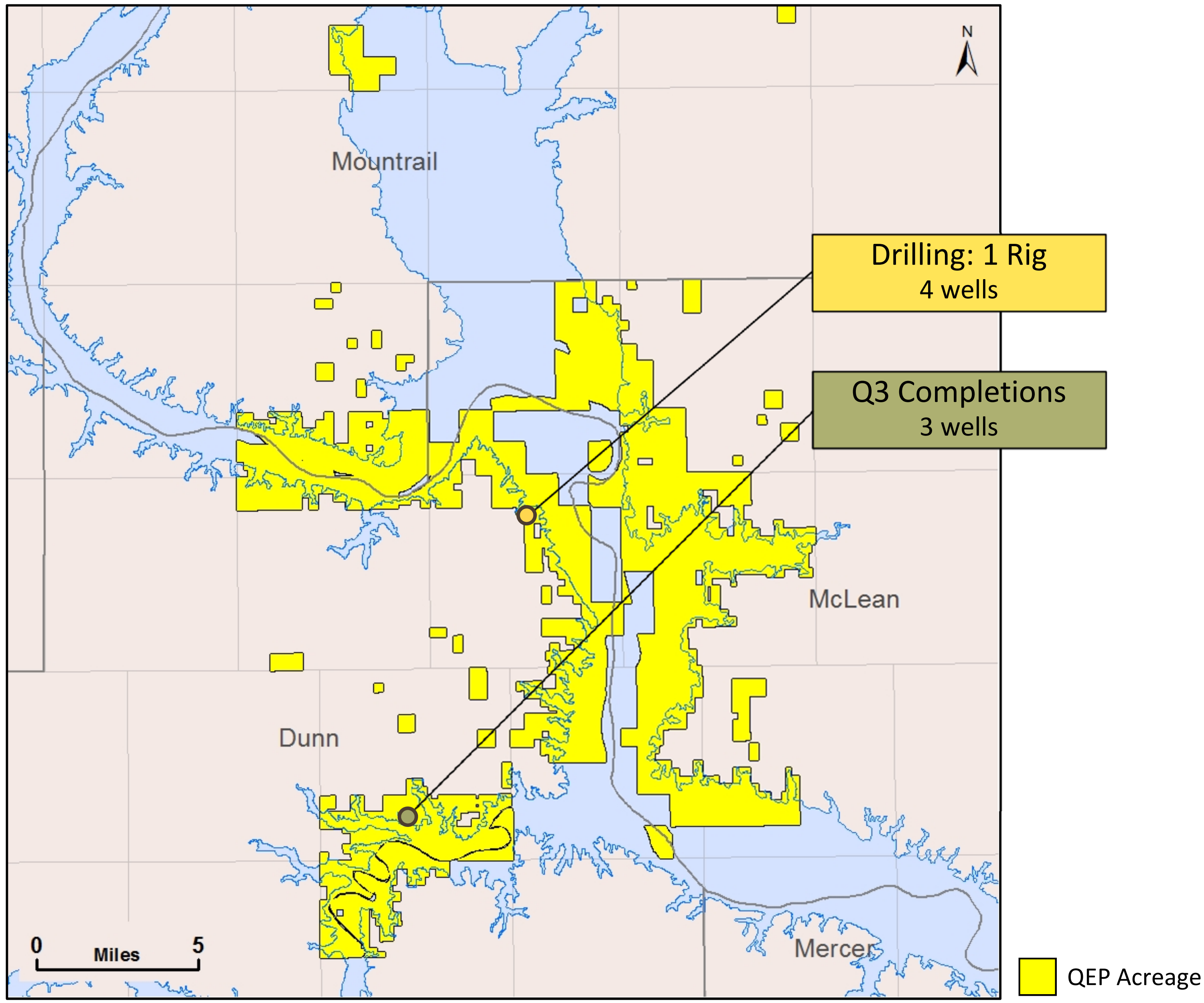
Development Plan – *South Antelope*



* Assumes lease-line wells actually drilled within DSU for Middle Bakken, TF1 and TF3

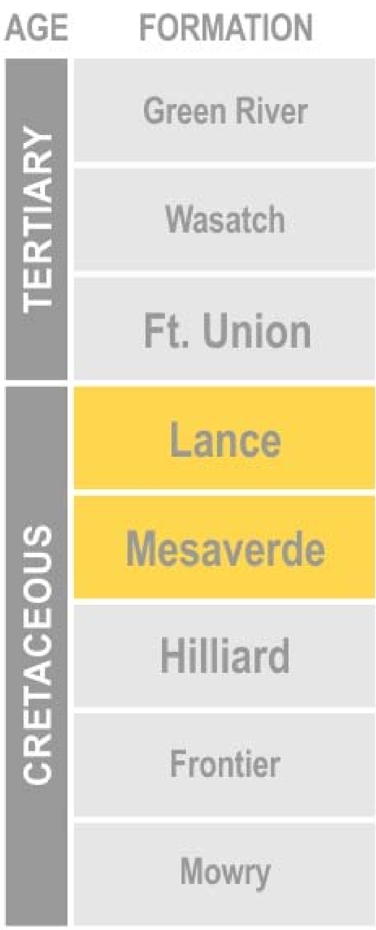
Williston Basin Activity – *Fort Berthold*

- **Net Acres: ~65,200**
- **Rig Count: 1 horizontal**
- **Completions: 3**
  - **Middle Bakken (2)**
  - **TF 1 (1)**
- **WOC: 0**
- **Drilling: 4**
  - **Middle Bakken (2)**
  - **TF 1 (2)**

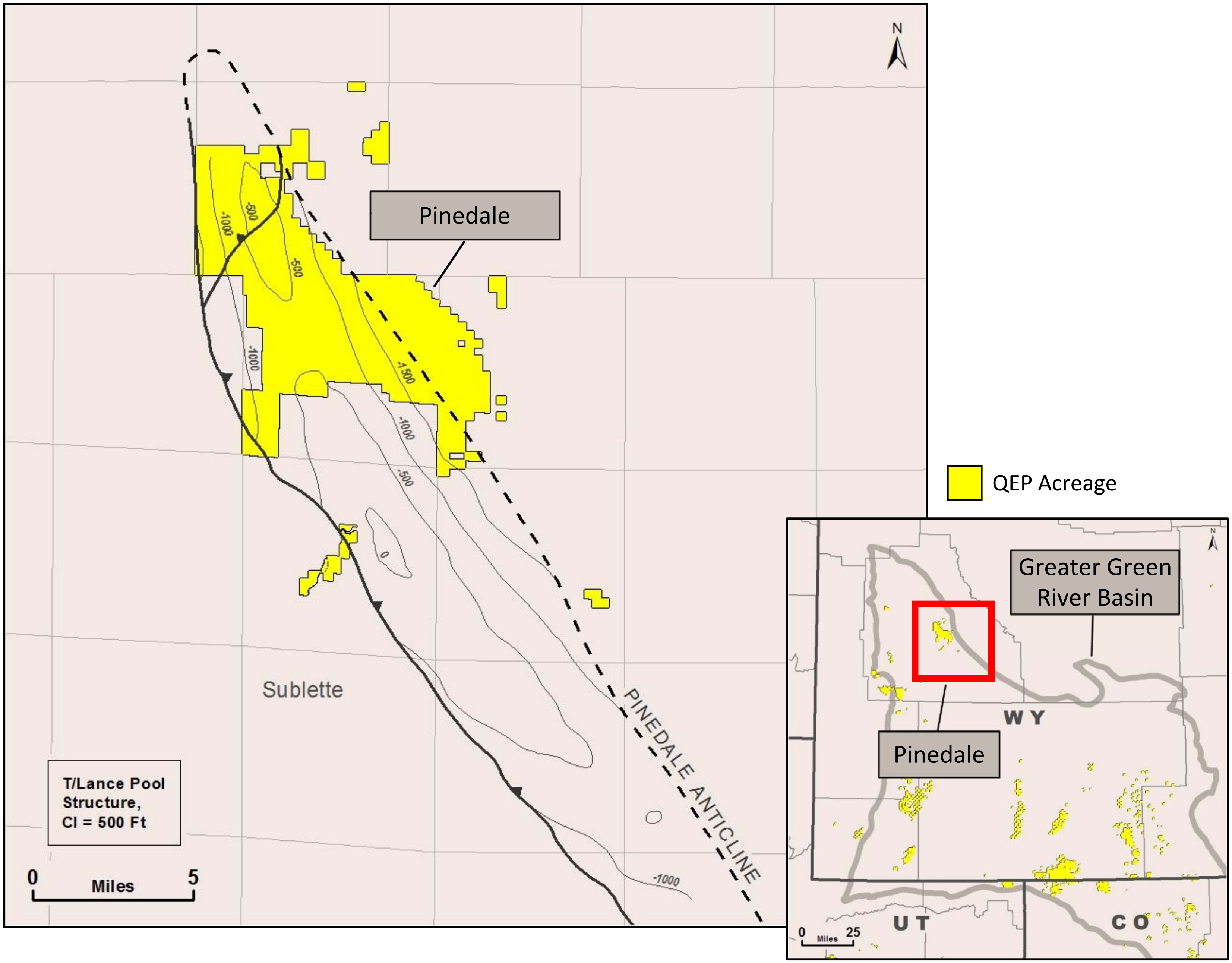


As of 9/30/2016

Pinedale



AGE
FORMATION
TERTIARY
Green River
Wasatch
Ft. Union
CRETACEOUS
Lance
Mesaverde
Hilliard
Frontier
Mowry



N
Pinedale
-1000
-500
-1500
0
Sublette
PINEDALE ANTICLINE
T/Lance Pool
Structure,
CI = 500 Ft
0
Miles
5
QEP Acreage
Greater Green
River Basin
Pinedale
WY
UT
CO
0
Miles
25

Pinedale Overview

3Q 2016 Program Highlights

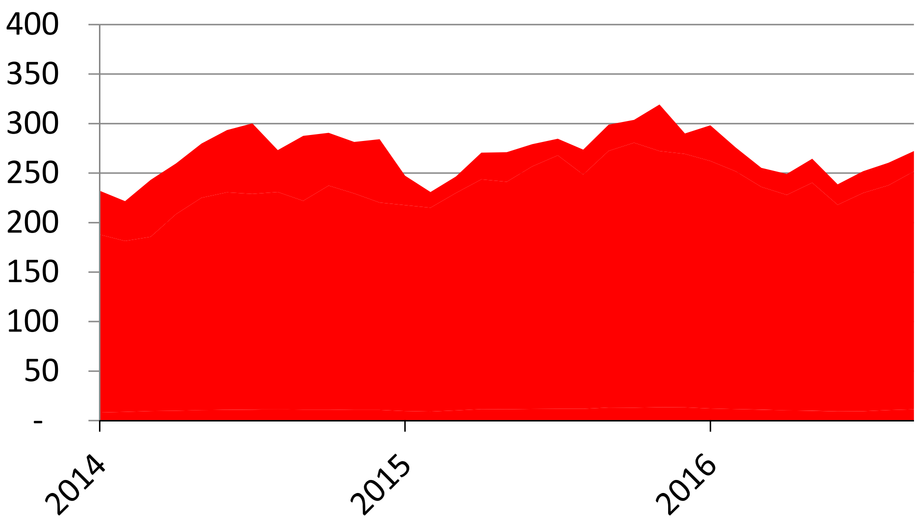
- Completed 34 wells during the quarter
- Continuing to refine drilling program in more challenging area of the field
- Evaluating horizontal potential
- Additional compression scheduled for Q4 2016

Profile[1]

Net acres	17,400
Gross operated producing wells	1,109
Average WI/average NRI	62/48%
Proved reserves (Bcfe)/% liquids[2]	1,125 / 13%
Production Split – oil/gas/NGL	4/87/9%
Current rig count	1

[1] As of September 30, 2016
[2] As of December 31, 2015, SEC Pricing

Net Production - Mmcfed

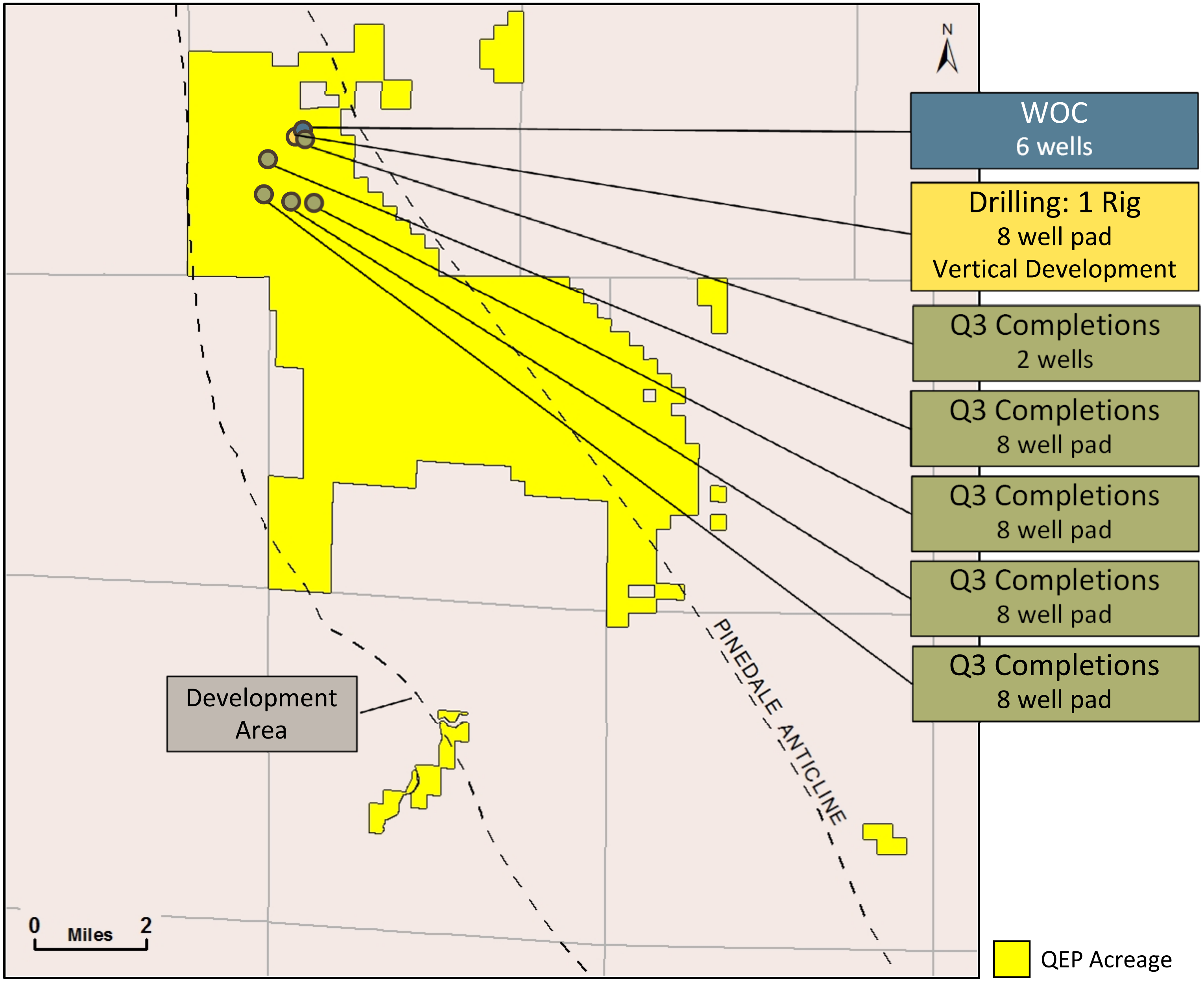


Gross Well Cost (AFE)

- Drill & complete: $2.7 MM (vertical)
  - 22 stage "Plug & Perf" design
- Facilities & artificial lift: $0.2 MM

Pinedale Activity

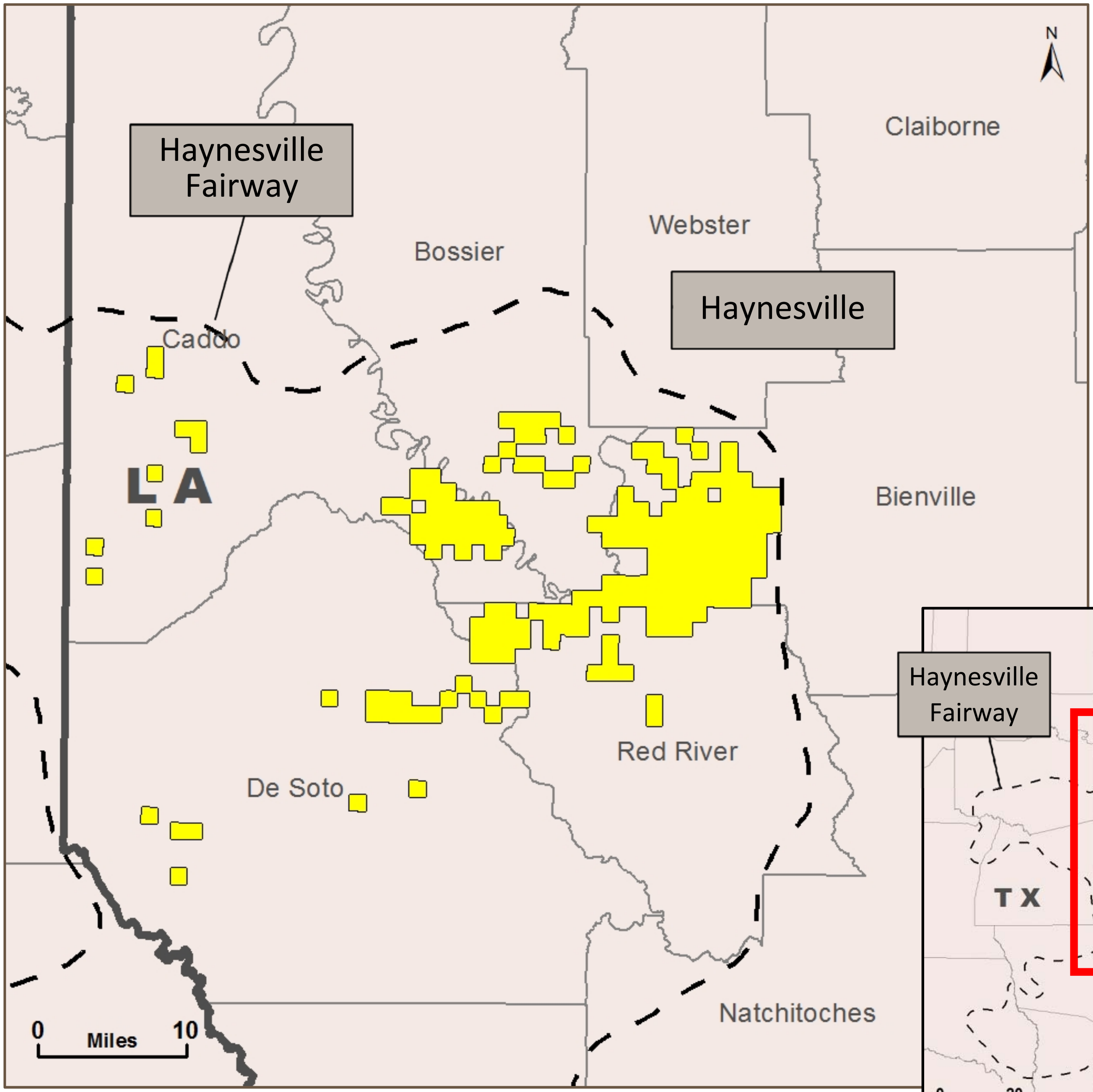
- **Net Acres: ~17,400**
- **Rig Count: 1 vertical**
- **Completions: 34**
- **WOC: 6**
- **Drilling: 8**

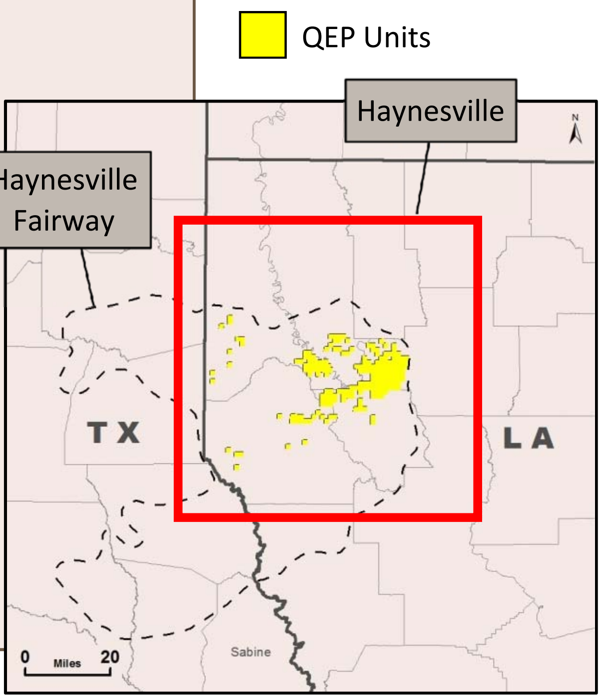


As of 9/30/2016

Haynesville

AGE	FORMATION
L. CRET.	Hosston
JURASSIC	Upper Cotton Valley
	Lower Cotton Valley
	Bossier
	Haynesville
	Buckner
	Smackover





As of 9/30/2016

Haynesville Overview

3Q 2016 Program Highlights

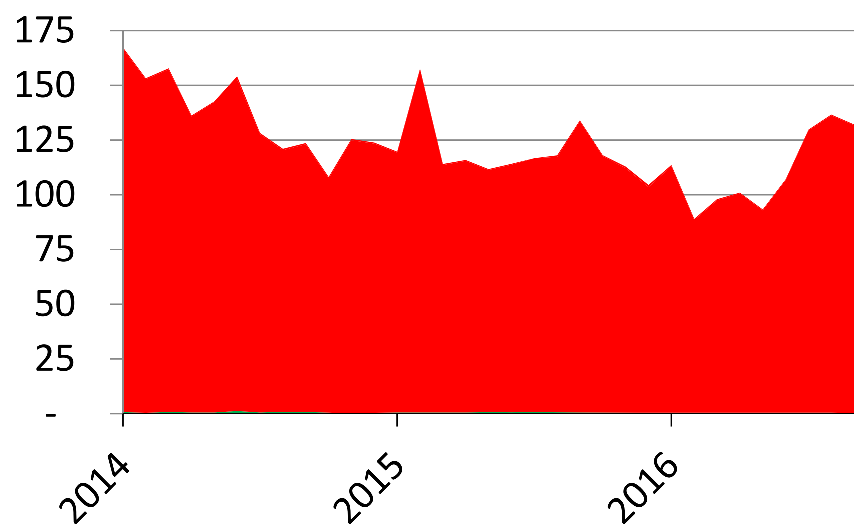
- Successful workover program and non-operated volumes increased net production
- Rig activity in the area continues to increase
- Non-operated well costs continue to trend lower
  - Increased lateral length
  - Larger completions with higher proppant volumes

Profile[1]

Net acres	48,100
Gross operated producing wells	130
Average WI/average NRI	69/53% (op) 34/26% (all)
Proved reserves (Bcfe)/% liquids[2]	397 / 0%
Production Split – oil/gas/NGL	0/100/0%
Current rig count	0

[1] As of September 30, 2016
[2] As of December 31, 2015, SEC Pricing

Net Production - Mmcfed

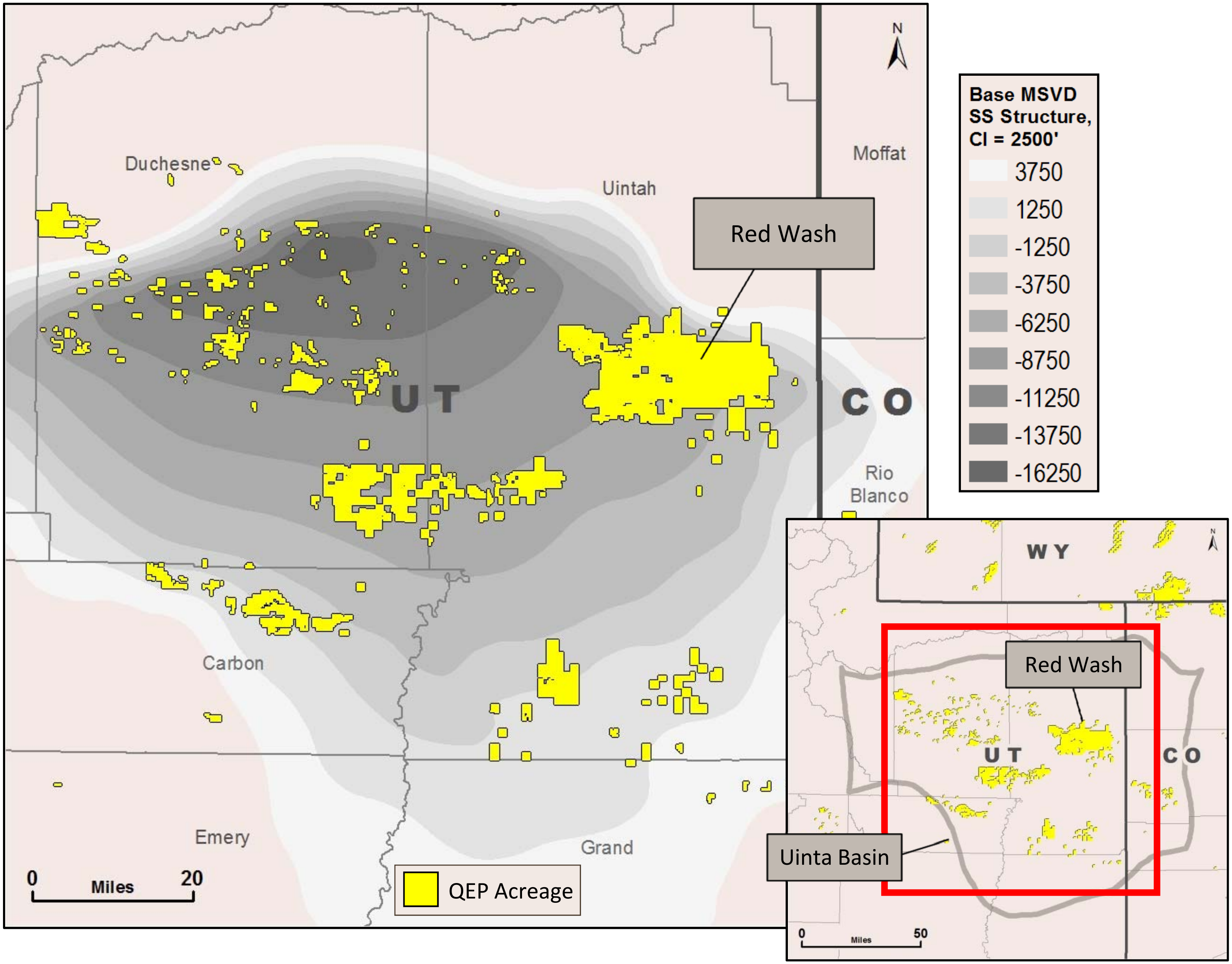


Gross Well Cost (AFE)

- Drill & complete: $8.0 MM (horizontal)
  - 7,500-ft. lateral, 33 stage "Plug & Perf" design
- Facilities & artificial lift: $0.6 MM

Uinta Basin

QEP Acreage



Uinta Basin Overview – *Lower Mesaverde*

3Q 2016 Program Highlights

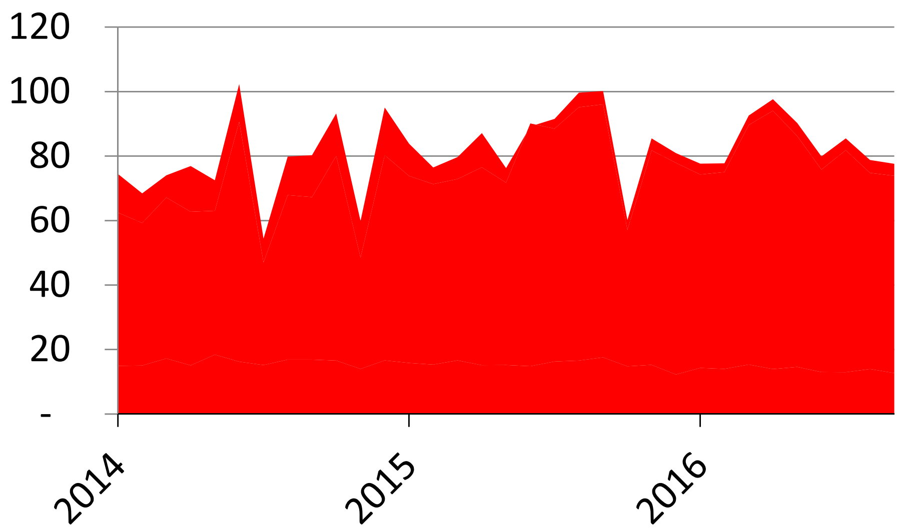
- Continue to evaluate recent vertical well performance
- Additional compression scheduled for 4Q 2016

Profile[1]

Net acres[2]	110,300
Gross operated producing wells[2]	106
Average WI/average NRI[2]	92/85%
Proved reserves (Bcfe)/% liquids[3]	559 / 18%
Production Split – oil/gas/NGL	4/91/5%
Current rig count	0

[1] As of September 30, 2016
[2] Eight townships in Mesaverde Fairway
[3] As of December 31, 2015 , SEC pricing total Uinta Basin

Net Production - Mmcfed



Gross Well Cost (AFE)

Vertical

- Drill & complete: $2.1 MM
  - Six stage "Plug & Perf" design
- Facilities & artificial lift: $0.3 MM

Horizontal

- Drill & complete: $5.8 MM
  - 5,000-ft lateral, sliding sleeve
- Facilities & artificial lift: $0.7 MM