4Q 2016
Corporate Update

February 22, 2017

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 oil production; growth strategy; potential drilling locations; evaluating well density; planned additional compression; development strategy and plans; minimizing well interference issues and maximizing production through drilling and completion program; guidance for 2017 production, LOE and transportation expense, DD&A, production taxes, general and administrative expense, and capital investment; and assumptions related to our guidance.

Actual results may differ materially from those included in the forward-looking statements due to a number of factors, including, but not limited to: 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; 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; permitting delays; 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; 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, 2016 (the “2016 Form 10-K”). 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. “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. Probable and possible reserves and 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 2016 Form 10-K.

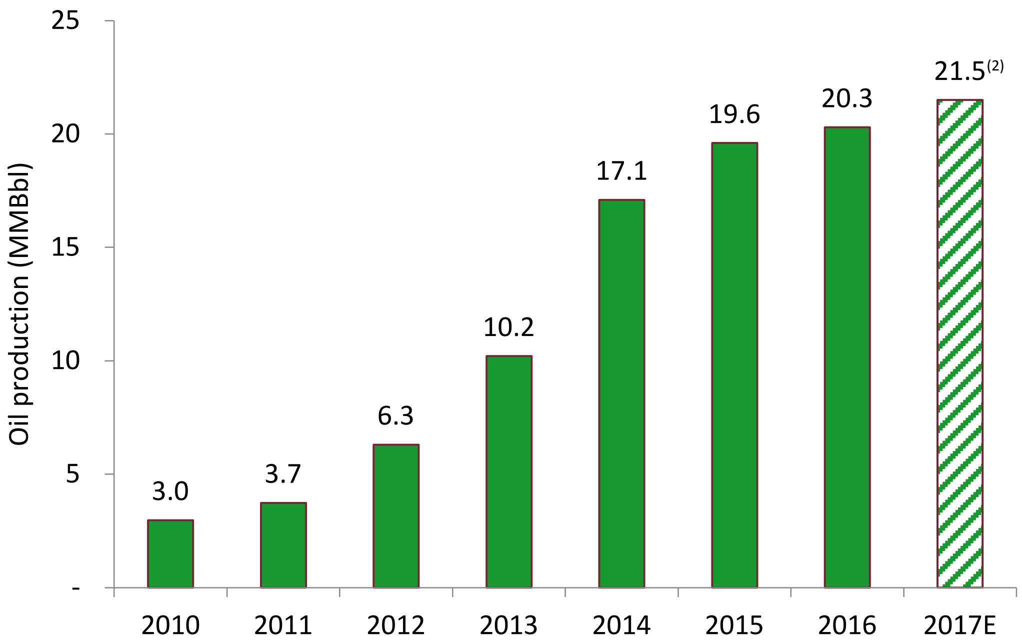
QEP refers to Adjusted EBITDA, Adjusted Net Income (Loss) and other non-GAAP financial measures that management believes are good tools to assess QEP’s operating results. For definitions of these terms and reconciliations to the most directly comparable GAAP measures, see the recent earnings press release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

QEP at a Glance

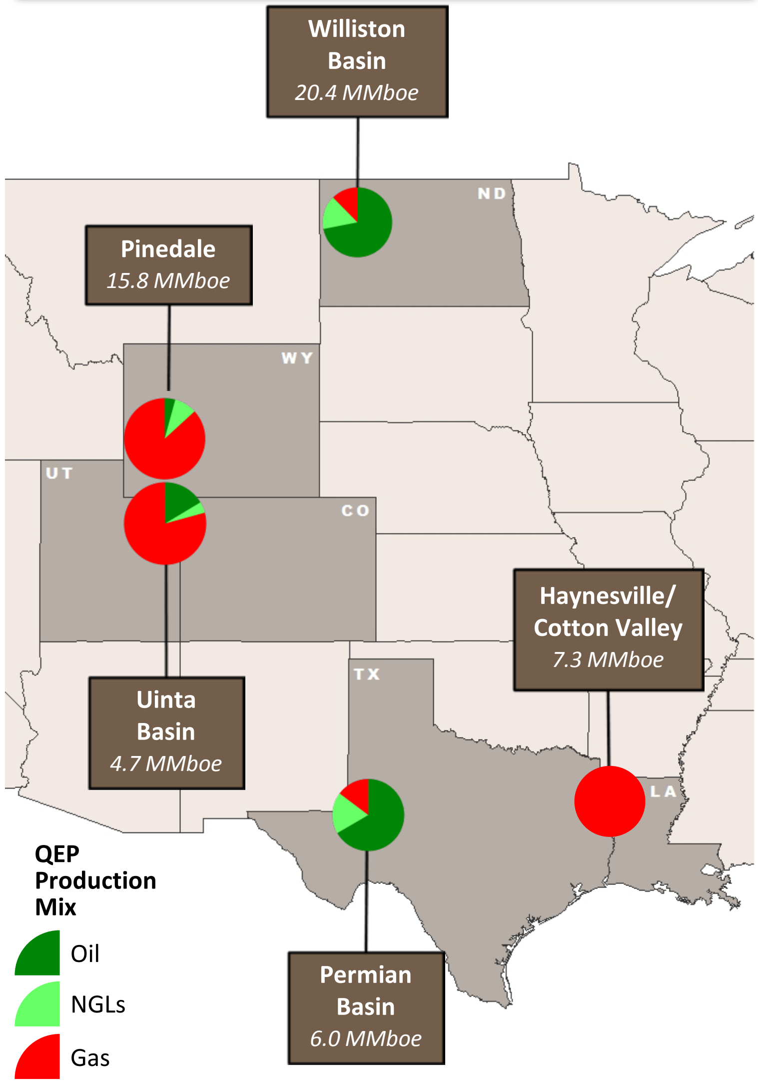
Profile

2016 production	55.8 MMboe
% crude oil production	36%
Total proved reserves[1]	731.4 MMboe
Total net acreage[1]	1,198,000

Increased Focus on Crude Oil



2016 Production by Asset[3]



[1] As of December 31, 2016
[2] 2017E represents production outlook as of February 22, 2017
[3] 2016 Production by Asset excludes 1.6 MMboe from Other Northern & Other Southern regions

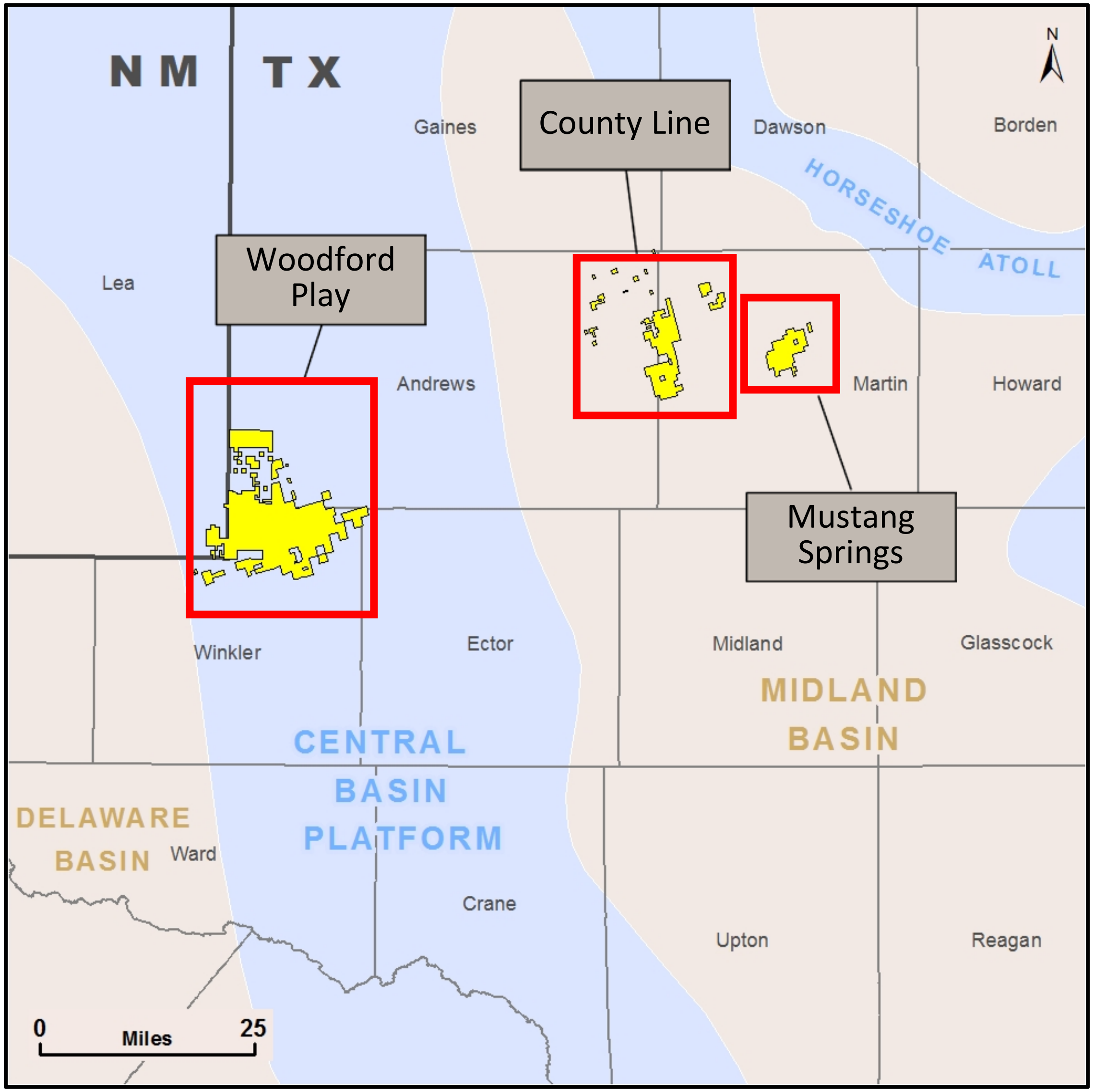
QEP's Strategy for Growth

Balanced & Diversified Upstream portfolio	• Focus investment in core crude oil plays with natural gas optionality
Financial Strength	• Maintain a strong balance sheet
Capital Efficiency	• Allocate capital to high rate of return projects
Operational Efficiency	• Optimize well completion design and placement to maximize economic recovery of oil in place

Permian Basin

Central Basin Platform

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



As of 12/31/2016

Midland Basin

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

4Q 2016 Program Highlights

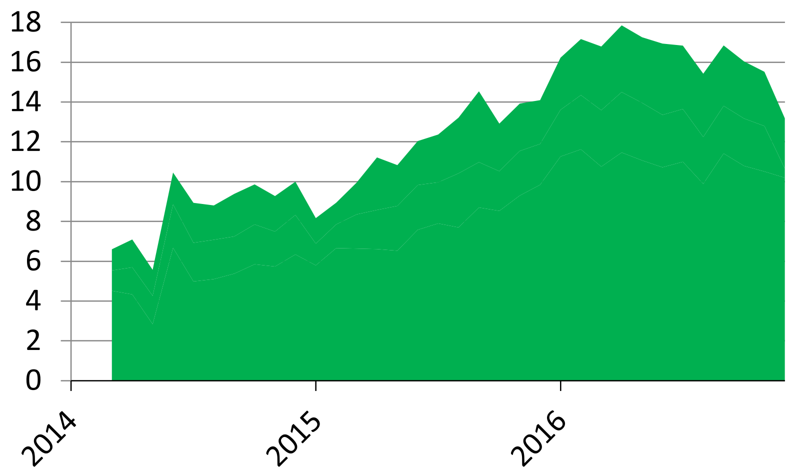
- Peak quarterly production of 18.0 Mboed
- Closed Mustang Springs acquisition
  - Spud first two wells in Mustang Springs
- Drilled first high density Spraberry Shale and Middle Spraberry tests
- Completed two horizontal infill wells in the Spraberry Shale

Profile [1]

Net acres	75,800
Gross operated producing wells	475
Average WI/average NRI	95/72%
Proved reserves (MMboe)/% liquids[2]	148 / 88%
Production Split – oil/gas/NGL	70/11/19%
Current rig count	3

[1] As of December 31, 2016
[2] As of December 31, 2016, SEC pricing

Net Production - Mboed

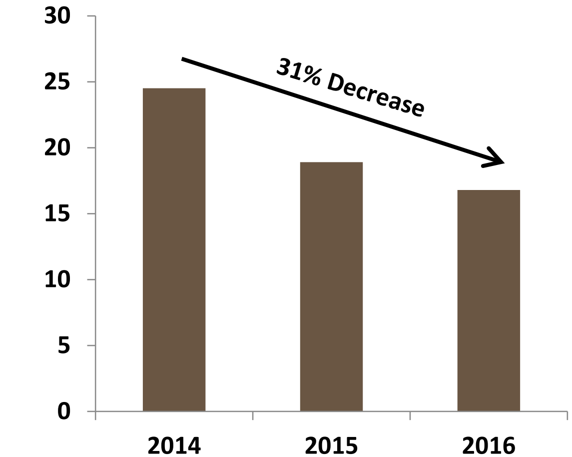


Gross Well Cost (AFE)

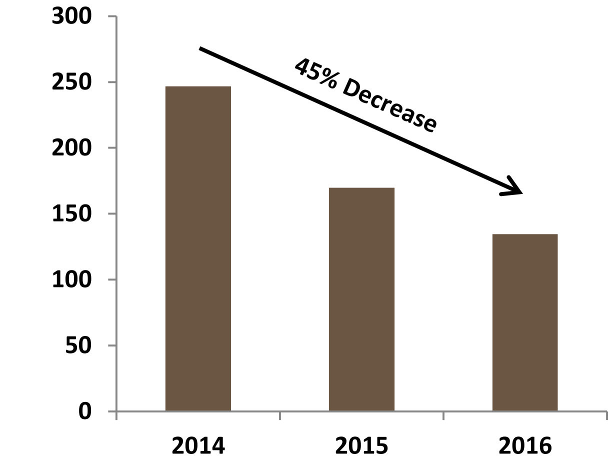
- Drill & complete: $5.0 MM (horizontal)
  - 7,500-ft. lateral, 51 stage “Plug & Perf” design
- Facilities & artificial lift: $0.7 MM

Permian Basin – *Drilling & Completion Performance* (1)

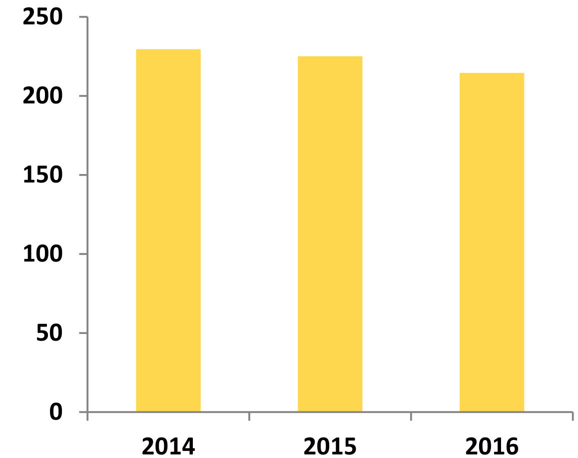
Spud to TD (days)



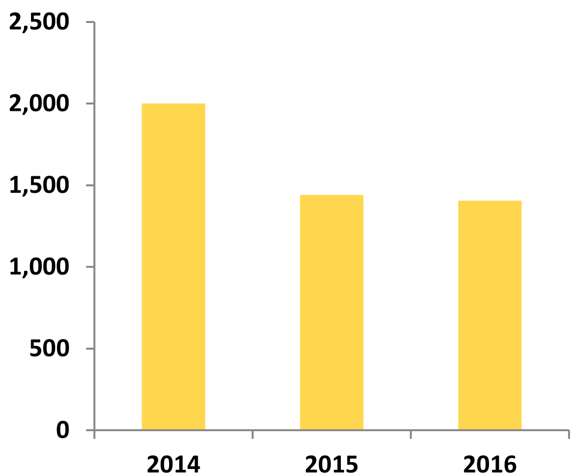
Drilling Cost ($/ft) (2)



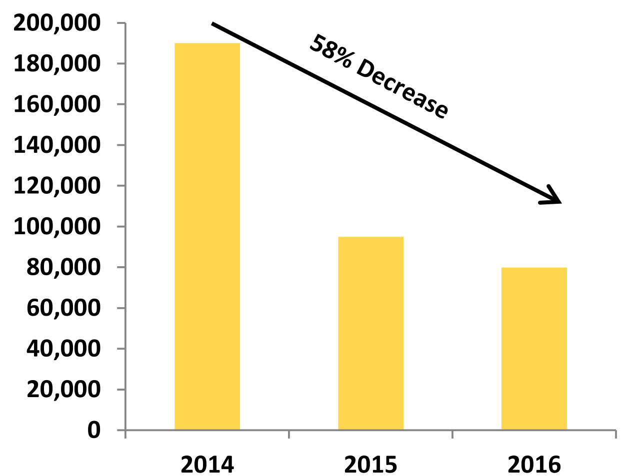
Stage Length (ft)



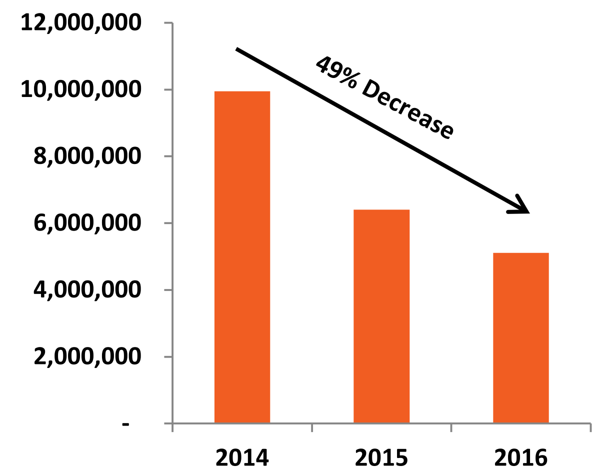
Proppant / ft. (lbs.)



Completion Cost per Stage ($)(3)



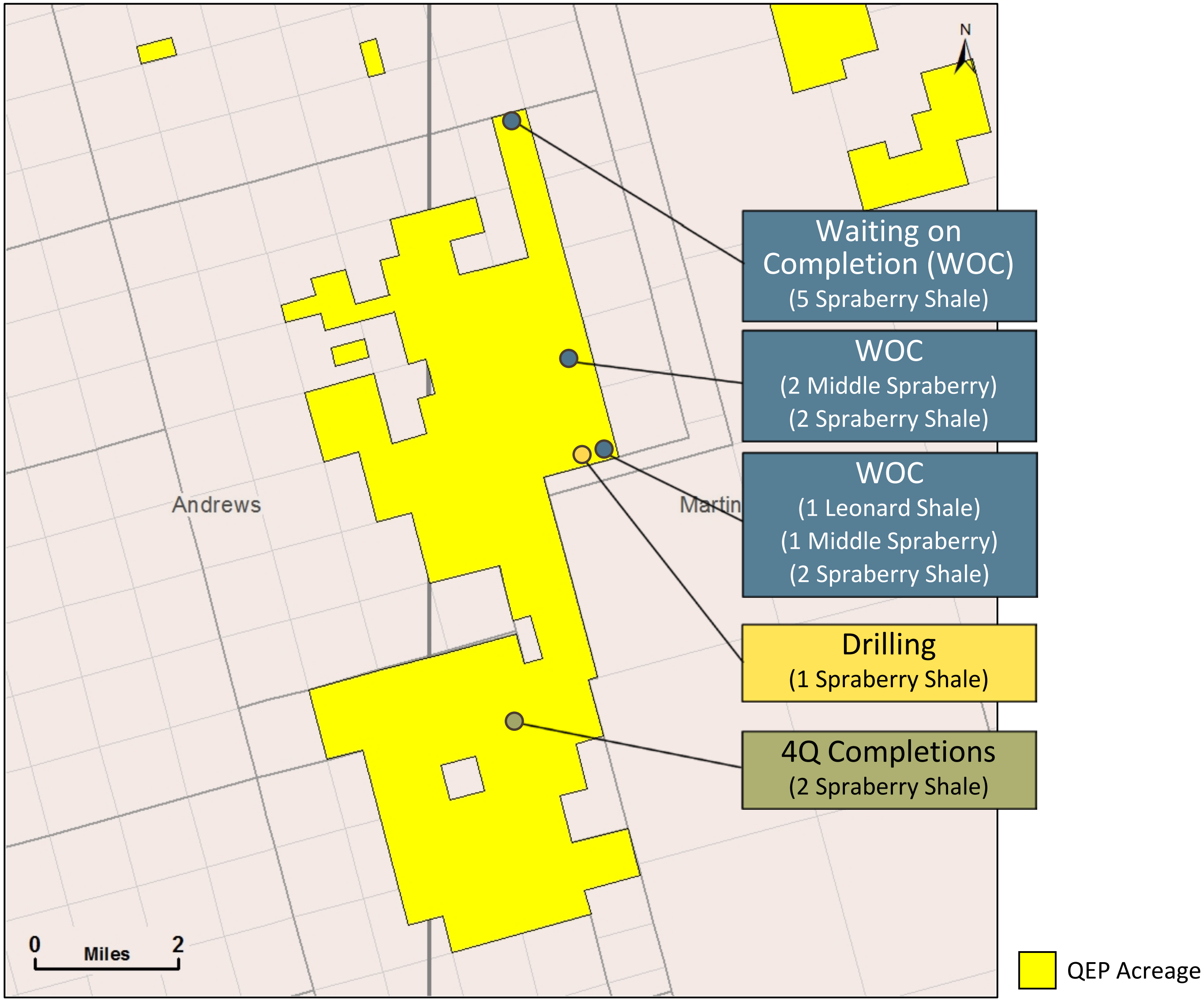
D&C Cost ($) (2,3)



(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**
  - **~1,000 net acres added via bolt-on and swaps since original acquisition**
- **Rig Count: 1 horizontal**
- **Completions: 2**
  - **Spraberry Shale (2)**
- **WOC: 13**
  - **Leonard Shale (1)**
  - **Middle Spraberry (3)**
  - **Spraberry Shale (9)**
- **Drilling: 1**
  - **Spraberry Shale (1)**



As of 12/31/2016

Well Density Assumptions – *County Line*

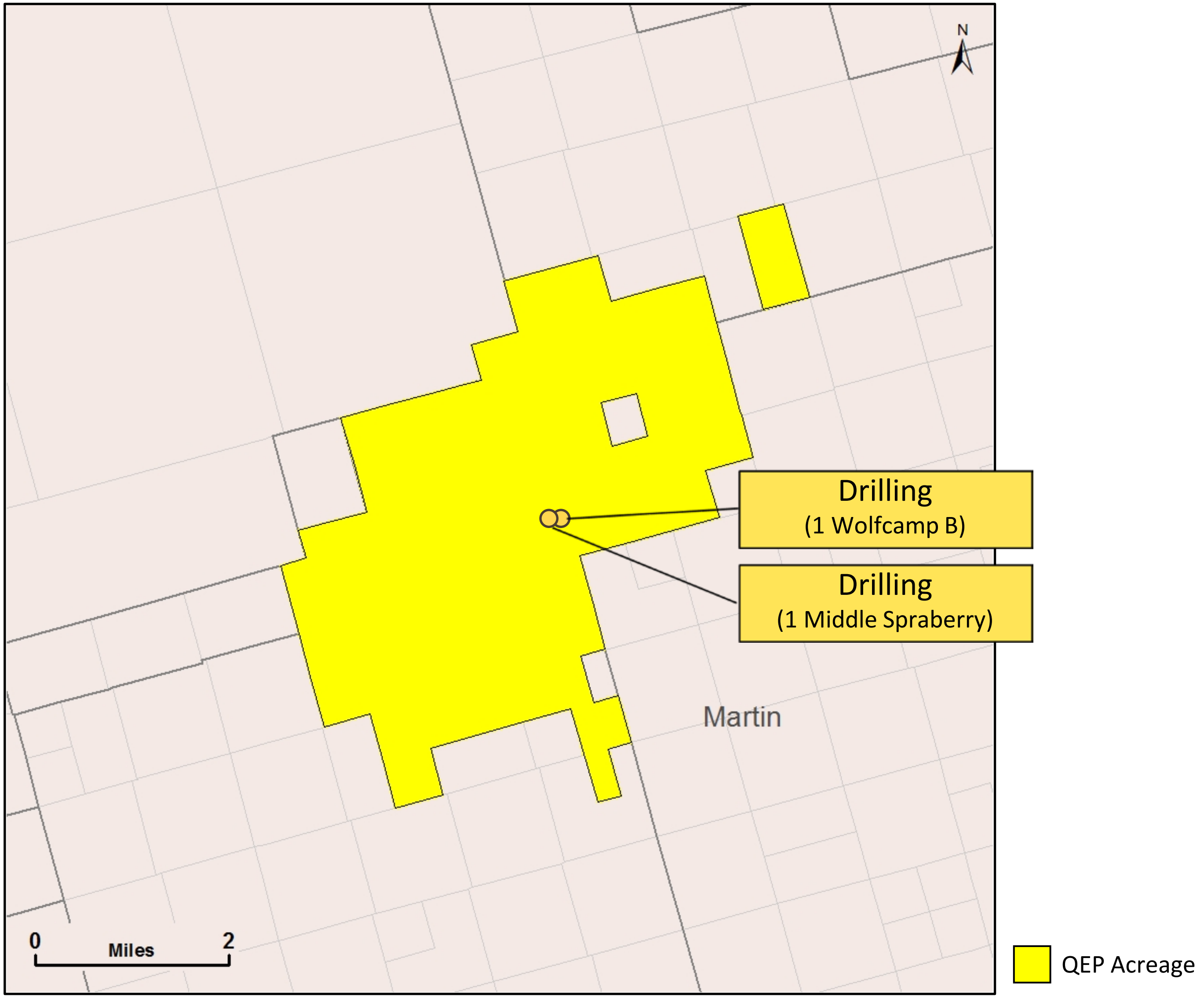
Formation	Well Density Assumptions: Reserves [1]	Resource [2]
	34 – 51 Wells/Section	
Leonard Shale	-	6
M. Spraberry	6	3
Spraberry Shale	16	-
Wolfcamp A	-	4
Wolfcamp B	6	2
Wolfcamp D	6	2

1 Mile

(1) Includes proven, probable and possible locations
(2) Includes non-reserve locations

Permian Basin – *Mustang Springs*

- **Net Acres: ~9,600**
- **Rig Count: 2 horizontal**
- **Completions: 0**
- **WOC: 0**
- **Drilling: 2**
  - **Middle Spraberry (1)**
  - **Wolfcamp B (1)**



As of 12/31/2016

Well Density Assumptions – *Mustang Springs*

32 – 45 Wells/Section

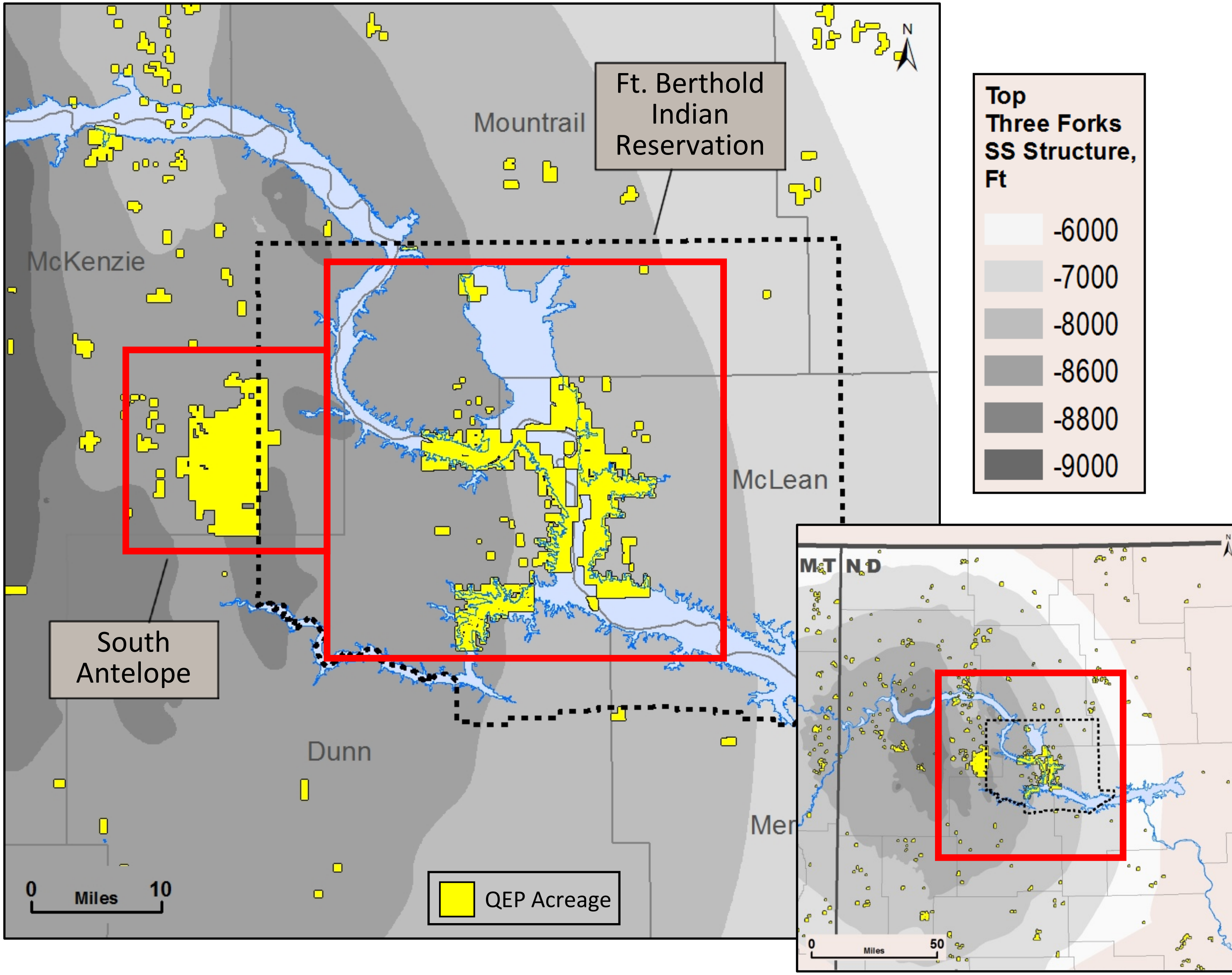
Formation	Well Density Assumptions	Reserves (1) ●	Resource (2) ○
Leonard Shale	Upside Potential	-	-
M. Spraberry		7	3
L. Spraberry	Upside Potential	-	-
Spraberry Shale		10	4
Dean	Upside Potential	-	-
Wolfcamp A		7	-
Wolfcamp B		8	6
Wolfcamp D	Upside Potential	-	-

1 Mile

(1) Includes proven, probable and possible locations
(2) Includes non-reserve locations

Williston Basin

AGE	FORMATION
MISSISSIPPIAN	Charles
MISSISSIPPIAN	Mission Canyon
MISSISSIPPIAN	Lodgepole
MISSISSIPPIAN	Bakken
DEVONIAN	Three Forks
DEVONIAN	Birdbear
DEVONIAN	Duperow
DEVONIAN	Souris River



Williston Basin Overview

4Q 2016 Program Highlights

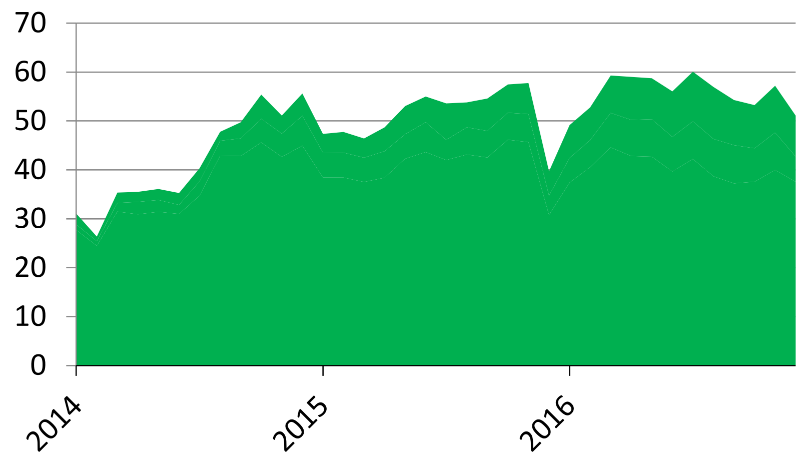
- Completed 14 wells on South Antelope
  - Average peak 24-hour IP of 2,589 Boed
- Focused on optimizing artificial lift techniques to accelerate value

Profile[1]

Net acres	116,200
Gross operated producing wells	354
Average WI/average NRI	87/69%
Proved reserves (MMboe)/% liquids[2]	160 / 86%
Production Split – oil/gas/NGL	71/12/17%
Current rig count	1

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

Net Production - Mboed



Gross Well Cost (AFE)

South Antelope

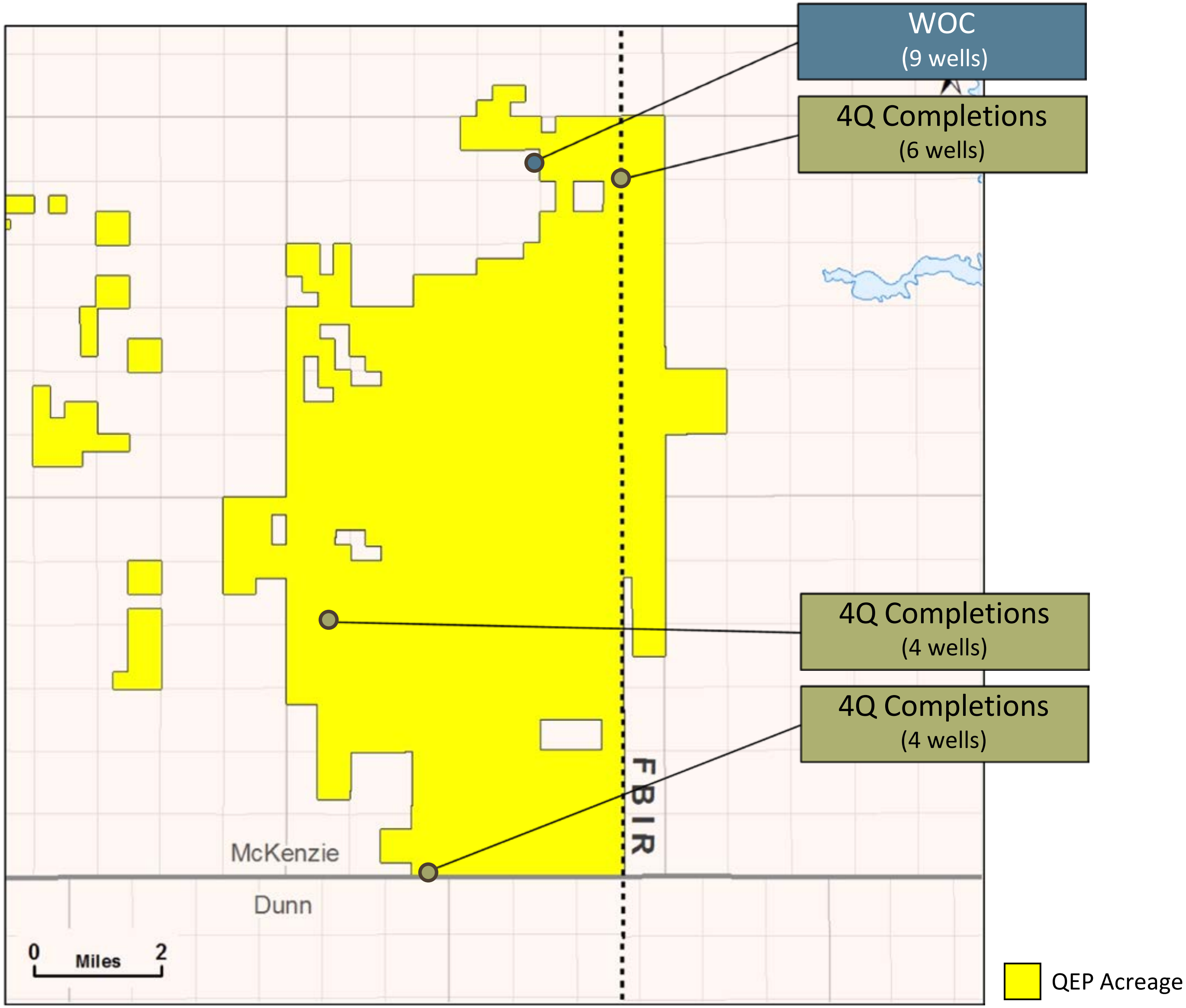
- Drill & complete: $5.6 MM (horizontal)
  - 10,000-ft. lateral, 50 stage “Plug & Perf” design
- Facilities & artificial lift: $0.8 MM

Fort Berthold

- Drill & complete: $6.2 MM (horizontal)
  - 10,000-ft. lateral, 50 stage “Plug & Perf” design
- Facilities & artificial lift: $1.3 MM

Williston Basin Activity – *South Antelope*

- **Net Acres: ~30,900**
- **Rig Count: 0**
- **Completions: 14**
  - **Middle Bakken (6)**
  - **Three Forks 1 (2)**
  - **Three Forks 2 (4)**
  - **Three Forks 3 (2)**
- **WOC: 9**
  - **Middle Bakken (5)**
  - **Three Forks 1 (2)**
  - **Three Forks 2 (1)**
  - **Three Forks 3 (1)**
- **Drilling: 0**



As of 12/31/2016

Well Performance Optimization – *South Antelope*

2012 – 2014

Low Density Spacing; Small Completion

- Completion design:
  - Sliding sleeves
  - 30 stages
  - 3-4 MM lbs/well
- Higher initial production
- 6-12 months of free flow
- Rod pump installation after free flow period

2014 – 2016

Low Density Spacing; Large Completion

- Completion design:
  - Sliding sleeves
  - 40-50 stages
  - 10 MM lbs/well
- Higher initial production
- 6-12 months of free flow
- Rod pump installation after free flow period

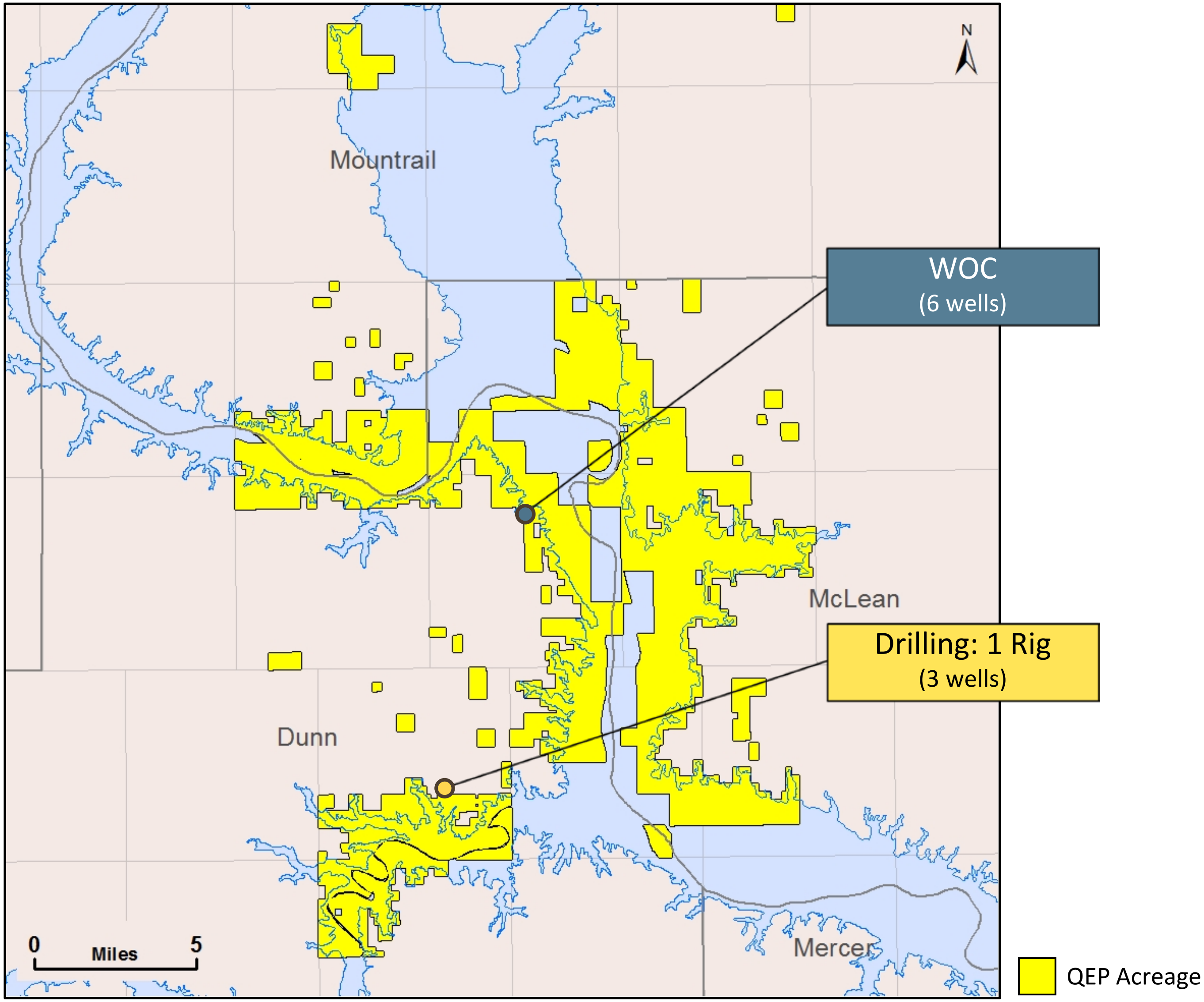
2016 →

High Density Infill; Customized Completion

- Completion design:
  - Plug and Perf;
  - 50 stages;
  - 5-10 MM lbs/well
- Lower initial production
- 1-3 months of free flow
- Electric submersible pump (ESP) installation after free flow period

Williston Basin Activity – *Fort Berthold*

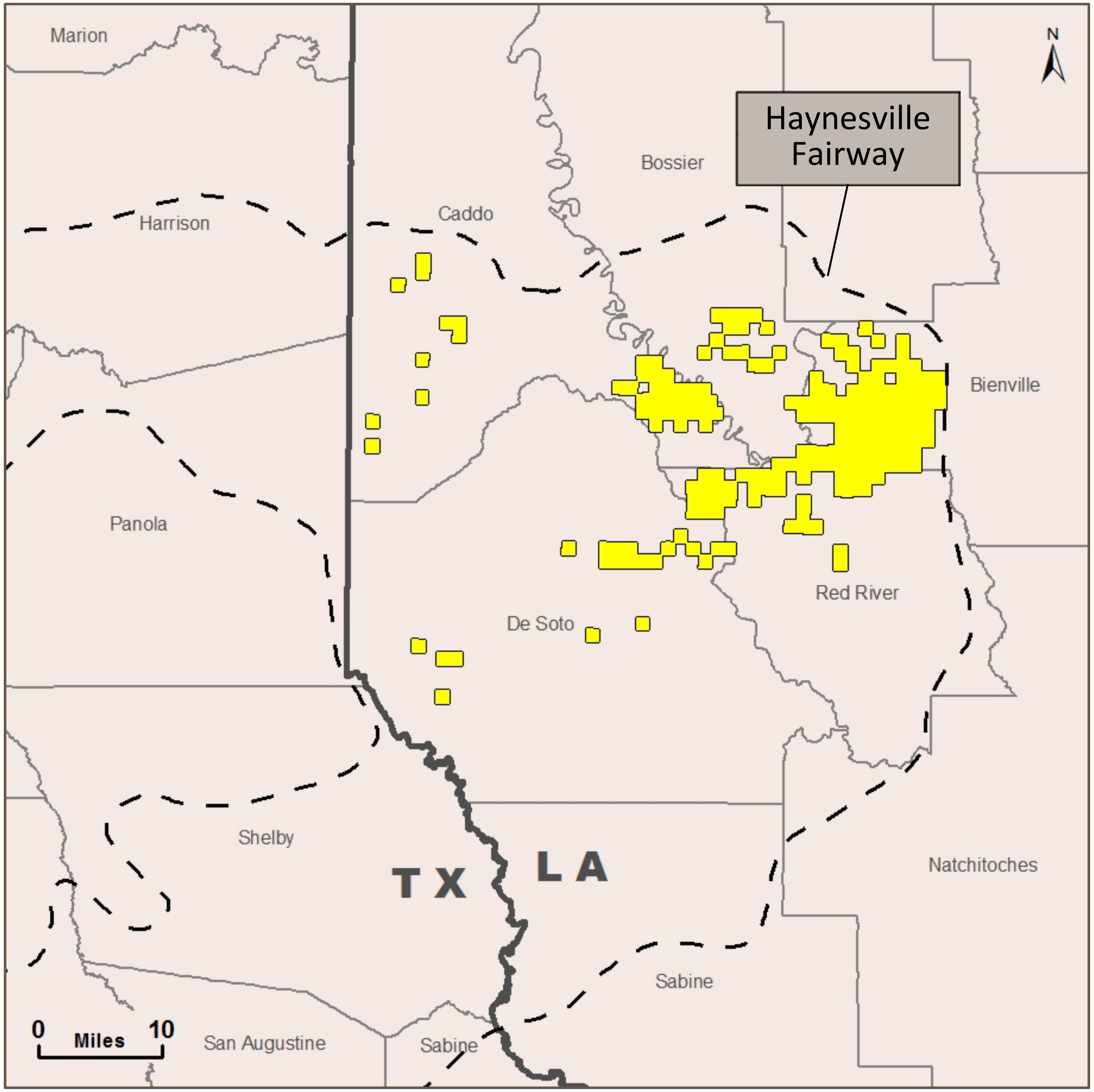
- **Net Acres: ~66,200**
- **Rig Count: 1 horizontal**
- **Completions: 0**
- **WOC: 6**
  - Middle Bakken (3)
  - Three Forks 1 (3)
- **Drilling: 3**
  - Middle Bakken (2)
  - Three Forks 1 (1)



As of 12/31/2016

Haynesville

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



QEP Units

As of 12/31/2016

Haynesville Overview

4Q 2016 Program Highlights

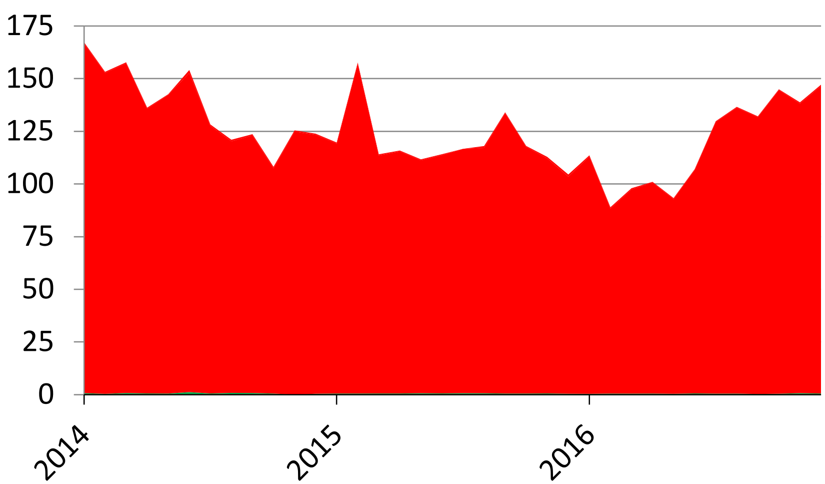
- Successful workover program and non-operated volumes, increased net production by 8%
- Completed four workovers
  - Average incremental 24-hour rate increase of 12.2 Mmcfed
- 2016 workover program - 10 wells
  - Average incremental 24-hour rate increase of 10.7 Mmcfed per well
  - Average incremental 30-day rate increase of 8.7 Mmcfed per well

Profile[1]

Net acres	48,100
Gross operated producing wells	130
Average WI/average NRI	74/57% (op) 37/29% (all)
Proved reserves (Bcfe)/% liquids[2]	866 / 0%
Production Split – oil/gas/NGL	0/100/0%
Current rig count	0

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

Net Production - MMcfed

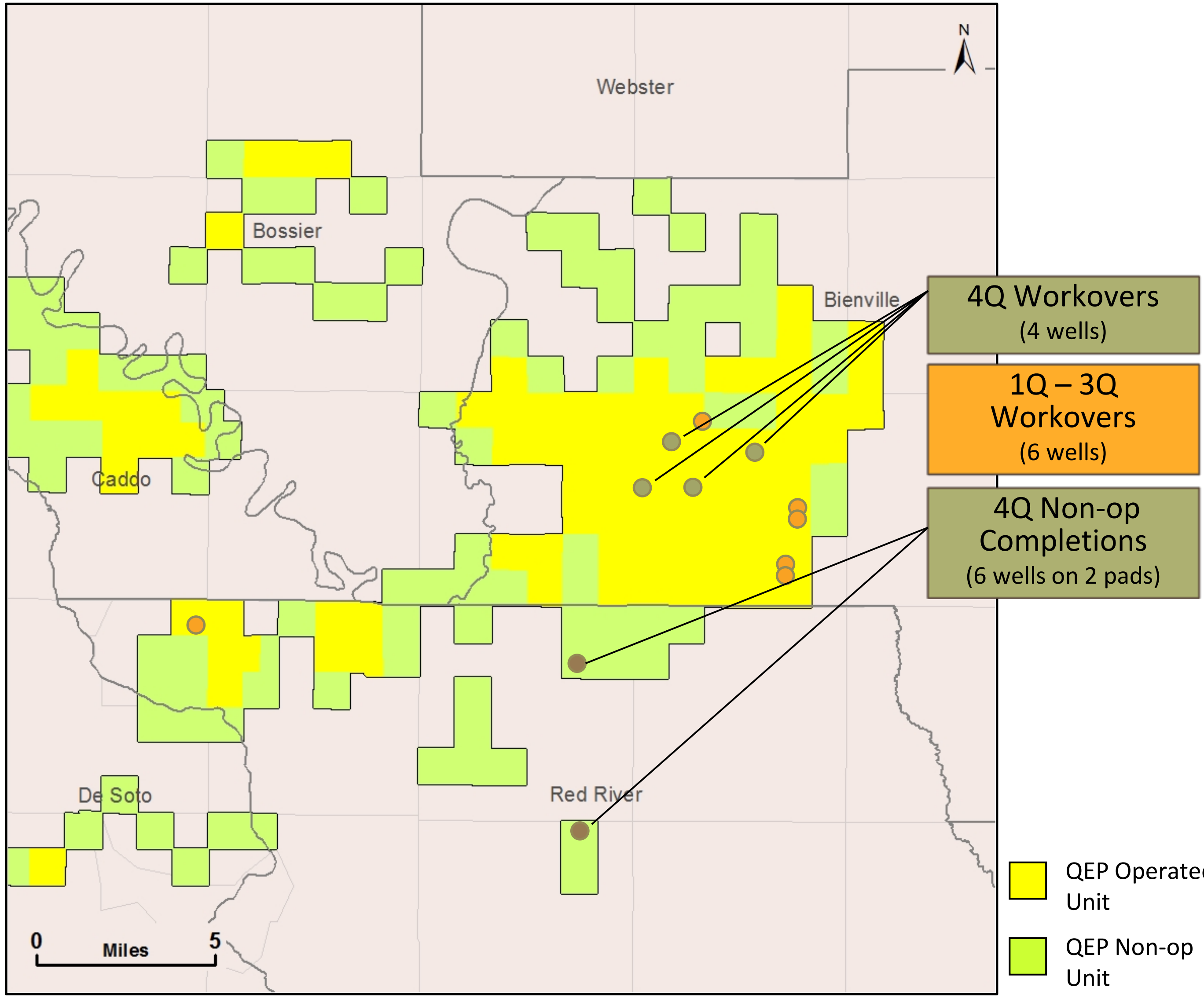


Gross Well Cost (AFE)

- Drill & complete: $8.0 MM (horizontal)
  - 7,500-ft. lateral, 33 stage "Plug & Perf" design
- Facilities & artificial lift: $0.6 MM
- Workover: $4.0 MM

Haynesville Activity

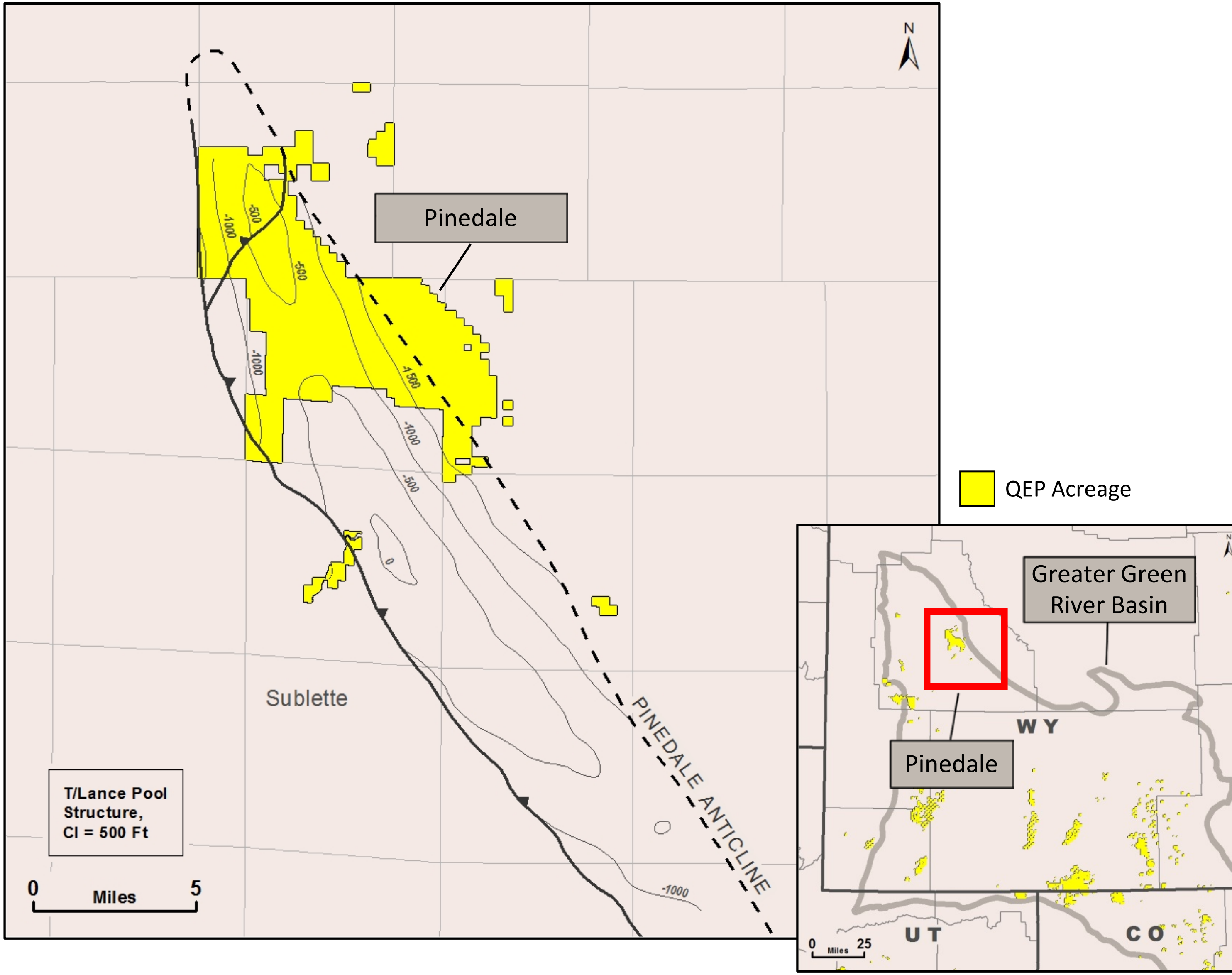
- **Net acres: 48,100**
- **Rig Count: 0**
- **Workovers Completed: 4**
- **Non-op Completions:**
  - 6 gross / 0.8 net



As of 12/31/2016

Pinedale

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



Pinedale Overview

4Q 2016 Program Highlights

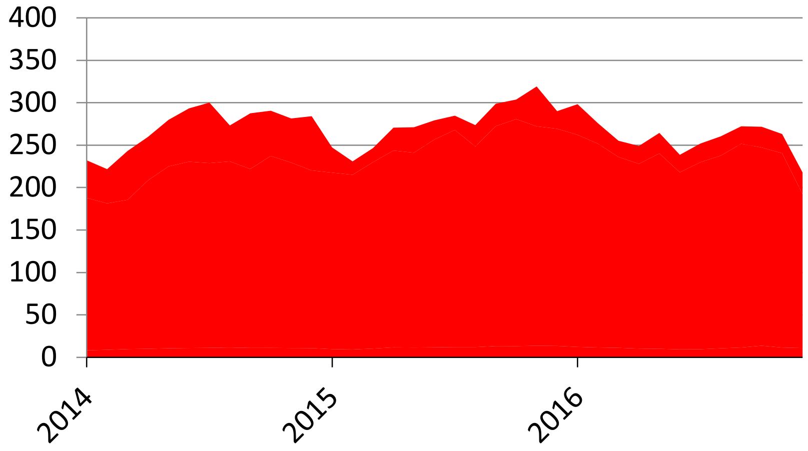
- Completed six wells during the quarter
- Continued to refine drilling program in more challenging area of the field
- Continued to evaluate horizontal potential
- Delayed additional compression until 1Q 2017

Profile[1]

Net acres	17,400
Gross operated producing wells	1,113
Average WI/average NRI	59/45%
Proved reserves (Bcfe)/% liquids[2]	964 / 13%
Production Split – oil/gas/NGL	5/86/9%
Current rig count	1

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

Net Production - MMcfed

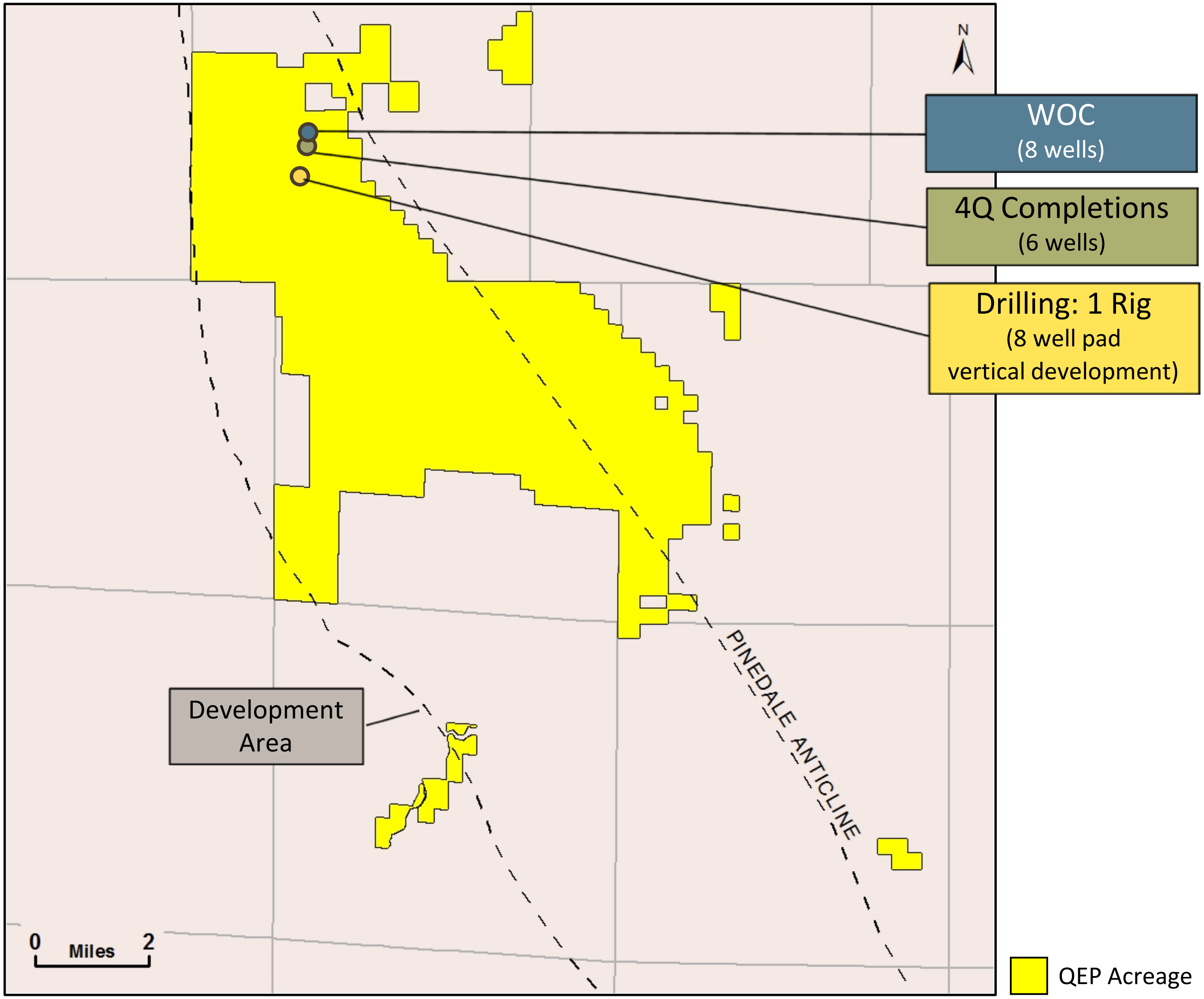


Gross Well Cost (AFE)

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

Pinedale Activity

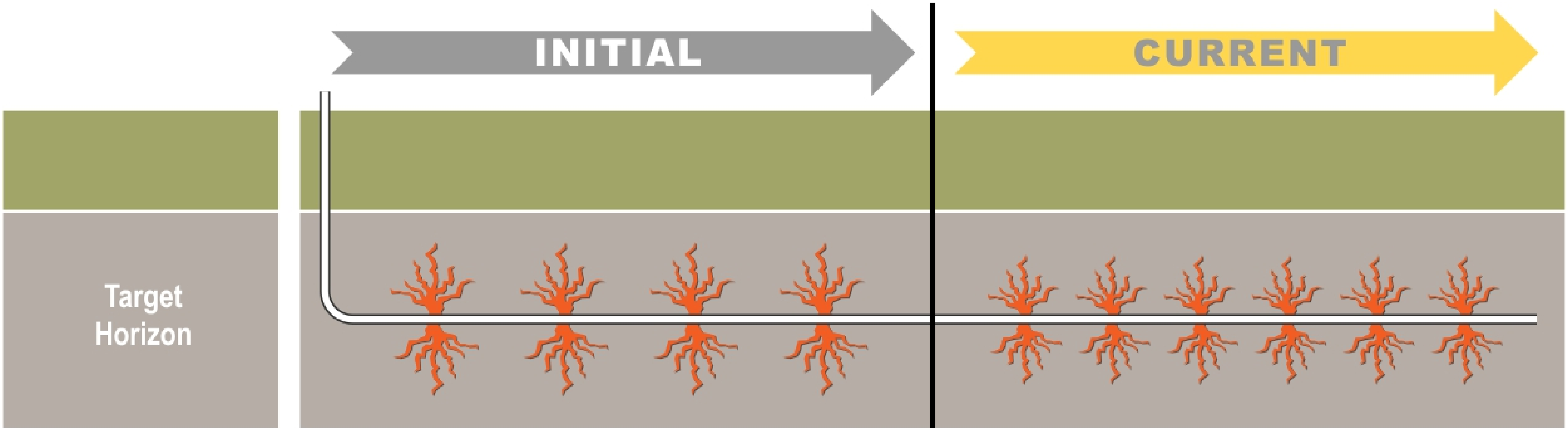
- **Net Acres: ~17,400**
- **Rig Count: 1 vertical**
- **Completions: 6**
- **WOC: 8**
- **Drilling: 6**



As of 12/31/2016

Mustang Springs Development Plan

Permian Basin – *Fracture Stimulation Design Evolution*

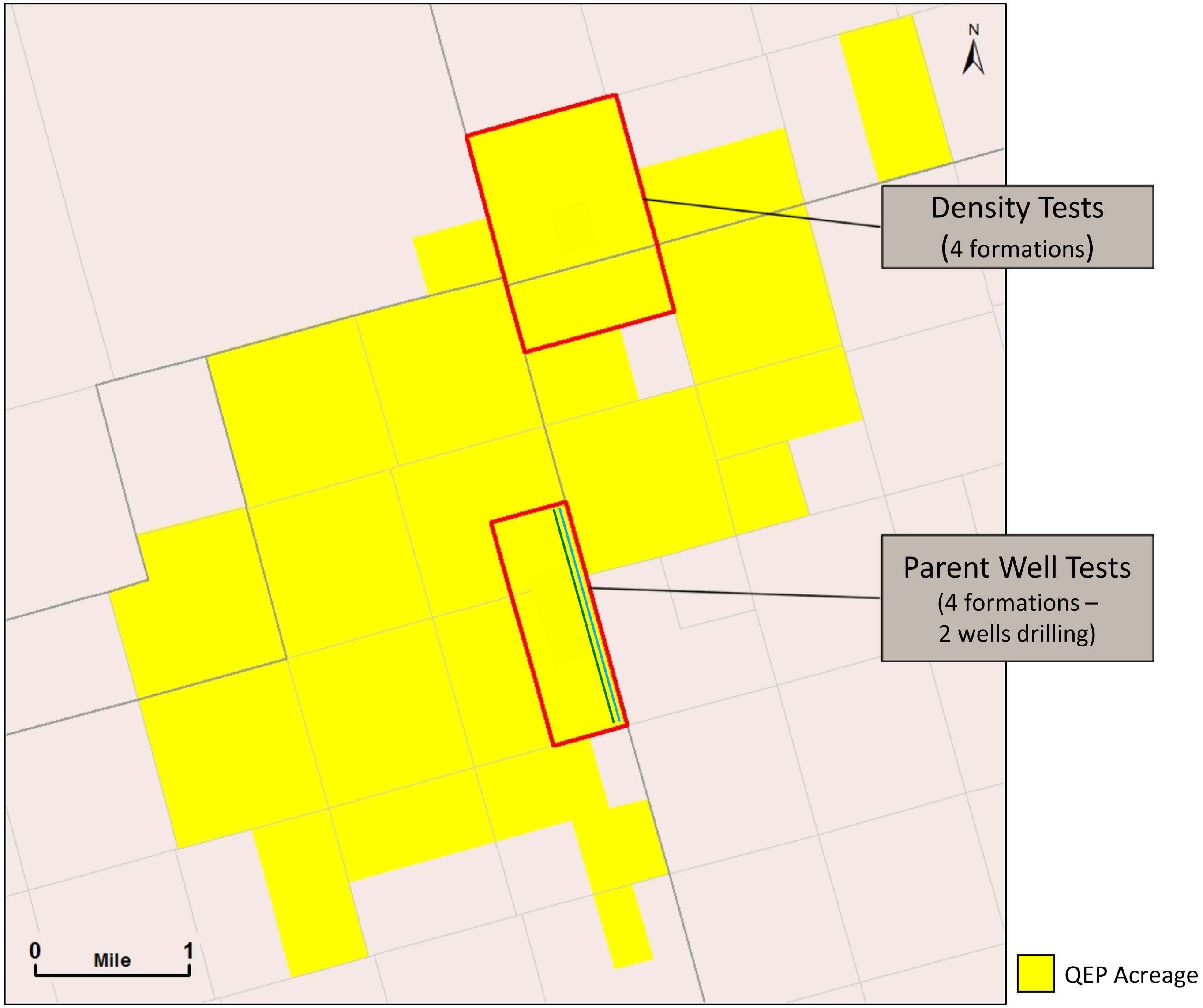


INITIAL – SPRABERRY	INITIAL – WOLFCAMP	CURRENT – SPRABERRY	CURRENT – WOLFCAMP
1,400 lbs/ft proppant	1,500 lbs/ft proppant	1,400 lbs/ft proppant	1,800 lbs/ft proppant
30 bbls/ft fluid	35 bbls/ft fluid	32 bbls/ft fluid	38 bbls/ft fluid
±32 Stages*	±32 Stages*	±50 Stages*	±50 Stages*
60 ft cluster spacing	60 ft cluster spacing	30 ft cluster spacing	30 ft cluster spacing
240 ft stage spacing	240 ft stage spacing	150 ft stage spacing	150 ft stage spacing

* 7,500’ lateral length

Development Plans – *Mustang Springs*

- **Parent well tests:**
  - **Middle Spraberry**
  - **Spraberry Shale**
  - **Wolfcamp A**
  - **Wolfcamp B**
- **Well density optimization test starting in Q1 2017**
- **Centralized oil, gas, and water infrastructure under development**



As of 12/31/2016

Development Optimization & Pilot Tests – *Mustang Springs*

	West Pilot Spacing/Section	East Pilot Spacing/Section
	Low WA & WB High MS & SS	High WA & WB Low MS & SS
Leonard Shale		
M. Spraberry	10-well density	6-well density
L. Spraberry		
Spraberry Shale	14-well density	8-well density
Dean		
Wolfcamp A	4-well density	7-well density
Wolfcamp B	8-well density	14-well density
Wolfcamp D		

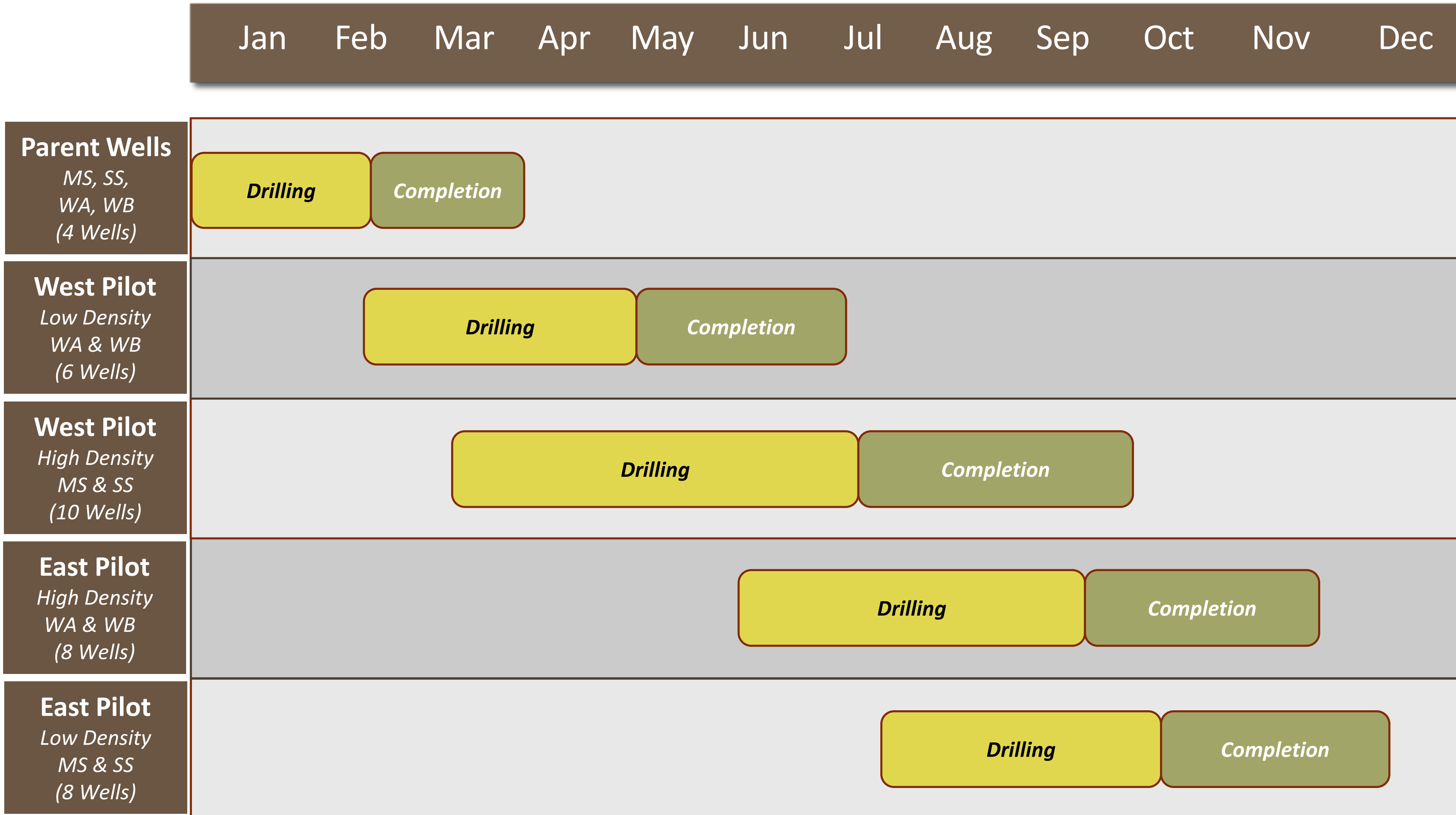
Development Optimization

- Parent well tests
  - Provide baseline well performance in four zones Middle Spraberry (MS), Spraberry Shale (SS), Wolfcamp A (WA) and Wolfcamp B (WB)
- Density tests
  - Drive ultimate spacing of each reservoir and sequencing of development
  - Establish optimum drilling and completion program to maximize production and minimize well interference

Density Pilot Tests

- Two pilot tests planned
  - Evaluate a continuum of wells across all four target horizons
- West Pilot
  - Evaluate higher well density in MS & SS and lower density in WA and WB
- East Pilot
  - Evaluate higher well density in WA & WB and lower density in MS and SS

2017 Drilling & Completion Timeline – *Mustang Springs*



Note: Assumes three rigs, two frac crews, and two drill-out crews

Appendix

2017 Guidance

2017 Guidance – *As of February 22, 2017*	**Current Forecast**
Oil production (MMbbl)	21.0 – 22.0
Gas production (Bcf)	180.0 – 190.0
NGL production (MMbbl)	5.75 – 6.25
Total oil equivalent production (MMboe)	57.0 – 60.0
Lease operating and transportation expense (per Boe)	$9.50 - $10.50
Depletion, depreciation and amortization (per Boe)	$16.00 - $17.00
Production and property taxes, % of field-level revenue	8.5%
(in millions)	
General and administrative expense[1]	$160 - $170
Capital investment (excluding property acquisitions)	
Drilling, Completion and Equip	$890 - $930
Infrastructure	$50 - $60
Corporate	$10
Total Capital Investment	$950 - $1,000

[1] Forecasted general and administrative expense includes approximately $31.5 million of expenses primarily related to share-based compensation.

Guidance Assumptions

- Seven operated rigs in 2017
  - Five rigs in the Permian Basin
  - One rig in the Williston Basin
  - One rig in Pinedale
- Complete ~115 to 130 gross operated wells (98 to 110 net)
  - ~75 to 80 gross (75 to 80 net) in the Permian Basin
  - ~20 to 25 gross (15 to 20 net) in the Williston Basin and
  - ~20 to 25 gross (8 to 10 net) in Pinedale
  - ~20 to 24 workovers in Haynesville/Cotton Valley

Derivative Positions

The following tables present QEP's volumes and average prices for its open derivative positions as of February 17, 2017:

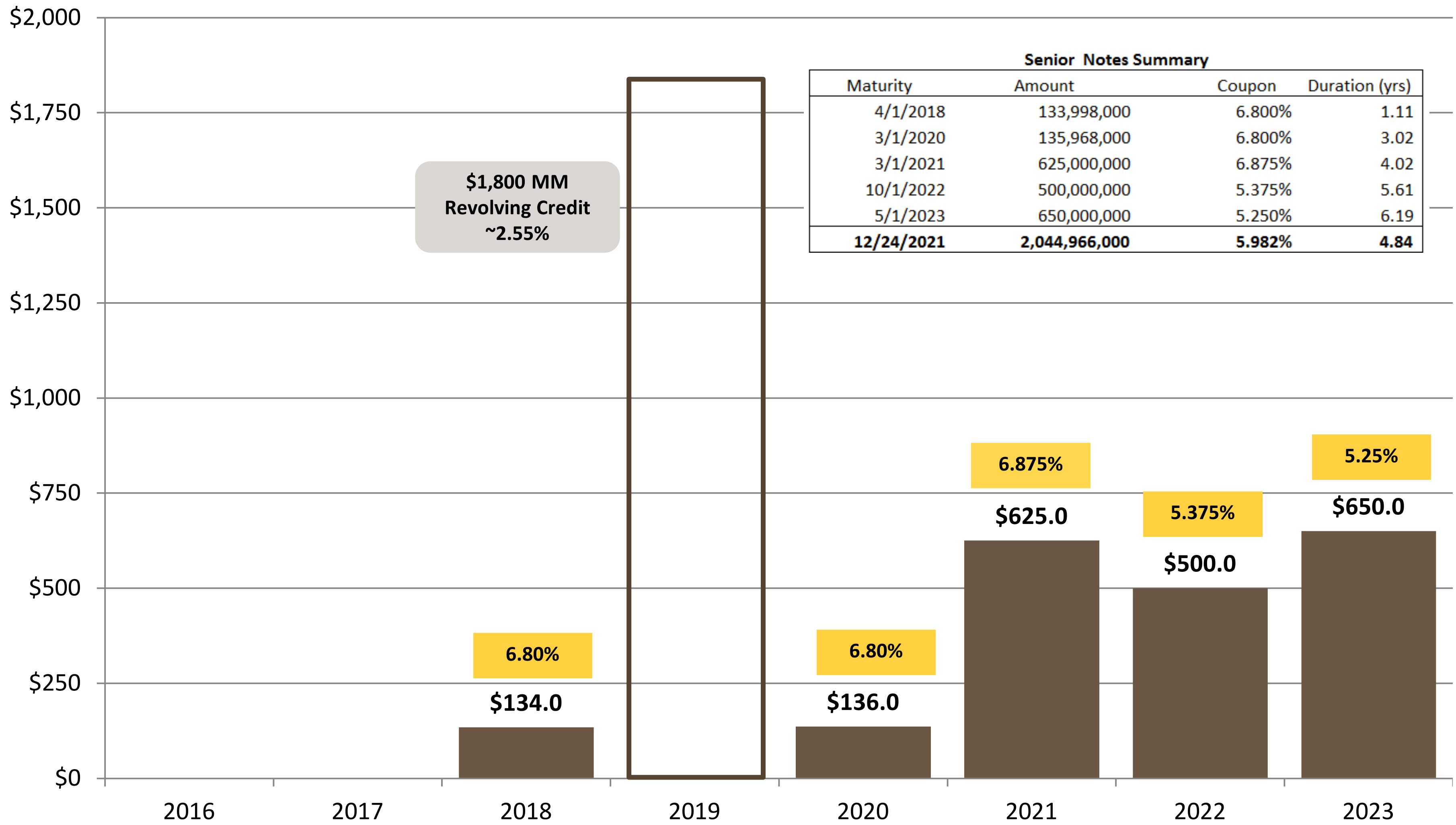
Production Commodity Derivative Swap Positions			
Year	**Index**	**Total Volumes**	**Average price per unit**
		(in millions)	
Oil sales		**(bbls)**	**($/bbl)**
2017	NYMEX WTI	12.4	$51.39
2018	NYMEX WTI	8.4	$53.71
Gas sales		**(MMBtu)**	**($/MMBtu)**
2017	NYMEX HH	79.6	$2.86
2017	IFNPCR	27.5	$2.51
2018	NYMEX HH	76.7	$2.98

Production Commodity Derivative Gas Collars				
Year	**Index**	**Total Volume MMBtu**	**Average Price Floor**	**Average Price Ceiling**
		(in millions)		
		(MMBtu)	**($/MMBtu)**	**($/MMBtu)**
2017	NYMEX HH	9.2	$2.50	$3.50

Production Commodity Derivative Basis Swaps				
Year	**Index Less Differential**	**Index**	**Total Volumes**	**Weighted Average Differential**
			(in millions)	
Oil Sales			**(MMBtu)**	**($/MMBtu)**
2017	NYMEX WTI	Argus WTI Midland (1)	3.5	(0.64)
2018	NYMEX WTI	Argus WTI Midland (1)	2.6	(0.96)
Gas Sales			**(bbls)**	**($/bbl)**
2017	NYMEX HH	IFNPCR	42.8	(0.18)
2018	NYMEX HH	IFNPCR	7.3	(0.16)

(1) Argus WTI Midland is an index price reflecting the weighted average price of WTI at the pipeline and storage hub at Midland, TX

QEP Resources – Debt Maturity Schedule



Senior Notes Summary

Maturity	Amount	Coupon	Duration (yrs)
4/1/2018	133,998,000	6.800%	1.11
3/1/2020	135,968,000	6.800%	3.02
3/1/2021	625,000,000	6.875%	4.02
10/1/2022	500,000,000	5.375%	5.61
5/1/2023	650,000,000	5.250%	6.19
12/24/2021	**2,044,966,000**	**5.982%**	**4.84**

Estimated Proved Reserves

	Oil (MMbbl)	Gas (Bcf)	NGL (MMbbl)	Total (MMboe)[1]
Balance at December 31, 2015	193.1	2,108.9	58.8	603.4
Revisions of previous estimates	(9.7)	412.8	(0.3)	58.8
Extensions and discoveries	13.0	158.1	3.3	42.6
Purchase of reserves in place	62.7	54.6	11.5	83.3
Sale of reserves in place	(0.2)	(3.6)	(0.1)	(0.9)
Production	(20.3)	(177.0)	(6.0)	(55.8)
Balance at December 31, 2016	**238.6**	**2,553.8**	**67.2**	**731.4**

(1) Natural gas is converted to crude oil equivalent at the ratio of six Mcf of natural gas to one barrel of crude oil equivalent.

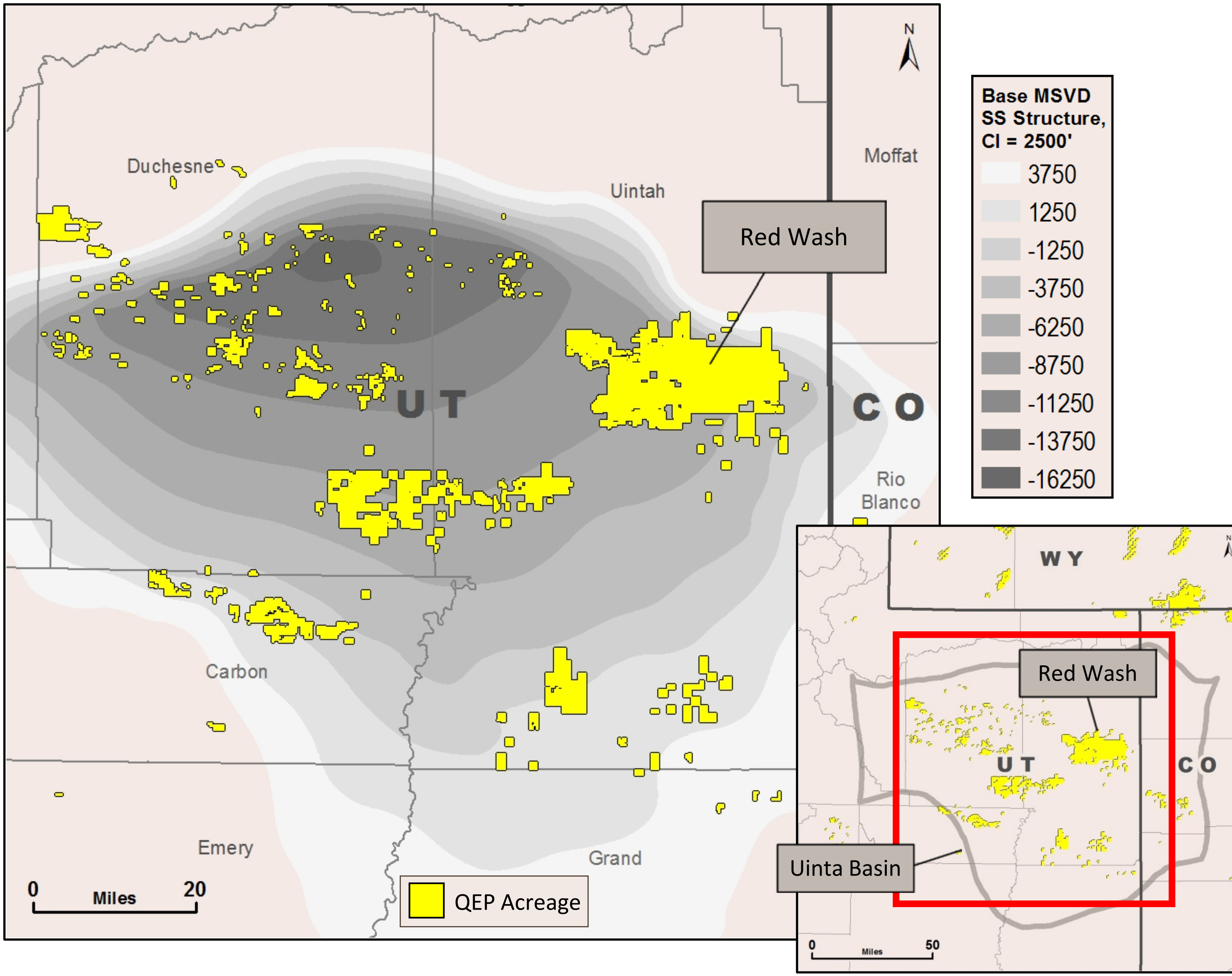
Estimated Proved Reserves – *By Operating Area*

	Total (in MMboe)	% of total	PUD %	liquids %
For the year ended December 31, 2016				
Northern Region				
Williston Basin	160.2	22%	37%	86%
Pinedale	160.7	22%	14%	13%
Uinta Basin	106.1	14%	62%	15%
Other Northern	12.3	2%	—%	6%
Southern Region				
Permian Basin	147.8	20%	81%	88%
Haynesville/Cotton Valley	144.3	20%	74%	—%
Other Southern	—	—%	—%	—%
Total proved reserves	**731.4**	**100%**	**51%**	**42%**
For the year ended December 31, 2015				
Northern Region				
Williston Basin	181.0	30%	39%	86%
Pinedale	187.5	31%	27%	13%
Uinta Basin	93.1	16%	55%	18%
Other Northern	12.4	2%	—%	8%
Southern Region				
Permian Basin	62.4	10%	66%	87%
Haynesville/Cotton Valley	66.1	11%	57%	—%
Other Southern	0.9	—%	—%	32%
Total proved reserves	603.4	100%	42%	42%

Uinta Basin

AGE	FORMATION
TERTIARY	Duchesne River
	Uinta
	Green River
	Wasatch
CRETACEOUS	Mesaverde
	Mancos
	Dakota
	Cedar Mountain

QEP Acreage



Uinta Basin Overview – *Lower Mesaverde*

4Q 2016 Program Highlights

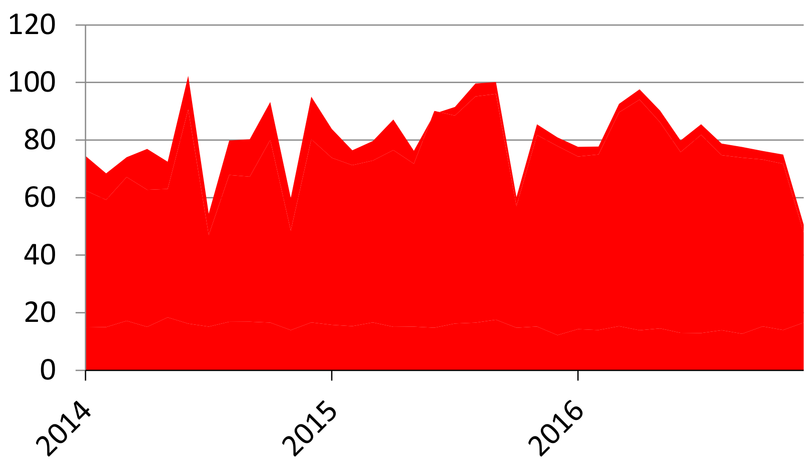
- Additional compression brought online in 4Q 2016

Profile[1]

Net acres[2]	110,300
Gross operated producing wells[2]	106
Average WI/average NRI[2]	98/85%
Proved reserves (Bcfe)/% liquids[3]	637 / 15%
Production Split – oil/gas/NGL	2/92/6%
Current rig count	0

[1] As of December 31, 2016
[2] Greater Red Wash Mesaverde Fairway
[3] As of December 31, 2016, SEC pricing total Uinta Basin

Net Production - MMcfed



Gross Well Cost (AFE)

Vertical

- Drill & complete: $2.3 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