QEP RESOURCES®

Investor Presentation

July 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; large upside potential in proven and unproven zones; rationalization of mature assets; peak production at Wolfcamp pilot wells; forecasted oil production; growth strategy; portfolio optimization; allocation of capital; potential drilling locations; evaluating well density; development strategy, plans and timeline; benefits of tank-style development in the Permian Basin; completion methodology; 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 oil, natural gas, and NGL; oil, natural gas and NGL 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 and other 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 sections of QEP’s Annual Report on Form 10-K for the year ended December 31, 2016 (the “2016 Form 10-K”), and QEP’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2017. 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; 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 Resources – *A Leading Independent E&P Company*

Balanced & Diversified Upstream Portfolio

- Focused investment in core crude oil and natural gas plays

Financial Strength

- $178.8 million of cash and cash equivalents as of June 30, 2017
- Undrawn $1.8 billion unsecured revolving credit facility
- Solid oil & gas derivative portfolio through 2019 to help mitigate cash-flow risk

Portfolio Optimization

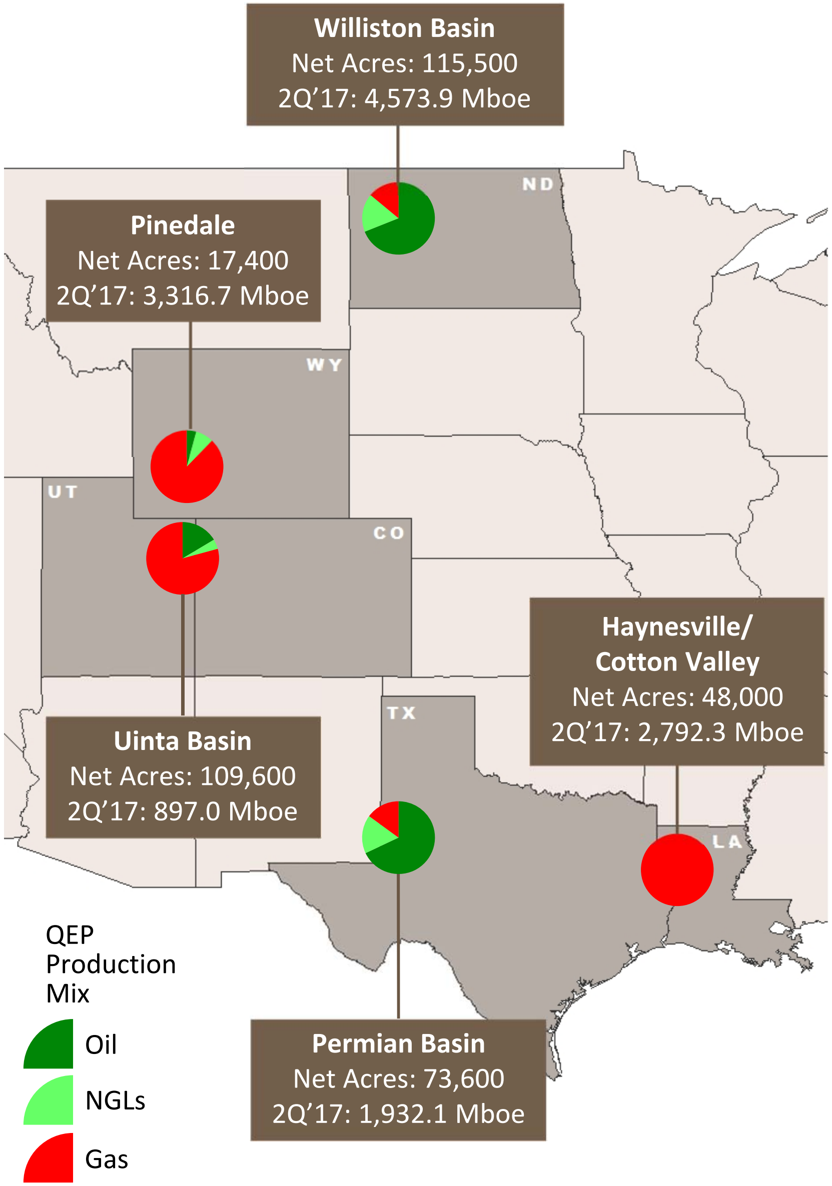
- Actively working to increase crude oil development drilling inventory through acquisitions, acreage swaps and organic growth opportunities
  - *Permian Basin Acquisition of ~13,800 net acres in Martin County, TX on July 26, 2017*
- Simplification of the QEP story through rationalization of mature assets
  - *Divestiture of southwest Wyoming gas assets for $777.5 million on July 24, 2017*

Capital & Operational Efficiency

- Allocate capital to highest rate of return projects
- Optimize well completion design and placement with tank-style development to maximize economic recovery of oil in place

QEP Resources – *2Q 2017 Financial & Operational Overview*

Asset Overview(1)



2Q 2017 Highlights

- Total Net Equivalent Production: 13,860.6 Mboe
  - Oil Production: 4,870.3 Mbbl
  - Gas Production: 45.8 Bcf
  - NGL Production: 1,354.9 Mbbl
- Impressive Permian Basin well results using tank-style completions on both County Line and Mustang Springs
  - County Line: four high-density Spraberry Shale test wells
    - Average peak 24-hour IP: 1,217 Boed (average 7,392' lateral, 83% oil)
  - Mustang Springs: six Wolfcamp pilot wells
    - Strong average initial flowback results: 1,169 Boed (average 7,087' lateral, 89% oil)
    - Wells flowing as of quarter end and may not reach peak production until installation of artificial lift in 3Q'17
- Haynesville refrac program continues to exceed expectations
  - Average incremental 24-hour rate increase of 16.0 Mmcfed on eight refracs
- Rig Count
  - Permian (5), Williston (1), Pinedale (1)

(1) Equivalent production excludes 348.6 Mboe from Other Northern & Other Southern regions

QEP Resources – *2017 Guidance*[1]

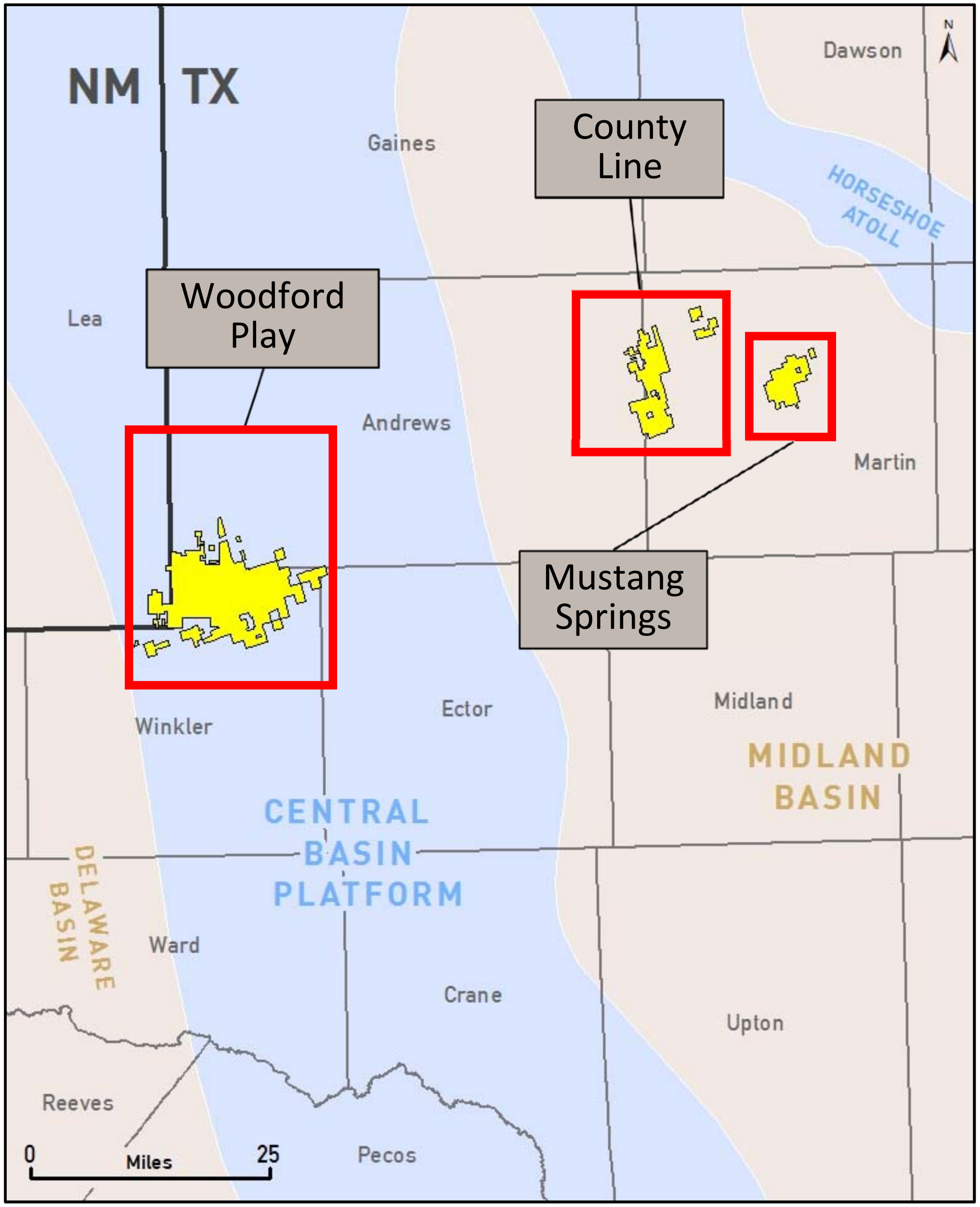
	2017 Current Forecast
Oil production (MMBbl)	21.0 - 22.0
Gas Production (Bcf)	182.5 - 192.5
NGL Production (MMBbl)	5.75 - 6.25
Total oil equivalent production (MMBoe)	57.2 - 60.3
Lease operating and transportation expense (per Boe)	$9.50 - $10.50
Depletion, depreciation and amortization (per Boe)	$15.00 - $16.00
Production and property taxes (% of field-level revenue)	8.50%
(in millions)	
General and administrative expense[2]	$155 - $165
Capital investment (excluding property acquisitions)	
Drilling, Completion and Equip[3]	$970 - $1,010
Infrastructure	$70 - $80
Corporate	$10
Total Capital Investment (excluding property acquisitions)	**$1,050 - $1,100**

(1) As of July 26, 2017: The Company's guidance has not been updated for the Pinedale Divestiture or the Acquisition, assumes no additional property acquisitions or divestitures and assumes that QEP will elect to reject ethane from its produced gas for the entire year where QEP has the right to make such an election. Assumes an average of nine rigs for the remainder of 2017, with six rigs in the Permian Basin, one rig in the Williston Basin, one rig in the Haynesville and one rig in Pinedale; assumes 10 additional refracs in the Haynesville in 2017 (for a total of approximately 30 refracs in 2017).

(2) General and administrative expense includes approximately $25.0 million of non-cash share-based compensation expense.

(3) Drilling, Completion and Equip includes approximately $20.0 million of non-operated well completion costs.

Permian Basin



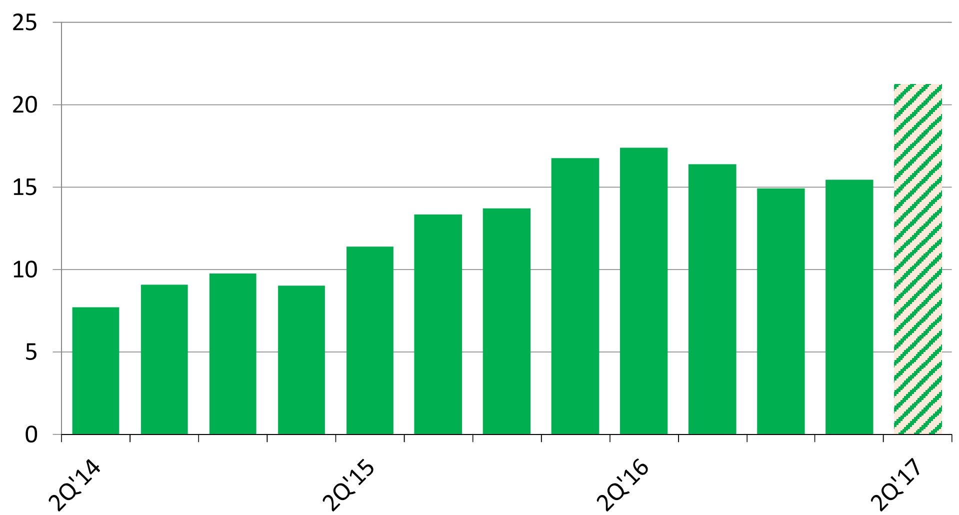
QEP Acreage as of 6/30/2017

Profile[1]

Net acres	73,600
Gross operated producing wells	491
Average WI/average NRI	96 / 73%
Proved reserves (MMboe)/% liquids[2]	148 / 88%
Production Split – oil/gas/NGL	75/11/14%
Rig Count	5

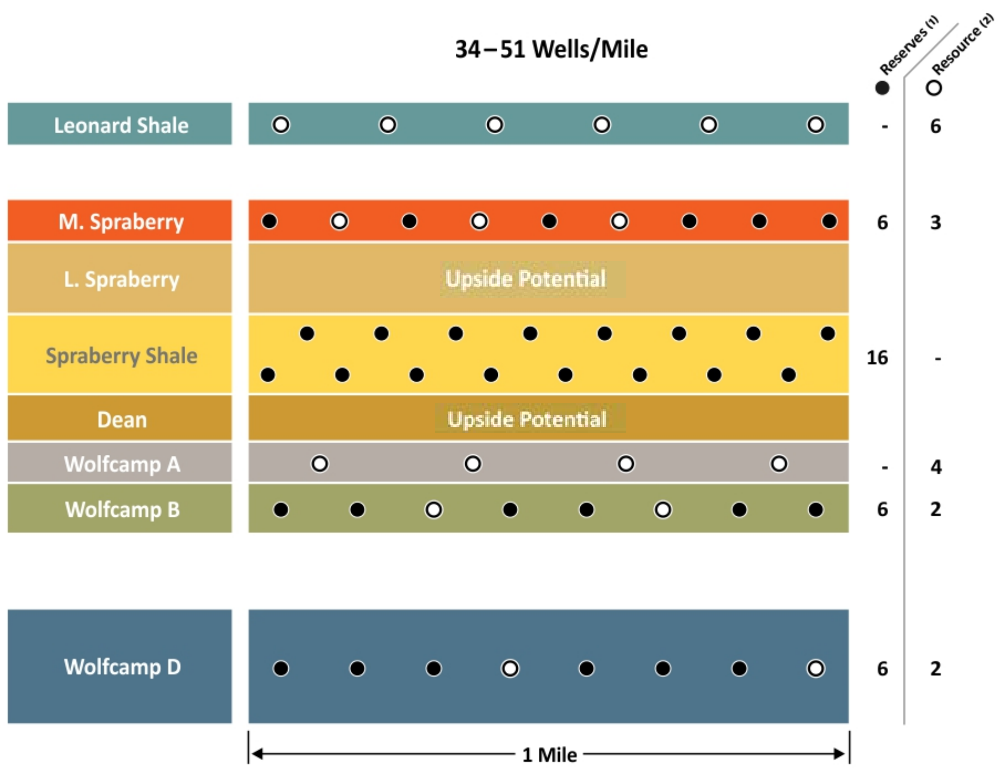
[1] As of June 30, 2017, except for reserve estimates
[2] As of December 31, 2016, SEC Pricing

Net Production - Mboed

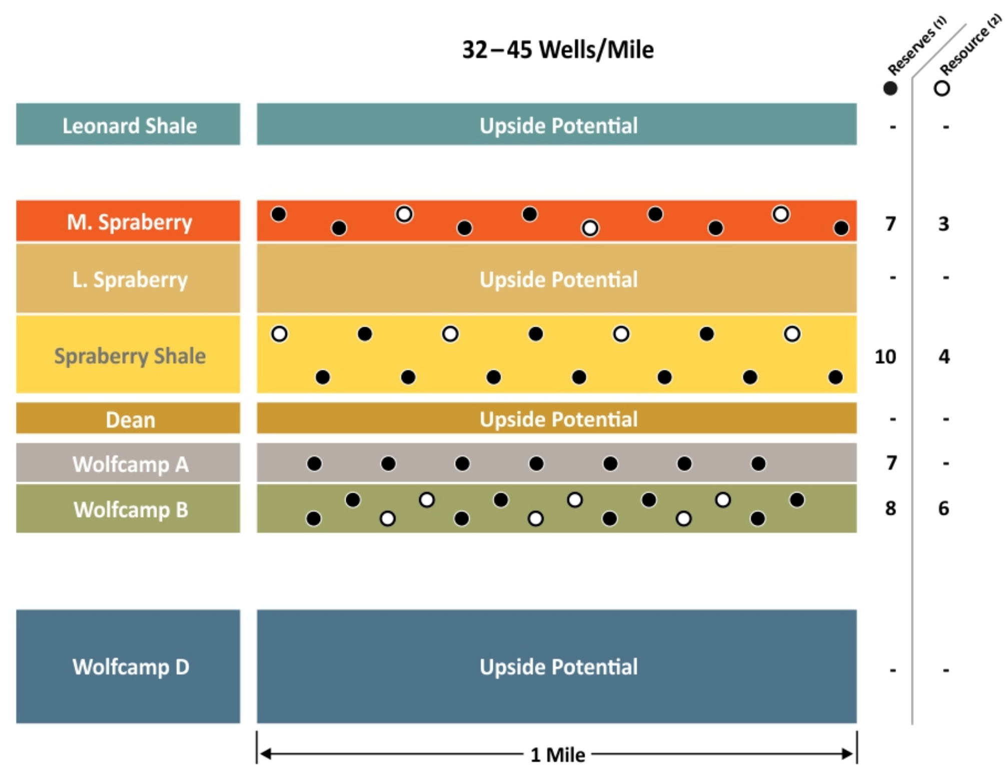


Permian Basin – *Well Density Assumptions*

County Line



Mustang Springs



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

- Stacked pay opportunity across core Permian acreage position
- Large upside opportunity in both proven and unproven zones
- More than 1,150 potential future locations of 7,500’ and 10,000’ laterals[3]

(3) County Line & Mustang Springs only; excludes zones labeled as upside potential

Permian Basin – *Tank-style Development*

Methodology

- Multiple stacked horizons from a single surface location
- Large multi-well pads and advanced completion designs
- Wells completed in a top-down pattern
- “Pressure Wall” separates producing wells from completing wells
- “Buffer” minimizes interference between completed and drilling wells

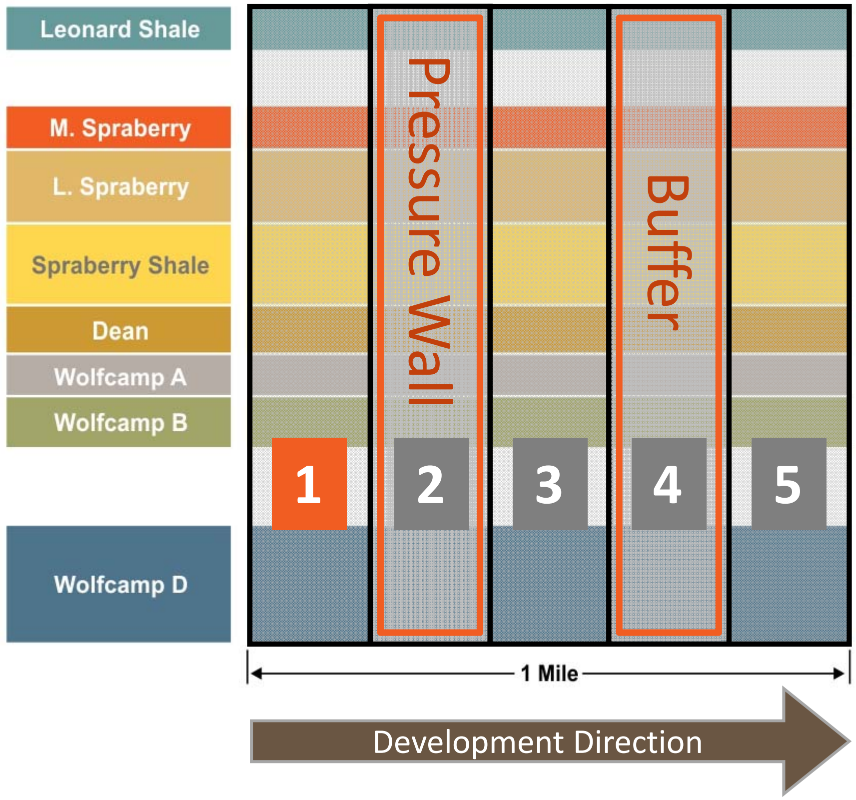
Benefits

<u>Above Ground</u>

- Maximizes efficiency and utilization of surface equipment, crews and infrastructure
- Simultaneous use of multiple drilling rigs reduces cycle time and allows for the sharing of services
- Integrated infrastructure provides cost savings through the recycling of water and the reduction of well site facility and pipeline costs

<u>Below Ground</u>

- Maximizes production and ultimate resource recovery
- Maintains “super-charged” reservoir pressure and optimizes rock stimulation and conservation of completion energy
- Minimizes the risk of interference and shut-in times for offset producing wells



LEGEND:

1 Producing wells

2 Completed wells waiting to be turned-to-sales (“Pressure Wall”)

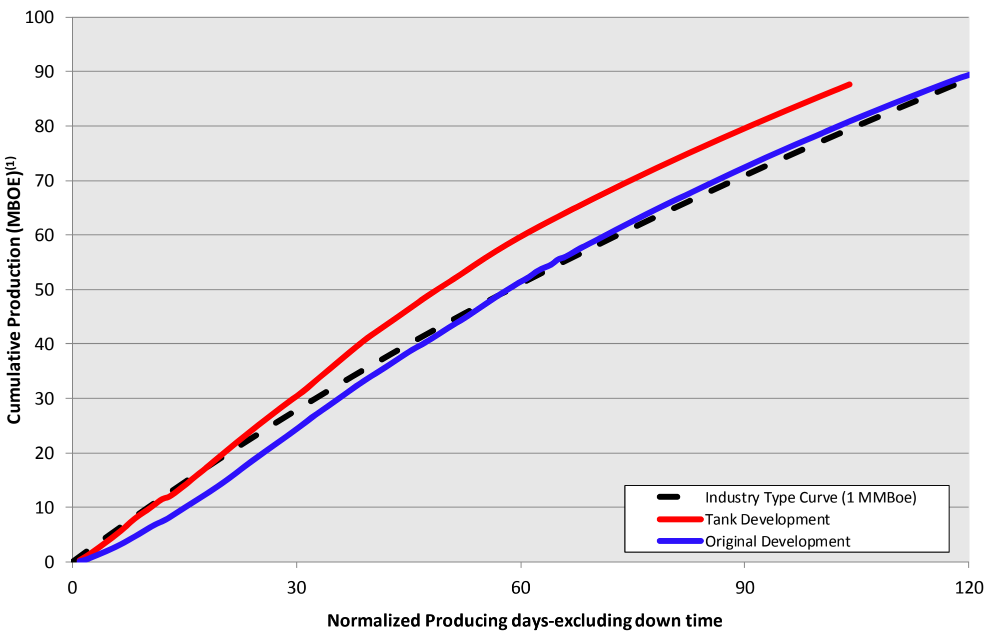
3 Wells being completed

4 Wells waiting-on-completion (“Buffer”)

5 Wells being drilled

Permian Basin – *County Line 2Q 2017 Activity*

- **Net Acres:** ~18,800
- **Rig Count:** 1
- **Completions:** 16
  - Leonard Shale (LNRD) (1)
  - Middle Spraberry (MS) (6)
  - Spraberry Shale (SS) (9)
- **Waiting on Completions:** 0
- **Drilling:** 7



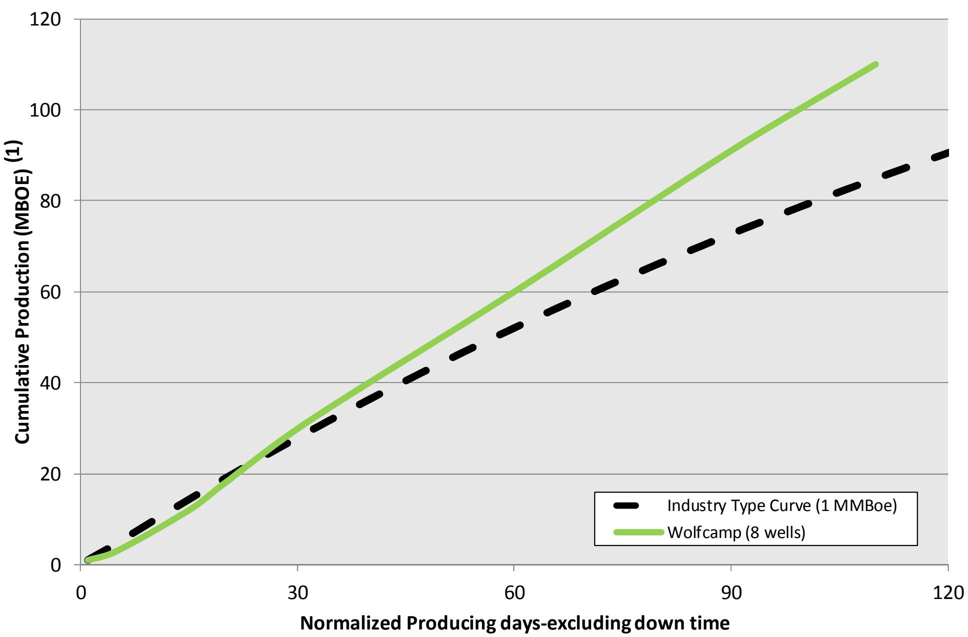
(1) Sprayberry wells normalized to 7,500' Lateral Length

QEP Acreage as of 6/30/2017

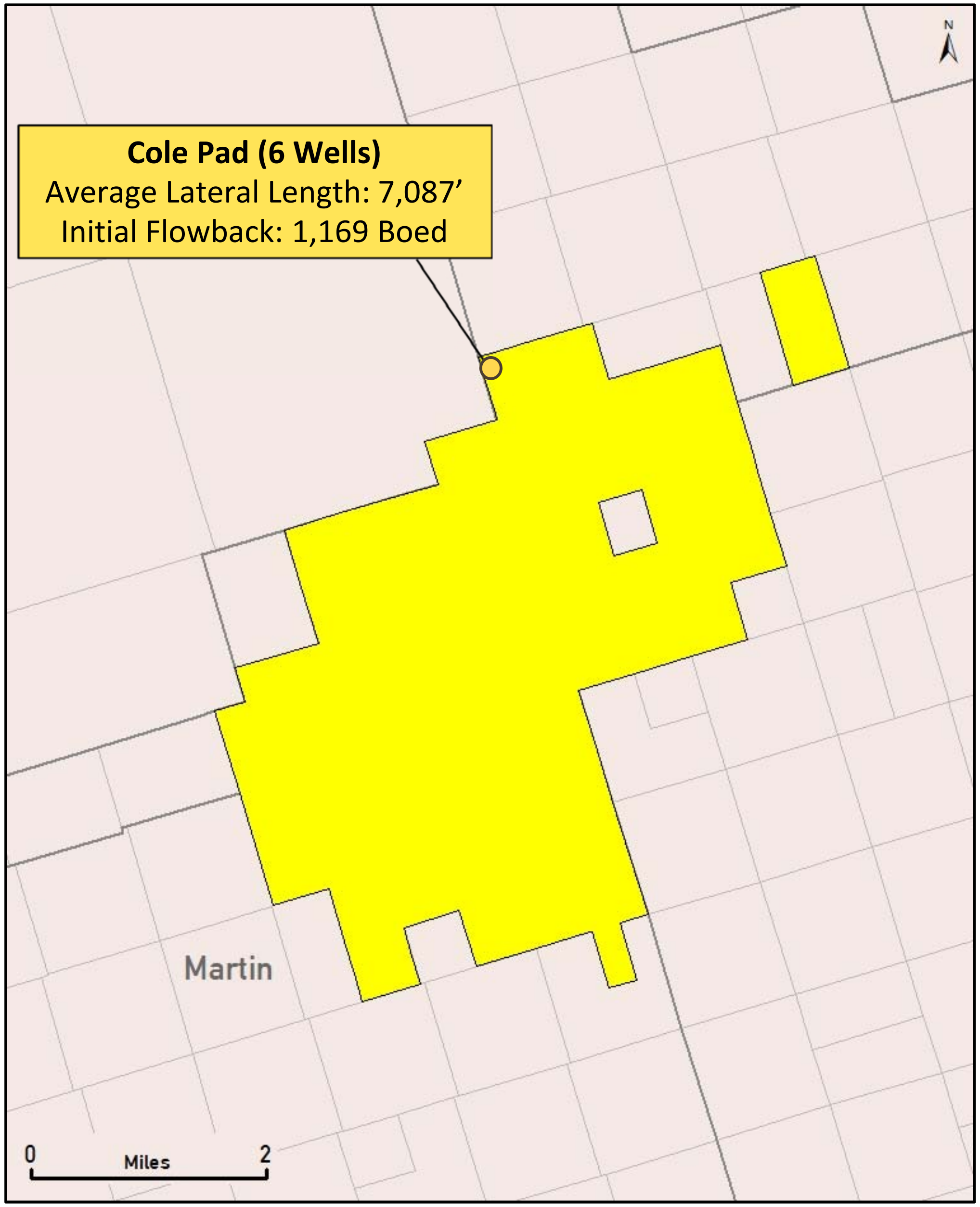
Note: Nine of the 16 wells were in the early stages of flowback at the end of 2Q'17 and had not reached peak IP rates.

Permian Basin – *Mustang Springs 2Q 2017 Activity*

- **Net Acres:** ~10,000
- **Rig Count:** 4
- **Completions:** 6
  - Wolfcamp A (WA) (2)
  - Wolfcamp B (WB) (4)
- **Waiting on Completion**: 7
  - Spraberry Shale (SS) (1)
  - Middle Spraberry (MS) (5)
  - Wolfcamp B (WB) (1)
- **Drilling:** 19



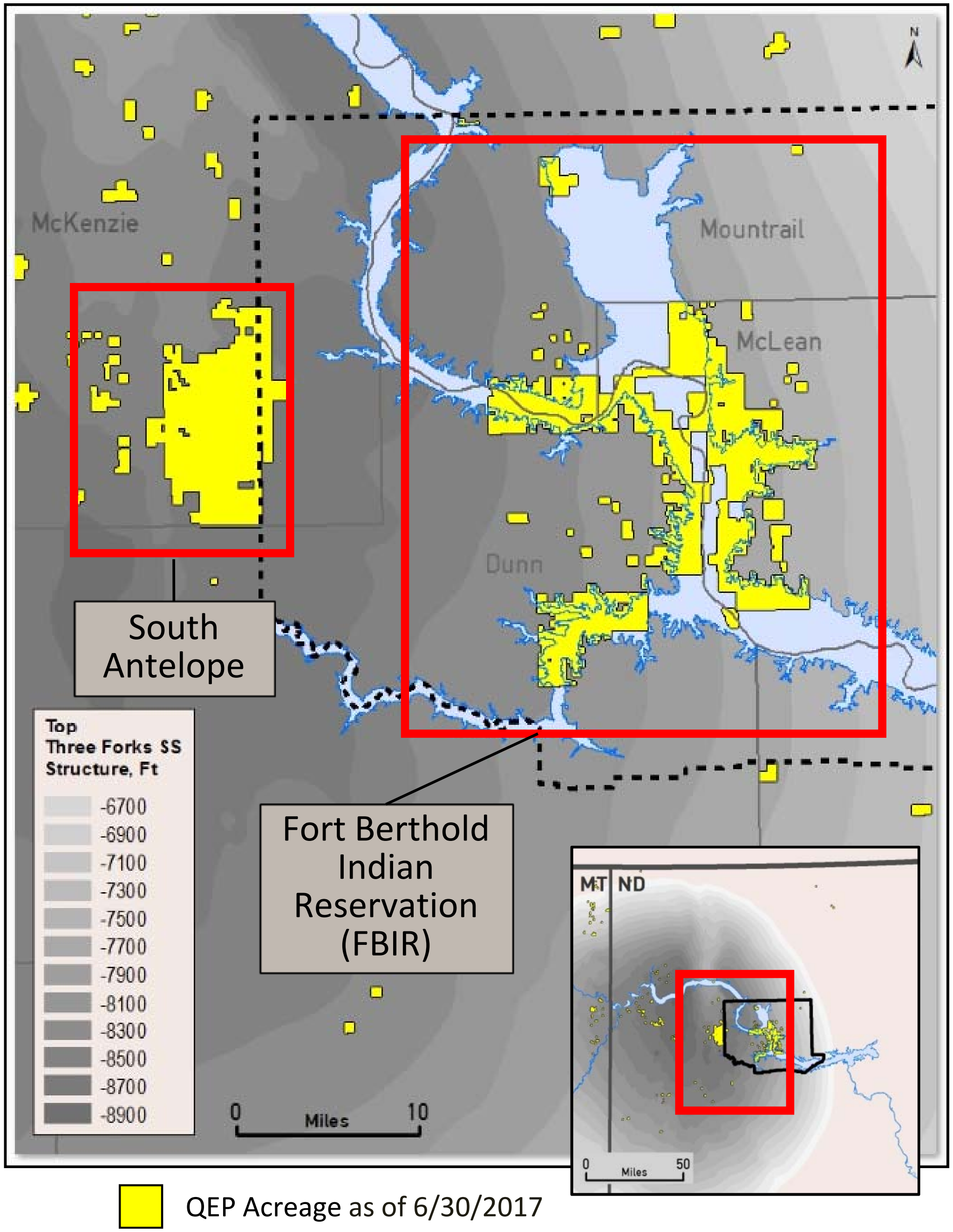
(1) Normalized to 7,500’ Lateral Length



QEP Acreage as of 6/30/2017

Note: All wells in early stages of testing at the end of 2Q’17 and are flowing without artificial lift.

Williston Basin

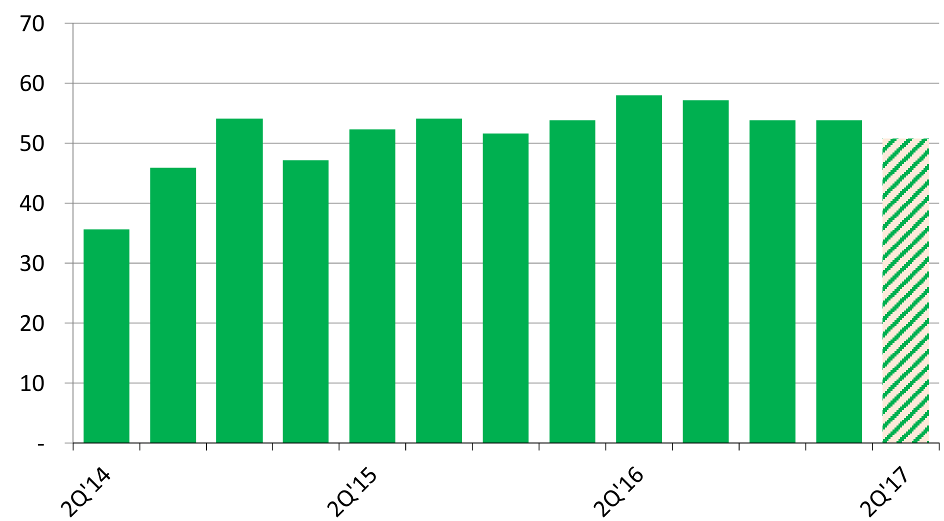


Profile[1]

Net acres	115,500
Gross operated producing wells	377
Average WI/average NRI	86/69%
Proved reserves (MMboe)/% liquids[2]	160 / 86%
Production Split – oil/gas/NGL	67/15/18%
Rig Count	1

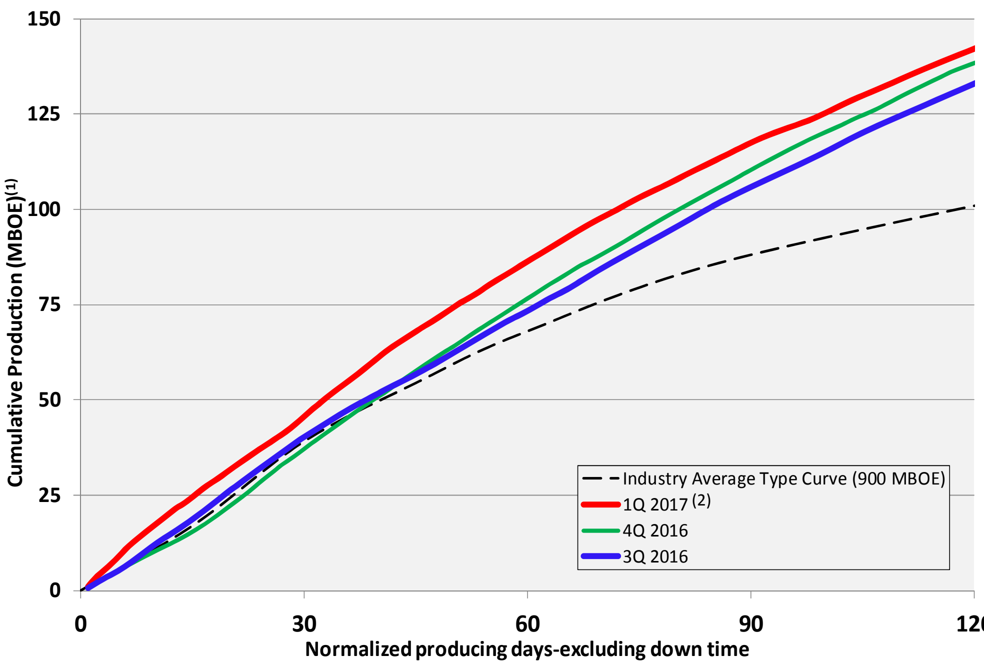
[1] As of June 30, 2017, except for reserve estimates
[2] As of December 31, 2016, SEC Pricing

Net Production - Mboed

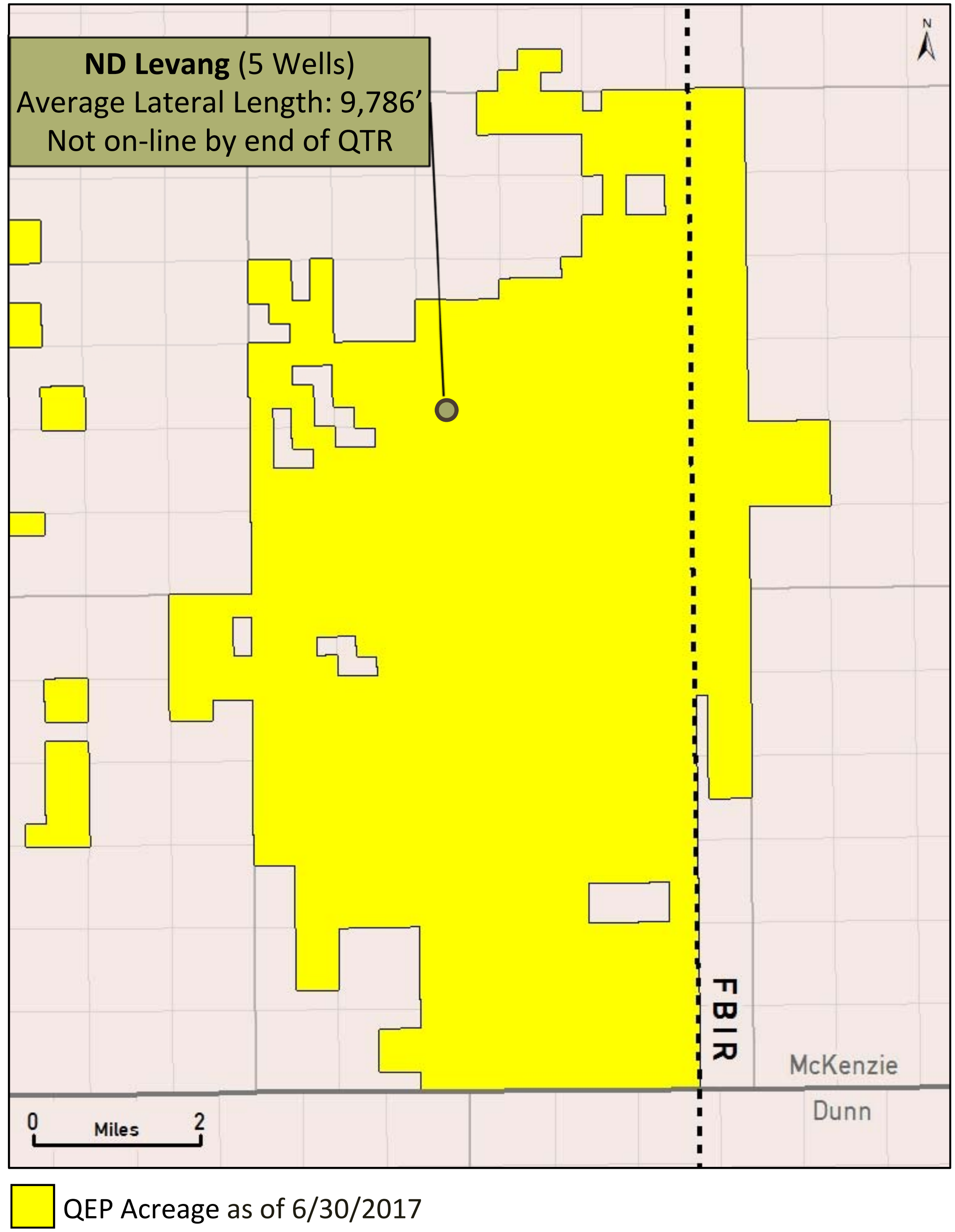


Williston Basin – *South Antelope 2Q 2017 Activity*

- **Net Acres:** ~30,900
- **Rig Count:** 1
- **Completions:** 5
  - Bakken (3)
  - Three Forks 2 (2)
- **Waiting on Completion**: 3
  - Bakken (2)
  - Three Forks 2 (1)
- **Drilling:** 3



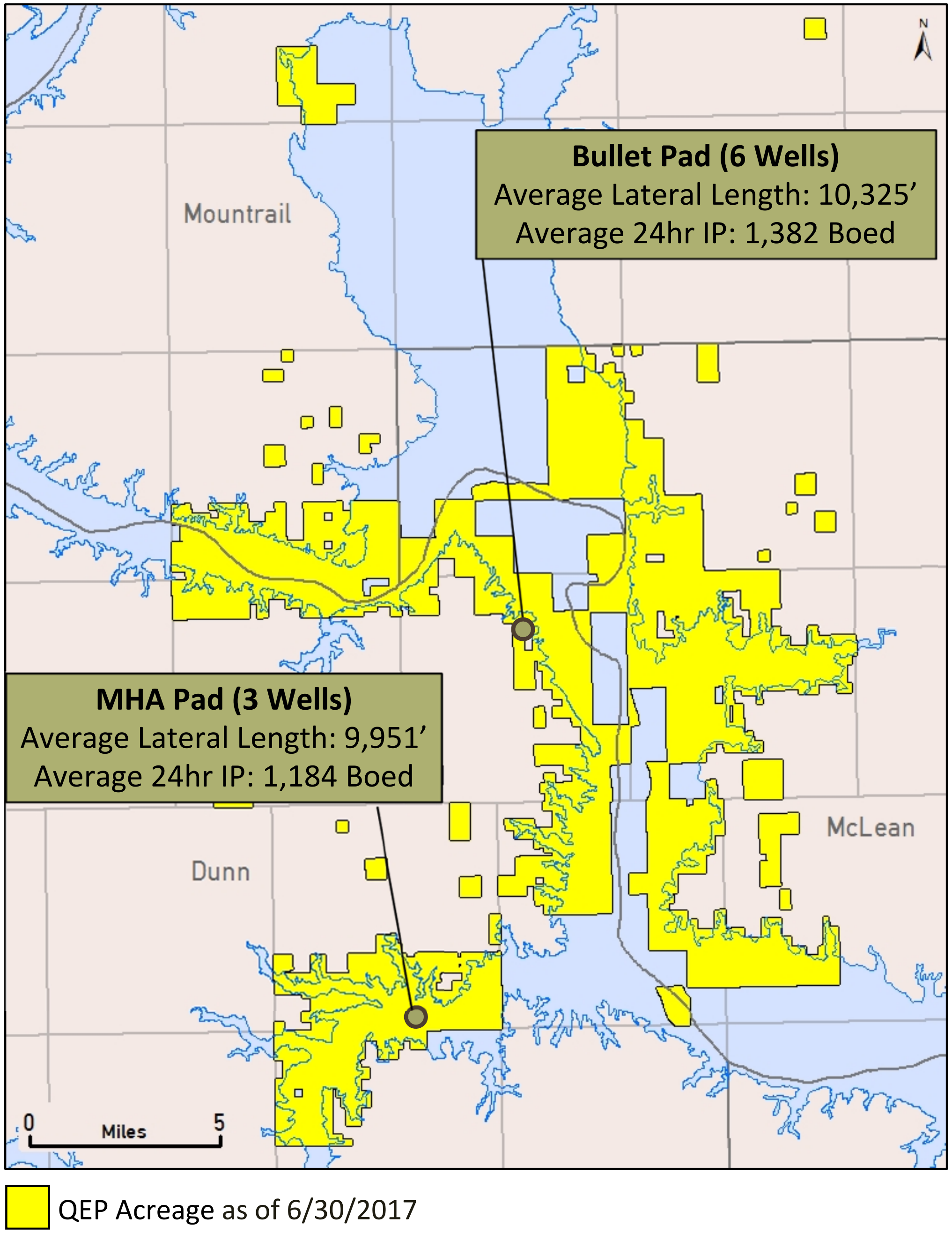
(1) Average 10,000’ lateral length, high-density infill wells at 600’ spacing
(2) Includes 1Q’17 Bakken and Three Forks 1 wells



Note: All wells in early stages of flowback at the end of 2Q’17 and did not have measurable production during the quarter

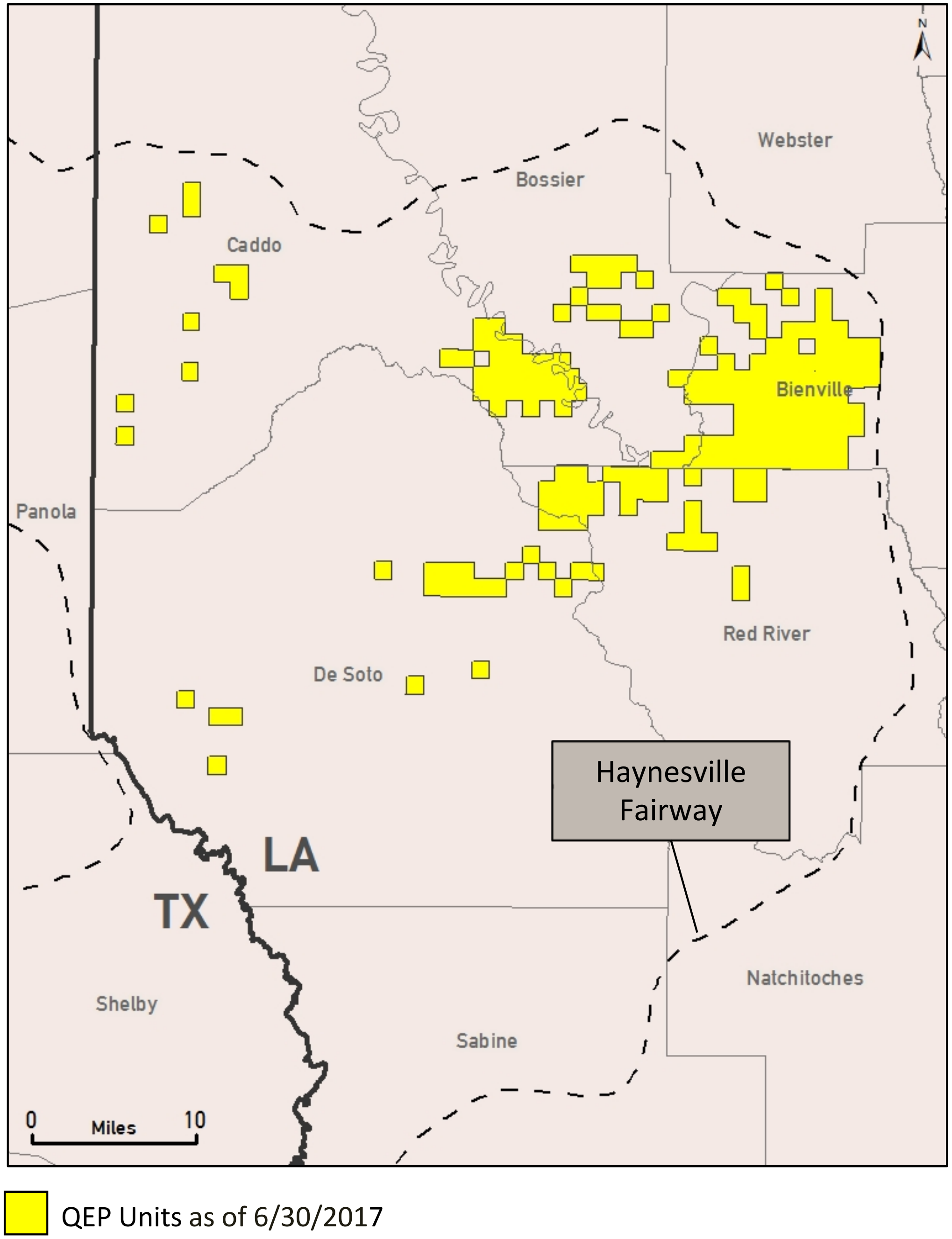
Williston Basin – *FBIR 2Q 2017 Activity*

- **Net Acres:** ~66,500
- **Rig Count:** 0
- **Completions:** 3
  - Bakken (2)
  - Three Forks 1 (1)
- **Waiting on Completion:** 0
- **Drilling:** 0



Note: Bullet Pad completed in 1Q’17 with Peak 24-hr IP’s occurring in 2Q’17

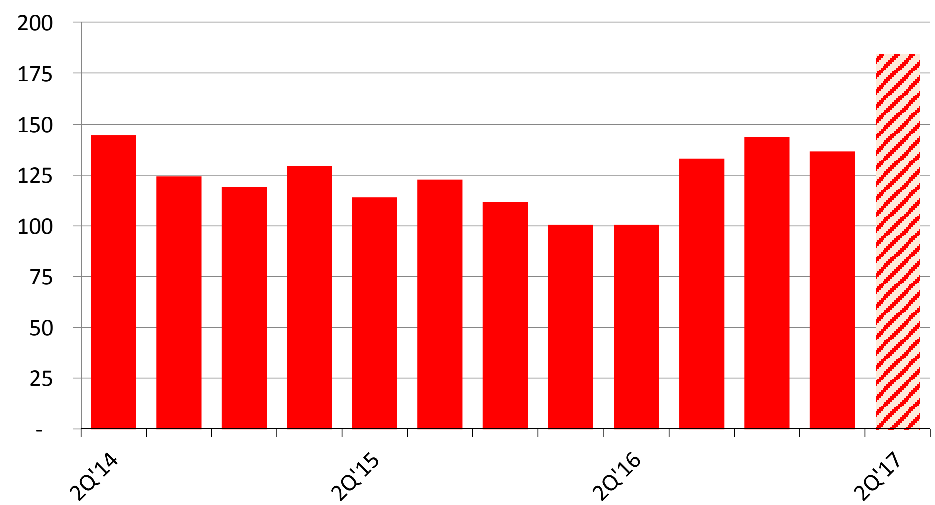
Haynesville



Profile(1)	
Net acres	48,000
Gross operated producing wells(2)	131
Average WI/average NRI	74/57% (op)
Proved reserves (Bcfe)/% liquids(3)	866 / 0%
Production Split – oil/gas/NGL	0/100/0%

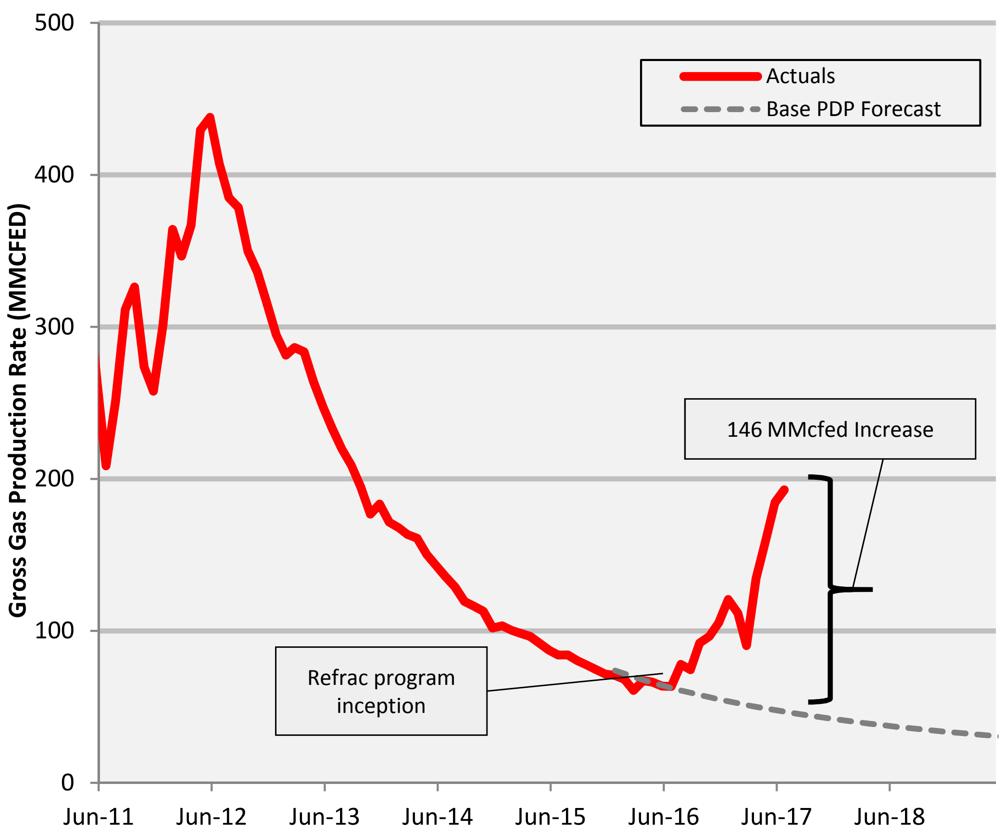
(1) As of June 30, 2017, except for reserve estimates
(2) Includes only Haynesville interval wells
(3) As of December 31, 2016, SEC Pricing

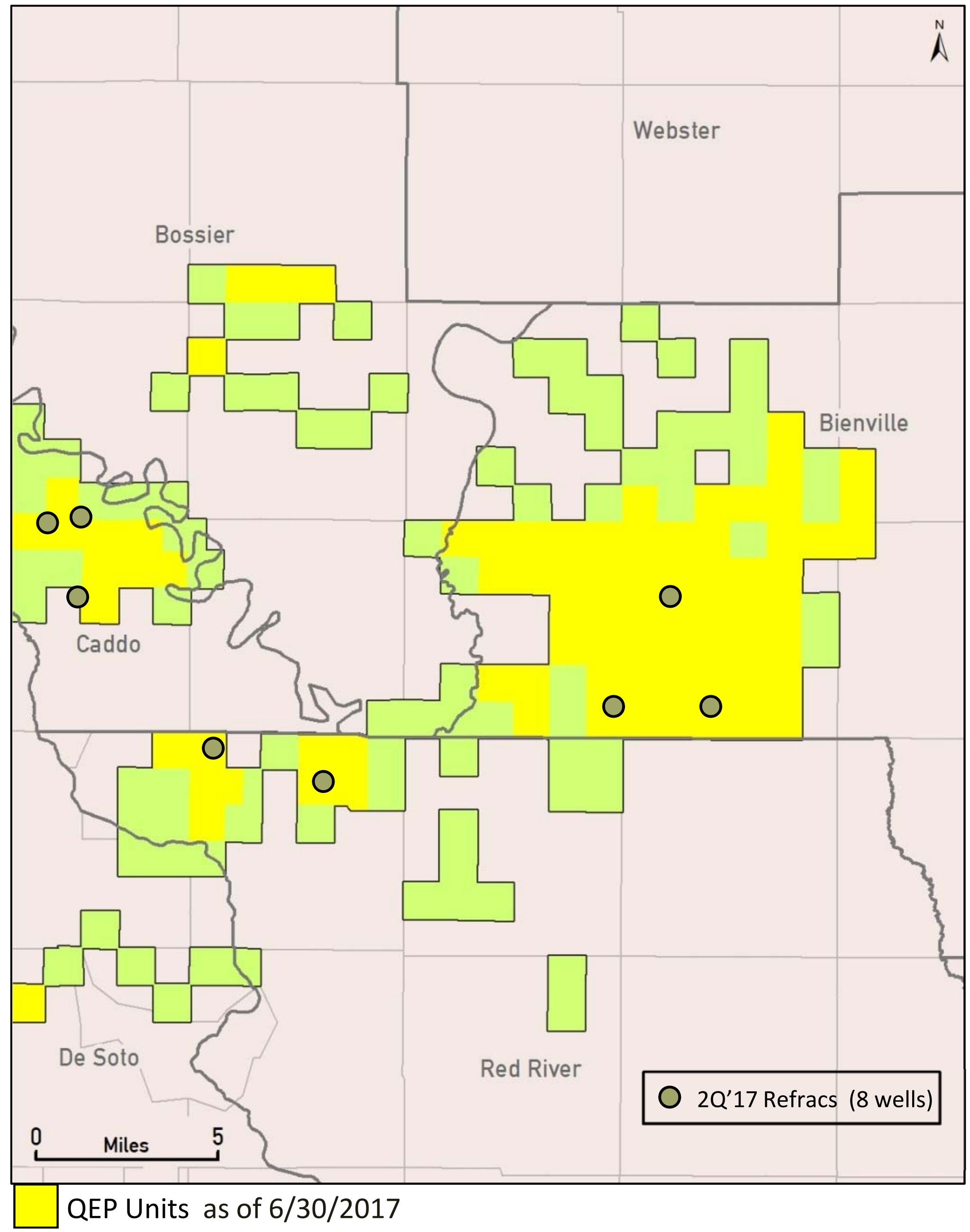
Net Production – MMcfed



Haynesville – *2Q 2017 Activity*

- Completed eight refracs
  - Average incremental 24-hour rate increase of 16.0 MMcfed per well
- Refrac program has increased Haynesville gross production by ~146 MMcfed since inception





Appendix

Permian & Williston Basins – *Detailed Well Cost Summary*

Permian Gross Well Costs (AFE)				
Area	**Target Formation**	**Lateral Length (ft.)**	**Drill & Complete ($mm)**	**Facilities & Artificial Lift ($mm)**
County Line	Spraberry Shale	7,500	$5.0	$0.8
	Spraberry Shale	10,000	$6.3	$0.8
Mustang Springs	Middle Spraberry	7,500	$5.0	$0.7
	Spraberry Shale	7,500	$5.0	$0.7
	Wolfcamp A	7,500	$6.3	$0.7
	Wolfcamp B	7,500	$6.6	$0.7

Williston Basin Gross Well Costs (AFE)				
Area	**Target Formation**	**Lateral Length (ft.)**	**Drill & Complete ($mm)**	**Facilities & Artificial Lift ($mm)**
South Antelope	Middle Bakken / Three Forks	10,000	$5.6	$0.8
FBIR	Middle Bakken / Three Forks	10,000	$6.2	$1.3

Permian Basin – *Mustang Springs Optimization & Pilot Tests*

	West Pilot Density/Section	East Pilot Density/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		

← 1 Mile →

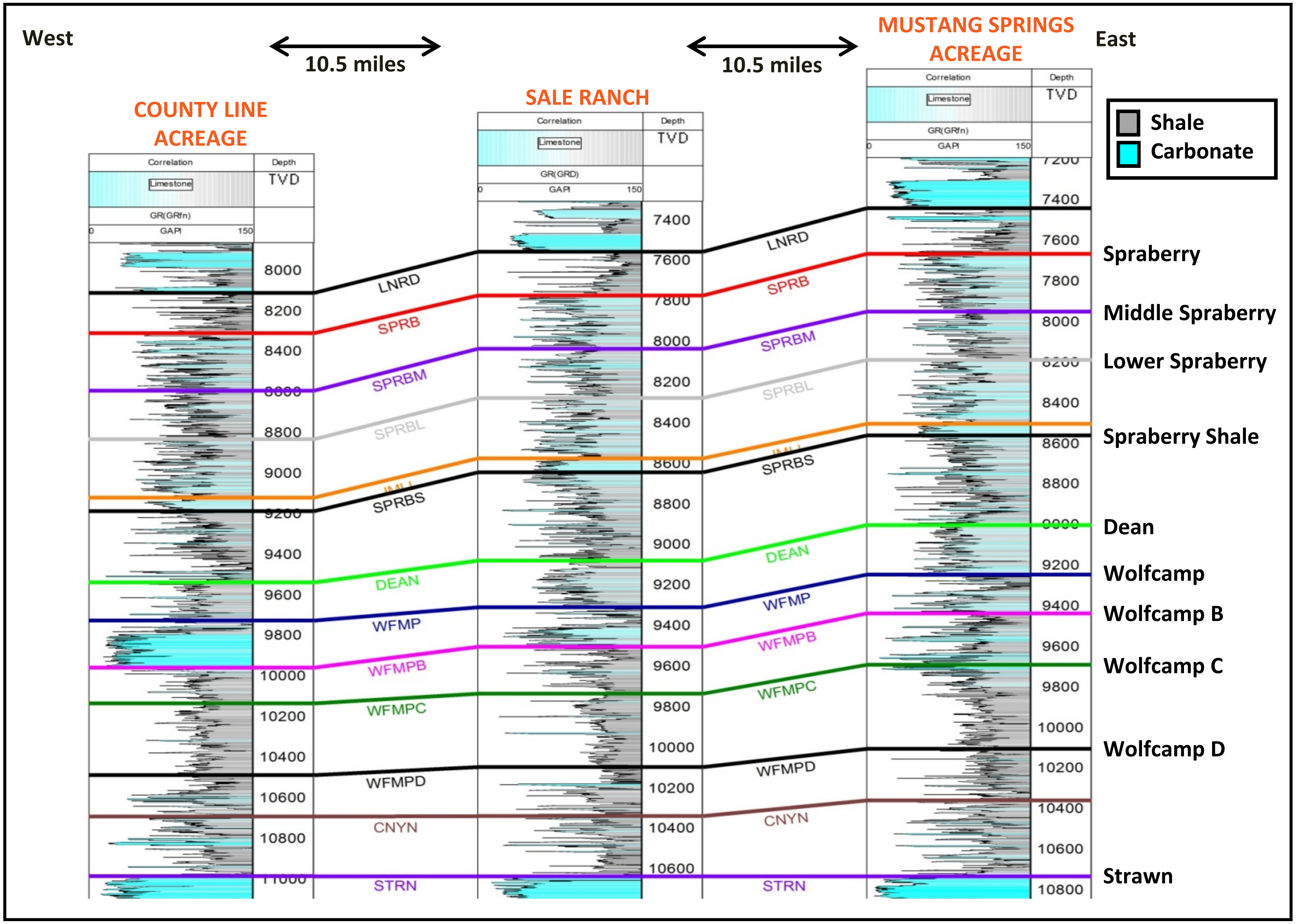
Development Optimization

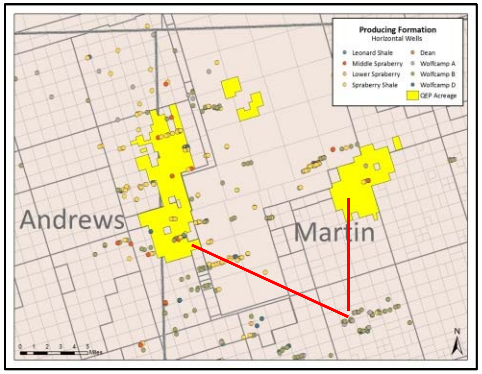
- Parent well tests
  - Provide baseline well performance in four zones MS, SS, WA and WB
- Density tests
  - Drive ultimate spacing of each reservoir and sequencing of development
  - Establish optimum drilling and completion program to maximize production and minimize well interference

Density Pilot Tests

- Two pilot tests planned
  - Evaluate a continuum of wells across all four target horizons
- West Pilot – *estimated completion August 2017*
  - Evaluate higher well density in MS & SS and lower density in WA and WB
- East Pilot – *estimated completion November 2017*
  - Evaluate higher well density in WA & WB and lower density in MS and SS

Permian Basin – *Predictable Geology Across Acreage*





County Line, Sale Ranch, and Mustang Springs acreage have similar reservoir characteristics in the Spraberry and Wolfcamp intervals

QEP Resources – *Derivative Positions*

The following tables present QEP's volumes and average prices for its open production derivative positions as of July 21, 2017:

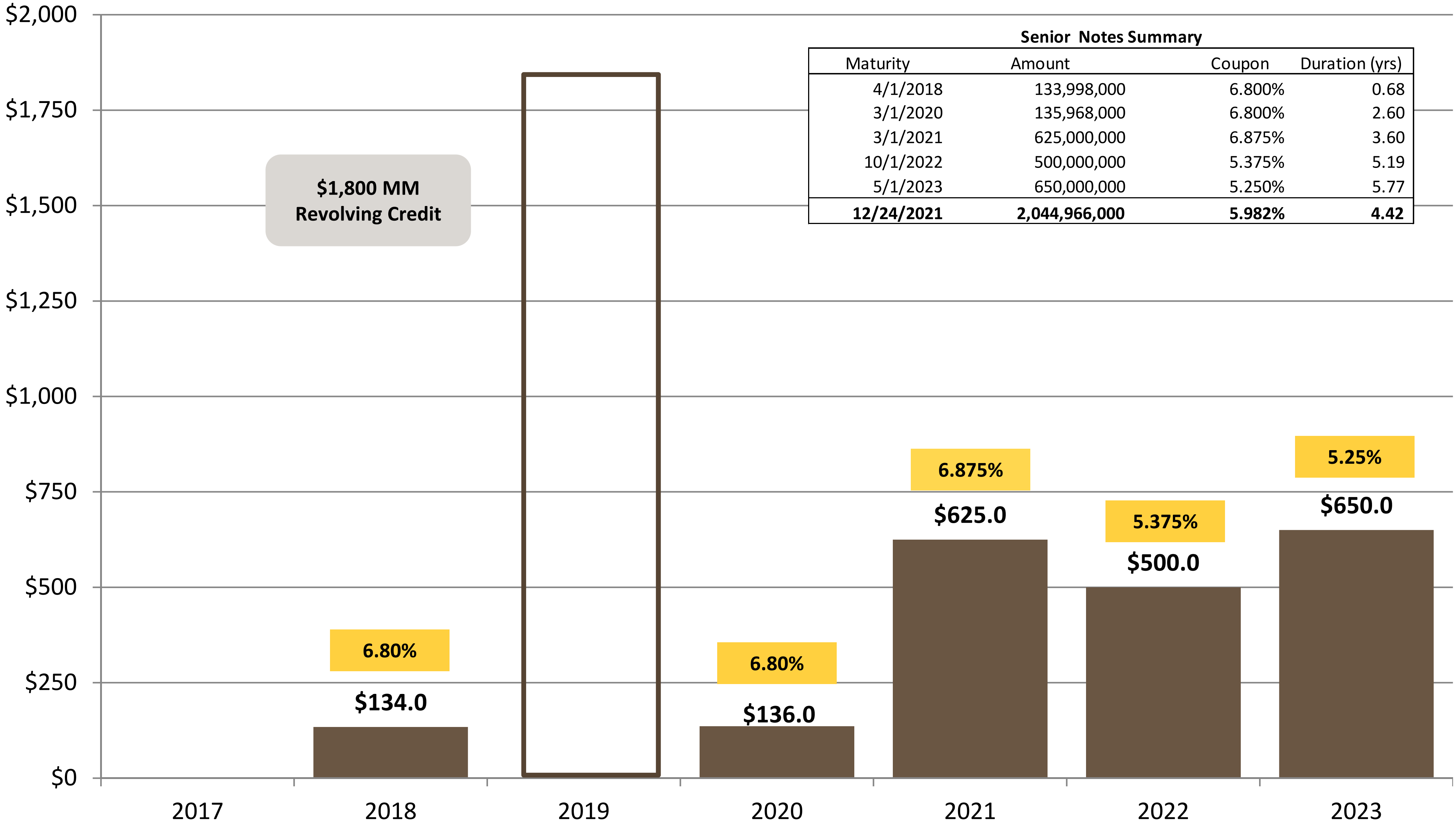
Production Commodity Derivative Swap Positions			
Year	Index	Total Volumes	Average Price per Unit
Oil Sales		**(MMBbls)**	**($/Bbl)**
2017	NYMEX WTI	7.2	$51.51
2018	NYMEX WTI	10.6	$53.22
2019	NYMEX WTI	0.4	$49.75
Gas Sales		**(million MMBtus)**	**($/MMBtu)**
2017	NYMEX HH	41.3	$2.87
2017	IFNPCR	13.8	$2.51
2018	NYMEX HH	98.6	$2.99
2019	NYMEX HH	3.7	$2.85

Production Commodity Derivative Gas Collars				
Year	Index	Total Volume (million MMbtu)	Average Price Floor ($/MMBtu)	Average Price Celing ($/MMBtu)
2017	NYMEX HH	4.6	$2.50	$3.50

Production Commodity Derivative Basis Swaps				
Year	Index less Differential	Index	Total Volumes	Weighted Average Differential
Oil Sales			**(MMBbls)**	**($/Bbl)**
2017	NYMEX WTI	Argus WTI Midland(1)	2.2	($0.67)
2018	NYMEX WTI	Argus WTI Midland(1)	6.2	($1.09)
2019	NYMEX WTI	Argus WTI Midland(1)	0.4	($1.10)
Gas Sales			**(million MMBtus)**	**($/MMBtu)**
2017	NYMEX HH	IFNPCR	21.4	($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%	0.68
3/1/2020	135,968,000	6.800%	2.60
3/1/2021	625,000,000	6.875%	3.60
10/1/2022	500,000,000	5.375%	5.19
5/1/2023	650,000,000	5.250%	5.77
12/24/2021	**2,044,966,000**	**5.982%**	**4.42**

QEP Resources – *Estimated Proved Reserves*

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**

Total Costs Incurred (December 31, 2016)	($MM)
Proved Property Acquisitions	$431.6
Unproved Property Acquisitions	$208.7
Exploration (capitalized and expensed)	$13.4
Development	$509.2
Total Costs Incurred	**$1,162.9**

(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 (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%	5%
Other Northern	12.3	2%	0%	6%
Southern Region				
Permian Basin	147.8	20%	81%	88%
Haynesville/Cotton Valley	144.3	20%	74%	0%
Other Southern	-	0%	0%	0%
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%	0%	8%
Southern Region				
Permian Basin	62.4	10%	66%	87%
Haynesville/Cotton Valley	66.1	11%	57%	0%
Other Southern	0.9	0%	0%	32%
Total Proved Reserves	**603.4**	**100%**	**42%**	**42%**