Investor Presentation

April 2019

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; guidance for second quarter 2019 and fiscal 2019 production; guidance for 2019 Lease Operating and Adjusted Transportation & Processing Expense per Boe, DD&A per Boe, production and property taxes as a percentage of revenue, non-cash share-based compensation expense, restructuring expense, and capital investment; assumptions related to our guidance; guidance for general and administrative expense for 2019 and 2020 and components thereof; reduction of G&A expense to less than $3.00 per BOE by 2020; and optimizing the Company’s cost structure.

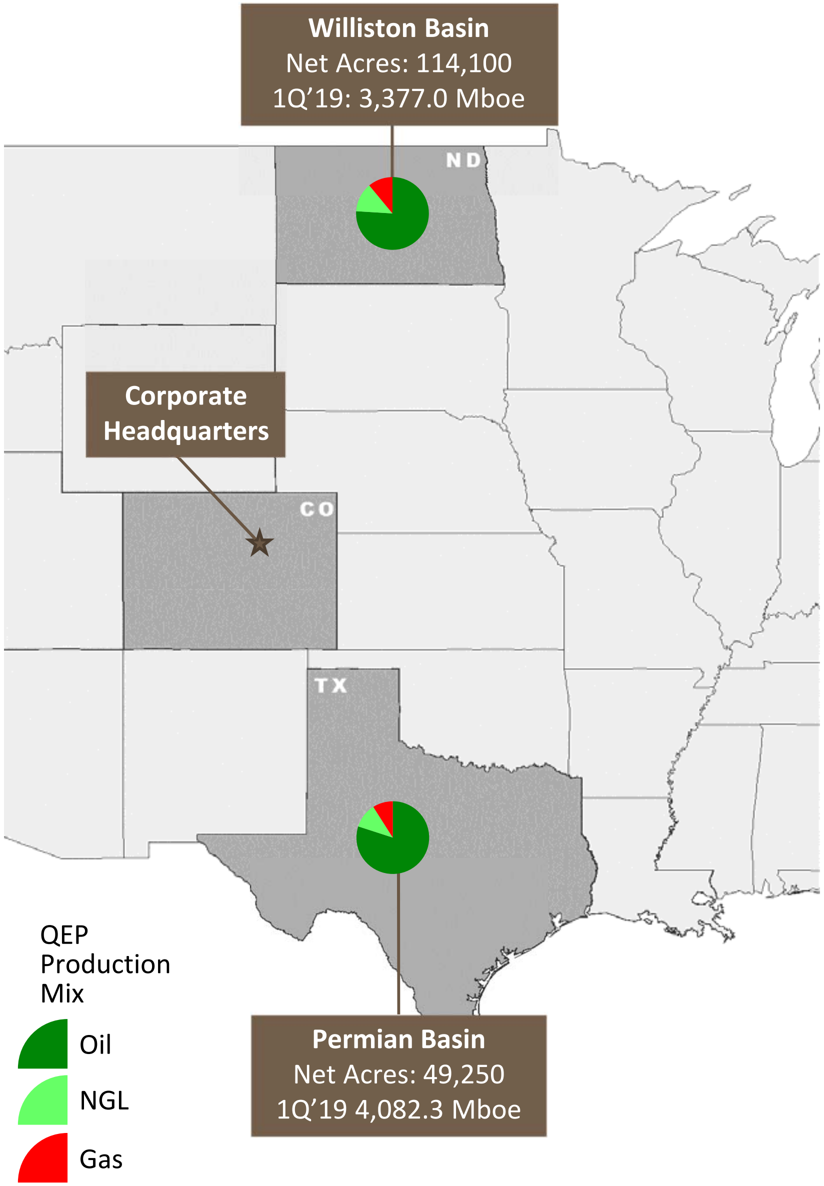
Actual results may differ materially from those included in the forward-looking statements due to a number of factors, including, but not limited to: the availability and cost of capital; actions of activist shareholders; results from our review of strategic alternatives; changes in local, regional, national and global demand for oil, natural gas, and NGL; oil, natural gas and NGL prices; market conditions; value of the U.S. dollar; actions of federal, state, local and tribal governments, foreign countries and the Organization of Petroleum Exporting Countries; timing of and actual proceeds from asset sales; tariffs on products QEP uses in its operations or sells; changes in, adoption of and compliance with laws and regulations, including those related to taxes (including decisions, policies and guidance concerning taxes), the environment, climate change, greenhouse gas or other emissions, renewable energy mandates, 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; 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; transportation constraints, including gas and crude oil pipeline takeaway capacity in the Permian Basin; technological advances affecting energy supply and consumption; competition from the same and alternative sources of energy; natural disasters; creditworthiness of counterparties to agreements; 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, 2018. 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. “EURs” or “estimated ultimate recoveries” refer to QEP’s internal estimates of hydrocarbon quantities that may be potentially recovered and are not proved, probable or possible reserves within the meaning of the rules of the SEC. Probable and possible reserves and EURs 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; actions of lessors and surface owners; transportation constraints, including gas and crude oil pipeline takeaway capacity; 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 Form 10-K.

QEP refers to Adjusted Transportation & Processing Expense, Special G&A Expense 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, as applicable, see the recent earnings press release and SEC filings at the Company’s website at www.qepres.com under “Investor Relations.”

1Q 2019 Operational Overview

Asset Overview[1]



1Q 2019 Highlights

- Total Net Equivalent Production: 7,806.3 Mboe
  - Oil Production: 5,083.6 Mbbl
  - Gas Production: 9.2 Bcf
  - NGL Production: 1,178.8 Mbbl
- Permian Basin
  - Net Equivalent Production: 4,082.3 Mboe
    - Oil Production: 2,914.5 Mbbl
    - Gas Production: 3.4 Bcf
    - NGL Production: 599.9 Mbbl
  - Placed 12 gross wells on production
- Williston Basin
  - Net Equivalent Production: 3,377.0 Mboe
    - Oil Production: 2,158.0 Mbbl
    - Gas Production: 3.8 Bcf
    - NGL Production: 578.8 Mbbl
  - Spudded seven well Vegas pad on South Antelope
    - Initial production expected in 4Q 2019

(1) Excludes equivalent production of 347.0 Mboe from Hayneville/Cotton Valley, Other Northern & Other Southern regions.

2019 Updated Guidance[1]

	2Q 2019 Guidance	2019 Updated Guidance
Oil & Condensate Production (MMBbl)	4.95 - 5.15	20.5 - 21.5
Gas Production (Bcf)	5.4 - 5.8	25.5 - 27.5 ↑
NGL Production (MMBbl)	0.9 - 1.1	3.7 - 4.2
Total oil equivalent production (MMBoe)	6.8 - 7.2	28.5 -30.3 ↑
Lease operating expense and Adjusted Transportation & Processing Costs (per Boe)		$9.00 - $10.00
Depletion, depreciation and amortization (per Boe)		$16.75 - $17.75
Production and property taxes (% of field-level revenue)		7.0%
(in millions)		
General and administrative expense[2]		$165 - $175 ↓
Capital investment (excluding property acquisitions)		
Drilling, Completion and Equip[3]		$540 - $590
Midstream Infrastructure[4]		$70
Corporate		$5
Total Capital Investment (excluding property acquisitions)	**$185 - $205**	**$615 - $665**
Wells put on production (net)	**23**	**63 - 65** ↑

(1) As of April 24, 2019: The Company's second quarter and full year 2019 guidance assumes: (1) an oil price of $55 per barrel and a natural gas price of $2.75 per MMBtu, (2) that QEP will elect to recover ethane from its produced gas in the Permian Basin where processing economics support it, (3) no property acquisitions or divestitures, other than the Haynesville / Cotton Valley Divestiture and (4) includes approximately 10 days of production activity in the Haynesville / Cotton Valley, which was excluded from previous guidance.

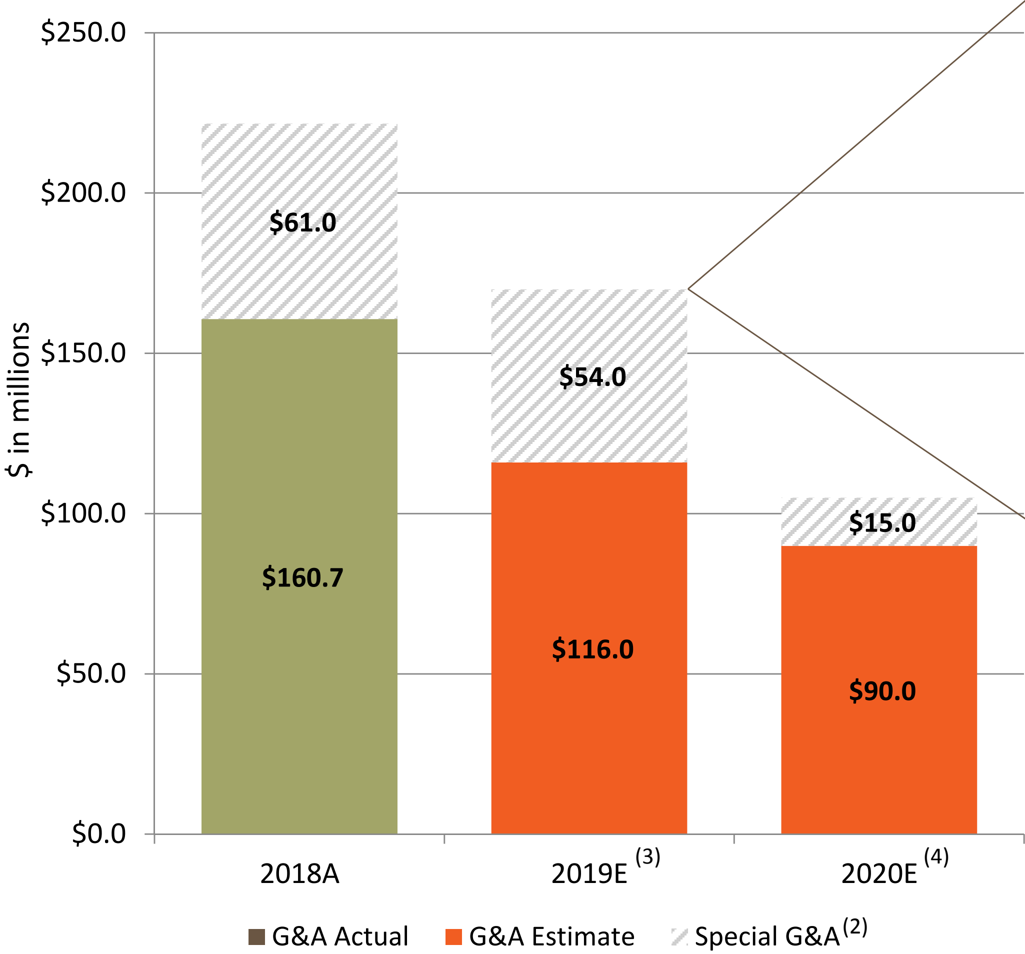
(2) The mid-point general and administrative expense includes approximately $35.0 million of expenses related to non-cash, share-based compensation and other mark-to-market liabilities. Because these mark-to-market liabilities fluctuate with stock price changes, the amount of actual expense may vary from the forecasted amount. The mid-point general and administrative expense also includes approximately $54.0 million of estimated expenses related to our strategic initiatives, primarily related to severance and retention agreements and includes approximately $11.0 million of accelerated shared-based compensation expense that is included in the $35.0 million of expenses related to non-cash, share-based compensation and other mark-to-market liabilities.

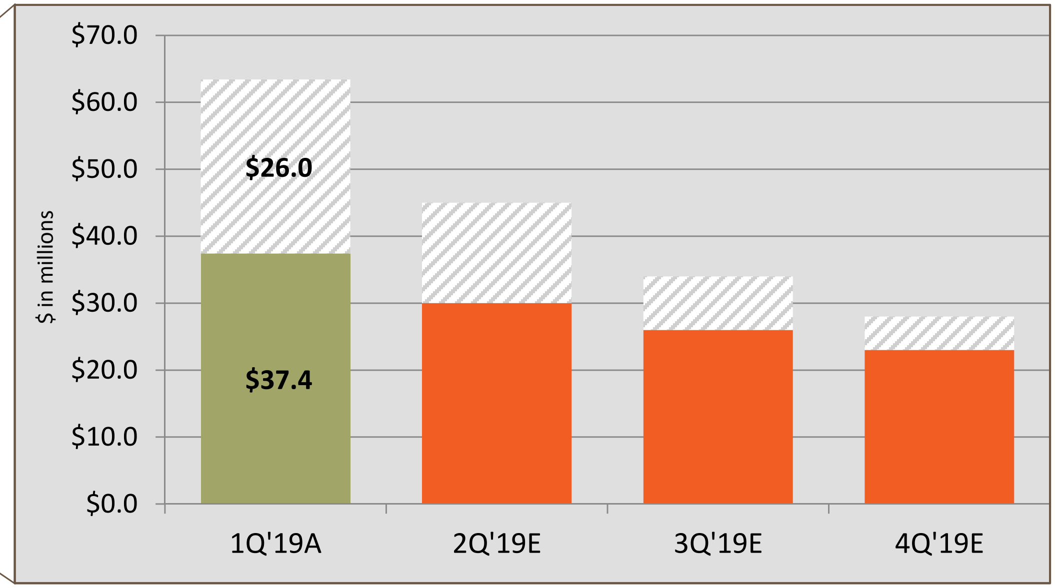
(3) Drilling, Completion and Equip includes approximately $37.0 million of non-operated well costs.

(4) Includes capital expenditures in the Permian Basin associated with (a) water sourcing, gathering, recycling and disposal and (b) crude oil and natural gas gathering systems.

2019 Corporate Overhead Reset

QEP is Focused on Optimizing Its Cost Structure





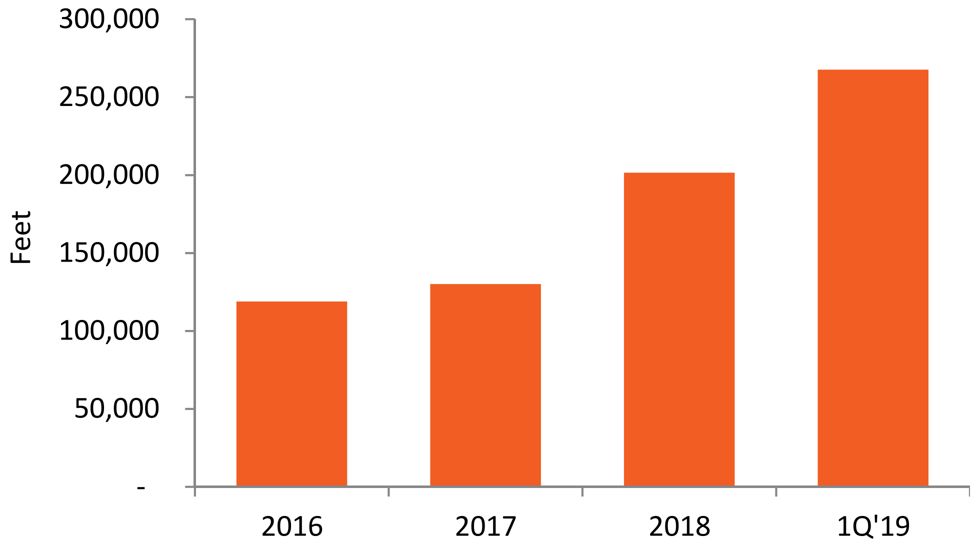
- Reduce “normalized” expense by 45% from YE18 to 2020
- Reduce staff by 60% from March 2018 to July 2019
- Reduce IT systems and support costs by >$10mm
- Close Salt Lake City office and consolidate Denver Corporate Headquarters
- Sell corporate aircraft

QEP Expects to Decrease General & Administrative Expense (G&A)(1) to Less Than $3.00 per BOE by 2020

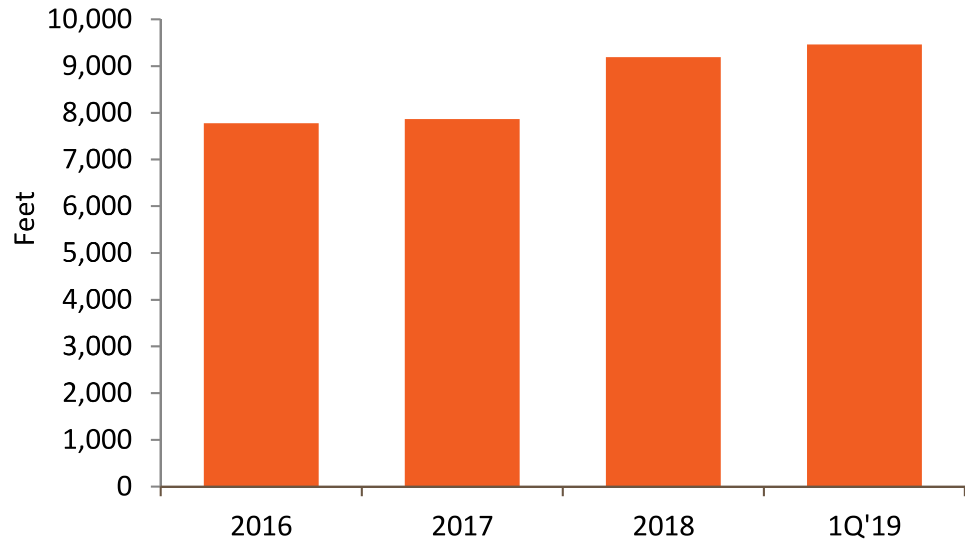
(1) G&A includes cash and non-cash share based compensation expense and does not include any mark-to-market liabilities
(2) Special G&A includes estimated expenses related to restructuring costs, primarily severance and retention agreements
(3) 2019E represents the midpoint of guidance as of April 24, 2019
(4) $90 million G&A expense represents the 2020E target at less than $3.00 per BOE

Continuous Capital Efficiency Improvement in Permian Basin

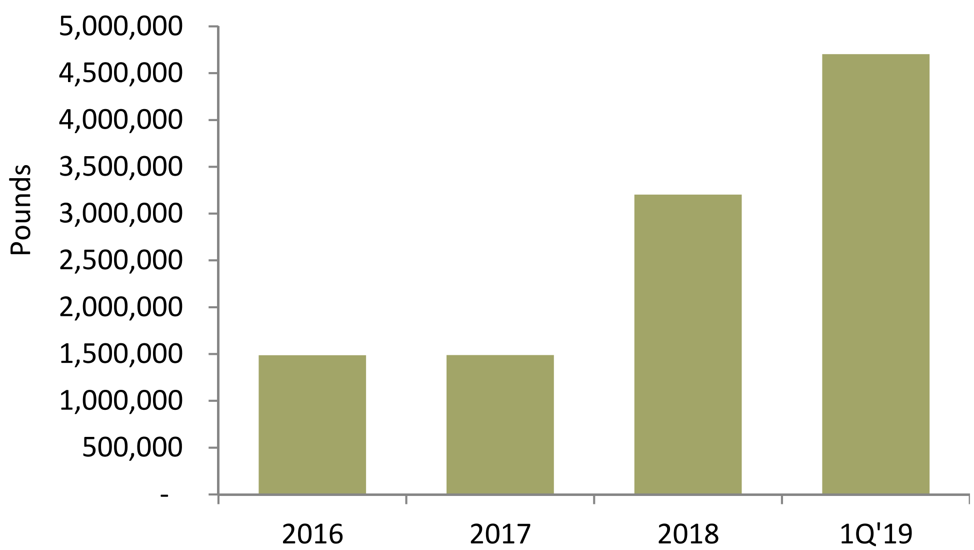
Lateral Footage Drilled per Year per Rig



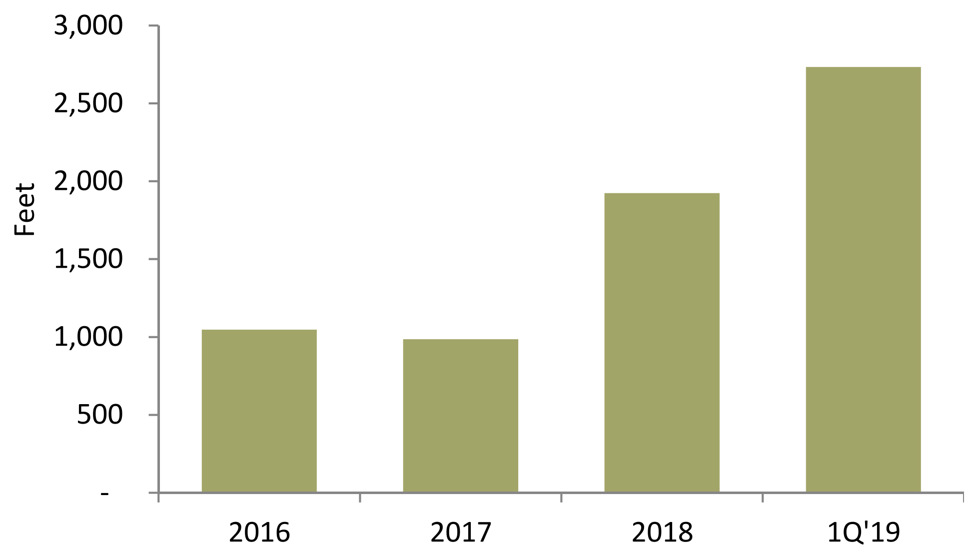
Average Drilled Lateral Length



Average Proppant Placed per Day per Frac Crew

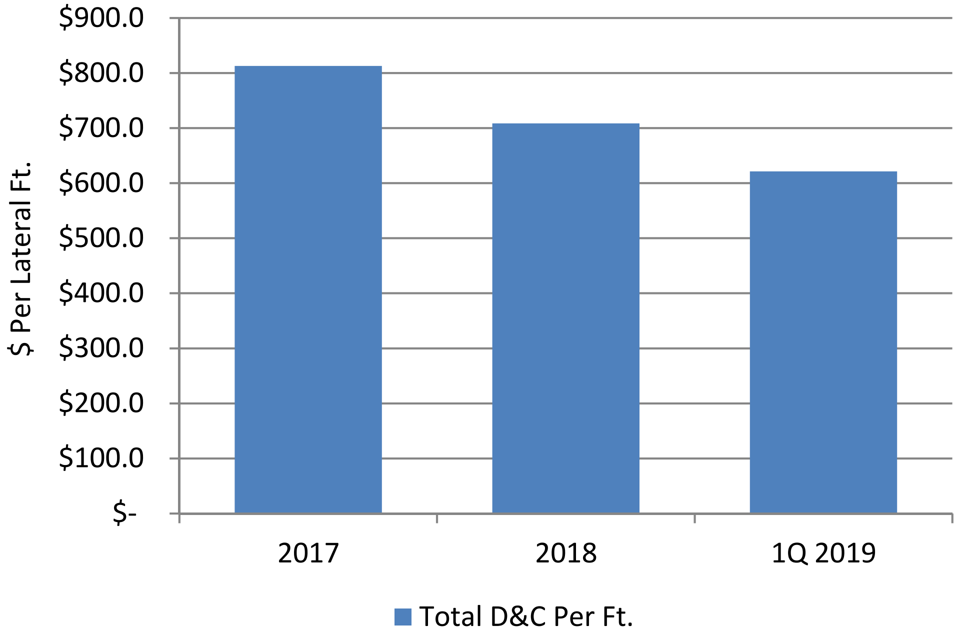


Lateral Length Completed per Day per Frac Crew

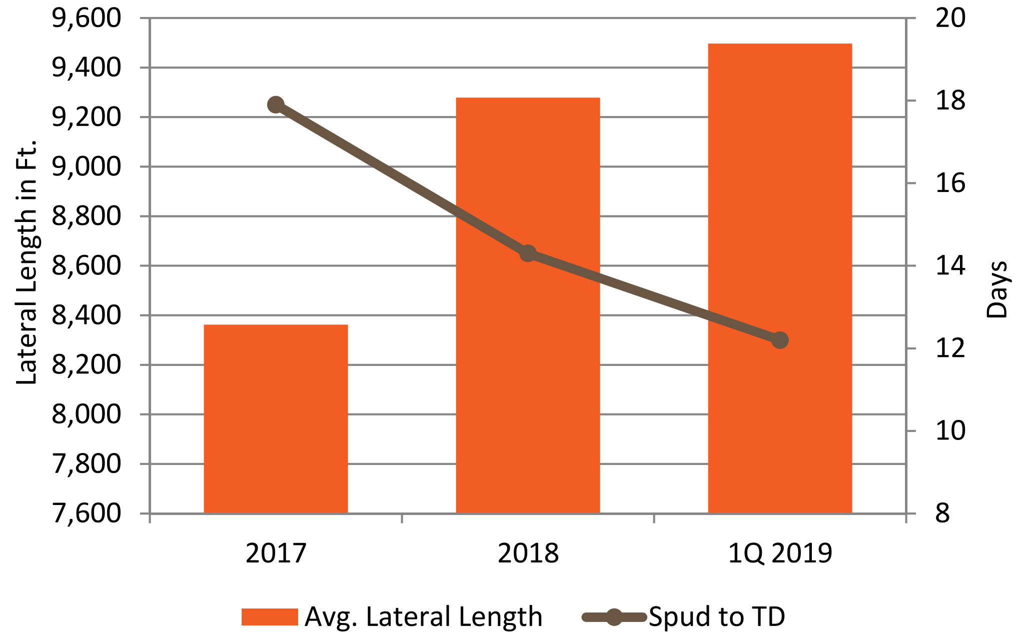


Continuous Capital Efficiency Improvement in Permian Basin

Drilling & Completion Cost Improvement



Longer Laterals / Shorter Drill Times



QEP Continues to Achieve Significant Operational Improvements in the Permian Basin

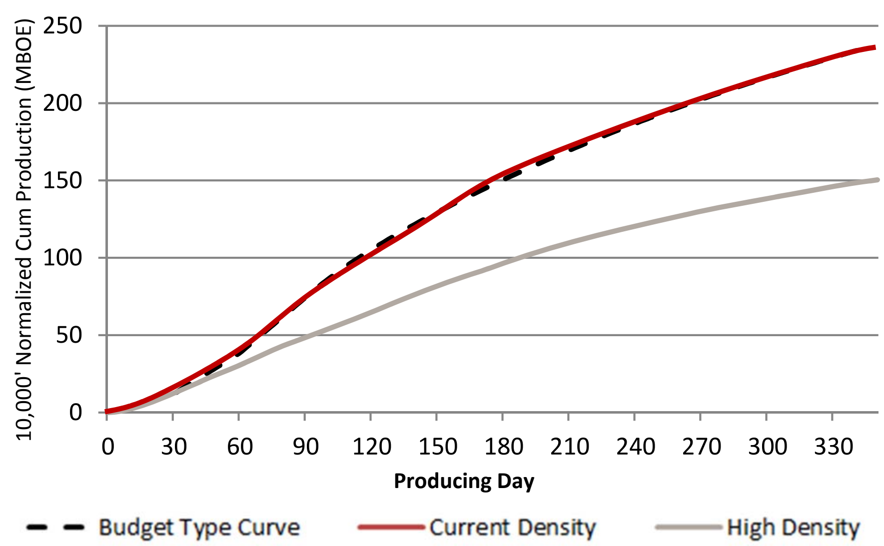
- Drilling & completion efficiencies have significantly lowered well costs
  - Bit and mud optimization to increase penetration rate
  - Full utilization of in-basin sand
  - Increased recycled water usage
  - Increased pump rate and perforation optimization

Current Density Wells (Drilled 2H'17 to Present) Delivering as Expected

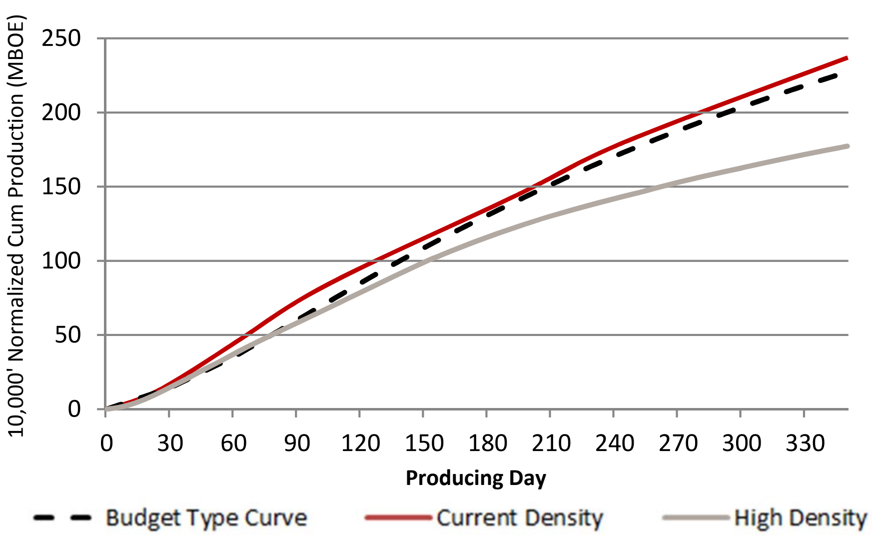
Permian Basin Density

- Current Density(1) development DSU's are outpacing High Density(2) test DSU's well performance
- Current Density results are in-line with budgeted type curves
- Majority of near term development expected to be in Spraberry Shale, Wolfcamp A and Wolfcamp B
- Tank Style development leading to consistent, repeatable, high-return wells
  - Parent/Child issues not a concern with Tank Style development

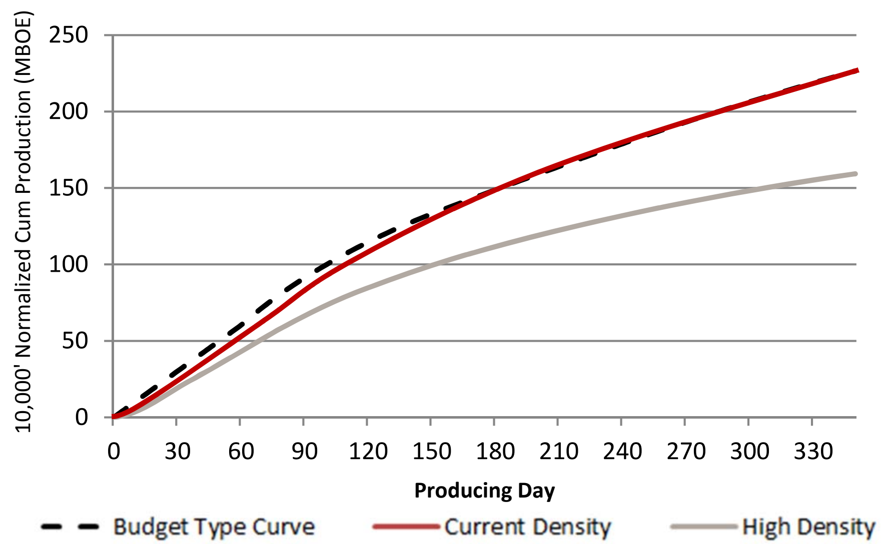
Spraberry Shale



Wolfcamp A



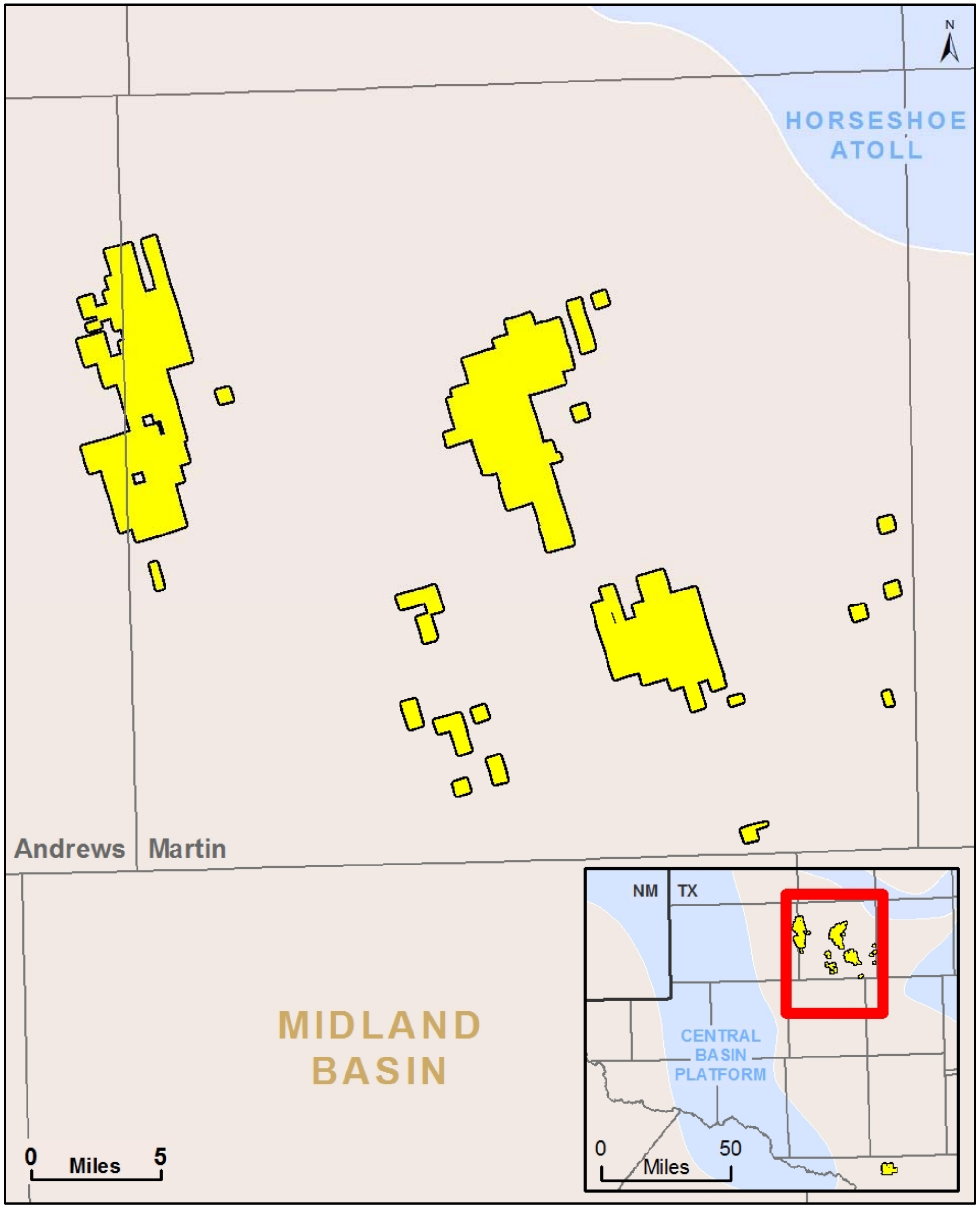
Wolfcamp B



(1) Current Density spacing – Spraberry Shale 8 wells per mile; Wolfcamp A 6 wells per mile; Wolfcamp B 7 wells per mile
(2) High Density spacing – Spraberry Shale 14 wells per mile; Wolfcamp A 8 wells per mile; Wolfcamp B 14 wells per mile

Asset Overview

Midland Basin



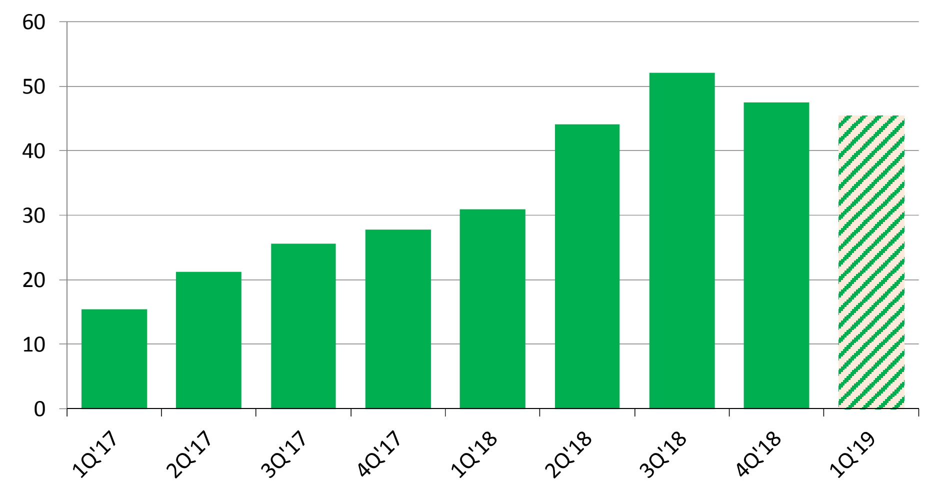
QEP Acreage as of 3/31/2019

Profile[1]

Net acres[2]	49,250
Gross operated producing wells (Vertical/Horizontal)	487/243
Average WI/average NRI	96 / 73%
Proved reserves (MMboe)/% liquids[3]	308 / 87%
Production Split – oil/gas/NGL	71/14/15%
Rig Count	3

(1) As of March 31, 2019
(2) Includes Crockett County leasehold
(3) As of December 31, 2018, SEC Pricing

Net Production - Mboed

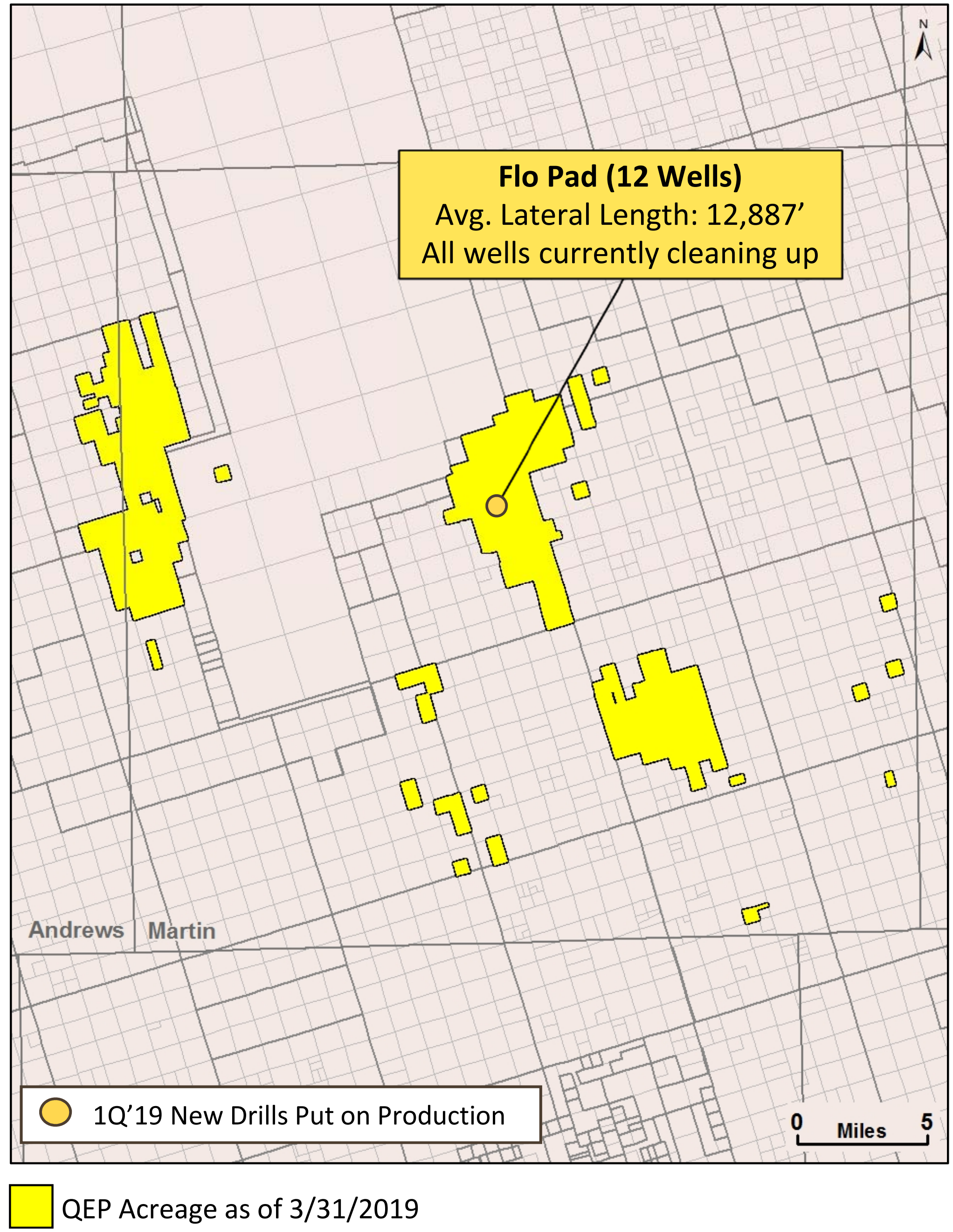


Midland Basin – 1Q 2019 Activity

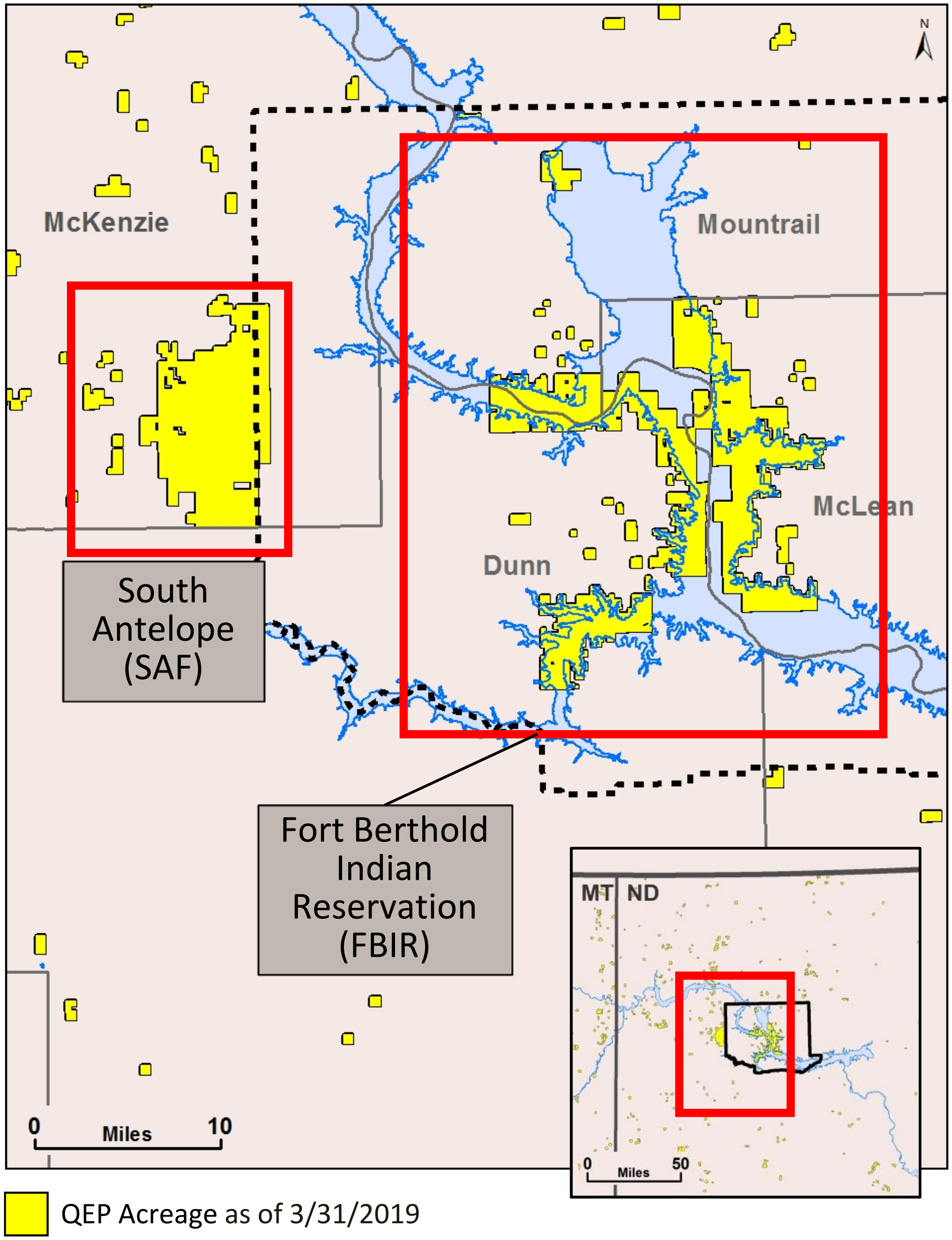
Well Progress (as of March 31, 2019)	Gross	Net
Drilling	11	11.0
At total depth – under drilling rig	3	3.0
Waiting to be completed	28	28.0
Undergoing completion	4	4.0
Completed, awaiting production	11	11.0
Waiting on completion	46	46.0
Put on production[1]	12	12.0

[1] Total wells put on production during the quarter ended March 31, 2019

- 12 wells put on production in 1Q 2019
  - All wells on Mustang Springs
  - First 12,500' spacing unit test
  - All wells still cleaning up



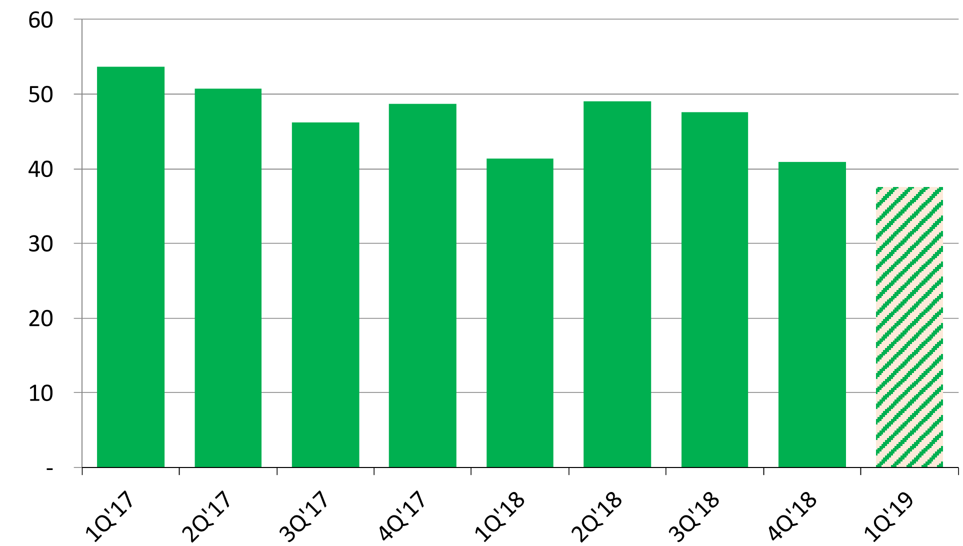
Williston Basin



Profile[1]	
Net acres	114,100
Gross operated producing wells	394
Average WI/average NRI	86/69%
Proved reserves (MMboe)/% liquids[2]	167 / 85%
Production Split – oil/gas/NGL	64/19/17%

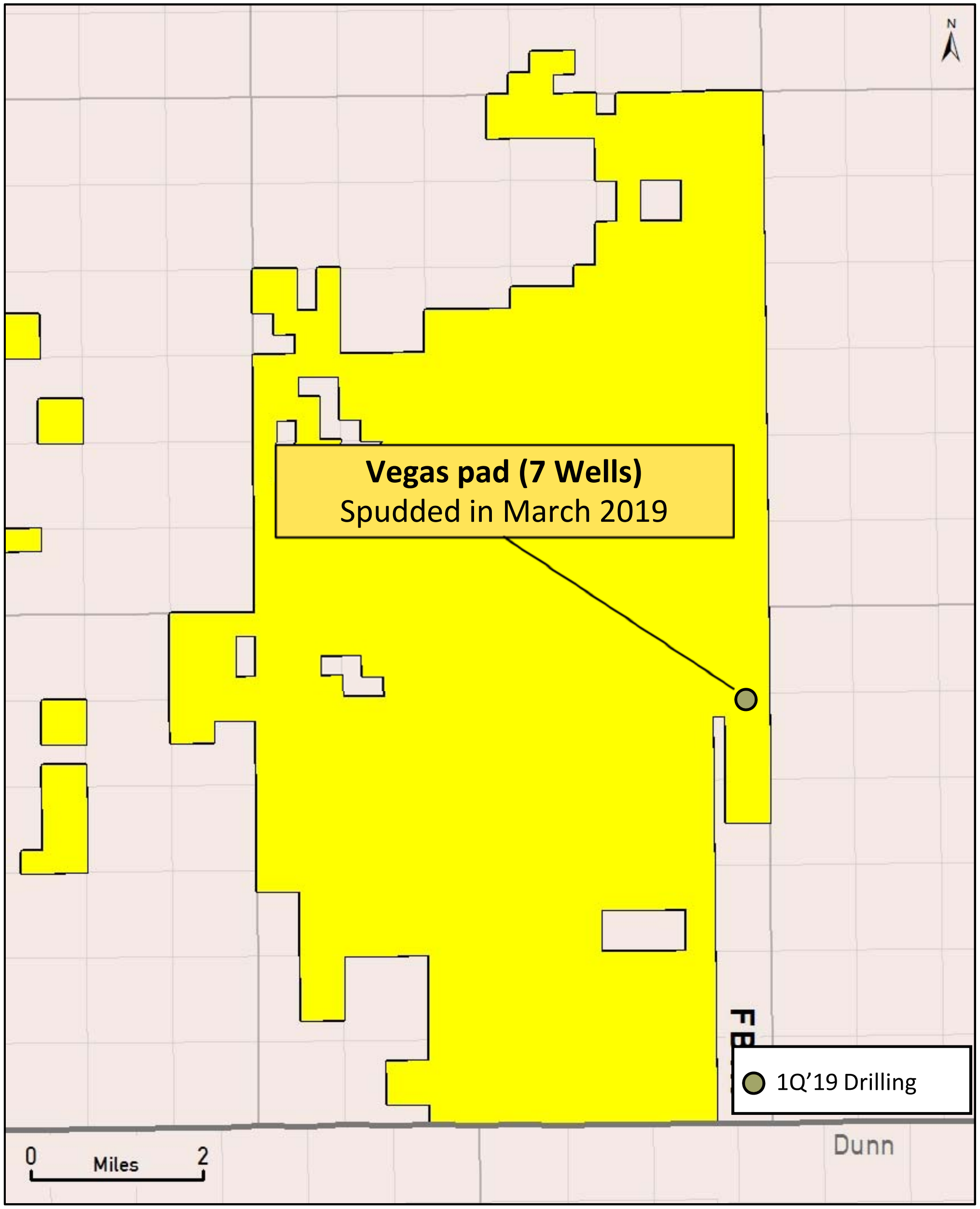
[1] As of March 31, 2019
[2] As of December 31, 2018, SEC Pricing

Net Production - Mboed



Williston Basin – South Antelope 1Q 2019 Summary & Activity

- Spudded seven well Vegas pad
  - Initial production expected in 4Q 2019



QEP Acreage as of 3/31/2019

Appendix

Derivative Positions

The following tables present QEP's volumes and average prices for its open production derivative positions as of April 19, 2019:

Production Commodity Derivative Swaps			
Year	**Index**	**Total Volumes**	**Average Swap Price per Unit**
Oil Sales		(MMBbls)	($/Bbl)
2019	NYMEX WTI	9.5	$54.93
2019	ICE Brent	1.4	$66.73
2019 (May through December)	Argus Houston MEH	0.2	$65.70
2020	NYMEX WTI	5.5	$60.01
2020	Argus WTI Midland	0.4	$60.00

Production Commodity Derivative Basis Swaps				
Year	**Index less Differential**	**Index**	**Total Volumes**	**Weighted Average Differential**
Oil Sales			**(MMBbls)**	**($/Bbl)**
2019	NYMEX WTI	Argus WTI Midland	5.0	($2.22)
2019	NYMEX WTI	Argus WTI Houston	0.6	$3.75
2020	NYMEX WTI	Argus WTI Midland	2.6	($0.46)

(1) Argus WTI Midland is an index price reflecting the weighted average price of WTI at the pipeline and storage hub at Midland, TX.
(2) Argus WTI Houston is an index price reflecting the weighted average price of WTI at Magellan's East Houston crude oil terminal.