QEP RESOURCES®

Investor Presentation

June 2018

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: planned strategic initiatives; transition to a pure-play Permian Basin company; concentration on core Permian asset and benefits of such concentration; marketing and divestiture of assets; use of proceeds from asset sales; reaching cash flow neutrality in 2019; factors impacting share repurchases; delivering strong production growth; reducing drilling and completion cost, operating cost and F&D cost per boe; expanding operating margins and returns on invested capital; advancing simultaneous development; percentage of 2018 drilled wells with 10,000 foot laterals; timing and total number of wells put on production; 2018 netback per boe; estimated LOE and Adjusted transportation expenses and decreases in the total of such expenses; growth in production; estimated proved reserves; estimated production split among oil, gas and NGL; large upside opportunity in proven and unproven zones; capital costs and pros and cons of ESP and gas lift installation; water recycling capacity and disposal in the Midland Basin and benefits of water infrastructure; benefits of centralized infrastructure; stacked pay opportunity across core Permian acreage position; amount and allocation of capital investment; number, and lateral lengths of, potential future horizontal drilling locations; number and location of drilling rigs; benefits of tank-style development; maximizing economic recovery of oil and capital efficiency; minimizing risk of interference and shut-in times; quarterly and annual guidance regarding production and net wells; guidance for 2018 LOE and Adjusted transportation expense, DD&A, production and property taxes, general and administrative expense, non-cash share-based compensation expense, retention program 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; market conditions; actual proceeds from asset sales; actions of activist shareholders; changes in, adoption of and compliance with laws and regulations, including decisions, policies and guidance concerning taxes, 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; 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; actions of operators on properties where we own an interest but are not the operator; 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, 2017 (the “2017 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. “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; 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 2017 Form 10 K.

QEP refers to F&D Costs per Boe, Adjusted transportation expense, netback 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.”

QEP Resources – *2018 Strategic Initiatives*

In February 2018, QEP's Board of Directors unanimously approved certain Strategic Initiatives to transition to a pure-play Permian Basin company

- Divest of the Company's Williston and Uinta basin assets
- Market remaining non-Permian assets, including the Haynesville/Cotton Valley, in the second half of 2018
- Use proceeds from asset sales to fund Permian Basin development program, until the program reaches operating cash flow neutrality in 2019, reduce debt and return cash to shareholders through share repurchases
- Authorized a $1.25 billion share repurchase program[(1)]

Today our Permian assets consist of approximately 44,430 net acres in the core of the northern Midland Basin, which delivered 2.8 MMBoe of net production in 1Q 2018 with estimated total proved year-end 2017 reserves of 272.7 MMboe

(1) Subject to available liquidity, market conditions and proceeds from asset sales.

QEP Resources – *Pure-Play Permian Basin Company*

- **Concentrating our efforts on our core Permian assets**
  - Contiguous 44,430 net acres in the core of the northern Midland Basin
    - *Avg. WI 96%/ NRI 73%*
  - Oil production growth of over 85% at the midpoint in 2018
  - Anticipated benefits:
    - Achieves operating cash flow neutrality in 2019(1) while delivering strong production growth
    - Reduces drilling & completion cost, operating cost and F&D cost per Boe(2)
    - Expands operating margins and improves returns on invested capital

- **Advancing the simultaneous development of our stacked pay utilizing "tank-style" completions, which we believe:**
  - Maximizes the economic recovery of oil
  - Maximizes capital efficiency through shared surface facilities and service logistics
  - Minimizes risk of interference with and shut-in times of offset producing wells

Pure-play Permian company delivering strong returns for our shareholders

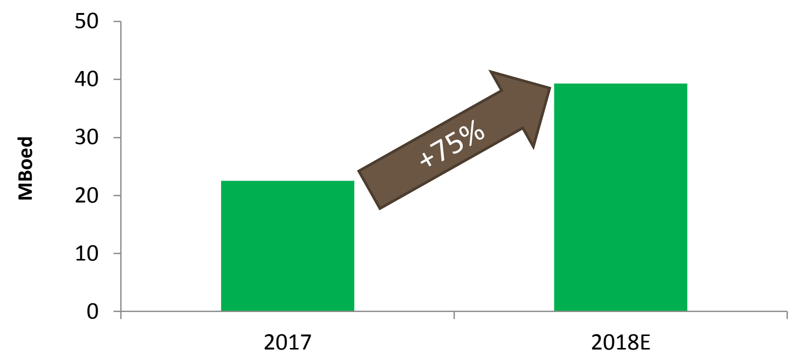
(1) Defined as capital expenditures being approximately equal to operating cash flow.
(2) Management defines F&D Cost (a non-GAAP measure) as total costs incurred (an unaudited GAAP measure) divided by the sum of revisions of previous reserve estimates, extensions and discoveries and purchases of reserves in place.

Midland Basin – *Outlook*

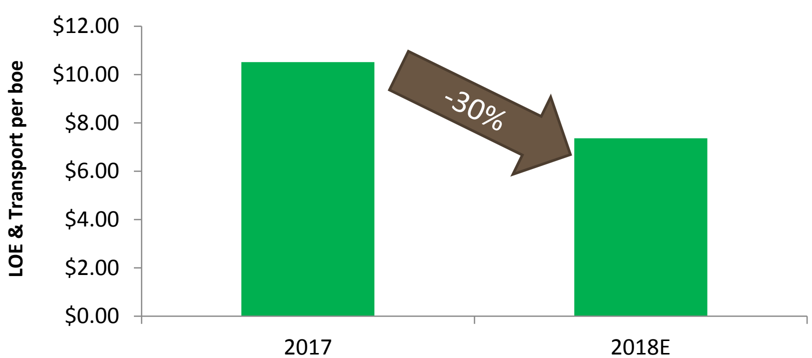
2018 Key Statistics

- Average of four and one-half operated rigs
- $725 - $775 million in drilling and completion capital
- $45 - $55 million of infrastructure capital
- Up to 1,900 potential future horizontal drilling locations of 7,500' to 12,500' lateral length
- Over 40% of wells put on production in 2018 to have 10,000'+ laterals
- ~$40 per Boe 2018 netback at current strip pricing(1)

Production Profile



LOE and Transportation Expense Target



2018 Outlook

	1Q18 *Actual*	2Q18	3Q18	4Q18	2018
Net Production ***(MMboe)***	*2.8*	3.4 – 3.6	3.8 – 4.2	3.9 – 4.3	13.9 – 14.8
Net Wells ***(Put on Production)***	*31*	33	24	16	104
Capex – D&C ***($ in millions)***					$725 - $775
Capex – Infrastructure ***($ in millions)***					$45 - $55

Assuming $55 / bbl and $3 / MMbtu, we expect the Midland Basin assets to achieve operating cash flow neutrality in 2019, while delivering strong production growth

(1) Netback (a non-GAAP measure) is calculated as oil, natural gas and NGL sales less royalties, production taxes, cash operating expenses and transportation cost and excludes the impact of hedges.

Midland Basin – *Crude Oil Marketing Strategy*

Methodology

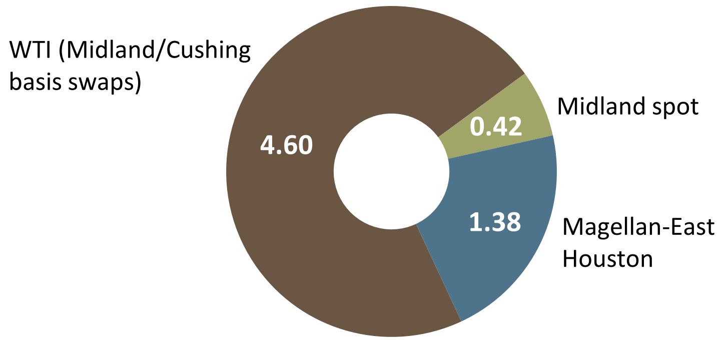
- Utilize "back-to-back" physical sales that secure takeaway without firm pipeline commitments
  - Enter into term physical sales agreements with refiners and marketers holding firm capacity on existing and new pipelines to Gulf Coast and Mid-Continent
  - Spread counterparty risk/concentration while also maximizing economics and flow assurance
- Controlling gathering to local trading points allows QEP to benefit from producing premium crude oil (38-40 API gravity, ultra low sulfur content "neat barrel")
- Physical sales strategy complements QEP's derivative strategy[2]

Physical Sales Summary[(1)]

- More than 95% of 2018 and 2019 QEP marketed Permian oil production has dedicated/firm takeaway capacity
  - Term sales (2 years) to large counterparties who hold firm capacity on interstate/intrastate pipelines
  - WTI Midland (Argus)
  - Magellan-East Houston (MEH)
  - Evergreen deals

Oil Market Price Exposure (MMBbls)

Jul – Dec 2018



2019

- WTI (Midland/Cushing basis swaps)
  - 4.75 MMBbls at ($0.77)
- Magellan-East Houston
  - 2.74 MMBbls
- Midland spot
  - Remaining volumes

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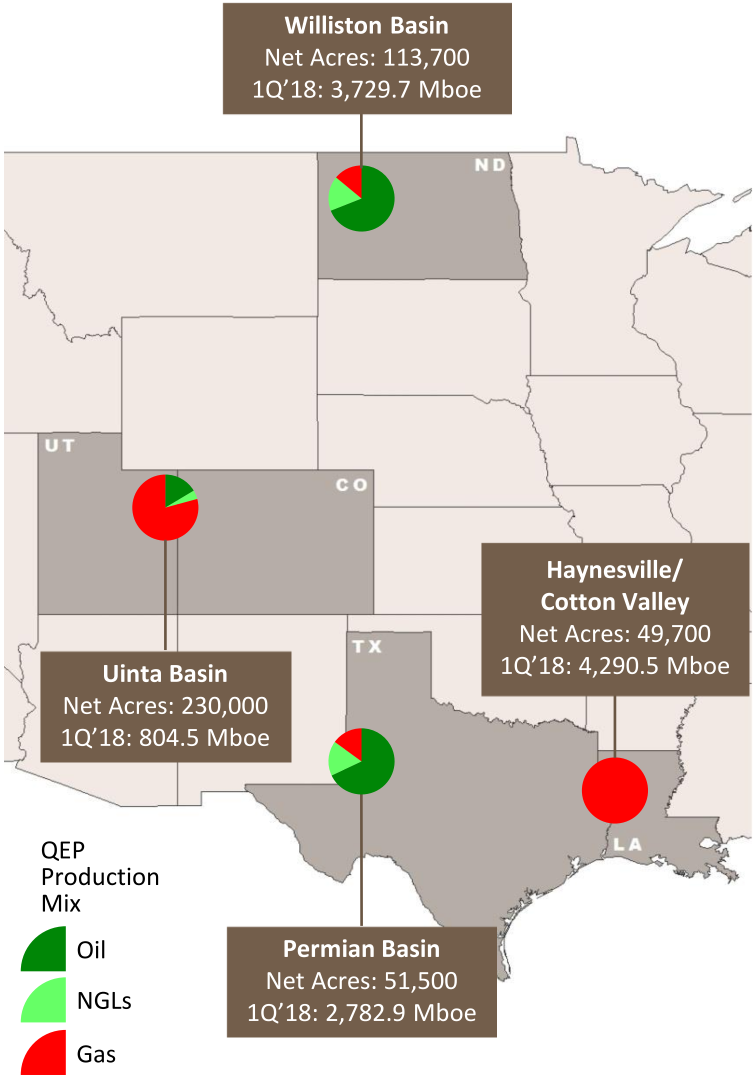
* Jul – Dec 2018 Midland spot based off mid-point of company guidance as of April 25, 2018.

(1) QEP markets 100% of produced oil volumes for our working interest partners
(2) See derivatives table on slide 26 of this presentation

QEP Resources – *1Q 2018 Financial & Operational Overview*

Asset Overview[1]



1Q 2018 Highlights

- Total Net Equivalent Production: 11,724.6 Mboe
  - Oil Production: 4,974.0 Mbbl
  - Gas Production: 35.1 Bcf
  - NGL Production: 904.4 Mbbl
- Delivered record net oil equivalent production in the Permian Basin of 30.9 Mboed, including record oil production of 24.0 Mbod
- Reported net gas equivalent production of 286.0 MMcfed in Haynesville/Cotton Valley, a 110% year-over-year increase
- Increased 2018 production and capital expenditure guidance to reflect an accelerated well delivery cadence in the Permian Basin, resulting from significant improvements in drilling and completion efficiency
- Opened data rooms for the divestiture of the Company's Williston and Uinta basin assets
- Commenced execution of an authorized $1.25 billion share repurchase program

(1) Equivalent production excludes 116.9 Mboe from Other Northern & Other Southern regions.

QEP Resources – *Updated 2018 Guidance*(1)

	2018
Oil & Condensate Production (MMBbl)	21.5 - 23.0
Gas Production (Bcf)	135.0 - 145.0
NGL Production (MMBbl)	4.25 - 4.75
Total oil equivalent production (MMBoe)	48.3 - 51.9
Lease operating and transportation expense (per Boe)	$9.00 - $10.00
Depletion, depreciation and amortization (per Boe)	$17.00 - $18.00
Production and property taxes (% of field-level revenue)	8.5%
(in millions)	
General and administrative expense(2)	$195 - $215
Capital investment (excluding property acquisitions)	
Drilling, Completion and Equip(3)	$1,000 - $1,100
Infrastructure	$60
Corporate	$10
Total Capital Investment (excluding property acquisitions)	**$1,070 - $1,170**

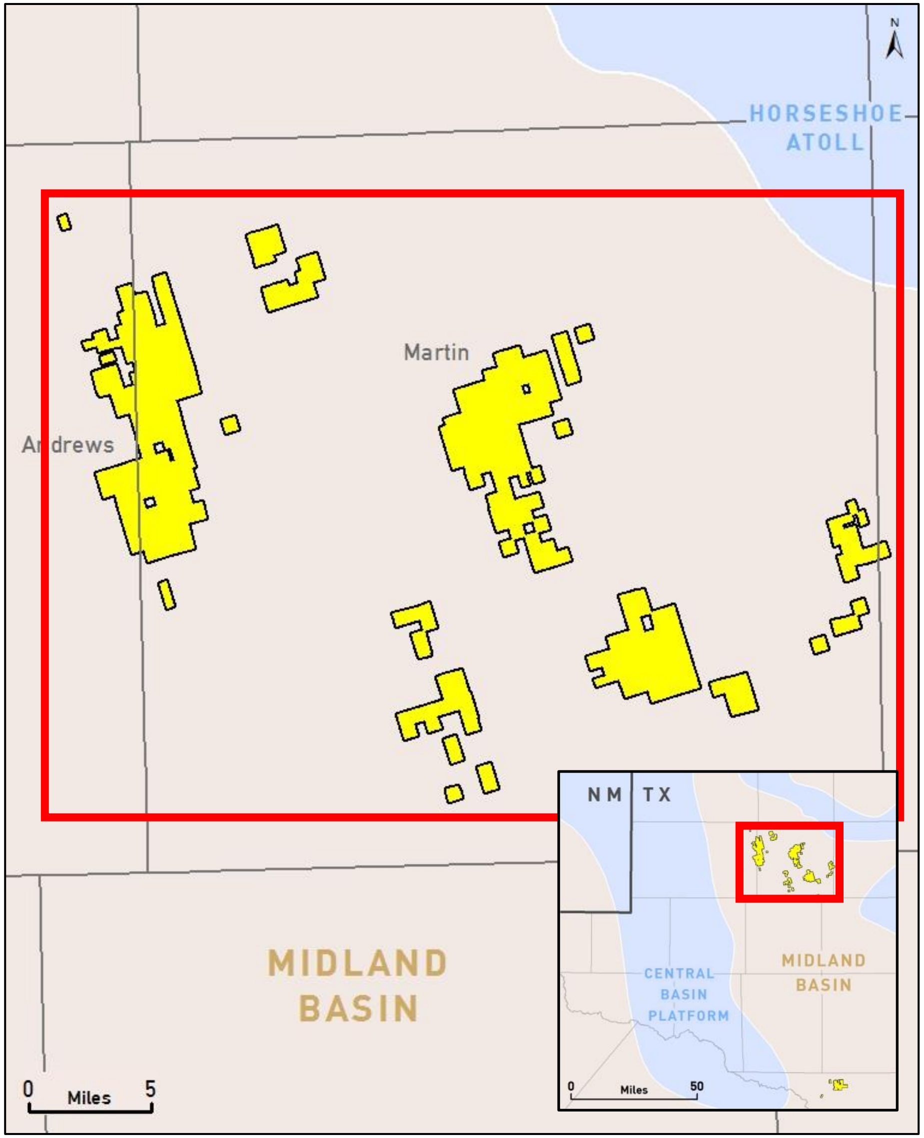
(1) As of April 25, 2018: The Company's guidance assumes no additional property acquisitions or divestitures, other than those executed in the first quarter 2018, and assumes that QEP will elect to reject ethane from its produced gas for the entire year, where QEP has the right to make such an election, except in the Permian Basin where processing economics support ethane recovery. Assumes an average of four and one- half rigs in the Permian Basin, an average of one-quarter rig in the Williston Basin and one-half rig in the Haynesville/Cotton Valley.

(2) General and administrative expense includes approximately $25.0 million of non-cash share-based compensation expense and approximately $20.0 million of estimated termination benefits and retention program expense.

(3) Approximately 70% of the planned capital investment is focused on projects in the Permian Basin. Drilling, Completion and Equip includes approximately $20.0 million of non-operated well completion costs.

Asset Overview

Midland Basin



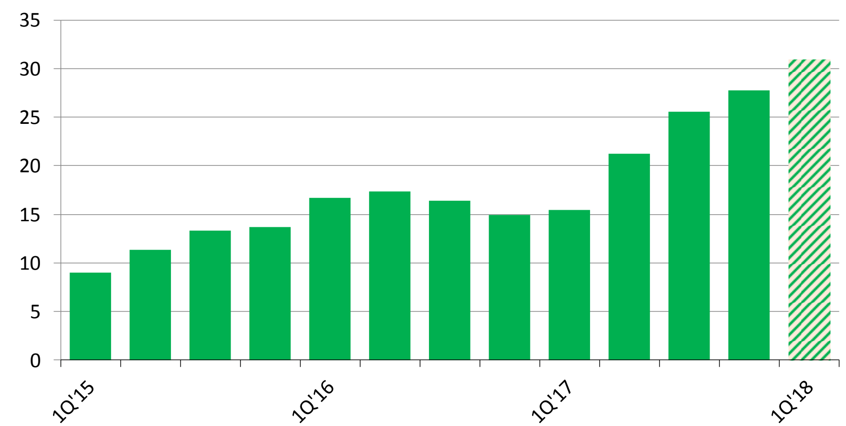
QEP Acreage as of 3/31/2018

Profile(1)

Net acres(2)	51,500
Gross operated producing wells (Vertical/Horizontal)	496/155
Average WI/average NRI	96 / 73%
Proved reserves (MMboe)/% liquids(3)	273 / 88%
Production Split – oil/gas/NGL	78/11/11%
Rig Count	6

(1) As of March 31, 2018
(2) Includes Crockett County leasehold
(3) As of December 31, 2017, SEC Pricing

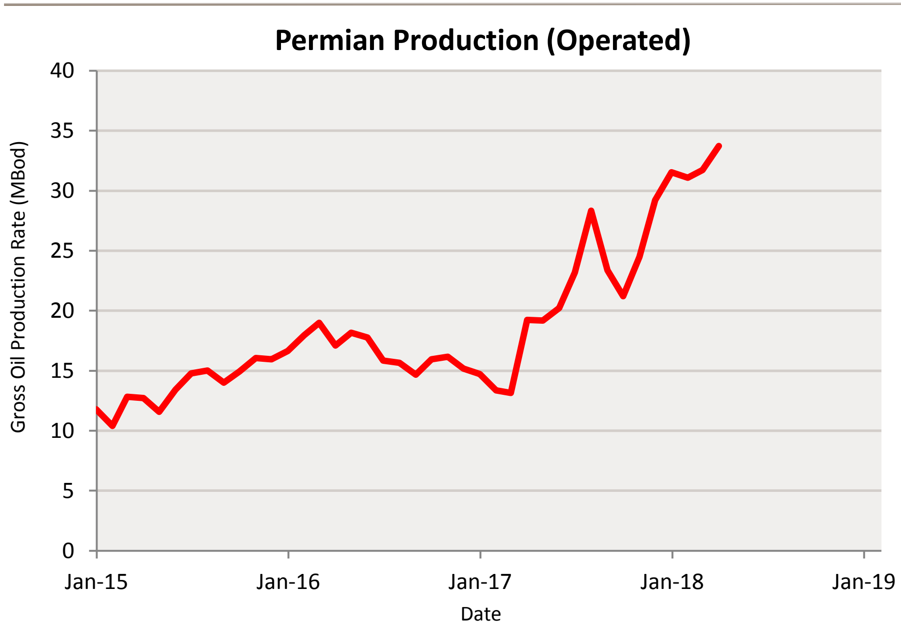
Net Production - Mboed

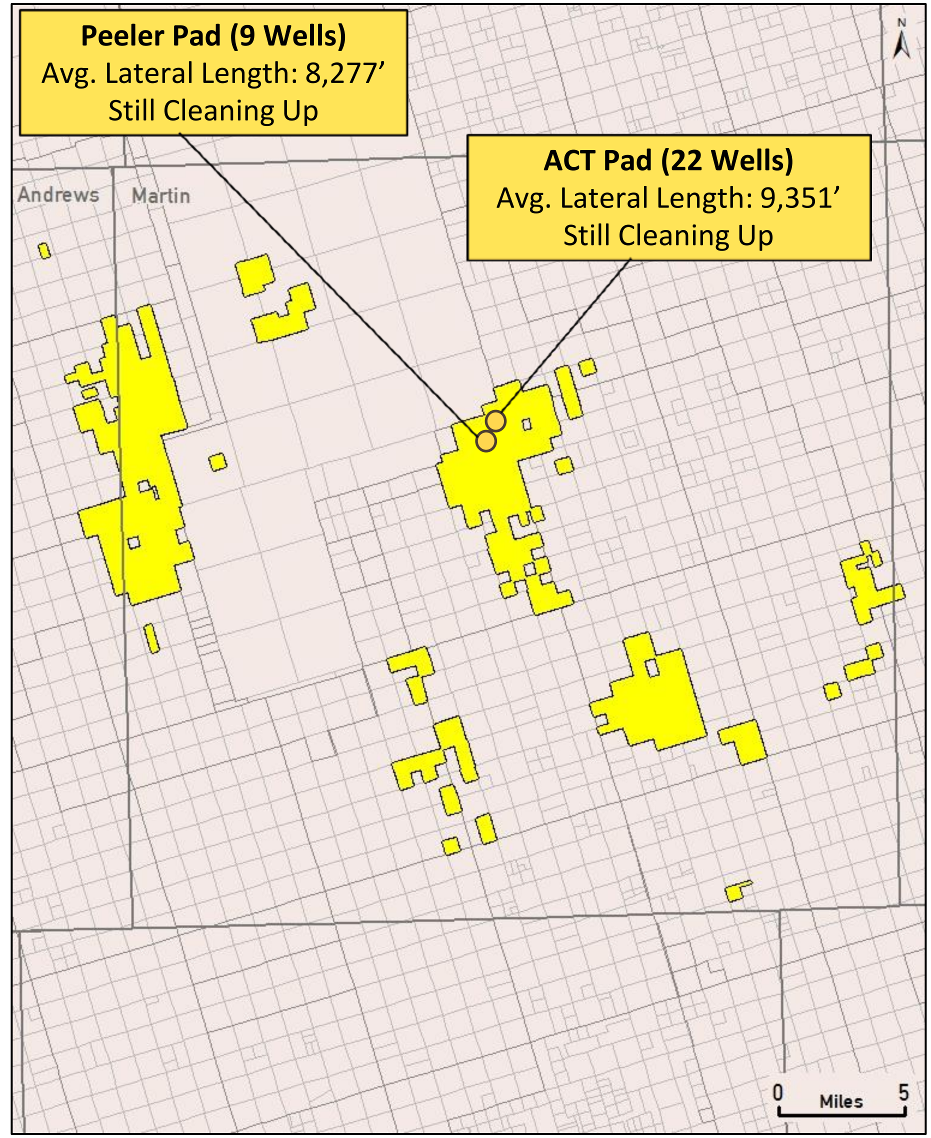


Midland Basin – *1Q 2018 Activity*

Well Progress	Gross	Net
Drilling	20	19.6
At total depth – under drilling rig	8	7.7
Waiting to be completed	15	14.4
Undergoing completion	6	6.0
Completed, awaiting production	9	9.0
Waiting on completion	38	37.1
Put on production[(1)]	31	31.0

(1) Total wells put on production during the quarter ended March 31, 2018.





QEP Acreage as of 3/31/2018

Midland 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

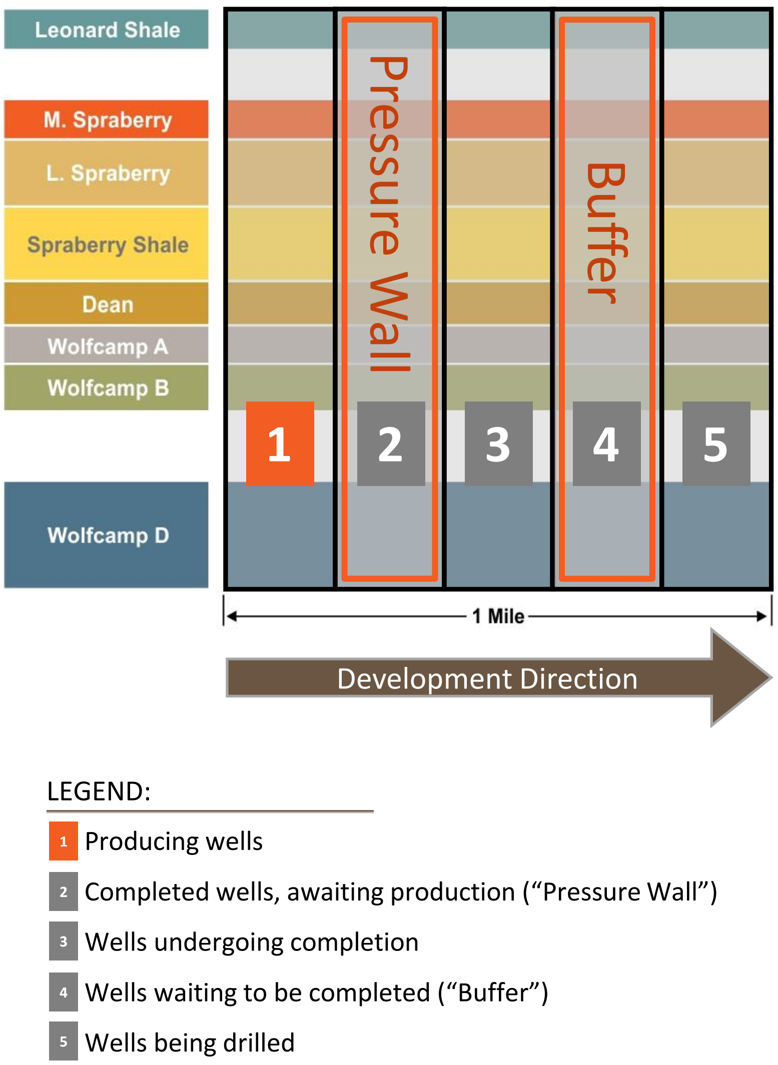
Benefits

Above Ground

- 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

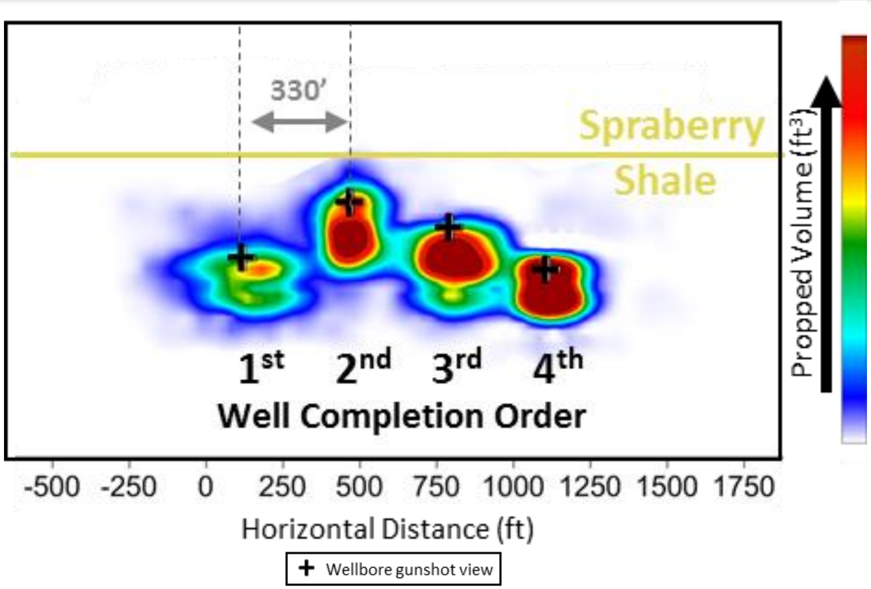
Below Ground

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

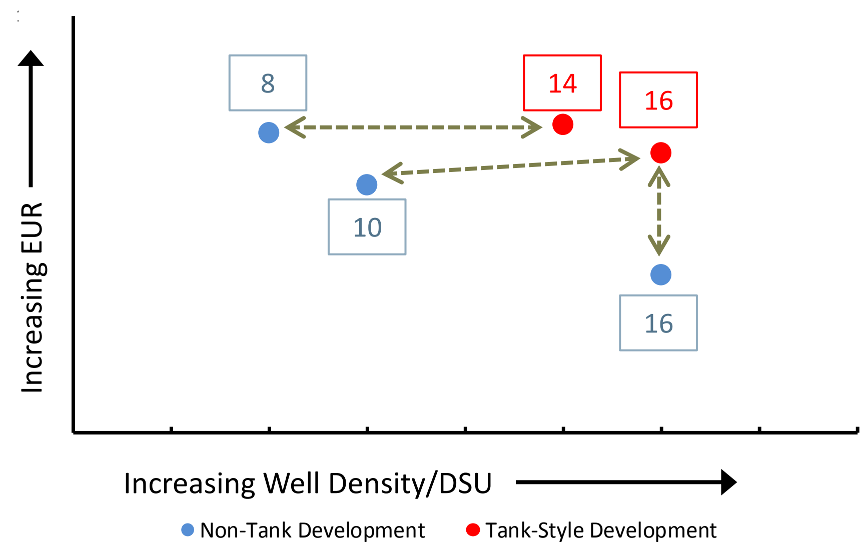


Midland Basin – *Tank-Style Development Allows for Increased Densities*

Microseismic Study



Tank-Style Proof of Concept



Microseismic Observations

- Increased fracture complexity for wells later in tank-style development sequence
- Evidence of increased stimulated rock volume

Maximization of economic oil recovery

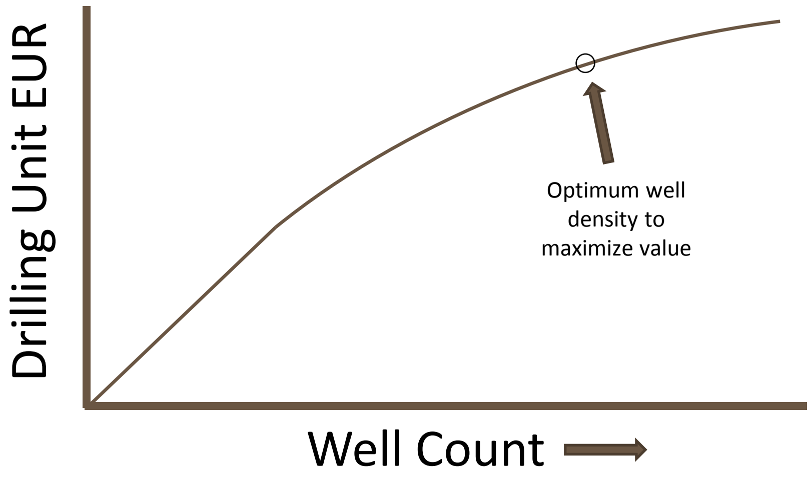
Tank Style Development Observations

- Increased density impacts are minimized
- Outperforming non-tank development wells
- Extracting more oil per square mile

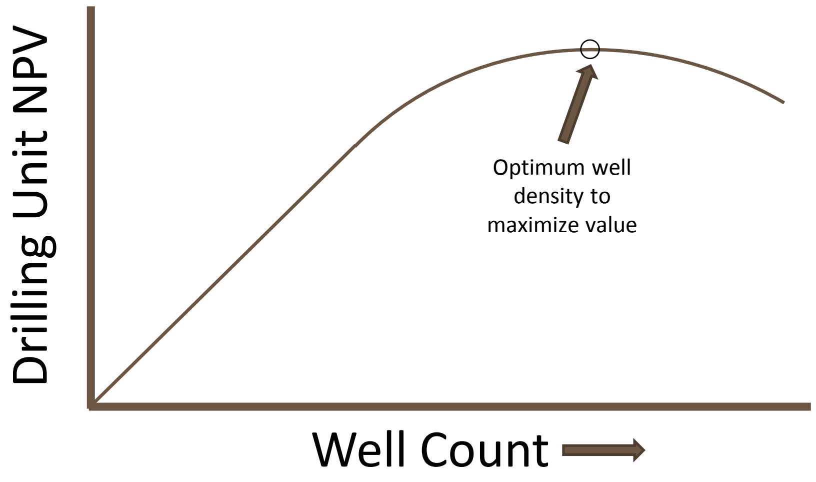
Development focus on Tank-Style completions

Midland Basin – *Tank-Style Development Maximizes Economic Recovery*

Total Drilling Unit EUR



Maximizing Economic Recovery



EUR Observations

- Non-tank style completions exhibit lower EUR
- Tank-style completions increase oil recovery across target horizons

Value Observation

- Tank-style completions increase economic recovery over non-tank completions
- Maximum economic recovery of oil achieved in tank-style development

Midland Basin – *Gas Lift Drives Significant Cost Savings*

QEP is shifting to gas lift in the Midland Basin

ESP Installation

- *Pros*
  - Potentially higher IP rates
  - No fuel gas required
- *Cons*
  - High capital and operating costs
  - More downtime
  - Later installation
- *Capital Cost*(1)
  - Typical ESP “life-cycle” cost: $800K

Gas Lift Installation

- *Pros*
  - Lower capital and operating costs
  - Less downtime
  - Earlier installation
- *Cons*
  - Must have a gas supply
  - Must have adequate compression
  - Require more engineering up front
- *Capital Cost*(1)
  - Typical gas lift “life-cycle” cost: $500K

Utilization of gas lift significantly reduces well operating costs over life of well

~$300K per well in “life-cycle” savings
~$80K per well of LOE savings in first two years

(1) Estimated.

Midland Basin – *Mustang Springs Water Infrastructure*

QEP has built significant water infrastructure on Mustang Springs

Water Infrastructure – Mustang Springs

- 20 water supply wells
- Three frac ponds (two supply/one recycled)
- Six miles of water piping for completions
- Five miles of produced water piping for recycling or disposal
- Significant water recycling capacity
  - ~40,000 bpd as of 1Q 2018
  - ~100,000 bpd expected by end of 3Q 2018
- Deep water disposal wells
  - Drilled below deepest production

Water Infrastructure – Benefits

- Ample supply and recycled water capacity to support "tank-style" completions
- Efficient delivery of water for completions
- Piped water handling reduces trucking
- Reduced operating costs

Midland Basin – *Centralized Infrastructure Benefits*

QEP operated centralized infrastructure drives capital & operating cost efficiencies

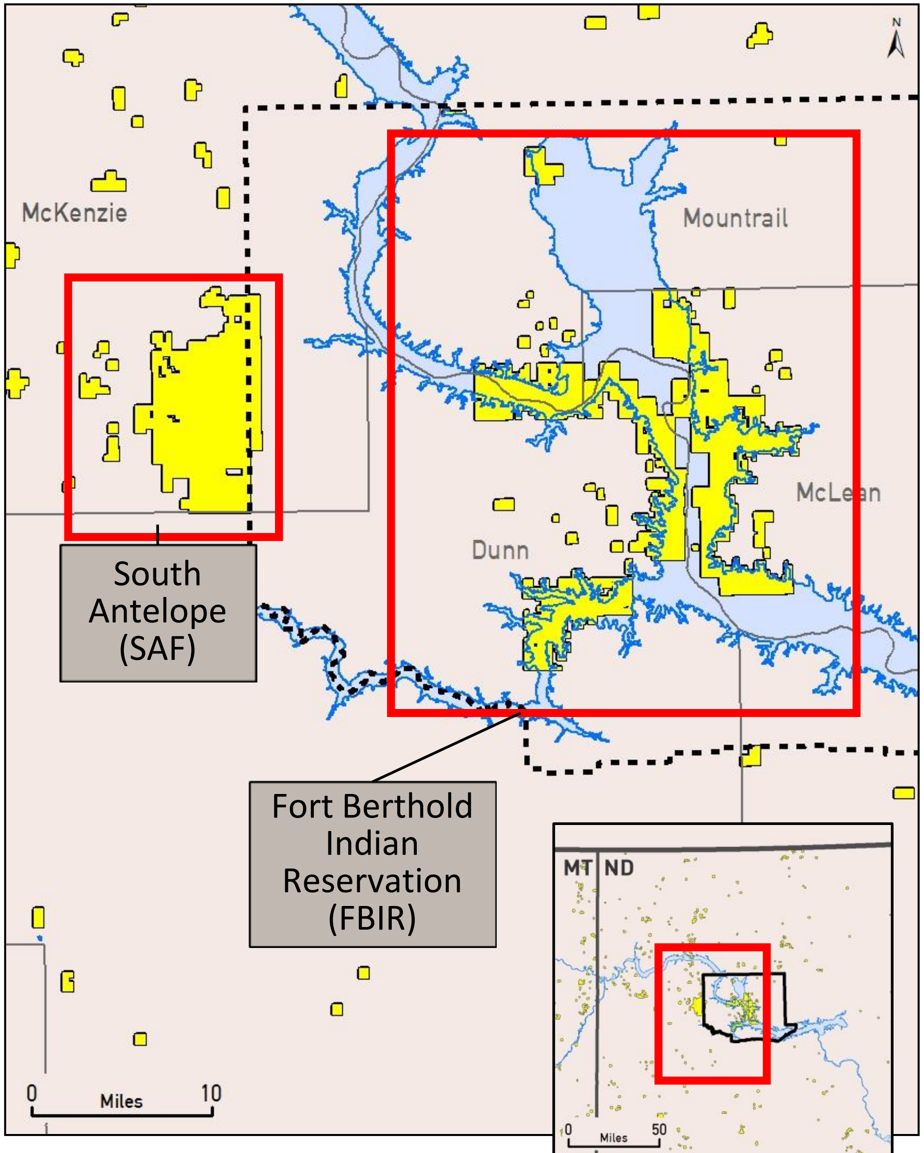
Capital Efficiencies

- ~$170K per well savings on facilities
- ~$200K per well savings on well site improvements

Operating Efficiencies

- 20% decrease in gas transportation
- 60% reduction in water disposal
- 40% drop in frac water costs
- $0.50/bbl uplift in oil price

Williston Basin



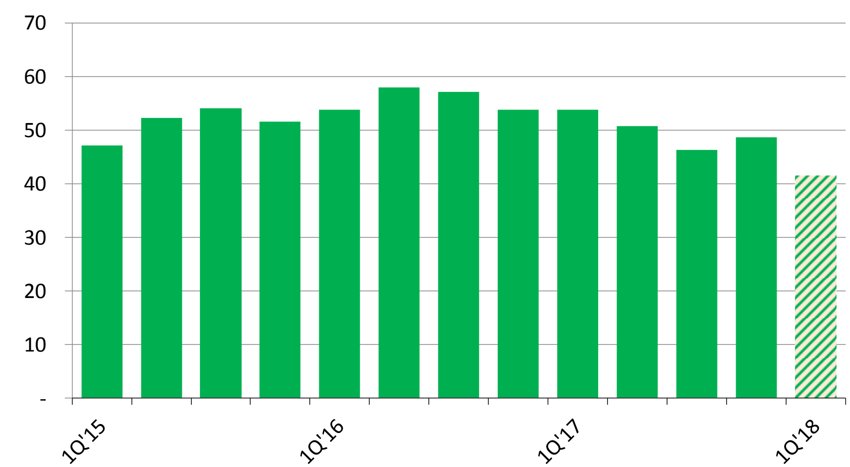
QEP Acreage as of 03/31/2018

Profile(1)

Net acres	113,700
Gross operated producing wells	384
Average WI/average NRI	86/69%
Proved reserves (MMboe)/% liquids(2)	147 / 88%
Production Split – oil/gas/NGL	70/15/15%
Rig Count	1

(1) As of March 31, 2018
(2) As of December 31, 2017, SEC Pricing

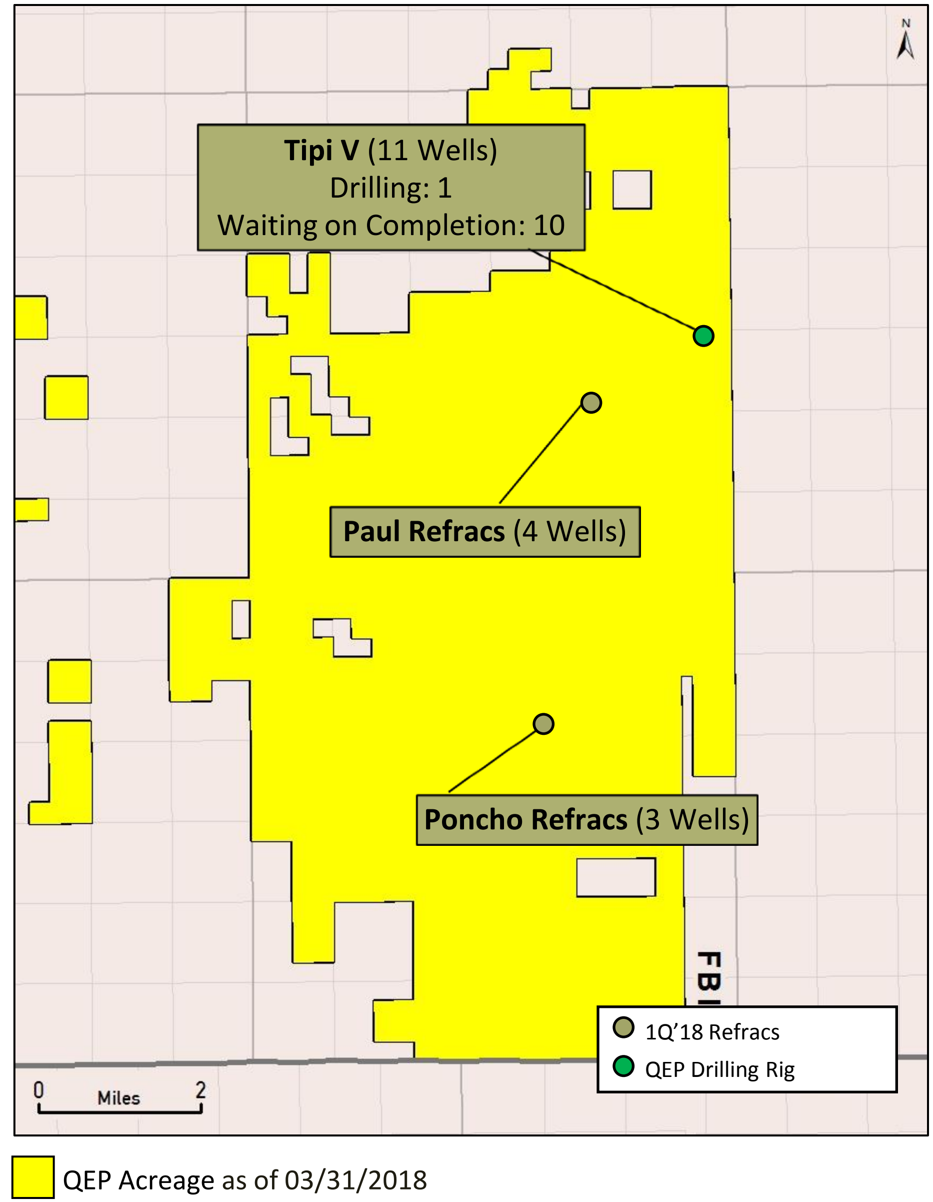
Net Production - Mboed



Williston Basin – *South Antelope 1Q 2018 Activity*

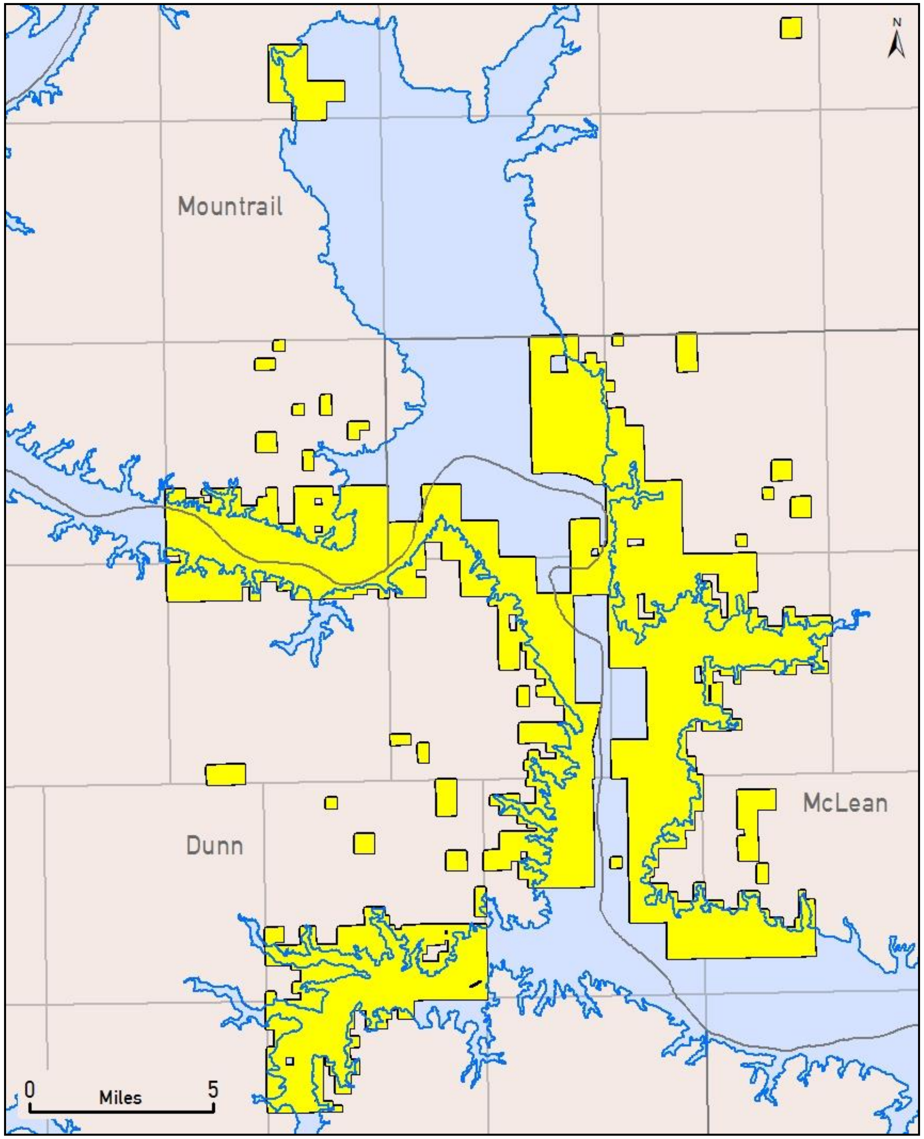
Well Progress	Gross	Net
Drilling	1	0.5
At total depth – under drilling rig	5	5.0
Waiting to be completed	2	2.0
Undergoing completion	2	2.0
Completed, awaiting production	1	1.0
Waiting on completion	10	10.0
Put on production[1]	-	-

[1] Total wells put on production during the quarter ended March 31, 2018.



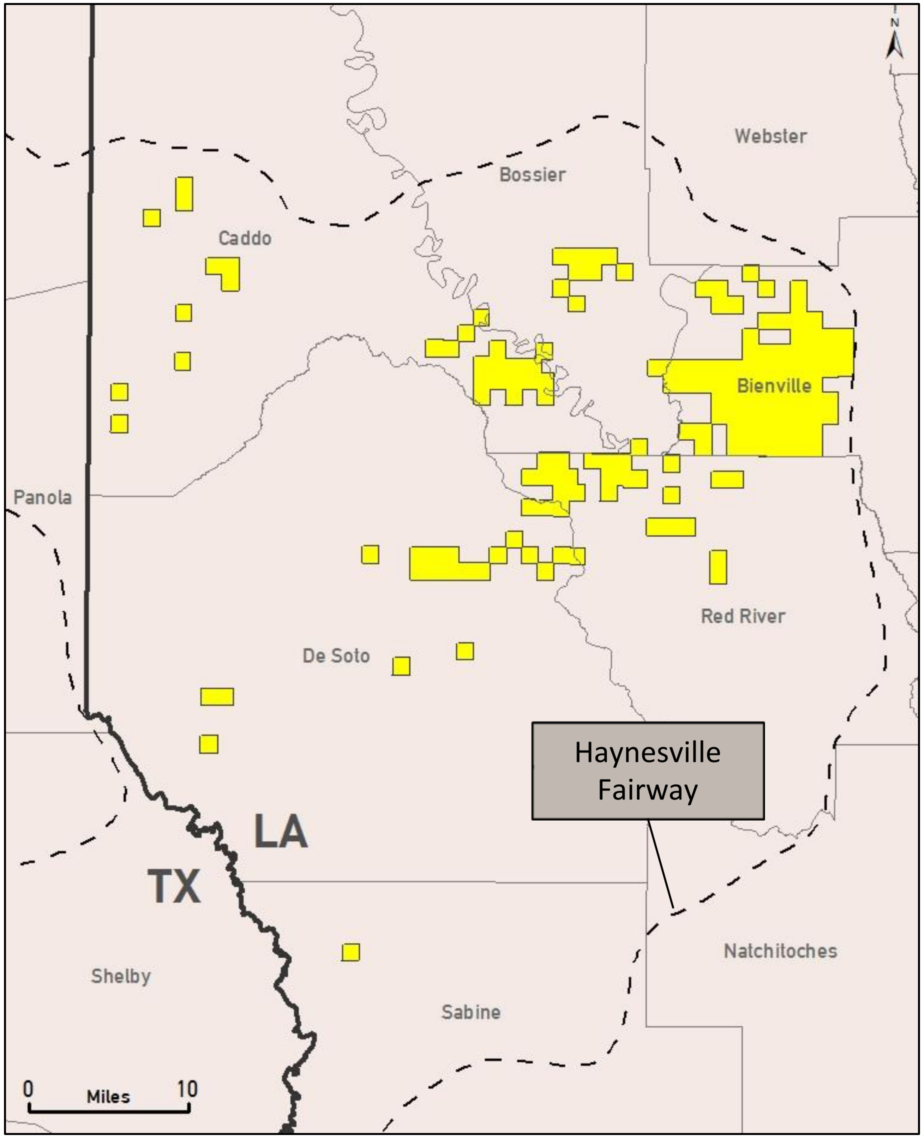
Williston Basin – *FBIR 1Q 2018 Activity*

- No activity in the quarter



QEP Acreage as of 03/31/2018

Haynesville



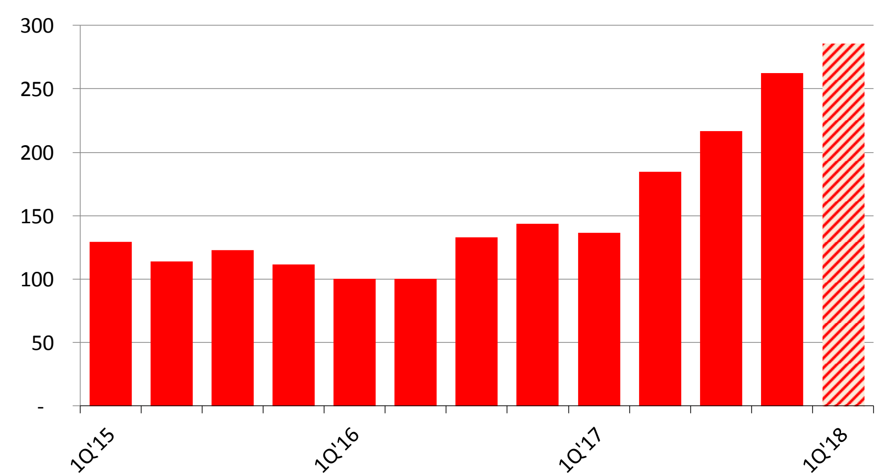
QEP Units as of 3/31/2018

Profile[1]

Net acres[2]	49,700
Gross operated producing wells[2]	135
Average WI/average NRI[2]	94/72% (op)
Proved reserves (Bcfe)/% gas[3]	959/100%
Production Split – oil/gas/NGL	0/100/0%

(1) As of March 31, 2018
(2) Includes only Haynesville interval wells and acreage
(3) As of December 31, 2017, SEC Pricing

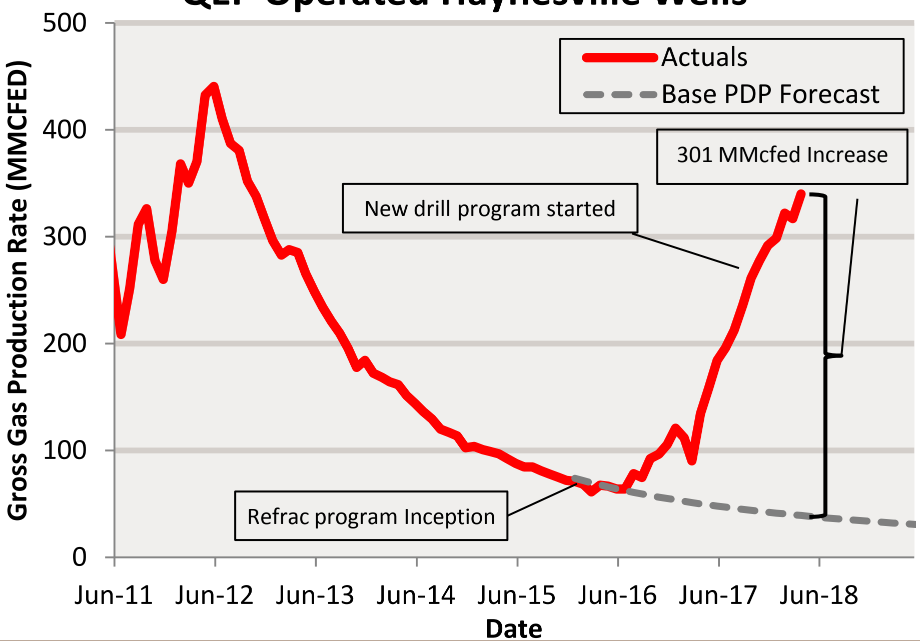
Net Production – MMcfed

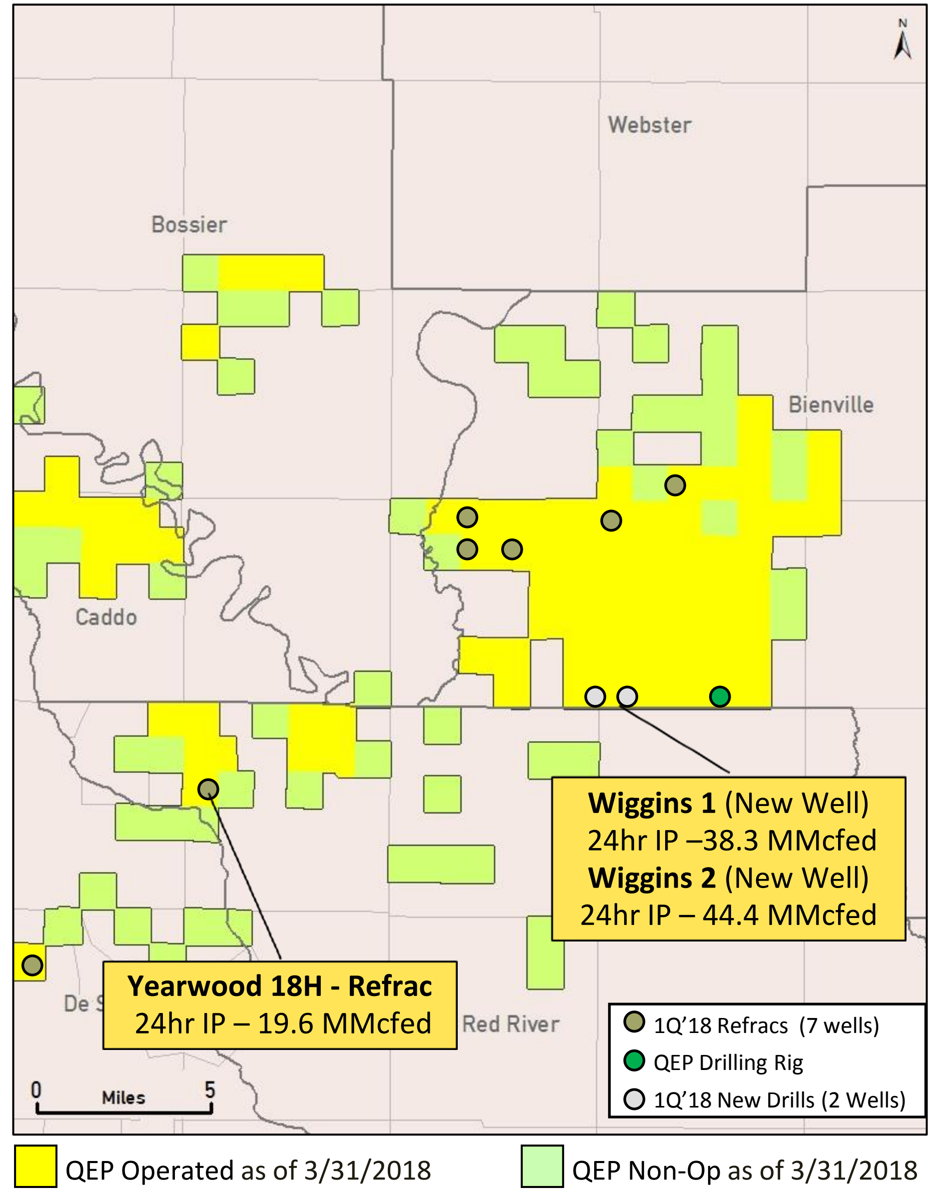


Haynesville – *1Q 2018 Activity*

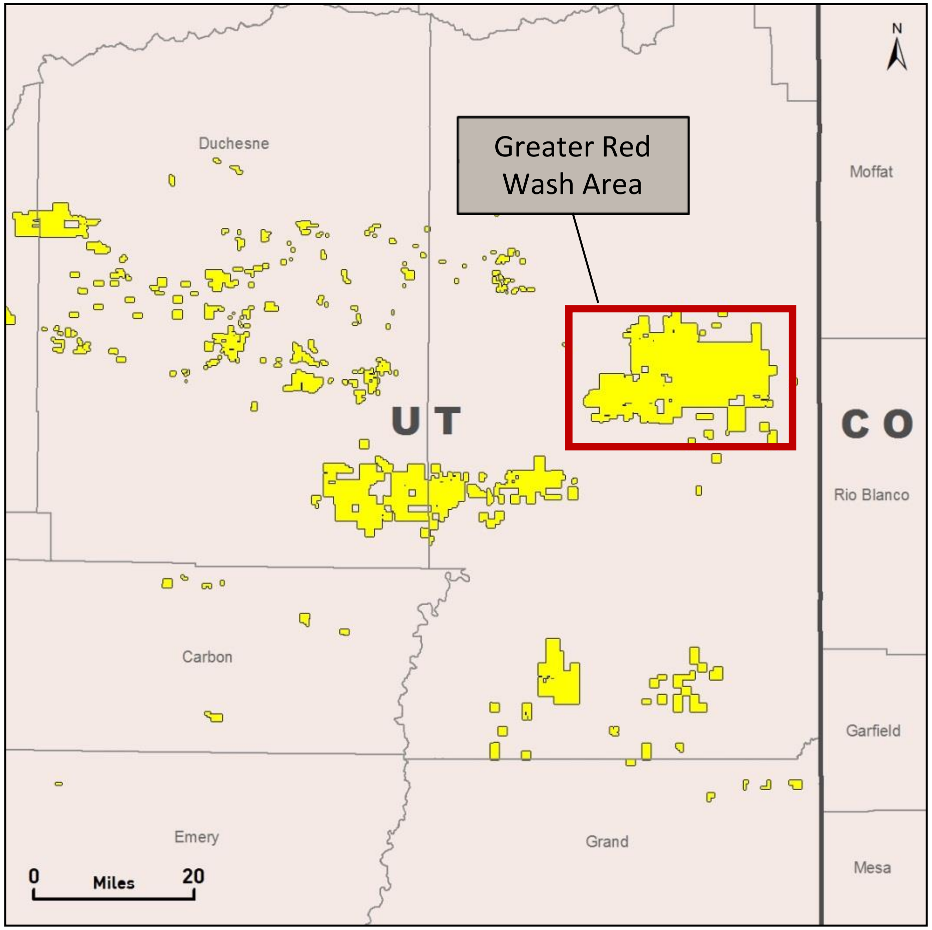
- Put on production two new wells
  - Both wells were 10,000' laterals
  - Wiggins 2 well is one of the highest 24-hour IP wells on record in the Haynesville Field at 44.4 MMcfed
- Completed and returned to production seven refracs
  - Yearwood 18H – best performing QEP refrac to date
    - 24-hour IP of 19.6 MMcfed
    - Produced 1.1 Bcfe in first 60 days
- Gross production has increased ~301 MMcfed since activity resumed 2Q 2016

QEP Operated Haynesville Wells





Uinta Basin



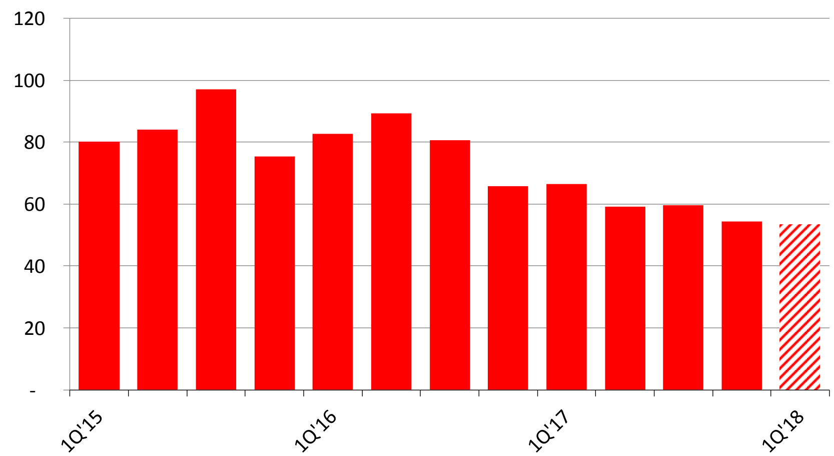
QEP Acreage as of 3/31/2018

Profile(1)

Net acres	230,000(2) 110,000(3)
Gross operated producing wells	766(2), 106(3)
Average WI – Current Producing Wells	84%(2), 98%(3)
Average WI/NRI – Remaining Locations (2)	94/81%
Proved reserves (Bcfe)/% liquids(4)	505/10%
Production Split – oil/gas/NGL(3)	5/90/5%

(1) As of March 31, 2018
(2) Total Uinta Basin
(3) Greater Red Wash Mesaverde Fairway (KJ, Red Wash & South Red Wash)
(4) As of December 31, 2017, SEC pricing Greater Red Wash Mesaverde Play Only

Net Production - MMcfed



Appendix

Midland & Williston Basins – *Detailed Well Cost Summary*[(1)]

Permian Gross Well Costs (AFE)				
Area	**Target Formation**	**Lateral Length (ft.)**	**Drill & Complete ($mm)**	**Facilities & Artificial Lift ($mm)**
County Line	Spraberry Shale	7,500	$5.2	$1.0
	Spraberry Shale	10,000	$6.4	$1.0
	Wolfcamp	7,500	$6.4	$1.0
	Wolfcamp	10,000	$7.8	$1.0
Mustang Springs	Middle Spraberry	7,500	$5.1	$1.0
	Spraberry Shale	7,500	$5.1	$1.0
	Wolfcamp A	7,500	$5.8	$1.0
	Wolfcamp B	7,500	$5.9	$1.0

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	$1.0
FBIR	Middle Bakken / Three Forks	10,000	$6.2	$1.5

(1) As of March 31, 2018.

Midland Basin – *Well Density Assumptions*

	County Line	Mustang Springs	2017 Permian Acquisition
Leonard Shale	0-6 wells/mile	Upside Potential	Upside Potential
M. Spraberry	5-9 wells/mile	5-8 wells/mile	5-8 wells/mile
L. Spraberry	Upside Potential	Upside Potential	Upside Potential
Spraberry Shale	8-16 wells/mile	8-14 wells/mile	8-14 wells/mile
Dean	Upside Potential	Upside Potential	Upside Potential
Wolfcamp A	0-4 wells/mile	4-8 wells/mile	4-8 wells/mile
Wolfcamp B	0-8 wells/mile	6-14 wells/mile	6-14 wells/mile
Wolfcamp D	0-8 wells/mile	Upside Potential	Upside Potential

- Stacked pay opportunity across core Permian acreage position
- Large upside opportunity in both proven and unproven zones
- Up to 1,900 potential future horizontal drilling locations of 7,500’, 10,000’, and 12,500’ laterals(1)

(1) Excludes zones labeled as upside potential

QEP Resources – *Derivative Positions*

The following tables present QEP's volumes and average prices for its open production derivative positions as of April 20, 2018:

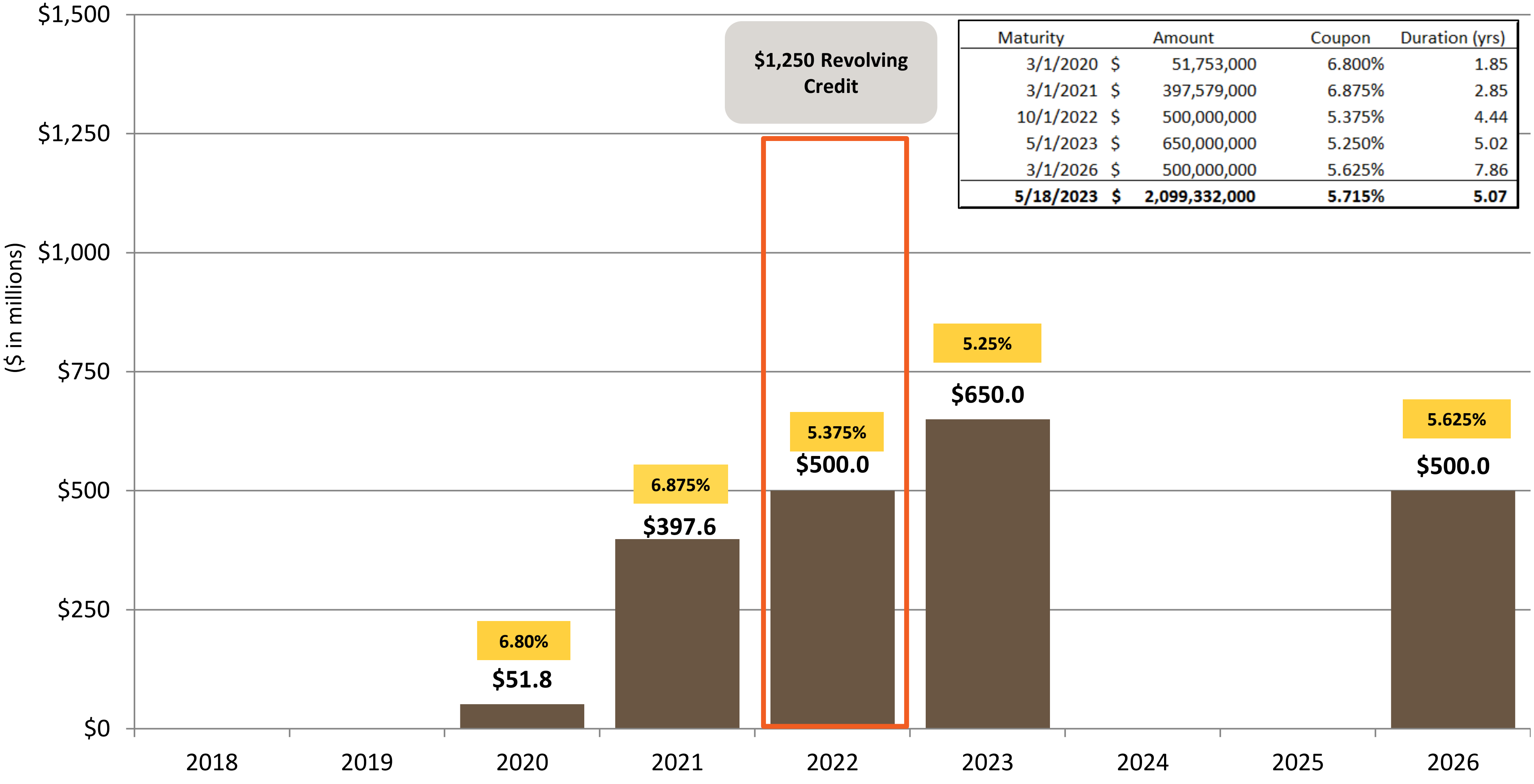
Production Commodity Derivative Swaps			
Year	**Index**	**Total Volumes**	**Average Price per Unit**
Oil Sales		(MMBbls)	($/Bbl)
2018 (April through December)	NYMEX WTI	12.7	$52.48
2019	NYMEX WTI	9.5	$52.66
Gas Sales		**(million MMBtu)**	**($/MMBtu)**
2018 (May through December)	NYMEX HH	71.7	$3.00
2018 (July through December)	NYMEX HH	1.8	$3.01
2019	NYMEX HH	43.8	$2.86

Production Commodity Derivative Basis Swaps				
Year	**Index less Differential**	**Index**	**Total Volumes**	**Weighted Average Differential**
Oil Sales			**(MMBbls)**	**($/Bbl)**
2018 (April through December)	NYMEX WTI	Argus WTI Midland(1)	5.5	($1.06)
2018 (July through December)	NYMEX WTI	Argus WTI Midland(1)	0.9	($0.71)
2019	NYMEX WTI	Argus WTI Midland(1)	4.7	($0.77)
Gas Sales			**(million MMBtu)**	**($/MMBtu)**
2018 (May through December)	NYMEX HH	IFNPCR	4.9	($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*

As of April 25, 2018



Maturity		Amount	Coupon	Duration (yrs)
3/1/2020	$	51,753,000	6.800%	1.85
3/1/2021	$	397,579,000	6.875%	2.85
10/1/2022	$	500,000,000	5.375%	4.44
5/1/2023	$	650,000,000	5.250%	5.02
3/1/2026	$	500,000,000	5.625%	7.86
5/18/2023	**$**	**2,099,332,000**	**5.715%**	**5.07**