QEP RESOURCES

Investor Presentation

July 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; marketing and divestiture of assets; use of proceeds from asset sales; Permian Basin development program and the Midland Basin assets reaching cash flow neutrality in 2019while delivering strong production growth; marketing strategy for crude oil production in the Permian Basin; factors impacting share repurchases; percentage of 2018 drilled wells with 10,000 foot laterals; timing and total number of wells put on production in 2018; 2018 netback per boe; estimated LOE and Adjusted transportation expenses and percentage decreases in the total of such expenses; percentage growth in production; estimated proved reserves; estimated production split among oil, gas and NGL; large upside opportunity in proven and unproven zones; ethane recovery and rejection; water recycling capacity in the Midland Basin and anticipated benefits of water infrastructure; planned benefits of centralized infrastructure; forecasted gross gas production rate in the Haynesville/Cotton Valley; amount and allocation of capital investment; crude oil marketing strategy, including the use of physical sales contracts to secure firm takeaway capacity; number, and lateral lengths of, potential future horizontal drilling locations; number of remaining risked drilling locations and refrac candidates in the Williston Basin; number and location of drilling rigs; anticipated benefits of tank-style development; maximizing production and economic recovery of oil; minimizing risk of interference and shut-in times; quarterly and annual guidance regarding production and net wells and related assumptions; guidance for 2018 Adjusted LOE and Adjusted transportation expense, DD&A, production and property taxes, general and administrative expense, non-cash share-based compensation expense, restructuring expense, and capital investment; and assumptions related to our guidance.

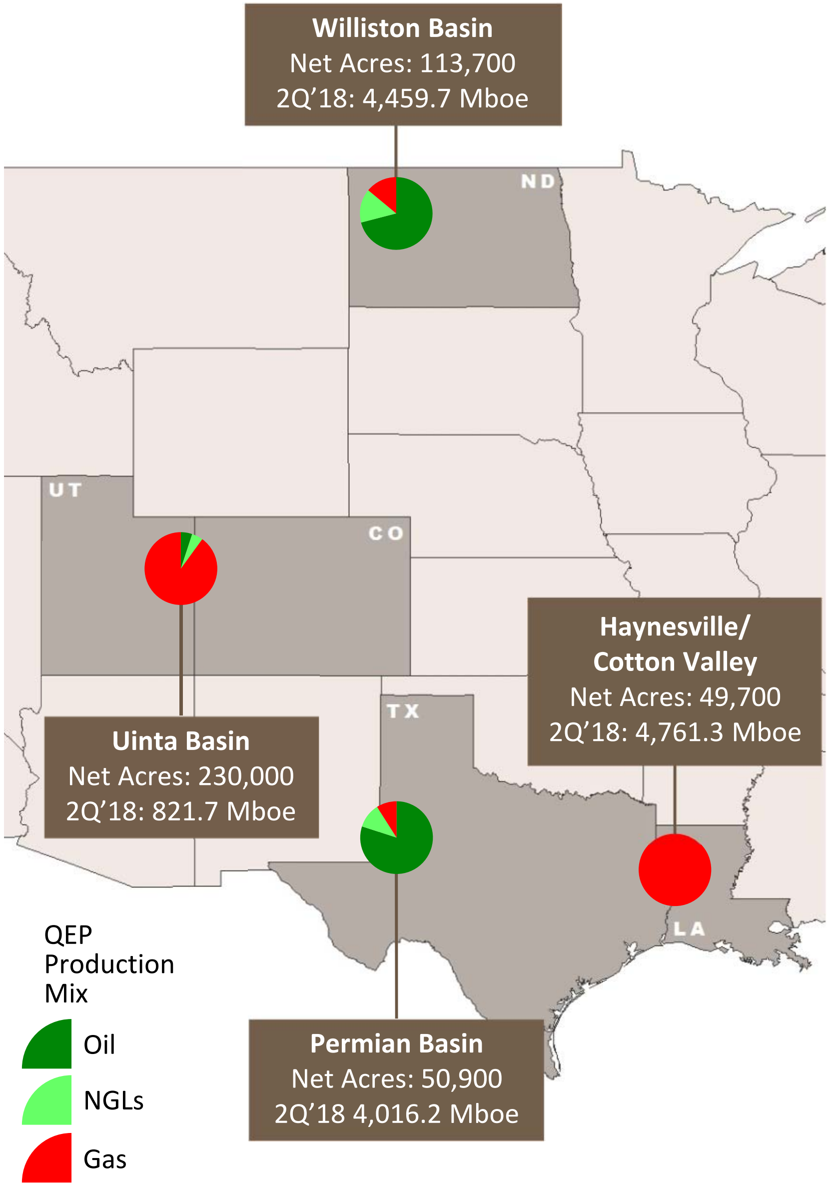
Actual results may differ materially from those included in the forward-looking statements due to a number of factors, including, but not limited to: the availability and cost of capital; changes in local, regional, national and global demand for oil, natural gas, and NGL; oil, natural gas and NGL prices; market conditions; timing of and actual proceeds from asset sales; actions of activist shareholders; tariffs on products QEP uses in its operations or sells; 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; 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; actions of operators on properties where we own an interest but are not the operator; 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, 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, including gas and crude oil pipeline takeaway capacity in the Permian Basin; 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 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 – *2Q 2018 Financial & Operational Overview*

Asset Overview[1]



2Q 2018 Highlights

- Total Net Equivalent Production: 14,106.1 Mboe, up 20% from 1Q 2018
  - Oil Production: 6,567.6 Mbbl
  - Gas Production: 38.3 Bcf
  - NGL Production: 1,152.8 Mbbl
- Strong production growth in all three areas – Permian, Williston & Haynesville
- Delivered record quarterly oil production of 6.6 MMbbls, including a record 3.2 MMbbls in the Permian Basin
- Delivered 20% quarter-over-quarter increase in Williston Basin production driven by strong results from our drilling and refrac programs on South Antelope
- Increased Haynesville/Cotton Valley quarterly gas production to 313.9 MMcfed driven by strong results from our drilling and refrac programs, up 10% from 1Q 2018
- Increased 2018 oil production guidance to 23.5 MMbbl[2] to reflect improved efficiencies in the Permian Basin and better than forecasted results in the Williston Basin

(1) Equivalent production excludes 47.2 Mboe from Other Northern & Other Southern regions.
(2) Midpoint of Company Oil & condensate production guidance as of July 25, 2018.

QEP Resources – *Updated 2018 Guidance*[1]

	2018
Oil & Condensate Production (MMBbl)	23.0 - 24.0
Gas Production (Bcf)	137.0 - 143.0
NGL Production (MMBbl)	4.0 - 4.5
Total oil equivalent production (MMBoe)	49.8 - 52.3
Adjusted lease operating and transportation expense (per Boe)	\$8.50 - \$9.50
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]	\$205 - \$225
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 July 25, 2018: The Company's updated guidance includes no adjustment for 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, 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 \$35.0 million of non-cash share-based compensation expense and approximately \$30.0 million of estimated restructuring 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.

QEP Resources – *2018 Strategic Initiatives Update*

- Divesture of the Company's Williston and Uinta basin assets
  - ***Uinta Basin divestiture for $155 million announced on July 10, 2018***
  - ***Williston Basin divestiture process ongoing - rejected bids received to date, but engaged in continuing discussions with several potential buyers for all, or a portion of, the assets***
- Market remaining non-Permian assets, including the Haynesville/Cotton Valley, in the second half of 2018
  - ***Entered into confidentiality agreements and provided data to third parties interested in a transaction involving the Company's Haynesville/Cotton Valley assets***
- 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)
  - ***Repurchased a total of 6.2 million shares at a weighted average share price of $9.37, for $58.4 million, as of June 30, 2018***

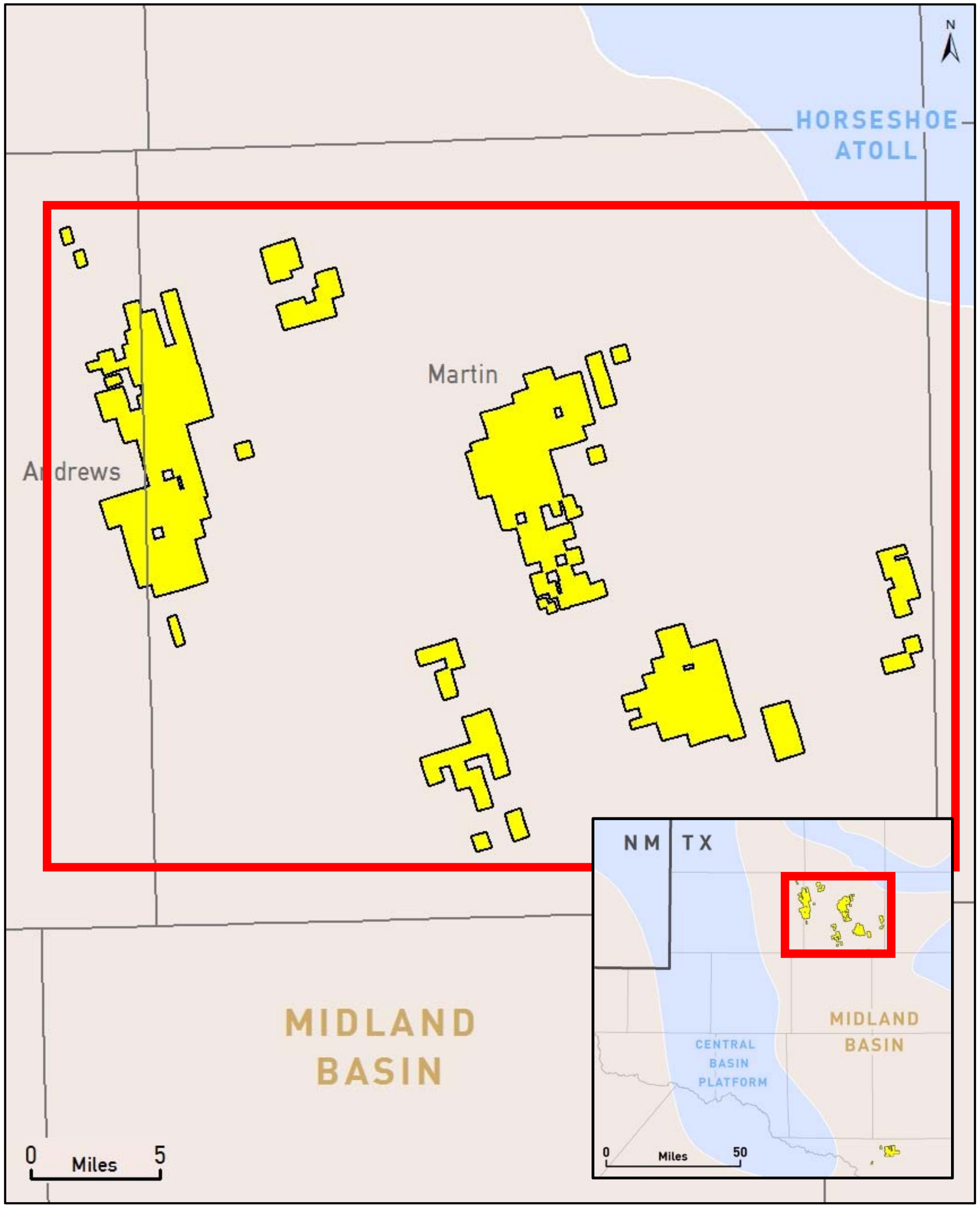
In February 2018, QEP's Board of Directors unanimously approved certain Strategic Initiatives to transition to a pure-play Permian Basin company

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

QEP RESOURCES

Asset Overview

Midland Basin



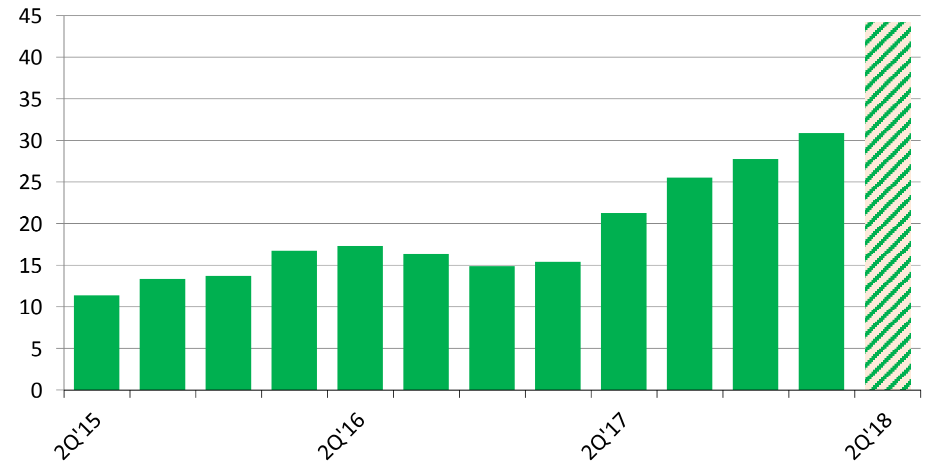
QEP Acreage as of 6/30/2018

Profile(1)

Net acres(2)	50,900
Gross operated producing wells (Vertical/Horizontal)	489/201
Average WI/average NRI	96 / 73%
Proved reserves (MMboe)/% liquids(3)	273 / 88%
Production Split – oil/gas/NGL	80/9/11%
Rig Count	5(4)

(1) As of June 30, 2018
(2) Includes Crockett County leasehold
(3) As of December 31, 2017, SEC Pricing
(4) Reduced to 4 rigs as of July 15, 2018

Net Production - Mboed

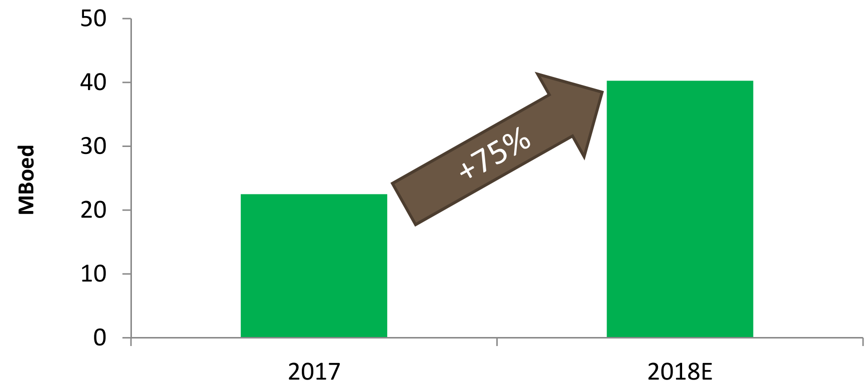


Midland Basin – *Outlook*

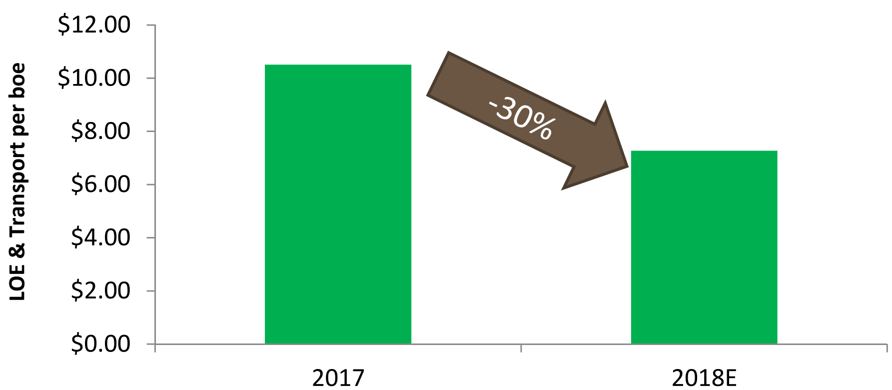
2018 Key Statistics

- 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* Actual**	**2Q18 Est.**	**4Q18 Est.**	**2018 Est.**
Net Production ***(MMboe)***	*2.8*	*4.0*	3.8 – 4.2	3.9 – 4.2	14.4 – 15.1
Net Wells ***(Put on Production)***	*31*	*36*	17	14	98
Capex – D&C ***($ in mm)***					$725 - $775
Capex – Infrastructure ***($ in mm)***					$45 - $55

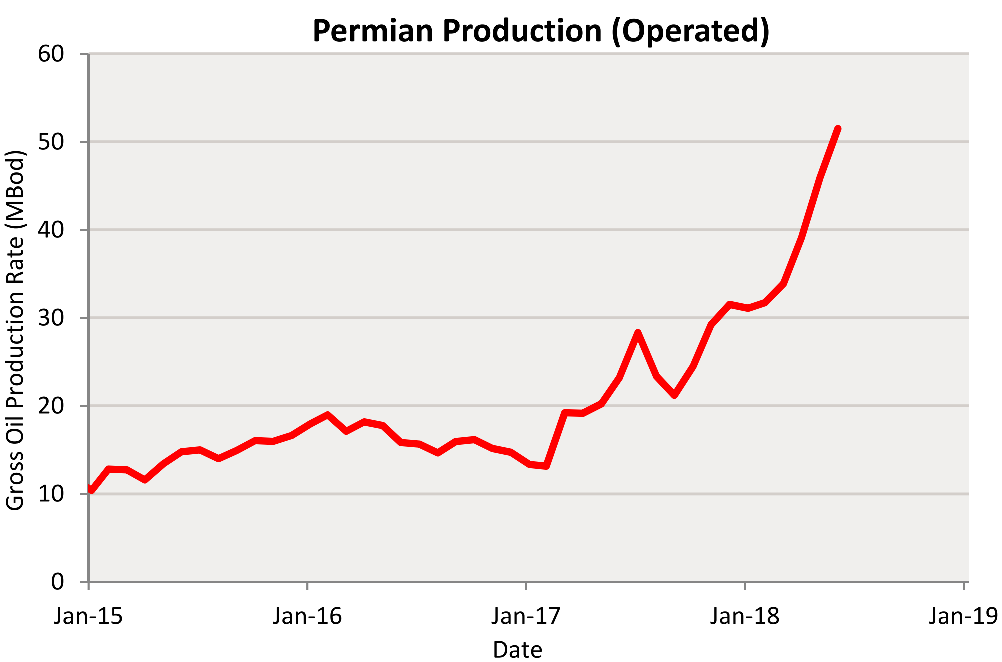
Assuming strip pricing, we expect the Midland Basin assets to achieve operating cash flow neutrality in 2019 while delivering strong production growth

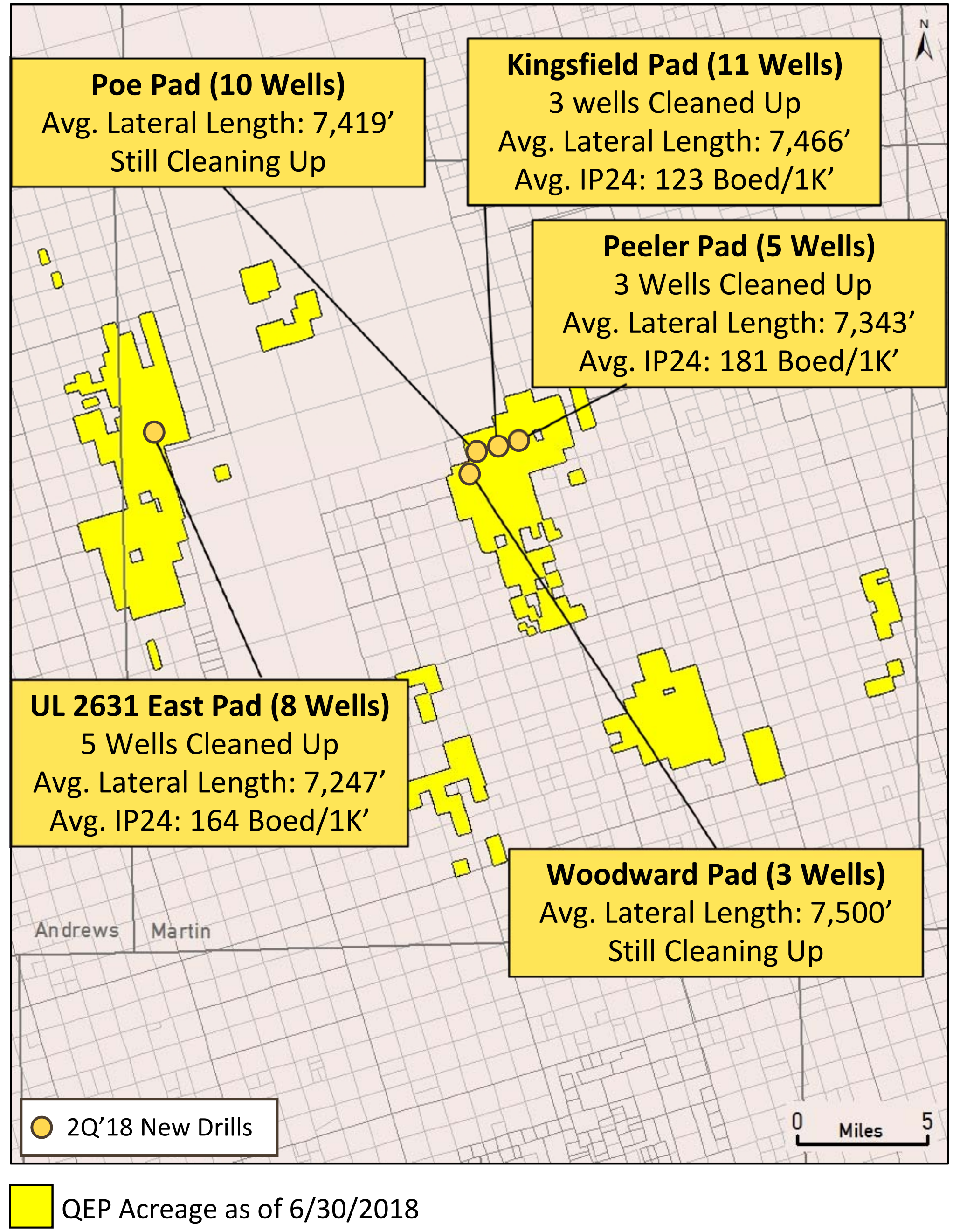
(1) Netback (a non-GAAP measure) is calculated as oil, natural gas and NGL sales less royalties, production taxes, cash operating expenses and transportation cost and excludes the impact of hedges.

Midland Basin – *2Q 2018 Activity*

Well Progress (as of June 30, 2018)	Gross	Net
Drilling	25	24.8
At total depth – under drilling rig	2	2
Waiting to be completed	12	11.7
Undergoing completion	5	4.8
Completed, awaiting production	8	8
Waiting on completion	27	26.5
Put on production[1]	37	36.1

[1] Total wells put on production during the quarter ended June 30, 2018.





Midland Basin – *Crude Oil Marketing Strategy*

Methodology

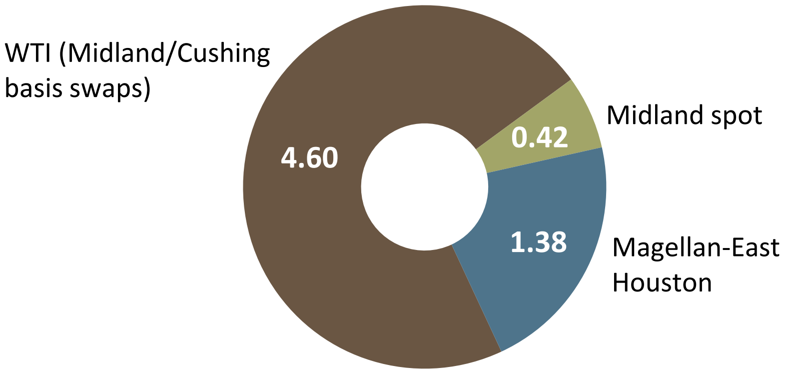
- Utilize “back-to-back” physical sales that secure takeaway without firm pipeline commitments
  - Enter into term physical sales agreements with refiners and marketers holding firm capacity on existing and new pipelines to Gulf Coast and Mid-Continent
  - Spread counterparty risk/concentration while 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

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

(1) QEP markets 100% of produced oil volumes for our working interest partners
(2) See derivatives table on slide 25 of this presentation

Midland Basin – *Mustang Springs Water Infrastructure*

QEP has built significant water infrastructure on Mustang Springs

Water Infrastructure Details

- 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 currently
  - ~100,000 bpd expected by end of 3Q 2018
- Deep water disposal wells (3 active wells)
  - Drilled below deepest production

Anticipated 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 Planned Benefits*

QEP operated centralized infrastructure drives capital & operating cost efficiencies

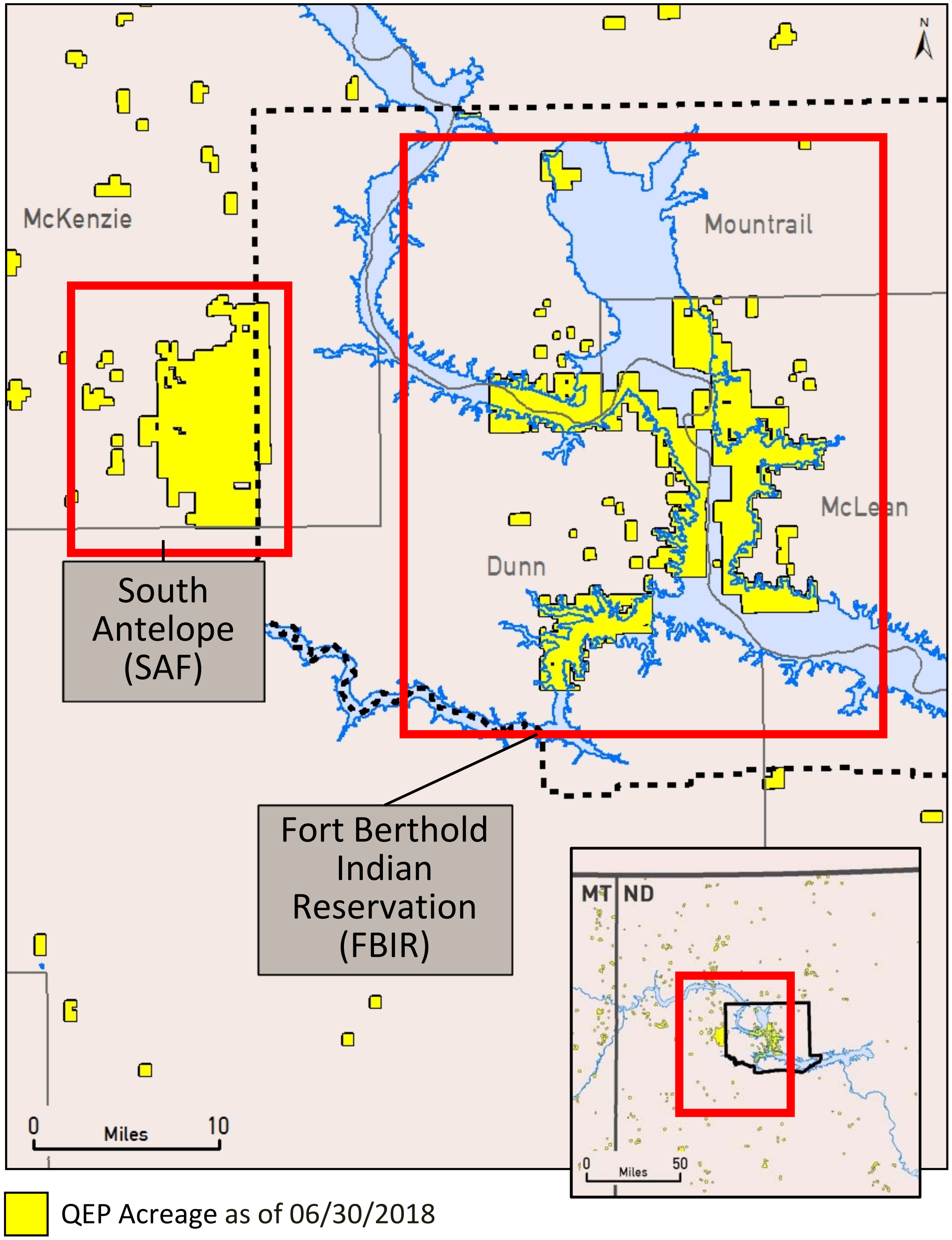
Capital Efficiencies

- ~$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

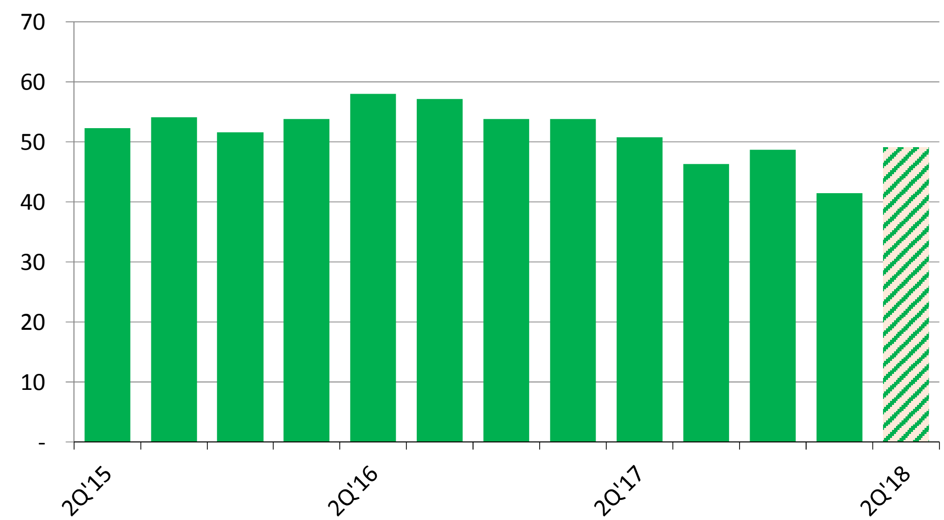
Williston Basin



Profile[1]	
Net acres	113,700
Gross operated producing wells	394
Average WI/average NRI	87/70%
Proved reserves (MMboe)/% liquids[2]	147 / 88%
Production Split – oil/gas/NGL	71/14/15%
Rig Count	0

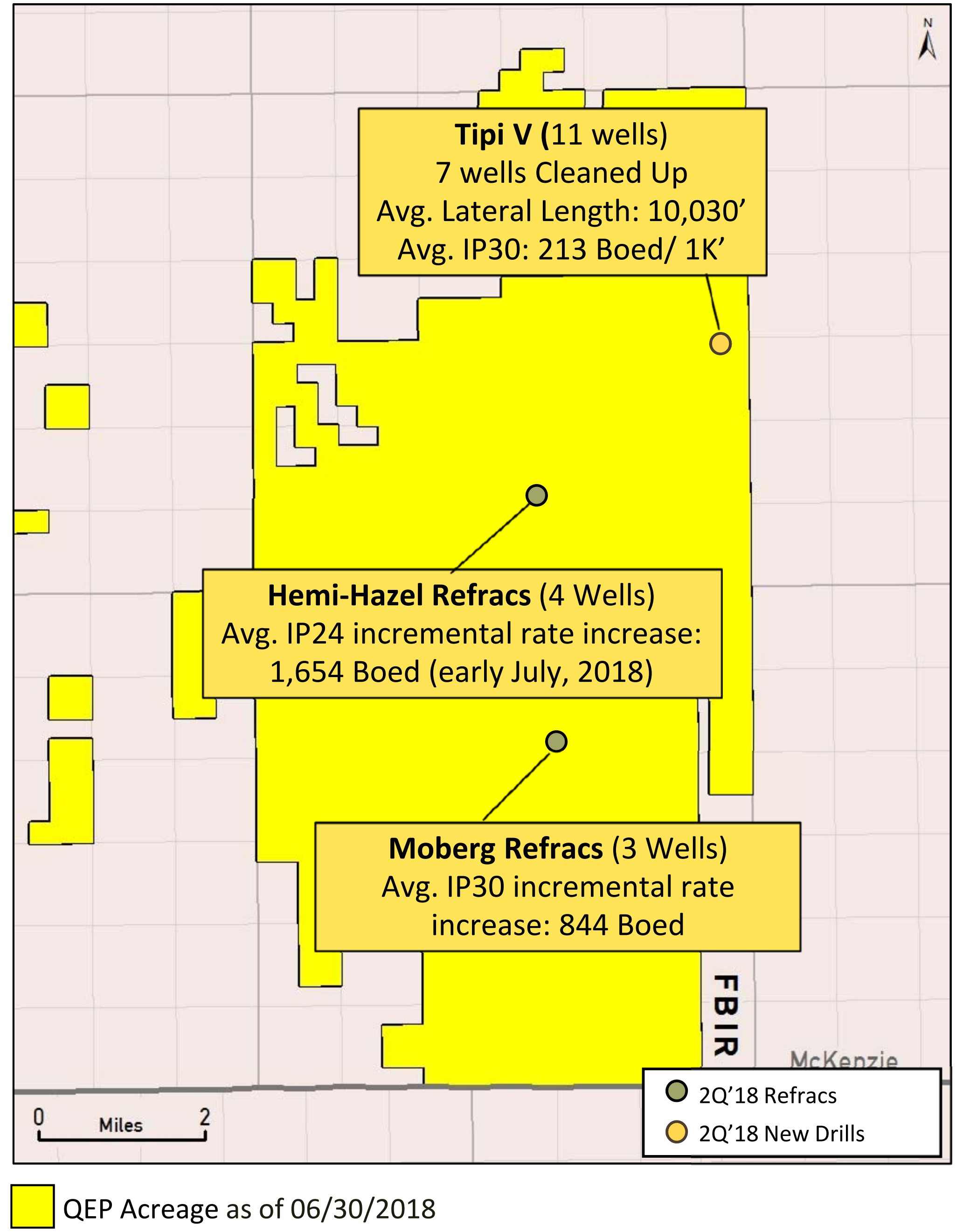
[1] As of June 30, 2018
[2] As of December 31, 2017, SEC Pricing

Net Production - Mboed



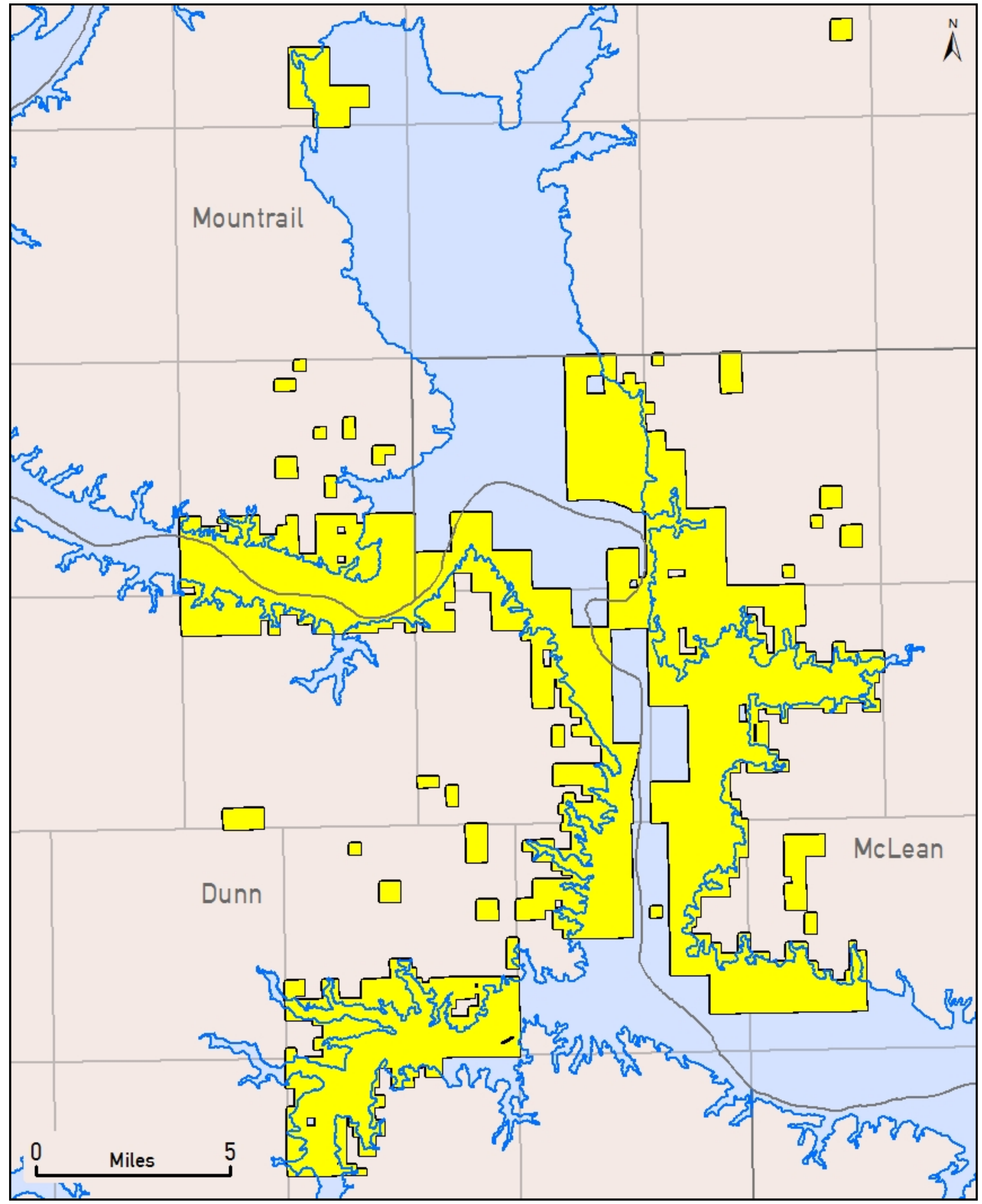
Williston Basin – *South Antelope 2Q 2018 Summary & Activity*

- Over 115 gross operated remaining risked drilling locations (all reserve categories)
- Over 240 gross operated remaining refrac candidates (includes modern completions)
- Put on production 11 new wells (gross)
  - Six Bakken & Five Three Forks
  - Average lateral length of 10,030’
  - Average peak 24-hour IP of 289 Boed per 1,000’
  - Best well peak 24-hour IP of 3,842 Boed (Tipi V 1-24-25 TH)
  - Seven of the 11 wells had 30 or more days on production with an average peak IP30 of 213 Boed per 1,000’
- Completed and returned to production seven refracs
  - Three refracs had reached peak oil rates with an average peak IP30 gross uplift of 844 Boed by the end of 2Q 2018
  - Four refracs reached an average incremental peak 24-hour IP rate increase of 1,654 Boed in early July, 2018
- Approximately 268 gross operated producing wells



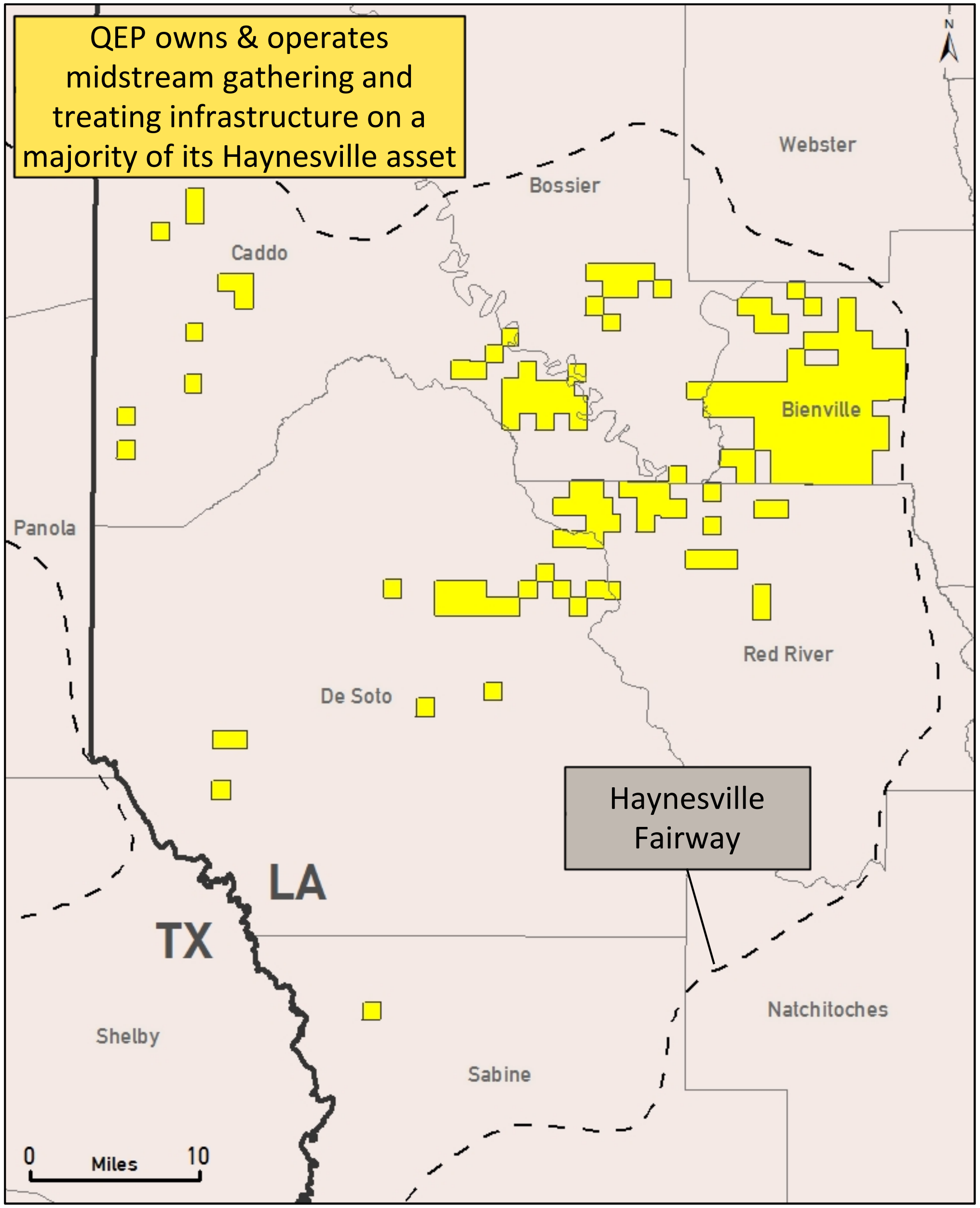
Williston Basin – *FBIR 2Q 2018 Summary & Activity*

- Over 240 gross operated remaining risked drilling locations (all reserve categories)
- Over 100 gross operated remaining refrac candidates (includes modern completions)
- Approximately 126 gross operated producing wells
- No activity in the quarter



QEP Acreage as of 06/30/2018

Haynesville



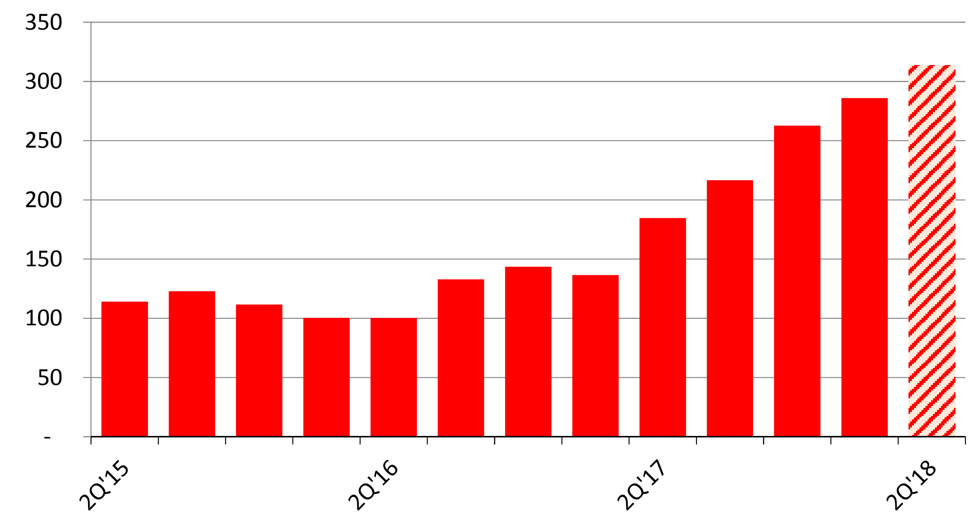
QEP Units as of 6/30/2018

Profile(1)

Net acres	49,700
Gross operated producing wells(2)	136
Average WI/average NRI(2)	94/72% (op)
Proved reserves (Bcfe)/% liquids(3)	959/ 0%
Production Split – oil/gas/NGL	0/100/0%

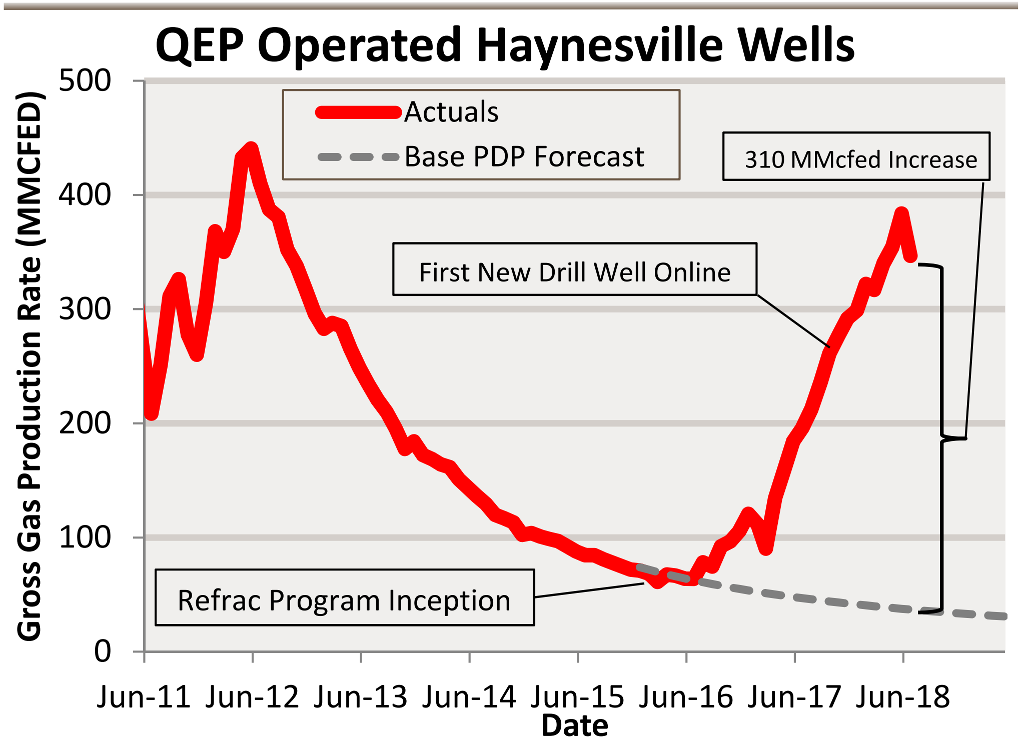
(1) As of June 30, 2018
(2) Includes only Haynesville interval wells
(3) As of December 31, 2017, SEC Pricing

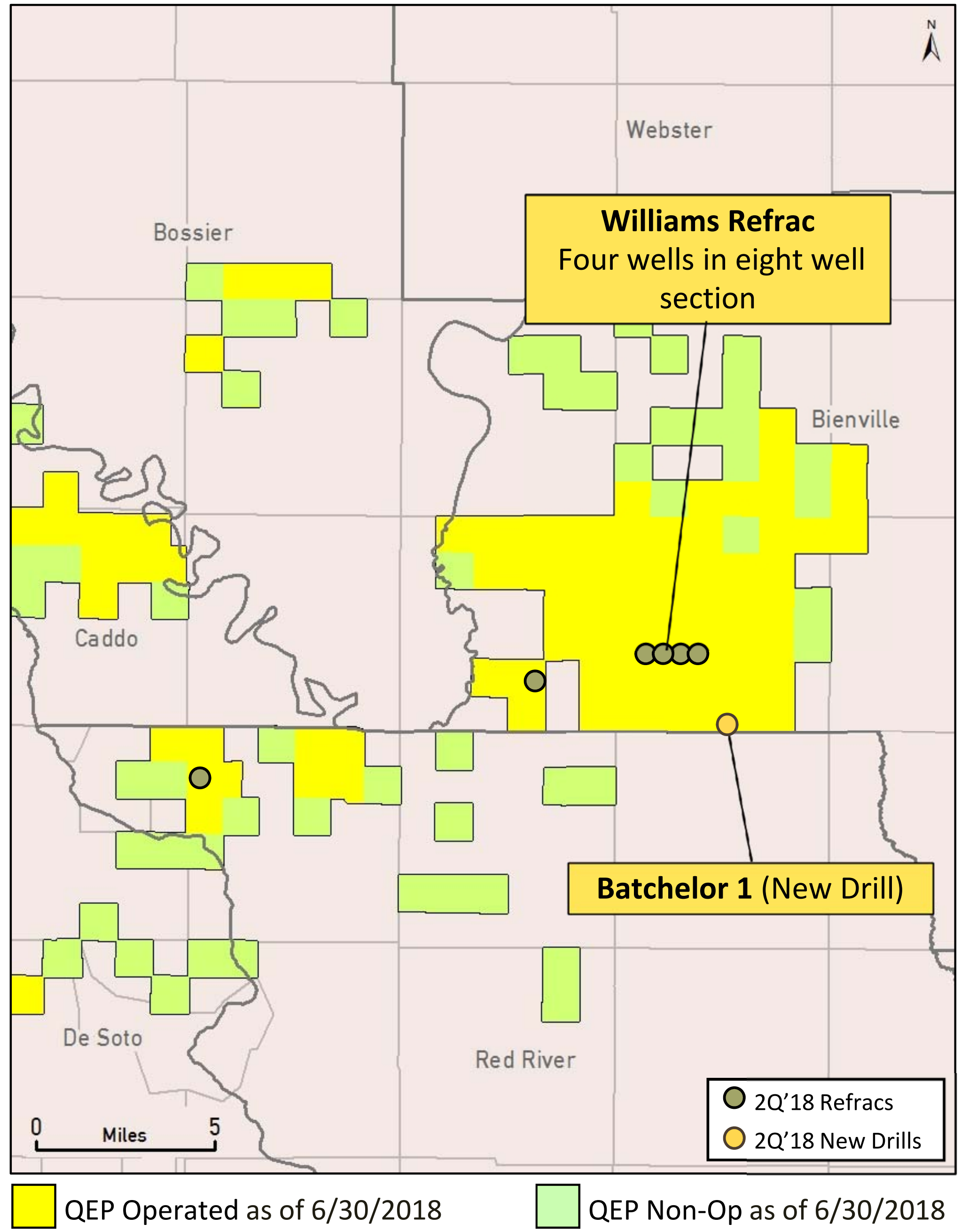
Net Production – MMcfed



Haynesville – *2Q 2018 Activity*

- Put on production one new 10,000’ lateral well at end of quarter
  - Well still cleaning up at quarter end and had not reached peak 24-hour IP
- Completed and returned to production six refracs
  - First high density refrac test (four well refrac in eight well section)
- Gross production has increased ~310 MMcfed since activity resumed 2Q 2016





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	$5.1	$1.0
	Spraberry Shale	10,000	$6.3	$1.0
	Wolfcamp	7,500	$6.4	$1.0
	Wolfcamp	10,000	$7.8	$1.0
Mustang Springs	Middle Spraberry	7,500	$4.9	$1.0
	Spraberry Shale	7,500	$4.9	$1.0
	Wolfcamp A	7,500	$5.4	$1.0
	Wolfcamp B	7,500	$5.6	$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 June 30, 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

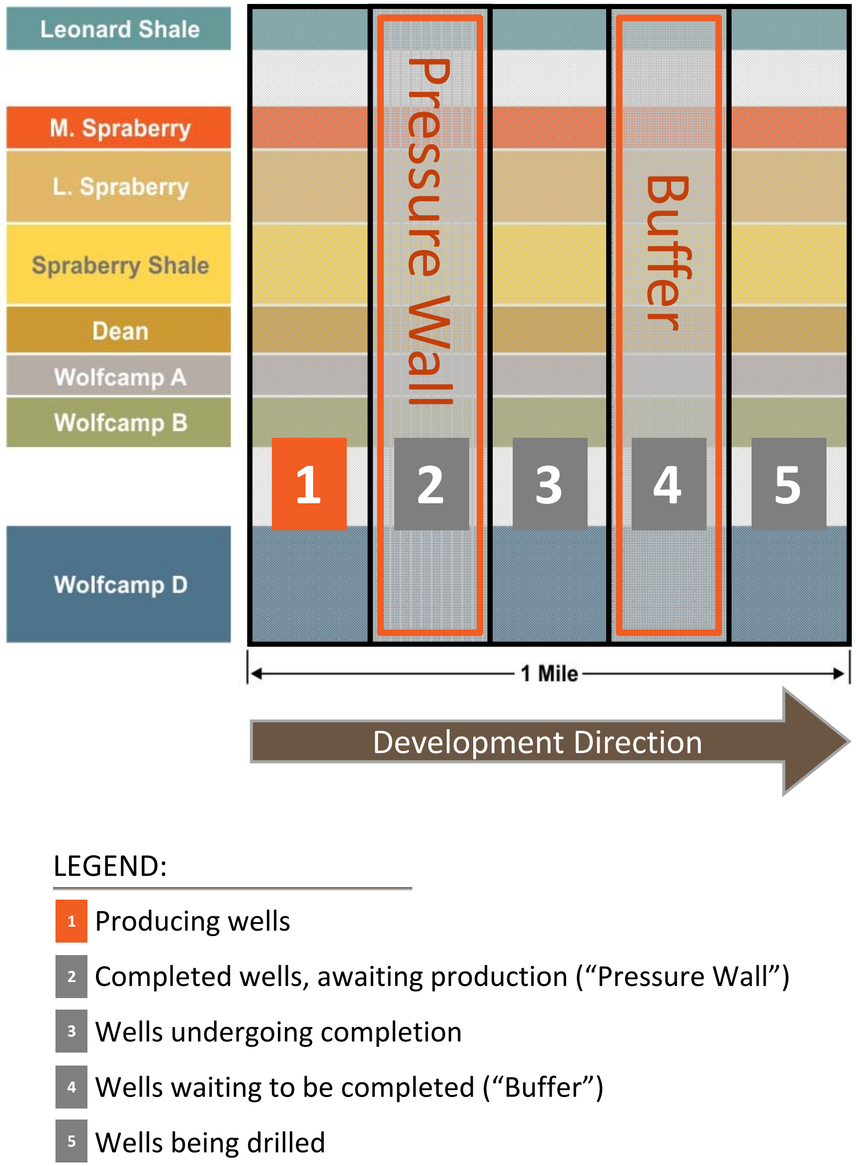
Anticipated Benefits

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

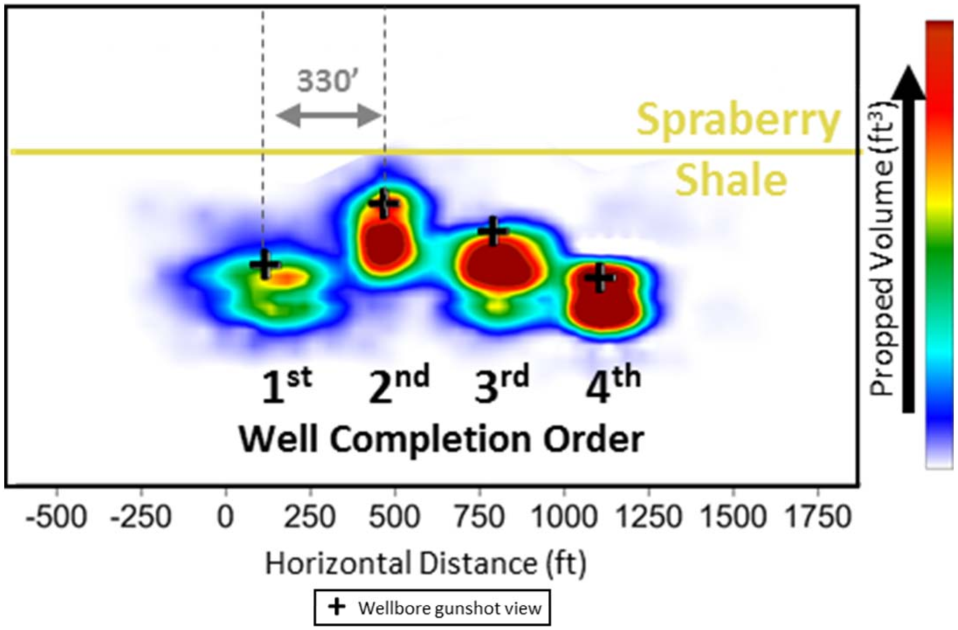
Below Ground

- Maximizes production and ultimate economic oil 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

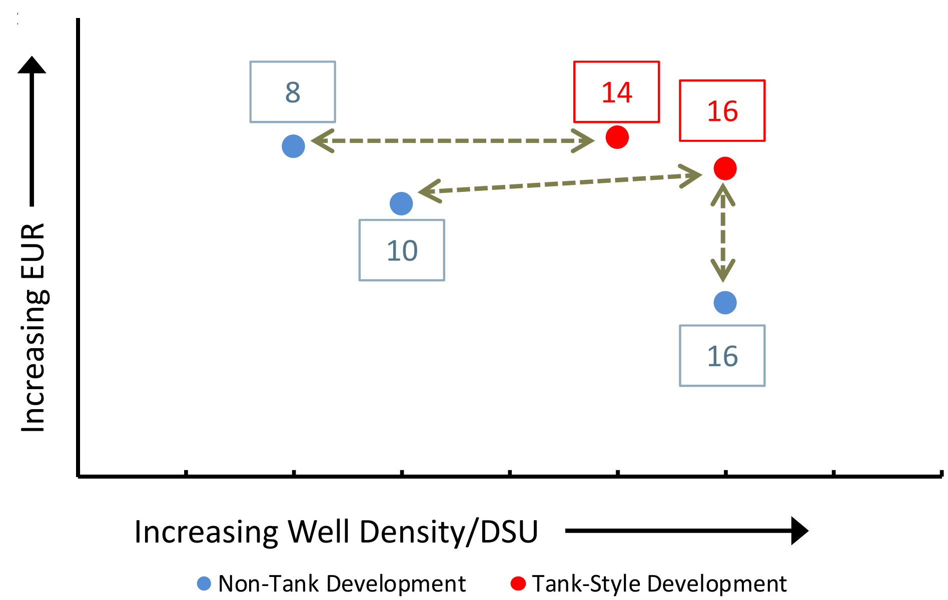


Midland Basin – *Tank-Style Development Allows for Increased Densities*

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 – *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 July 20, 2018 (excludes derivatives entered into in conjunction with the execution of the purchase and sale agreement for QEP's Uinta Basin Asset):

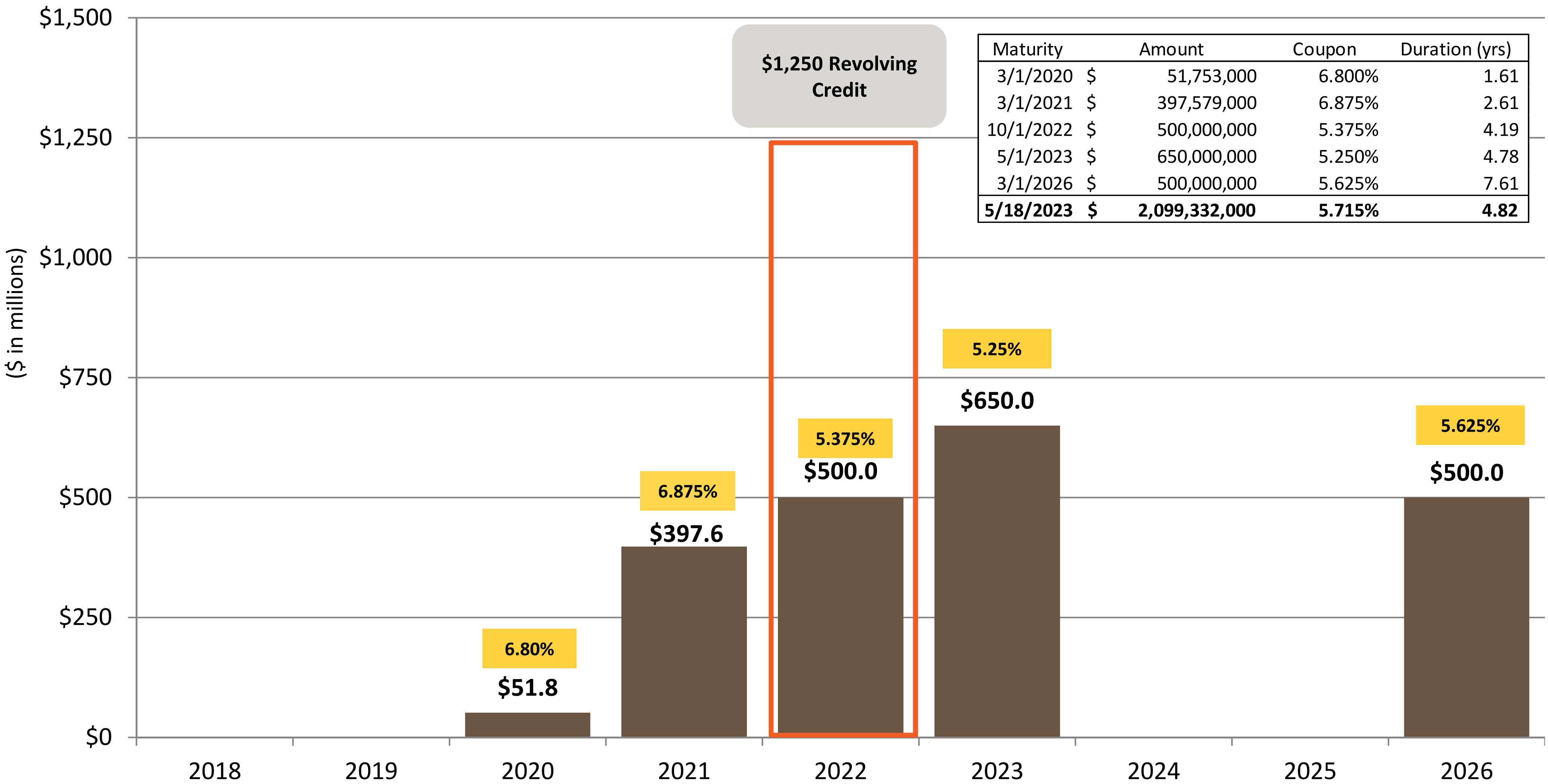
Production Commodity Derivative Swaps			
Year	**Index**	**Total Volumes**	**Average Price per Unit**
Oil Sales		(MMBbls)	($/Bbl)
2018	NYMEX WTI	8.3	$52.46
2019	NYMEX WTI	9.5	$52.66
2020	NYMEX WTI	1.8	$60.77
Gas Sales		**(million MMBtu)**	**($/MMBtu)**
2018	NYMEX HH	44.1	$3.00
2019	NYMEX HH	43.8	$2.86

Production Commodity Derivative Basis Swaps				
Year	**Index less Differential**	**Index**	**Total Volumes**	**Weighted Average Differential**
Oil Sales			**(MMBbls)**	**($/Bbl)**
2018	NYMEX WTI	Argus WTI Midland[1]	4.6	($0.99)
2018	NYMEX WTI	Argus WTI Houston[2]	0.2	$6.30
2019	NYMEX WTI	Argus WTI Midland	4.7	($0.77)
2019	NYMEX WTI	Argus WTI Houston	0.4	$4.35
2020	NYMEX WTI	Argus WTI Midland	1.5	($1.01)
Gas Sales			**(million MMBtu)**	**($/MMBtu)**
2018	NYMEX HH	IFNPCR	3.1	($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.
(2) Argus WTI Houston is an index price reflecting the weighted average price of WTI at Magellan's East Houston crude oil terminal.

QEP Resources – *Debt Maturity Schedule*

As of July 25, 2018



Maturity		Amount	Coupon	Duration (yrs)
3/1/2020	$	51,753,000	6.800%	1.61
3/1/2021	$	397,579,000	6.875%	2.61
10/1/2022	$	500,000,000	5.375%	4.19
5/1/2023	$	650,000,000	5.250%	4.78
3/1/2026	$	500,000,000	5.625%	7.61
5/18/2023	**$**	**2,099,332,000**	**5.715%**	**4.82**