

PetroQuest Energy, Inc.

August 2017

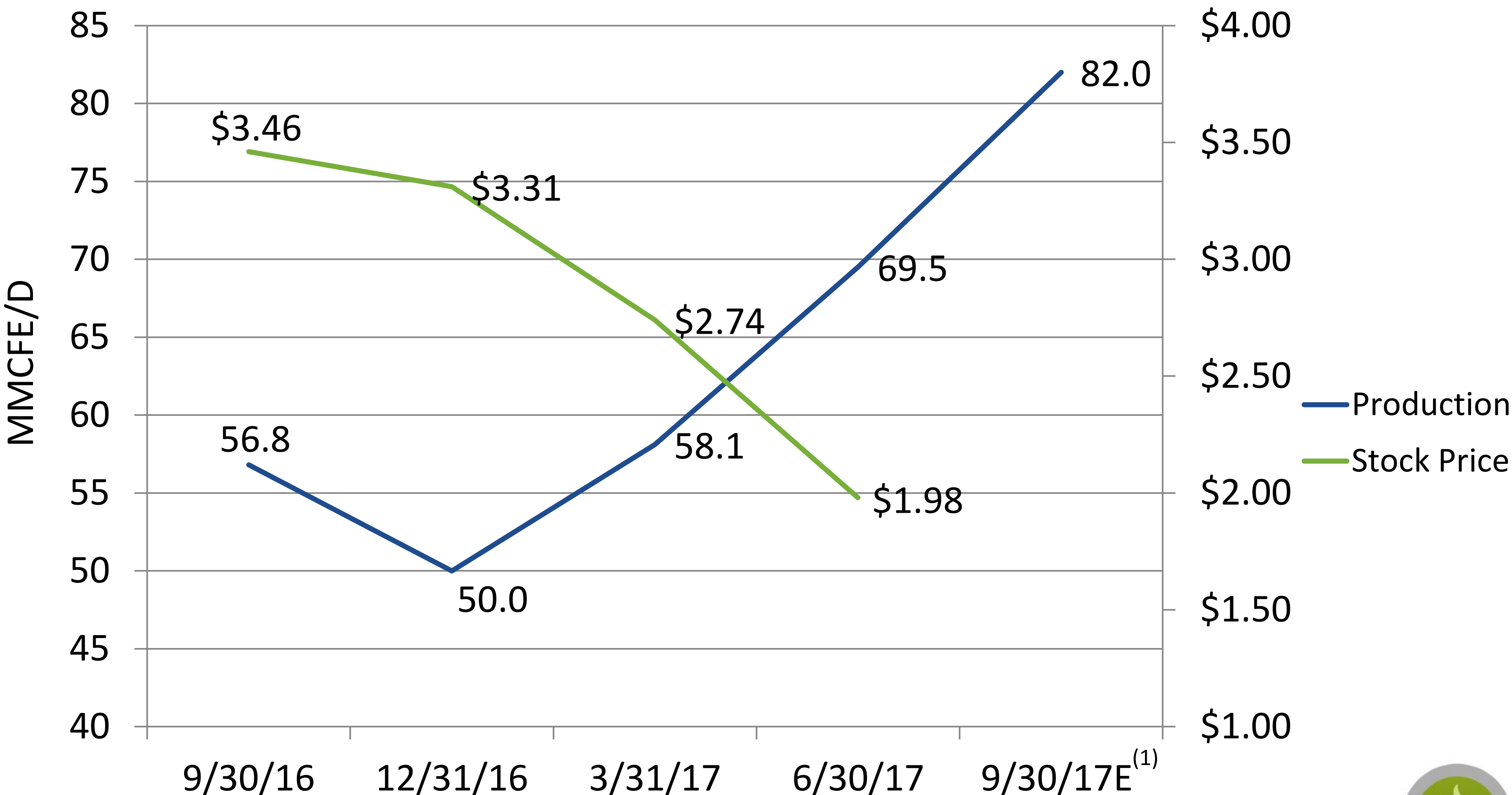
Forward-Looking Statements

This presentation contains "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. All statements other than statements of historical fact included in this presentation are forward-looking statements. Although PetroQuest believes that the expectations reflected in these forward-looking statements are reasonable, these statements are based upon assumptions and anticipated results that are subject to numerous uncertainties and risks. Actual results may vary significantly from those anticipated due to many factors, our ability to successfully close the previously disclosed commitment for a four-year multi-draw term loan facility or receive any proceeds from draws thereunder; the sufficiency of our current liquidity; the volatility of oil and natural gas prices and significantly depressed oil prices since the end of 2014; our indebtedness and the significant amount of cash required to service our indebtedness; our ability to improve our liquidity position and refinance or restructure our indebtedness, including our 2017 Notes and 2021 2L Notes; the potential need to sell assets or seek bankruptcy protection; our estimate of the sufficiency of our existing capital sources, including availability under our bank credit facility and the result of any borrowing base redetermination; our ability to post additional collateral to satisfy our offshore decommissioning obligations; our ability to hedge future production to reduce our exposure to price volatility in the current commodity pricing market; ceiling test write-downs resulting, and that could result in the future, from lower oil and natural gas prices; our ability to raise additional capital to fund cash requirements for future operations; limits on our growth and our ability to finance our operations, fund our capital needs; our ability to find, develop and produce oil and natural gas reserves that are economically recoverable and to replace reserves and sustain production; approximately 50% of our production being exposed to the additional risk of severe weather, including hurricanes, tropical storms and flooding, and natural disasters; losses and liabilities from uninsured or underinsured drilling and operating activities; changes in laws and governmental regulations as they relate to our operations; the operating hazards attendant to the oil and gas business; the volatility of our stock price; and our ability to meet the continued listing standards of the New York Stock Exchange with respect to our common stock or to cure any deficiency with respect thereto. In particular, careful consideration should be given to cautionary statements made in the various reports the Company has filed with the SEC. The Company undertakes no duty to update or revise these forward-looking statements. In particular, careful consideration should be given to cautionary statements made in the various reports PetroQuest has filed with the Securities and Exchange Commission. PetroQuest undertakes no duty to update or revise these forward-looking statements.

Prior to 2010, the Securities and Exchange Commission generally permitted oil and gas companies, in their filings, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. Beginning with year-end reserves for 2009, the SEC permits the optional disclosure of probable and possible reserves. We have elected not to disclose our probable and possible reserves in our filings with the SEC. We use the terms “reserve inventory,” “gross unrisked reserves,” “EUR,” “inventory”, “unrisked resource potential”, 3P reserves or other descriptions of volumes of hydrocarbons to describe volumes of resources potentially recoverable through additional drilling or recovery techniques that the SEC’s guidelines prohibit us from including in filings with the SEC. Estimates of reserve inventory, gross unrisked reserves EUR, inventory, unrisked 3P reserves do not reflect volumes that are demonstrated as being commercially or technically recoverable. Even if commercially or technically recoverable, a significant recovery factor would be applied to these volumes to determine estimates of volumes of proved reserves. Accordingly, these estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by the Company. The methodology for estimating unrisked inventory, gross unrisked reserves, EUR, or unrisked resource potential or 3P reserves may also be different than the methodology and guidelines used by the Society of Petroleum Engineers and is different from the SEC’s guidelines for estimating probable and possible reserves.

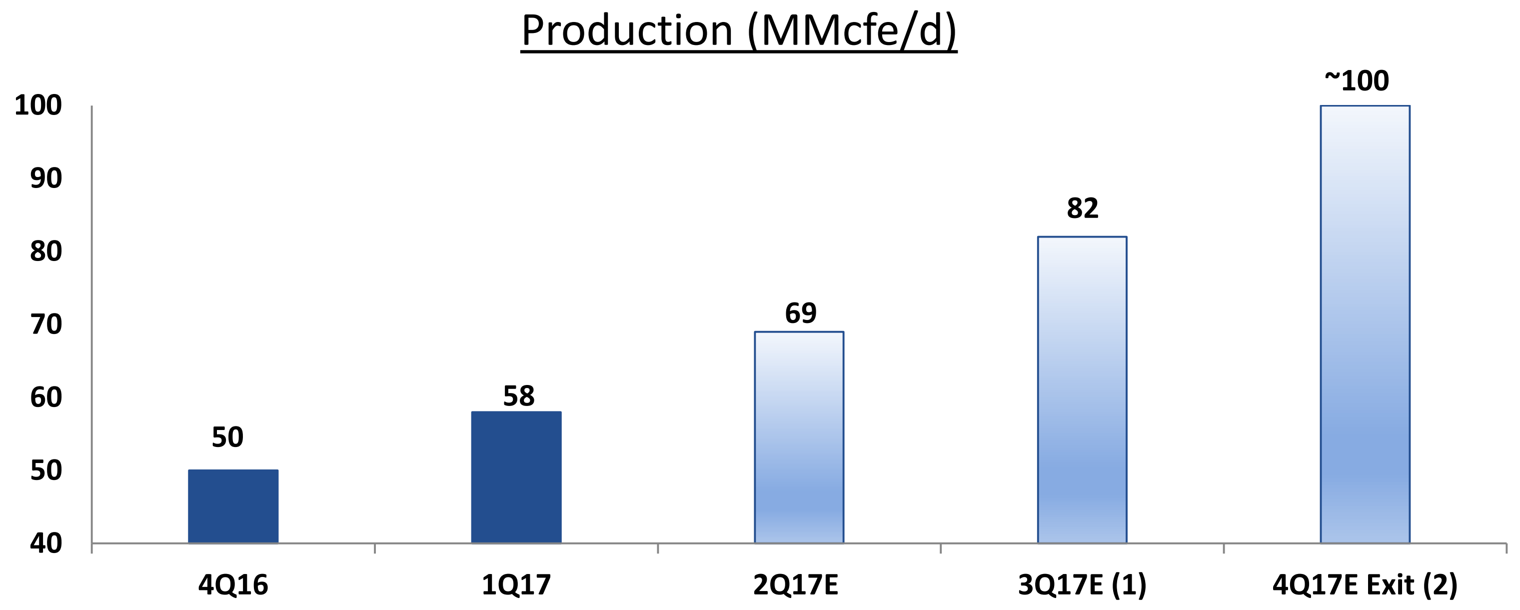
Underlying Fundamentals Decoupled From Market Valuation

Production up 44%
Stock price down 43%



(1) Based on the mid-point of 2Q17 and 3Q17E production guidance

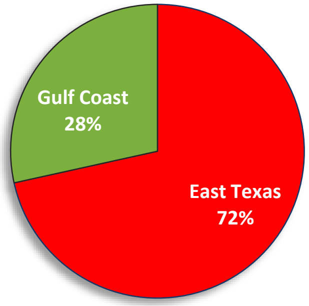
2017 Production & EBITDA Growth Profiles



(1) Based upon mid-point of guidance
(2) 4Q16 to 4Q17 production goal
(3) Factset average analyst estimate

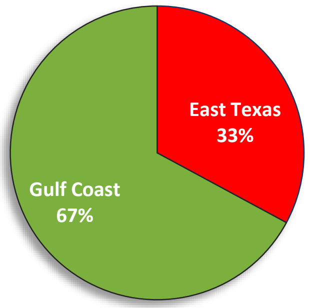
Our Properties

2016 Reserves



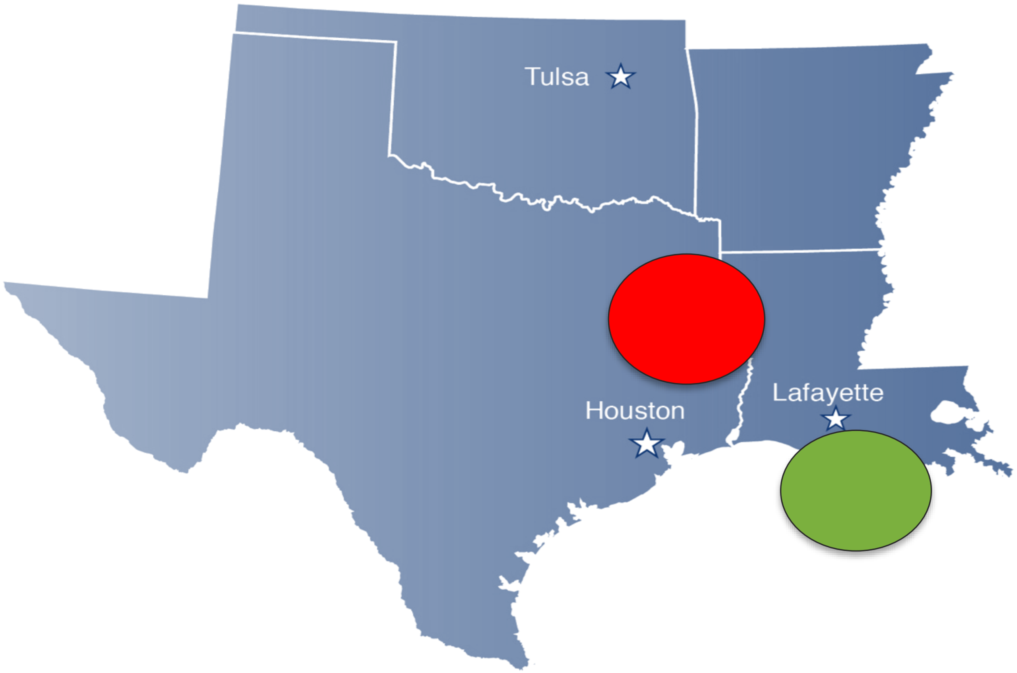
115 Bcfe

2Q17 Production



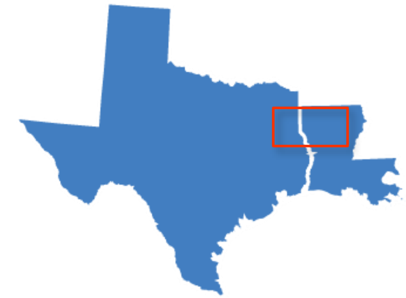
69% Gas
17% NGL
16% Oil

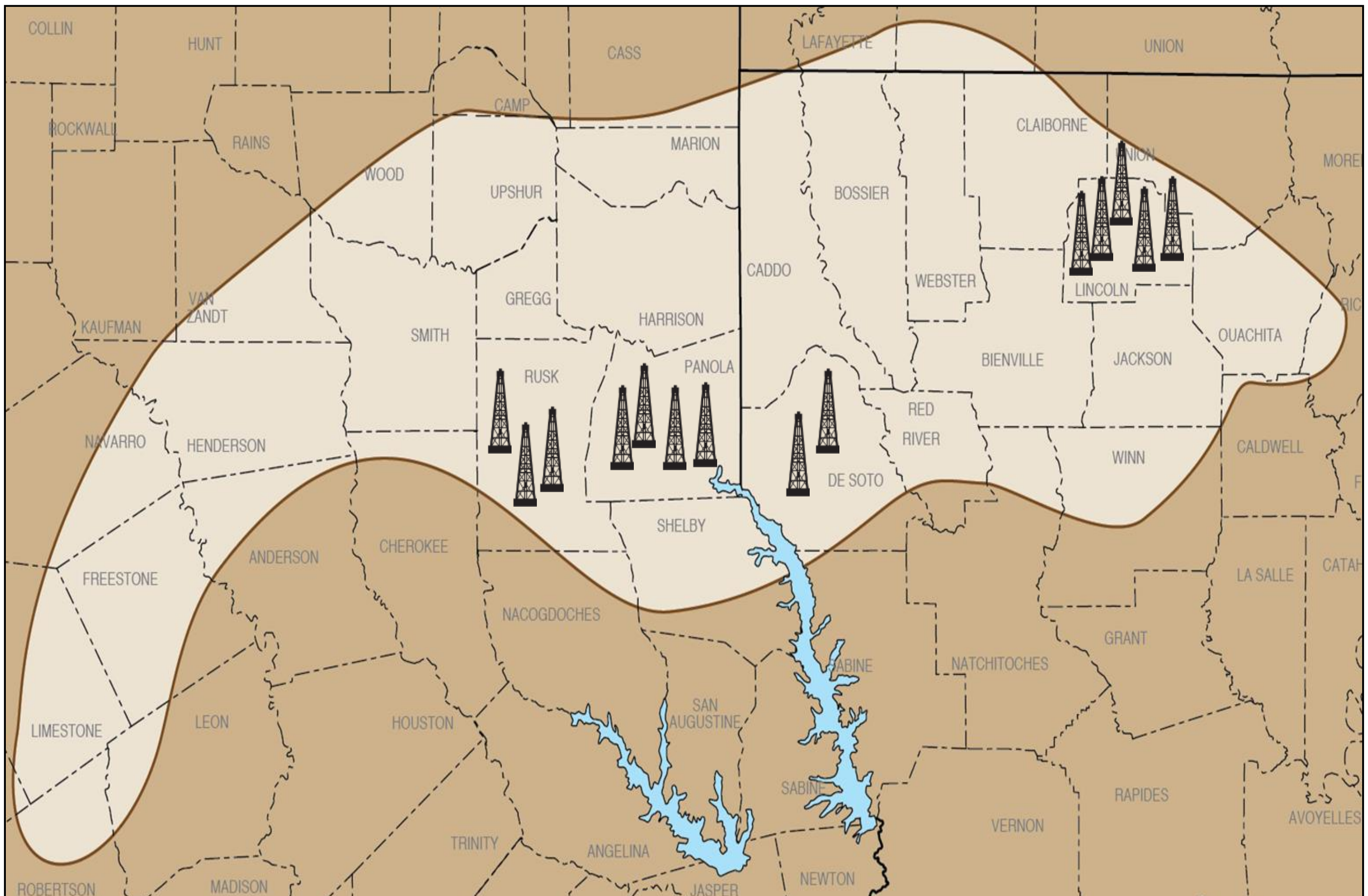
69 Mmcfe/d



Industry Activity - Cotton Valley Trend

Relative Rock Quality Comparison		
Porosity	Haynesville (3-14%)	**PQ Cotton Valley (10%)**
Permeability	Haynesville (<1 MD)	**PQ Cotton Valley (10 MD)**





County/Parish	Operator	Rig Count
Desoto	Exco Oper Co Indigo	1 1
Lincoln	Range Louisiana Wildhorse Res Mgmt	3 2
Panola	Brammer Engineering Memorial/Amplify PetroQuest Energy Tanos Exploration II	1 1 1 1
Rusk	Tanos Exploration II Valence Operating Co Verado Energy	1 1 1

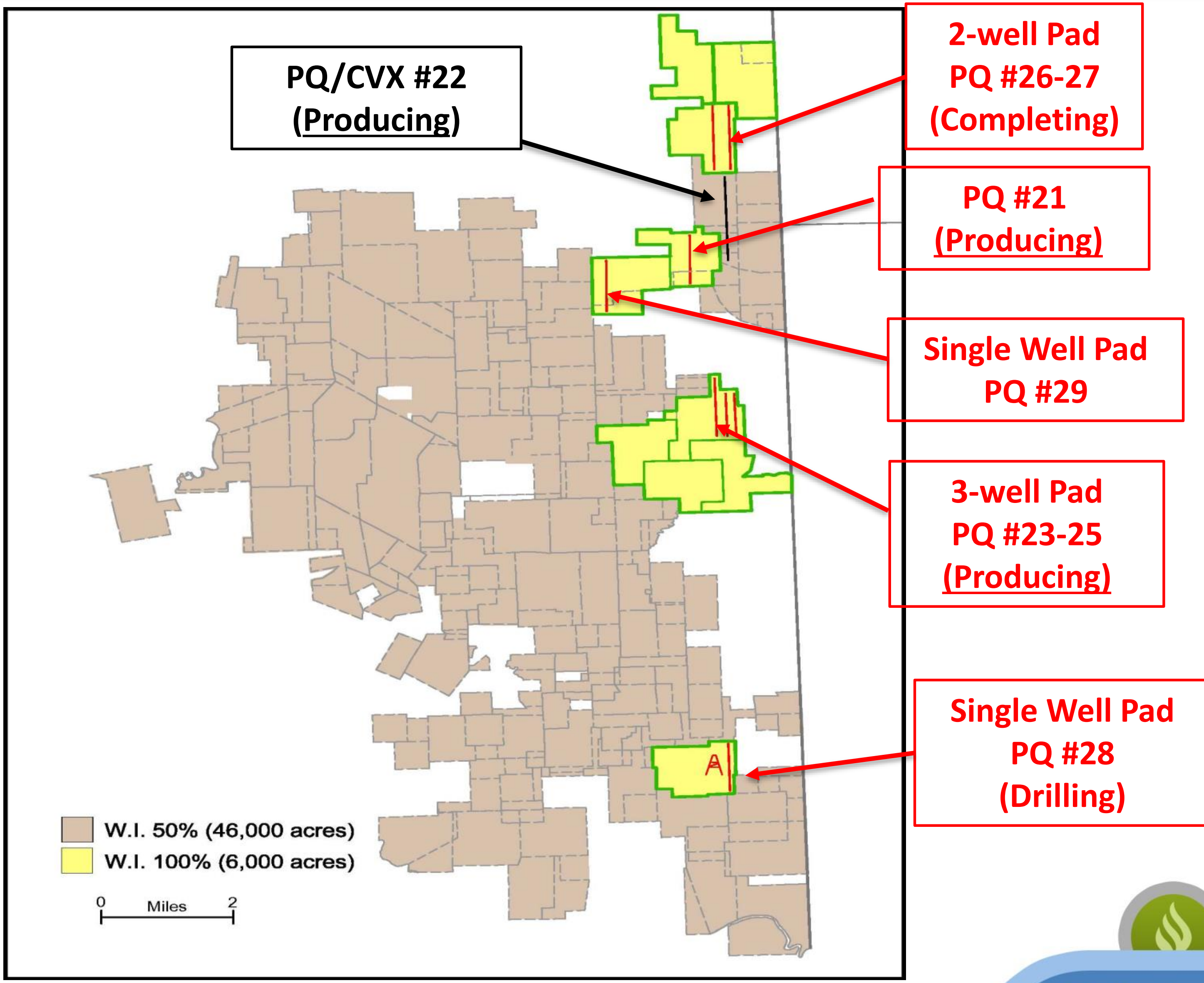
Advantages of PQ’s Cotton Valley

- **Geology:** high permeability sandstones relative to low permeability shales
- **Multiple targets:** >1,400’ thick sand column with seven benches to target
- **Low risk:** hundreds of vertical wells with decades of production history, cores and logs
- **Large resource potential:** previous vertical wells didn’t efficiently drain the producing zone – perfect application for horizontal development
- **Low cost:** normal pressure drilling environment, simple frac design and low operating costs
- **Superior location**: premium Gulf Coast pricing, supportive land owners and state/local agencies
- **Exceptional returns:** 67% IRR using a $3.00/Mcf natural gas price assumption and most recent well cost

2017 Cotton Valley Drilling Program

2017 Activity

- 5 Wells Producing
- 2 Wells Completing
- 2 Wells Remaining

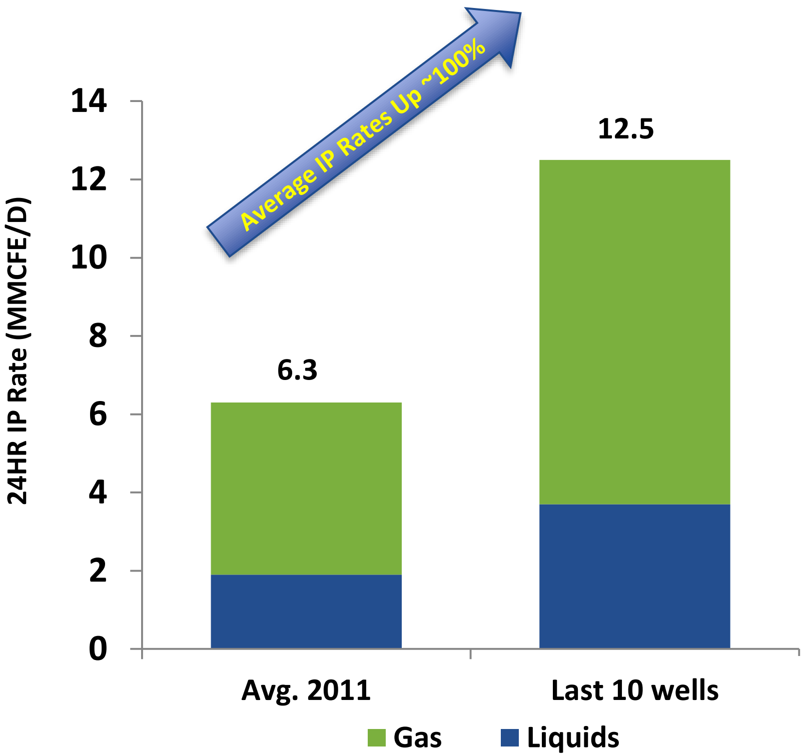


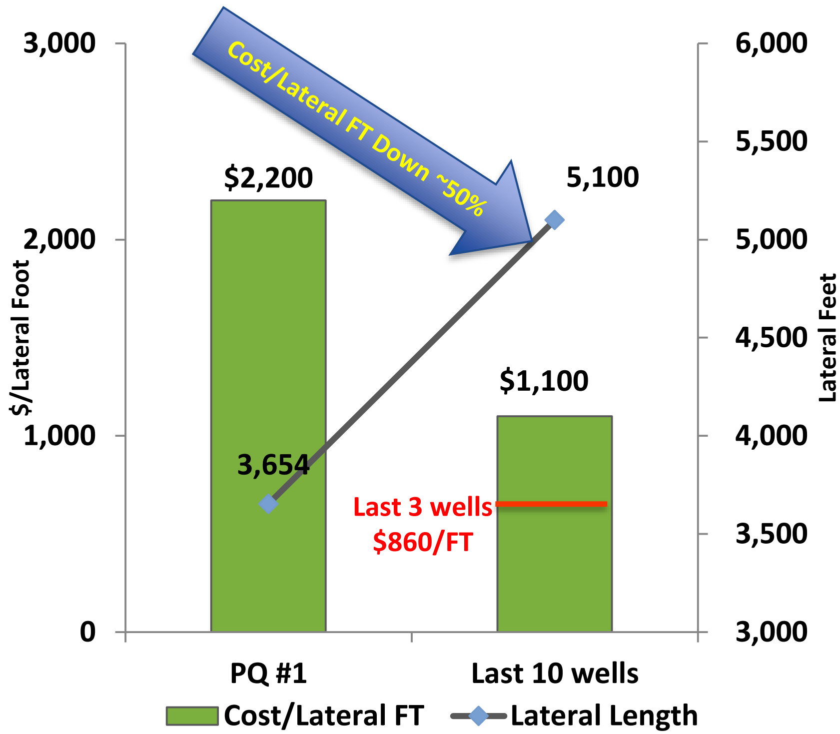
Achievements of First Multi-Well Pad (PQ #23- PQ #25)

- **Combined IP rate from the three well pad was ~38 Mmcfe/d (NRI 59%)**
- **Eastern well on the pad, PQ #25, achieved the Company's highest IP rate to date at ~18 Mmcfe/d (5,135 ft lateral well)**
  - **Increased frack size by approximately 70% to 1,200 lbs/foot representing largest Company frack in Cotton Valley**
  - **With higher frack intensity, total drill and complete was ~ $900/lateral foot**
  - **Based on early results, future wells should benefit from larger fracks**
- **Average drill and complete cost for the three wells totaled $860/lateral foot**
  - **Represents 14% improvement vs. corporate goal of < $1,000/lateral foot**
  - **Represents 60% improvement from Company's first horizontal CV well**

Cotton Valley Horizontal – Production Up with Costs Down

Improving Well Performance

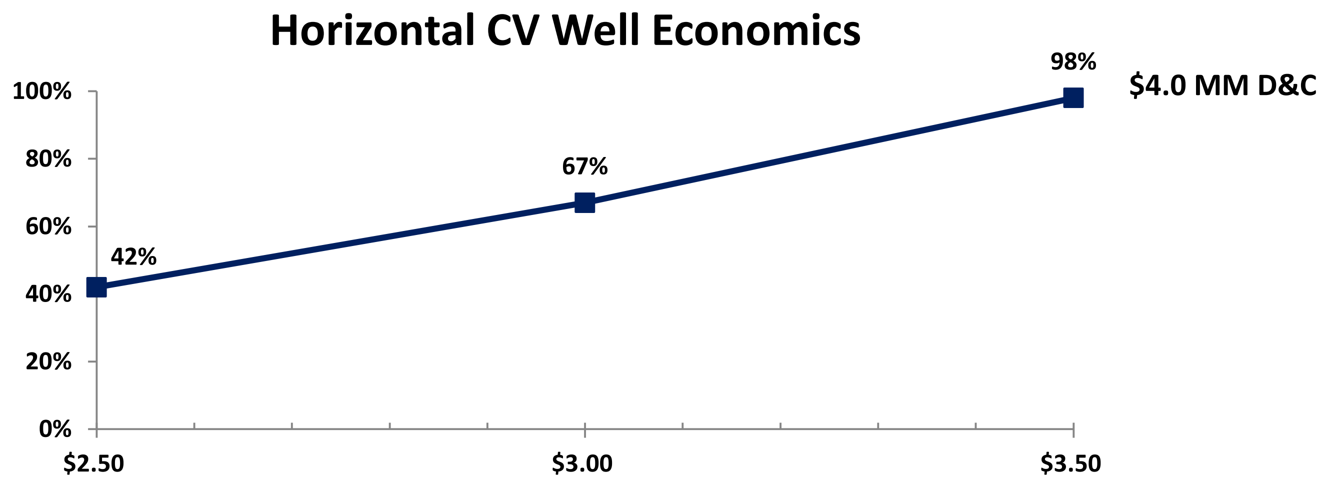




Goal to Consistently Execute Drilling @ Less than $1,000/lateral foot
Last 3 wells were drilled @ $860/FT

Cotton Valley Horizontal Economics

Sensitivity to Gas Prices



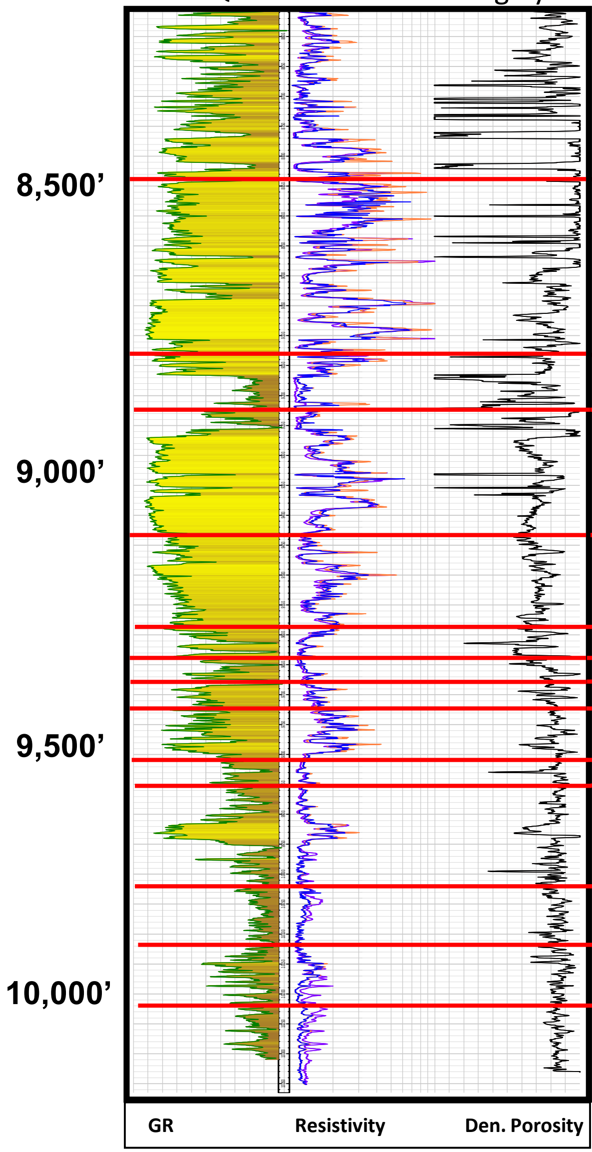
Economic Assumptions

Assumptions	
Gross Well Cost ($MM)	4.0 (~$900/lateral foot)
EUR (Bcfe) (1)	8.0
IP Rate (Mmcfe/d) (1)	11
% Gas / Liquids	70% / 30%
IRR (%)	67%

(1) 2015 Avg. well performance with laterals in excess of 4,500 feet - $3.00/Mcf gas, $18 NGL/Bbl and $50 oil/Bbl

Multi Bench Cotton Valley Opportunities

PetroQuest -- McFadden Bagley #1



Cotton Valley Benches

"C&D" Sands

Vaughn Sand

Davis Sand

E4 Sands

E Sands

Roseberry/Eberry Sand

Taylor/Sexton

Cotton Valley Drilling Locations

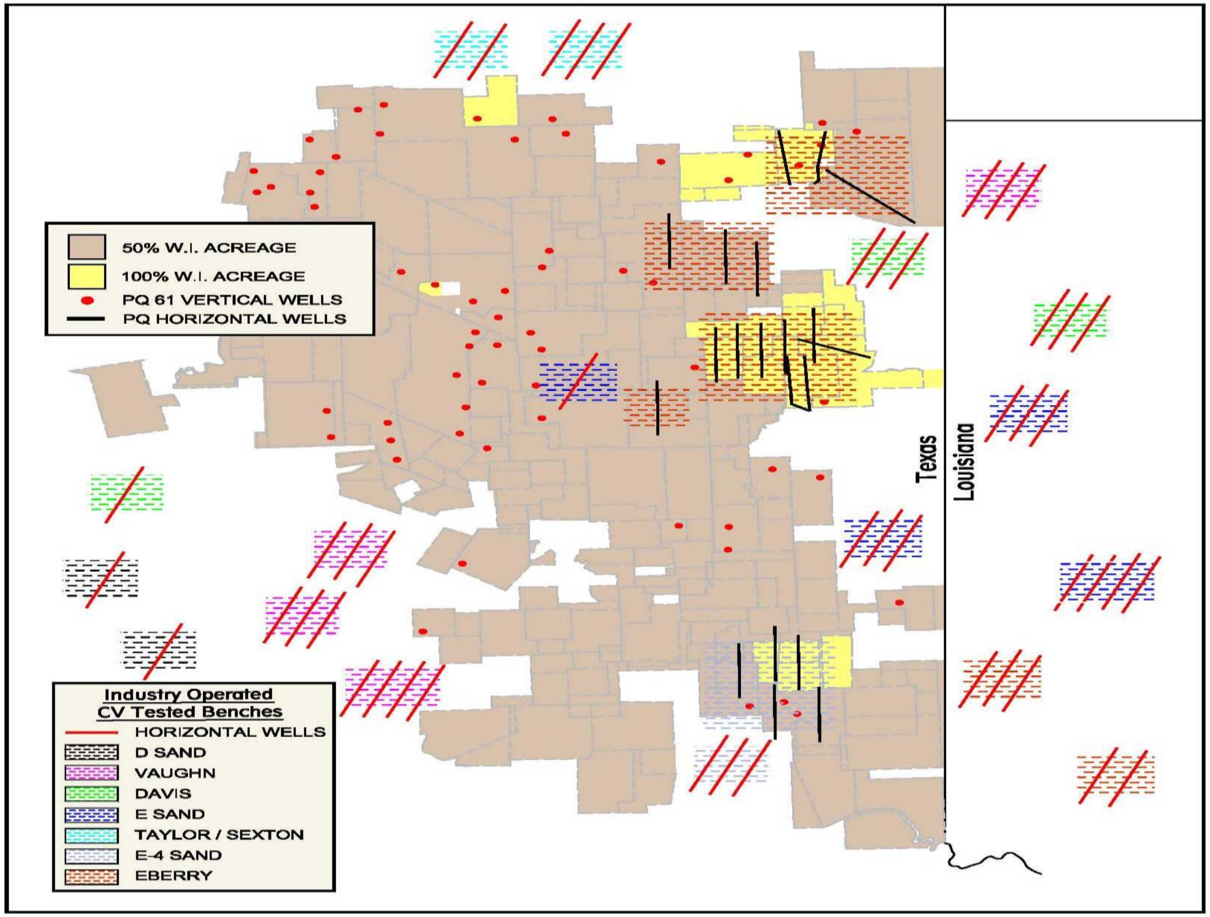
Bench	Gross Drilling Locations*
C&D	90
Vaughn	114
Davis	182
E4	65
E	95
Eberry/Roseberry	41
Sexton/Taylor	14
Total Gross Drilling Locations	**601**

* Locations based on 1500' spacing within area of estimated economic net feet of pay determined by offsetting vertical well logs

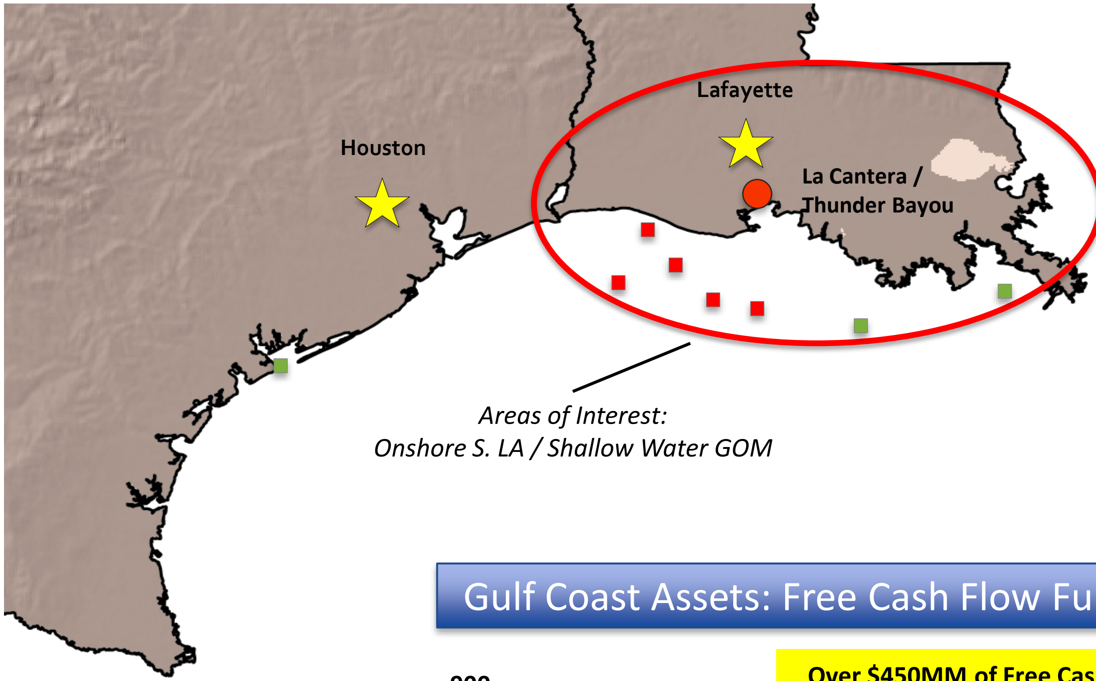
NOTE> **All of the above benches are productive on PQ acreage through >140 vertical wells and all benches have been tested horizontally in close proximity to PQ acreage**

Cotton Valley Acreage Position

55,000 Gross Acres (100% HBP)
~600 Gross Future Locations (450 Net)



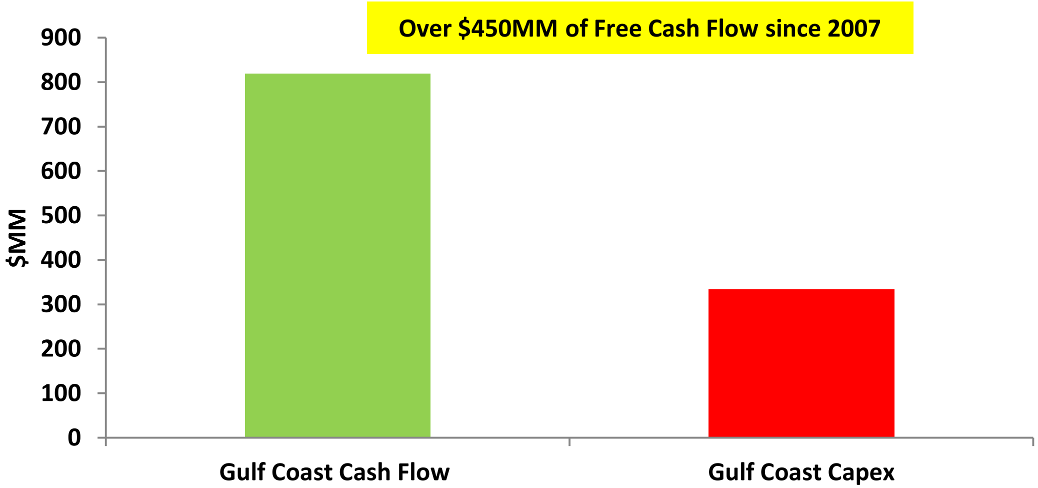
Gulf Coast – Free Cash Flow Generator



Key Operating Metrics

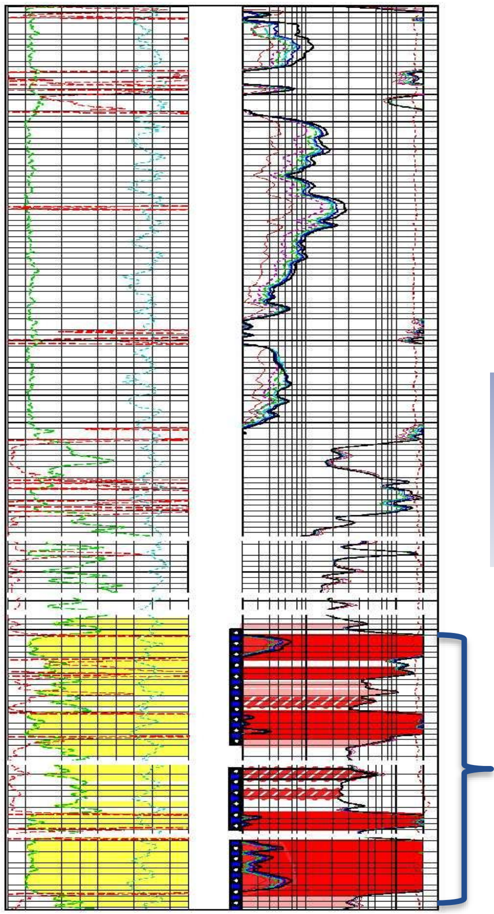
Ten Year Drilling Success Rate:	70%
2Q17 Production (Mmcfe/d)	46
% Gas:	68%
% NGL:	11%
% Oil:	21%

Gulf Coast Assets: Free Cash Flow Funds Growth (1)(2)



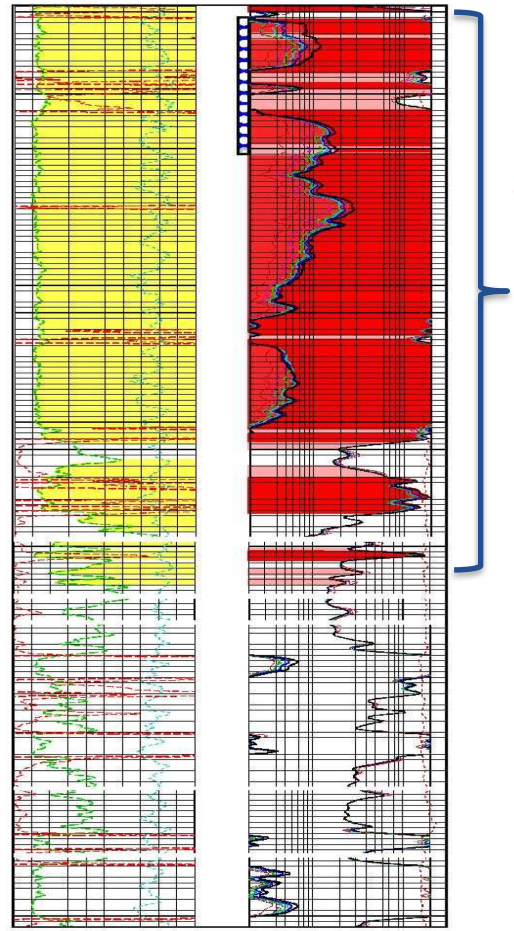
(1) Cash Flow = Revenues less lease operating expenses and severance taxes from Gulf Coast/Gulf of Mexico. Please see Appendix 4 for reconciliation.
(2) 2014 Capex excludes non-cash Fleetwood accruals and 2013 Capex excludes GOM acquisition.

Thunder Bayou Recompletion



~$35MM in field level cash flow

Bottom Zone
Cum Prod: 14.6 Bcfe
Original 1P: 8.6 Bcfe



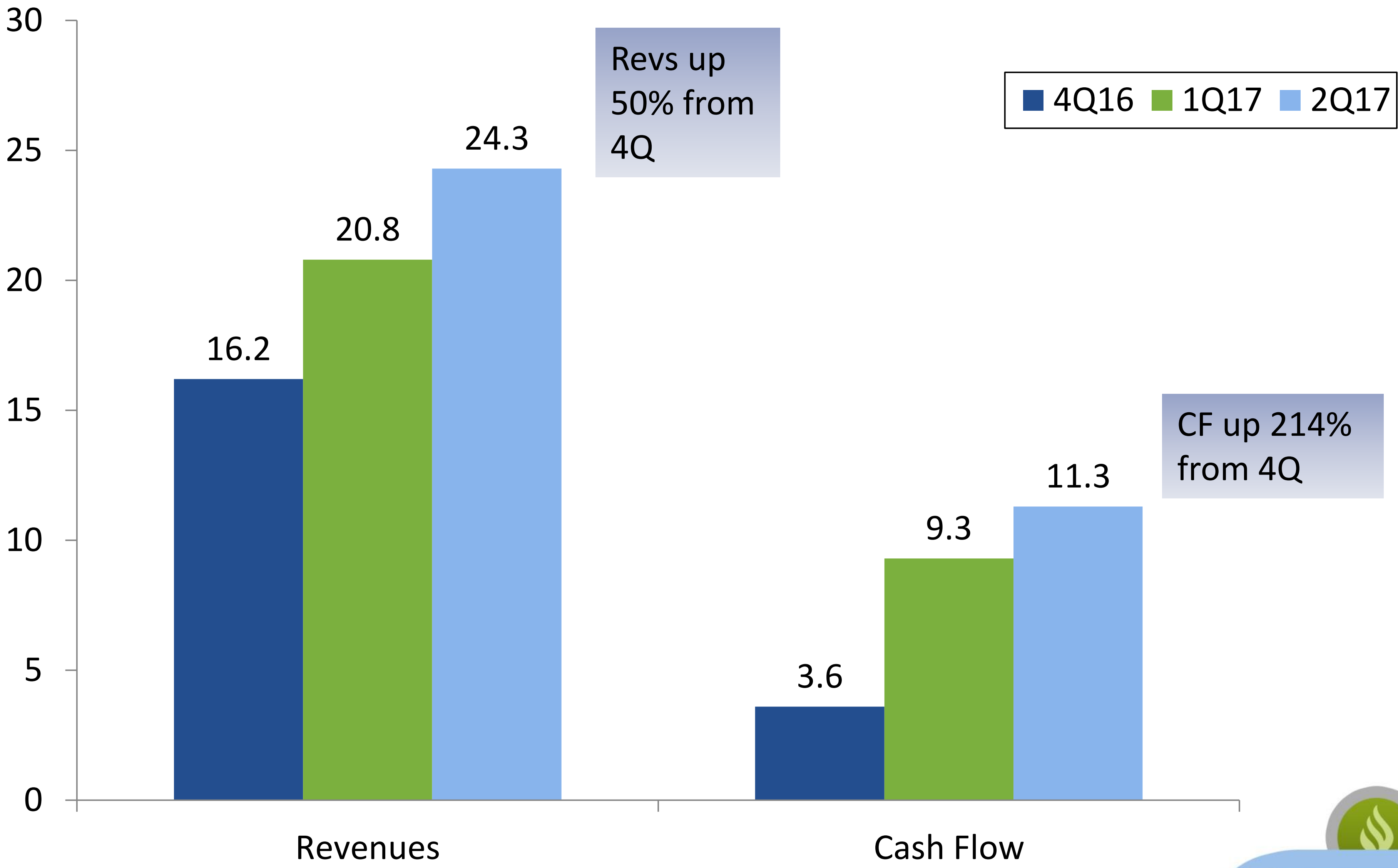
Recompletion
Current Production:
~61 MMCFE/D
39 MMCF/D of Gas
1,500 Bbls/D Oil
2,200 Bbls/D NGLs
3P Est: ~140 Bcfe

Thunder Bayou/La Cantera 3P Value

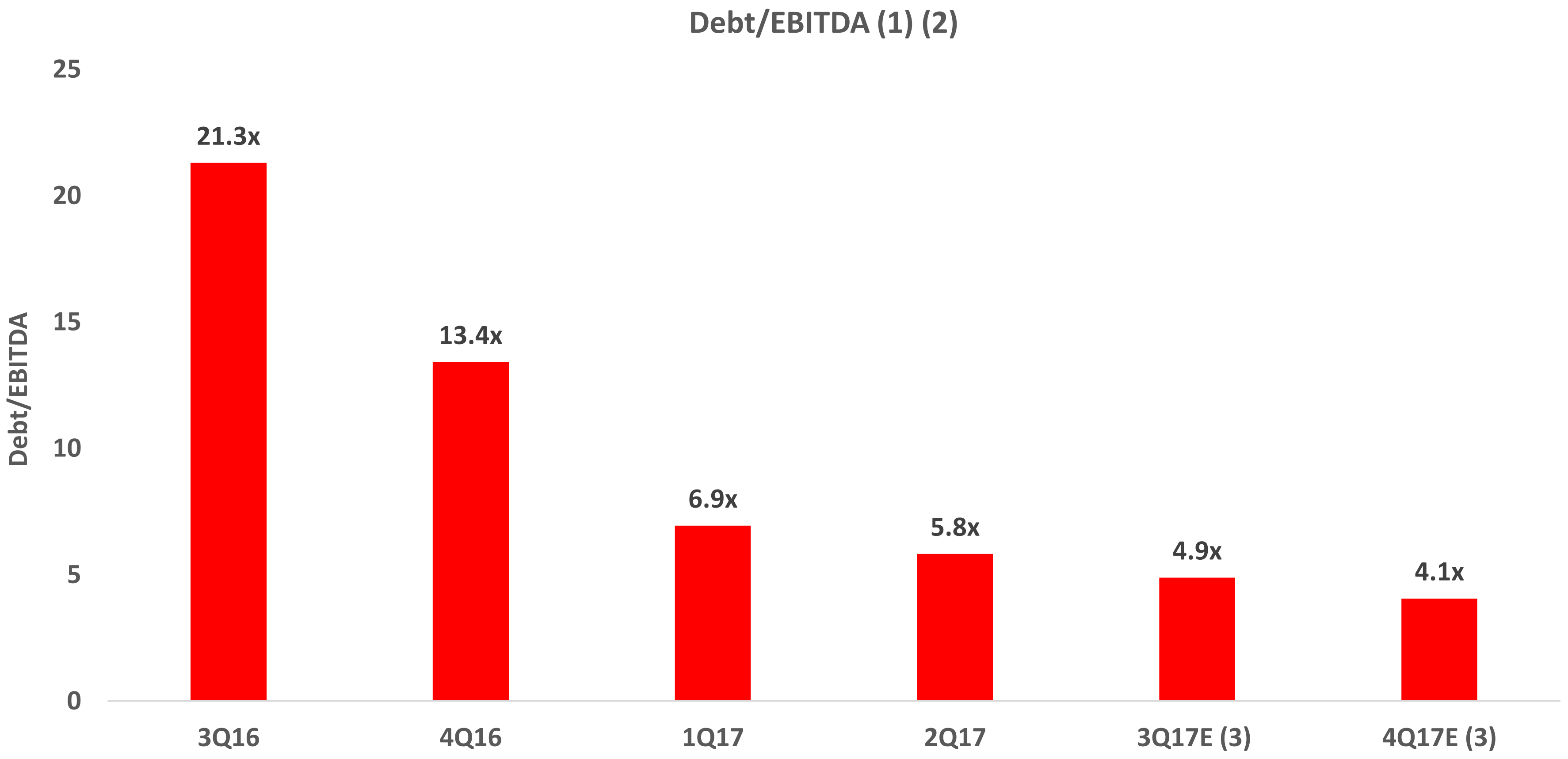
Remaining Gross 3P Reserves	~200 Bcfe
May 2017 Cash Margin(1)	$3.54
Remaining Gross 3P Value(undiscounted)	$708 MM
PQ Weighted Avg. NRI	31%
Net Value to PQ	$219 MM
Shares O/S	21,200,000
Value per Share	**$10.33**

(1) Revenues (oil, gas and ngl) less lifting costs (LOE and sev taxes)

Sequential Growth Profile ($mm)

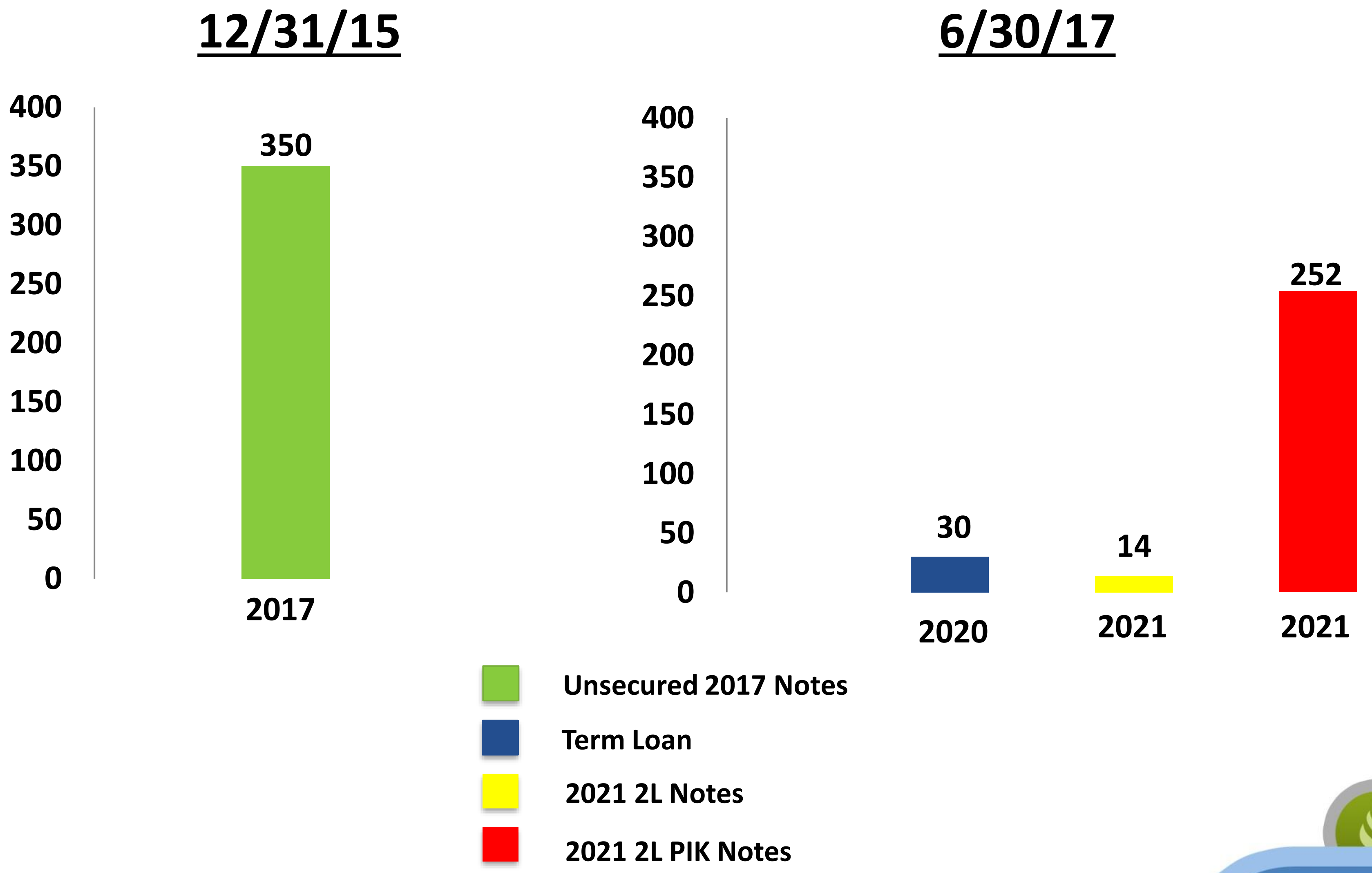


Relative Deleveraging Through Cash Flow Growth



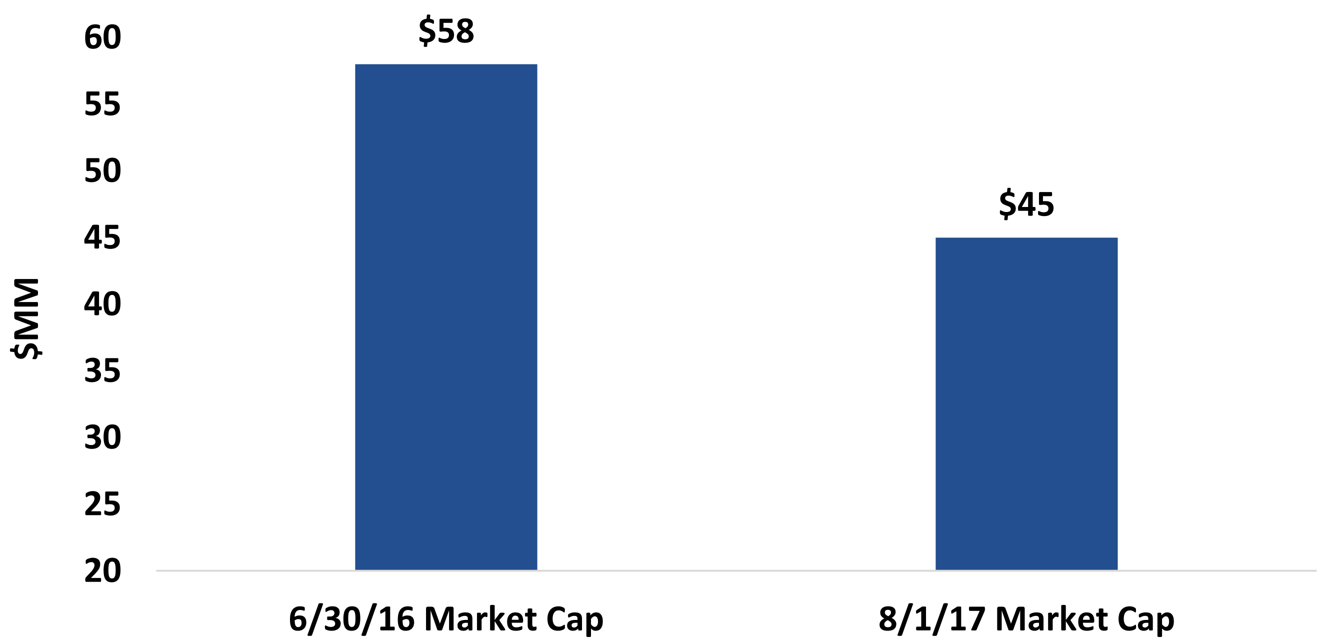
(1) Debt balance assumes PIK option is selected
(2) Quarterly EBITDA annualized
(3) FactSet quarterly average analyst estimate annualized

Changes to Maturity Profile ($000s)



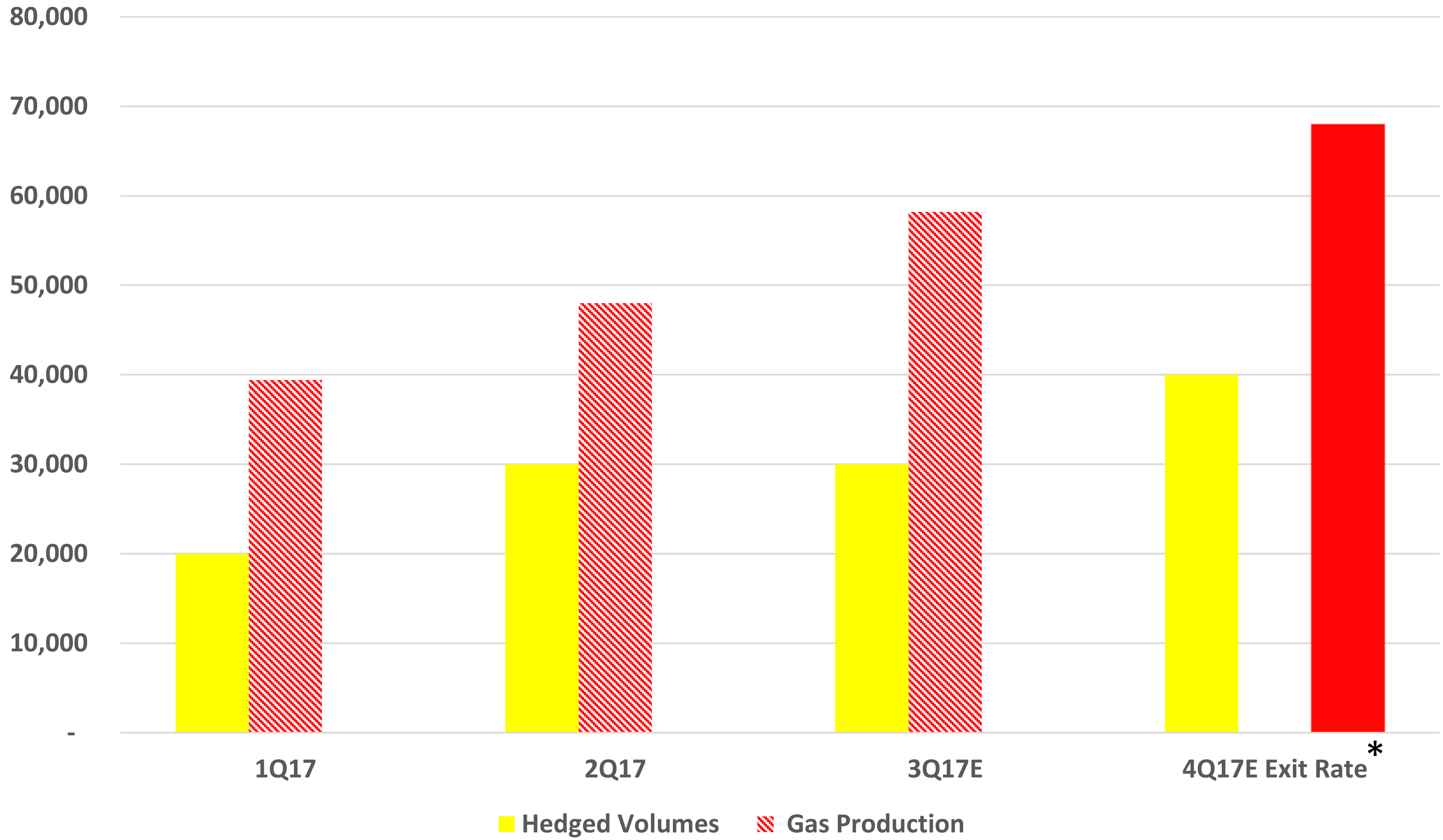
2Q16 vs 2Q17 Comparison

	2Q16	2Q17	% Change
EBITDA ($MM)	$5.5	$12.7	131%
Disc. Cash Flow ($MM)	($1.0)	$11.3	1200%
2017 Debt Maturity($MM)	$144	-	N/A
Realized Gas Price ($/Mcf)	$2.07	$3.16	53%



2017 Gas Hedge Position (MMcf/d)

Average floor gas price: $3.21
Cotton Valley IRR @ $3.00: 67%



* Assumes 4Q16 to 4Q17E exit growth of ~100%

Summary

- **Significant Growth through Cotton Valley development and Thunder Bayou recompletion**
  - **3Q17E production up 64% from 4Q16**
  - **2Q17 EBITDA up 20% from 4Q16**
    - **Annualized Debt/EBITDA at 6/30/17 down 57% from 12/31/16**
  - **Latest Cotton Valley well achieves highest IP rate in conjunction with larger frack job (~$900/ft)**
- **2016 Exchanges Provide Window for Growth**
  - **Refinanced or repaid 100% of the YE15 debt of $350MM**
  - **No material near-term maturities until 2021**
  - **Generating significant cash interest savings via debt reduction/PIK**

Appendix

Appendix 1 - Hedging Positions

Natural Gas	Hedged Volumes (Bcfe)	Price
2017	11.0	$3.21
1Q18	3.2	$3.24

$35.2 MM of revenue hedged for 2017
$10.2 MM of revenue hedged for 2018

Appendix 2 – Adjusted EBITDA Reconciliation

($ in thousands)	2012	2013	2014	2015	1Q16	2Q16	3Q16	4Q16	2016	1H17
Net Income (Loss) available to common stockholders	($137,218)	$8,943	$26,051	($299,977)	($39,137)	($24,143)	($23,306)	($4,310)	($90,896)	($8,303)
Income tax expense (benefit)	1,636	320	(2,941)	2,673	86	475	(18)	-	543	(189)
Interest expense & preferred dividends	14,947	27,025	34,420	38,905	9,751	7,788	9,022	8,807	35,368	16,975
Depreciation, depletion, and amortization	60,689	71,445	87,818	63,497	10,138	7,193	6,030	5,359	28,720	12,958
Share based compensation expense	6,910	4,216	5,248	4,617	442	483	436	83	1,444	425
Gain on Asset Sale	-	-	-	(21,937)	-	-	-	-	-	-
Accretion of asset retirement obligation	2,078	1,753	2,958	3,259	608	618	670	619	2,515	1,100
Derivative (income) expense	233	(233)	-	-	-	-	-	-	-	-
Ceiling test writedown	137,100	-	-	266,562	18,857	12,782	8,665	-	40,304	-
Adjusted EBITDA	$86,375	$113,469	$153,554	$57,599	$745	$5,196	$1,499	$10,558	$17,998	$22,966

- Adjusted EBITDA represents net income (loss) available to common stockholders before income tax expense (benefit), interest expense (net), preferred stock dividends, depreciation, depletion, amortization, loss on early extinguishment of debt, share based compensation expense, gain on asset sale, non-cash gain on legal settlement, accretion of asset retirement obligation, derivative (income) expense, costs incurred to issue 2021 Notes and ceiling test writedowns. We have reported Adjusted EBITDA because we believe Adjusted EBITDA is a measure commonly reported and widely used by investors as an indicator of a company's operating performance. We believe Adjusted EBITDA assists such investors in comparing a company's performance on a consistent basis without regard to depreciation, depletion and amortization, which can vary significantly depending upon accounting methods or nonoperating factors such as historical cost. Adjusted EBITDA is not a calculation based on generally accepted accounting principles, or GAAP, and should not be considered an alternative to net income in measuring our performance or used as an exclusive measure of cash flow because it does not consider the impact of working capital growth, capital expenditures, debt principal reductions and other sources and uses of cash which are disclosed in our consolidated statements of cash flows. Investors should carefully consider the specific items included in our computation of Adjusted EBITDA. While Adjusted EBITDA has been disclosed herein to permit a more complete comparative analysis of our operating performance relative to other companies, investors should be cautioned that Adjusted EBITDA as reported by us may not be comparable in all instances to Adjusted EBITDA as reported by other companies. Adjusted EBITDA amounts may not be fully available for management's discretionary use, due to certain requirements to conserve funds for capital expenditures, debt service and other commitments, and therefore management relies primarily on our GAAP results.

- Adjusted EBITDA is not intended to represent net income as defined by GAAP and such information should not be considered as an alternative to net income, cash flow from operations or any other measure of performance prescribed by GAAP in the United States. The above table reconciles net income (loss) available to common stockholders to Adjusted EBITDA for the periods presented.

Appendix 3 - Discretionary Cash Flow Reconciliation

($ in thousands)	2011	2012	2013	2014	2015	1Q16	2Q16	3Q16	4Q16	2016	1H17
Net income (loss)	$10,548	($132,079)	$14,082	$31,190	($294,838)	($37,643)	($22,858)	($22,021)	($8,374)	($90,896)	($5,733)
Reconciling items:											
Income tax expense (benefit)	(1,810)	1,636	320	(2,941)	2,673	86	475	(18)	-	543	(189)
Depreciation, depletion and amortization	58,243	60,689	71,445	87,818	63,497	10,138	7,193	6,030	5,359	28,720	12,958
Share based compensation expense	4,833	6,910	4,216	5,248	4,617	442	483	436	83	1,444	825
Gain on Asset Sale	-	-	-	-	(21,937)	-	-	-	-	-	-
Ceiling test write down	18,907	137,100	-	-	266,562	18,857	12,782	8,665	-	40,304	--
Accretion of asset retirement obligation	2,049	2,078	1,753	2,958	3,259	608	618	670	619	2,515	1,100
Costs incurred to issue 2021 Notes	-	-	-	-	-	4,740	68	5,265	66	10,139	-
Non-cash PIK interest	-	-	-	-	-	-	-	-	5,722	5,722	11,179
Other	625	1,114	1,240	2,188	2,259	562	248	1,180	116	2,106	450
Discretionary cash flow	$93,395	$77,448	$93,056	$126,461	$26,092	($2,210)	($991)	207	3,591	597	20,590
Changes in working capital accounts	26,686	13,770	(29,867)	55,370	6,789	(23,516)	3,166	(25,509)	(8,167)	(54,026)	(5,539)
Payments to settle asset retirement obligations	(905)	(2,627)	(3,335)	(3,623)	(2,776)	(464)	(2,051)	(369)	(285)	(3,169)	(1,357)
Net cash flow provided by operating activities	$119,176	$88,591	$59,854	$178,208	$30,105	($26,190)	$124	($25,671)	($4,861)	($56,598)	$13,694

Note: Management believes that discretionary cash flow is relevant and useful information, which is commonly used by analysts, investors and other interested parties in the oil and gas industry as a financial indicator of an oil and gas company's ability to generate cash used to internally fund exploration and development activities and to service debt. Discretionary cash flow is not a measure of financial performance prepared in accordance with generally accepted accounting principles ("GAAP") and should not be considered in isolation or as an alternative to net cash flow provided by operating activities. In addition, since discretionary cash flow is not a term defined by GAAP, it might not be comparable to similarly titled measures used by other companies.

Appendix 4 – Gulf Coast/GOM Free Cash Flow Reconciliation

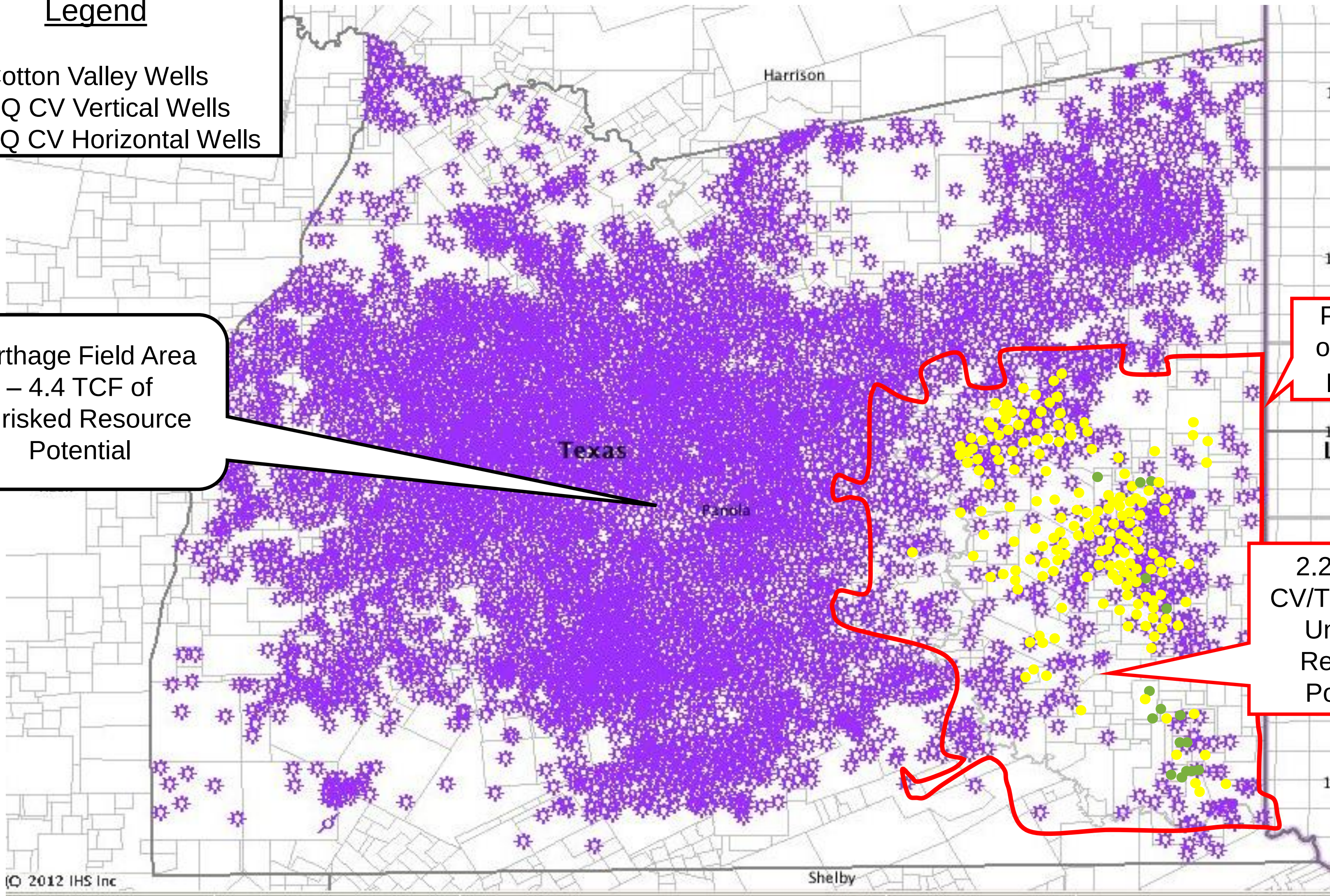
($ in thousands)	2007-2016
Revenues	$1,048,762
Lease Operating Expense	(203,456)
Severance Tax	(26,300)
Field level cash flow	$819,006
Capital Expenditures [1]	(367,023)
Free Cash Flow	$451,983

[1] 2013 Capex excludes GOM acquisition.

Appendix 5 - Panola County Cotton Valley – Room to Run

Legend

- Cotton Valley Wells
- PQ CV Vertical Wells
- PQ CV Horizontal Wells



Carthage Field Area – 4.4 TCF of Unrisked Resource Potential

PQ Area of Mutual Interest

2.2 Tcfe of CV/TP/Bossier Unrisked Resource Potential

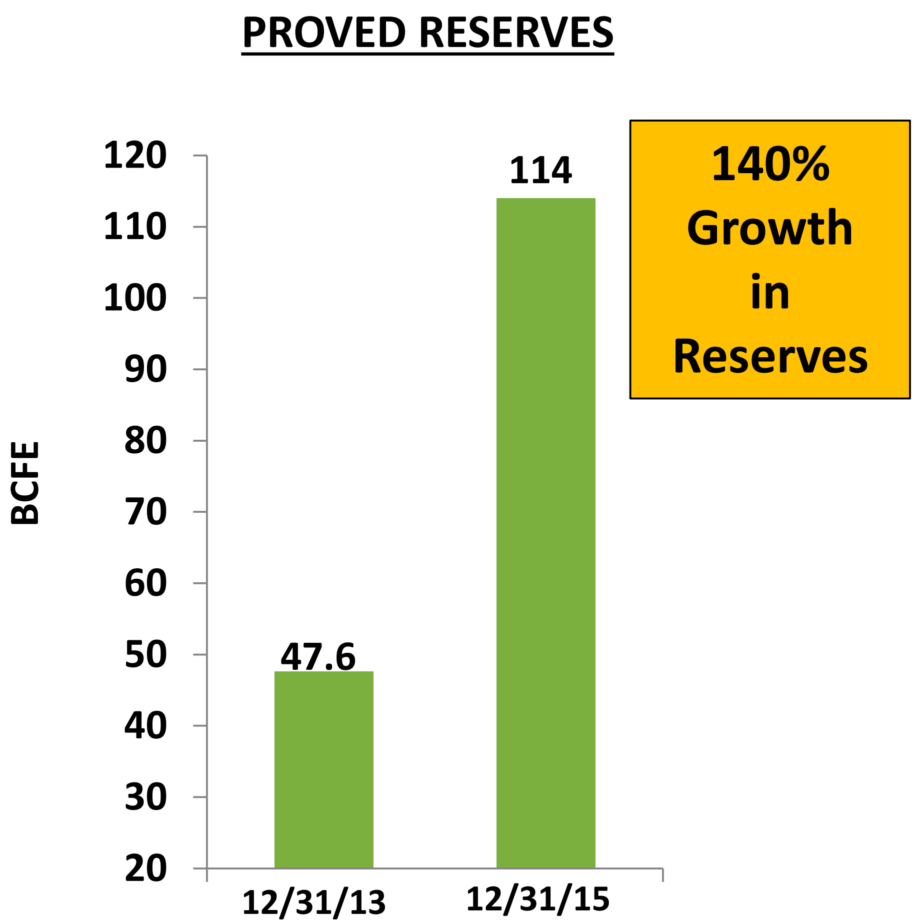
Appendix 6 – Cotton Valley Production Profile

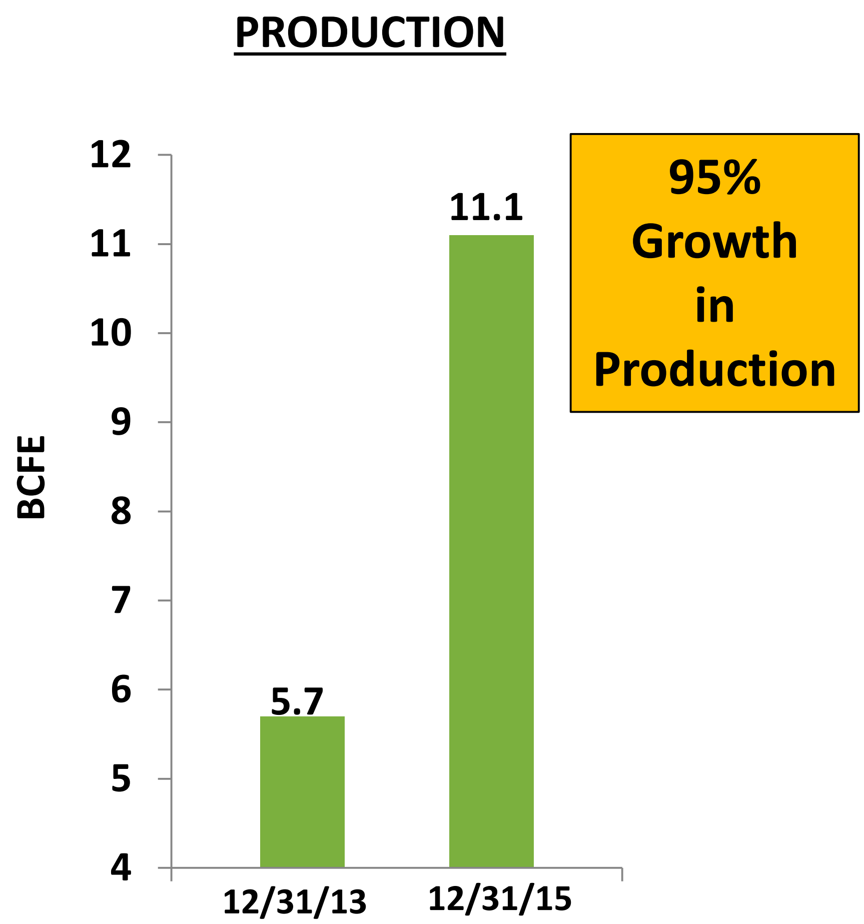
Recent Horizontal Cotton Valley Results

	PQ#15	PQ#16	PQ#17	PQ#18	PQ #19	PQ #20	PQ #21	PQ #22	PQ #23	PQ #24*	PQ #25	Avg.	% of IP
IP Rate (Mmcfe/d)	11.4	16.7	14.2	11.7	12.5	14.8	7.1	10.6	14.5	5.4	18.3	12.5	N/A
30 Day Avg. Rate (Mmcfe/d)	13.6	16.4	14.1	11.9	11.4	11.5	6.0	7.6	N/A	N/A	N/A	11.6	93%
60 Day Avg. Rate (Mmcfe/d)	13.5	13.9	13.2	11.3	10.6	10.4	5.2	7.7	N/A	N/A	N/A	10.7	86%
90 Day Avg. Rate (Mmcfe/d)	13.0	12.3	12.2	10.9	9.8	9.9	4.6	N/A	N/A	N/A	N/A	10.4	83%

* PQ #24 experienced mechanical issues (directional equipment failure) during the drilling process resulting in 50% of the well being drilled out of section

Appendix 7 - Cotton Valley Wells: Maximum Growth with Minimal Wells





- Growth metrics above achieved with only 9 gross wells.

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