Lonestar Resources US, Inc.

Second Quarter Conference Call

August 7, 2017

Forward-Looking Statements Safe Harbor & Disclaimer

Lonestar Resources US, Inc. cautions that this presentation (including oral commentary that accompanies this presentation) contains forward-looking statements, including, but not limited to, statements about performance expectations related to our assets and technical improvements made thereto; drilling and completion of wells; and other statements regarding our business strategy and operations. These statements involve substantial known and unknown risks, uncertainties and other important factors that may cause our actual results, levels of activity, performance or achievements to be materially different from the information expressed or implied by these forward-looking statements. These risks and uncertainties include, but are not limited to, the following: volatility of oil, natural gas and NGL prices, and potential write-down of the carrying values of crude oil and natural gas properties; inability to successfully replace proved producing reserves; substantial capital expenditures required for exploration, development and exploitation projects; potential liabilities resulting from operating hazards, natural disasters or other interruptions; risks related using the latest available horizontal drilling and completion techniques; uncertainties tied to lengthy period of development of identified drilling locations; unexpected delays and cost overrun related to the development of estimated proved undeveloped reserves; concentration risk related to properties, which are located primarily in the Eagle Ford Shale of South Texas; loss of lease on undeveloped leasehold acreage that may result from lack of development or commercialization; inaccuracies in assumptions made in estimating proved reserves; our limited control over activities in properties Lonestar does not operate; potential inconsistency between the present value of future net revenues from our proved reserves and the current market value of our estimated oil and natural gas reserves; risks related to derivative activities; losses resulting from title deficiencies; risks related to health, safety and environmental laws and regulations; additional regulation of hydraulic fracturing; reduced demand for crude oil, natural gas and NGLs resulting from conservation measures and technological advances; inability to acquire adequate supplies of water for our drilling operations or to dispose of or recycle the used water economically and in an environmentally safe manner; climate change laws and regulations restricting emissions of "greenhouse gases" that may increase operating costs and reduce demand for the crude oil and natural gas; fluctuations in the differential between benchmark prices of crude oil and natural gas and the reference or regional index price used to price actual crude oil and natural gas sales; and the other important factors discussed under the caption "Risk Factors" in our Registration Statement on Form 10, as amended and filed with the Securities and Exchange Commission, or the SEC, on June 9, 2016, as well as other documents that we have filed and may file from time to time with the SEC. We may not actually achieve the plans, intentions or expectations disclosed in our forward-looking statements, and you should not place undue reliance on our forward-looking statements. Actual results or events could differ materially from the plans, intentions and expectations disclosed in the forward-looking statements we make. The forward-looking statements in this presentation represent our views as of the date of this presentation. We anticipate that subsequent events and developments will cause our views to change. However, while we may elect to update these forward-looking statements at some point in the future, we have no current intention of doing so except to the extent required by applicable law. You should, therefore, not rely on these forward-looking statements as representing our views as of any date subsequent to the date of this presentation.

This presentation also contains estimates and other statistical data made by independent parties and by us relating to well performance, finding and development costs, recycle ratio and other data about our industry. This data involves a number of assumptions and limitations, and you are cautioned not to give undue weight to such estimates. In addition, projections, assumptions and estimates of our future performance and the future performance of the markets in which we operate are necessarily subject to a high degree of uncertainty and risk.

Strategy Overview

Closed Marquis & Battlecat Acquisitions

- $99 MM in Cash, 2.7 MM common shares [1]
- 31.4 MMBOE Proved Reserves in Karnes, Gonzales, DeWitt, Lavaca & Fayette Counties
- Financed with $80 MM Convertible Preferred & Revolver to Continue Deleveraging

Lonestar Setting "10 and 100" Objectives For 2018

- >10,000 BOEPD
- $100 MM EBITDAX
- Borrowing Base of $190 to $200 MM

2017 New Drills Are Performing Well

- Burns Ranch / Cyclone / Wildcat

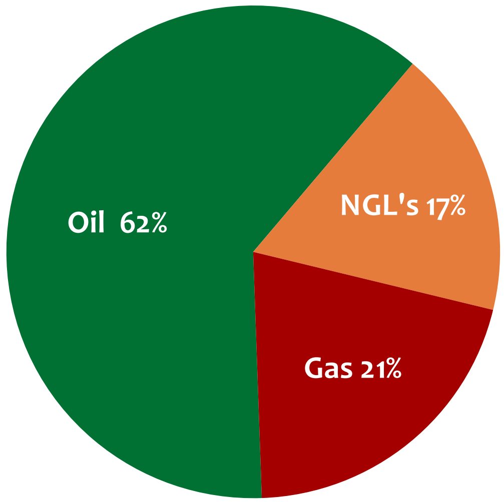
Significant Progress In HBP'ing Core Development Areas

- Burns Ranch & Cyclone Approaching 100% HBP'd
- All Recently Acquired Properties are 100% HBP'd

Hedge Book Bolstered to Secure Cash Flows & Returns

- Bal '17- 3,613 bbl/d @$53.10/bbl
- Cal '18- 4,695 bbl/d @$51.63/bbl
- Cal '19- 2,930 bbl/d @$49.16/bbl

2Q17 Production by Product



Product	Volume
Crude Oil	3,564 bbl/d
NGL's	1,004 bbl/d
Natural Gas	6,402 Mcf/d
Total	**5,635 Boe/d**

Key Financial Highlights

2Q17 Production Rose 7% to 5,635 Boe/d

- Only 1 New Completion During 2Q17
  - Wildcat B1H (Brazos)- Onstream May, 2017 (1.0 gross / 0.5 net wells)
  - Marquis & Battlecat Acquisitions Included For 15 days in 2Q17
  - Proforma 2Q17 Production- 7,345 Boe/d

2Q17 Adjusted EBITDAX Rose 10% to $12.7 MM

- Only 1 New Completion During 2Q17
- Assimilating Newly Acquired Assets, Costs Always Higher Early
- Proforma 2Q17 EBITDAX- $16.4 MM

Cash Costs[1] Were Noisy

- Included Several One-Time Items
  - LOE- $6.83 per Boe, Acquired properties are higher cost
  - G&A- $3.1 MM, included $0.6 MM non-recurring
  - Int. Exp.- $6.0 MM, included $1.1 MM related to prepayment of Second Lien Notes

3Q17 Production Expected to Rise 35 to 45%

- 7,600 Boe/d to 8,100 Boe/d
  - Crude Oil Mix- ~70%
  - NGL Mix- 16 to 17%
  - Gas Mix- 14 to 13%

Daily Production

	1Q17	Mix	2Q17	Mix
Crude Oil	3,250	62%	3,564	63%
Natural Gas Liquids	927	17%	1,004	18%
Natural Gas	6,528	21%	6,402	19%
Total	**5,266**	**100%**	**5,635**	**100%**

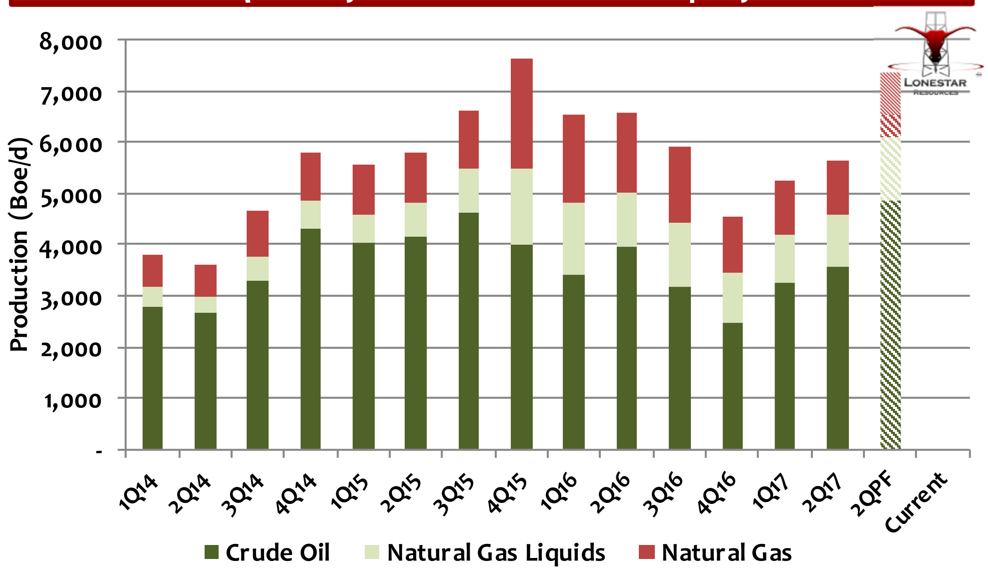
Cash Operating Costs

	$ MM			$ / Boe		
Expense	1Q17	2Q17	Adj.	1Q17	2Q17	Adj.
LOE	$3.0	$3.5	$3.5	$6.24	$6.87	$6.87
G&A	$2.5	$3.1	$2.5	$5.26	$6.12	$4.85
Int. Exp.	$4.4	$6.0	$4.9	$9.38	$11.65	$9.56
Total	**$9.9**	**$12.6**	**$10.9**	**$20.88**	**$24.64**	**$21.27**

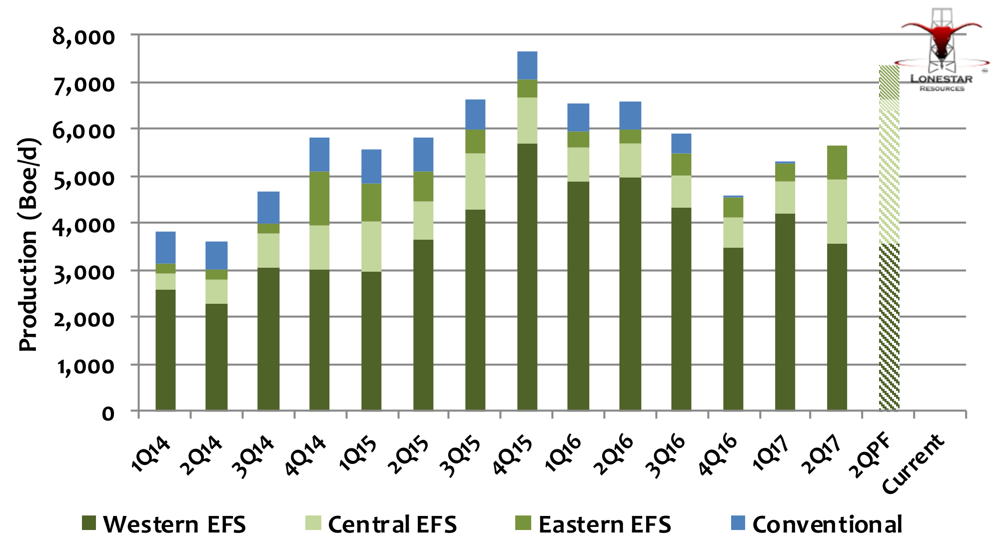
[1] *"Cash Operating Costs are controllable expenses incurred by the Company. They do not include production taxes, as those are determined by local governments and fluctuate with price..*

Quarterly Financial Summary

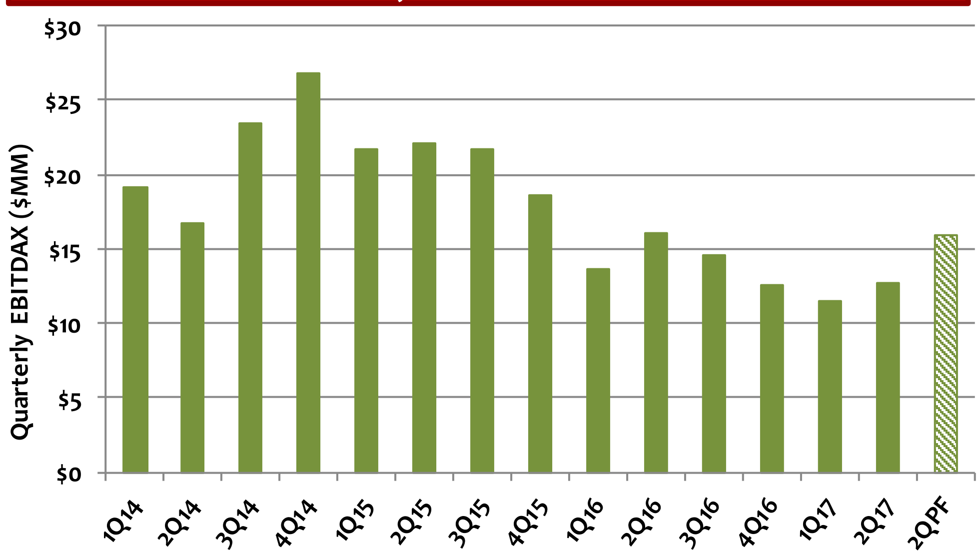
Quarterly Production – Total Company



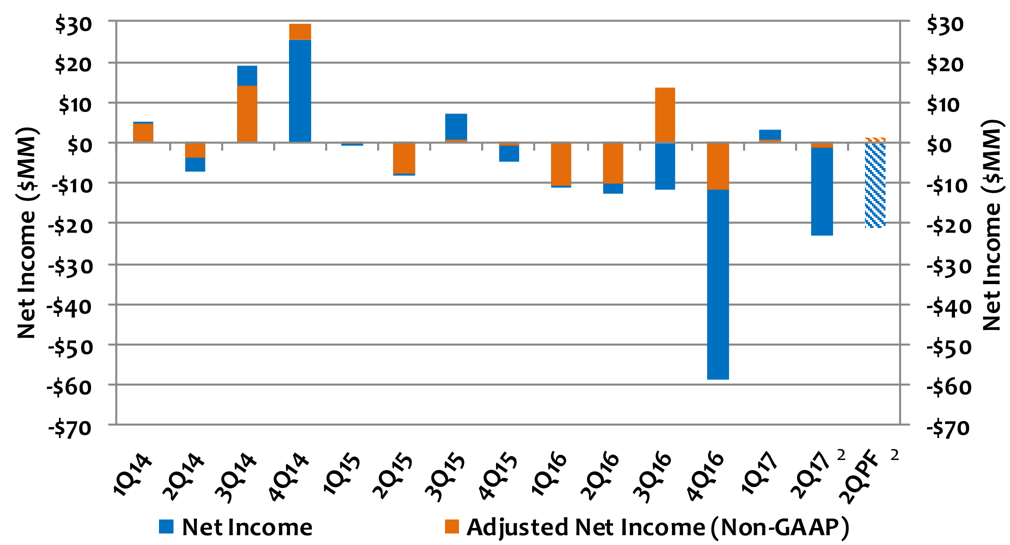
Quarterly Production – Total Company



Adjusted EBITDAX[1]



Net Income



Note- All 2014 , 2015, 2016, and 2017 figures are unaudited

[1] Please see "Non-GAAP Financial Reconciliation" in the Appendix for the definition of Adjusted EBITDAX, a reconciliation of Net Income (loss) to Adjusted EBITDAX, and the reasons for its use.

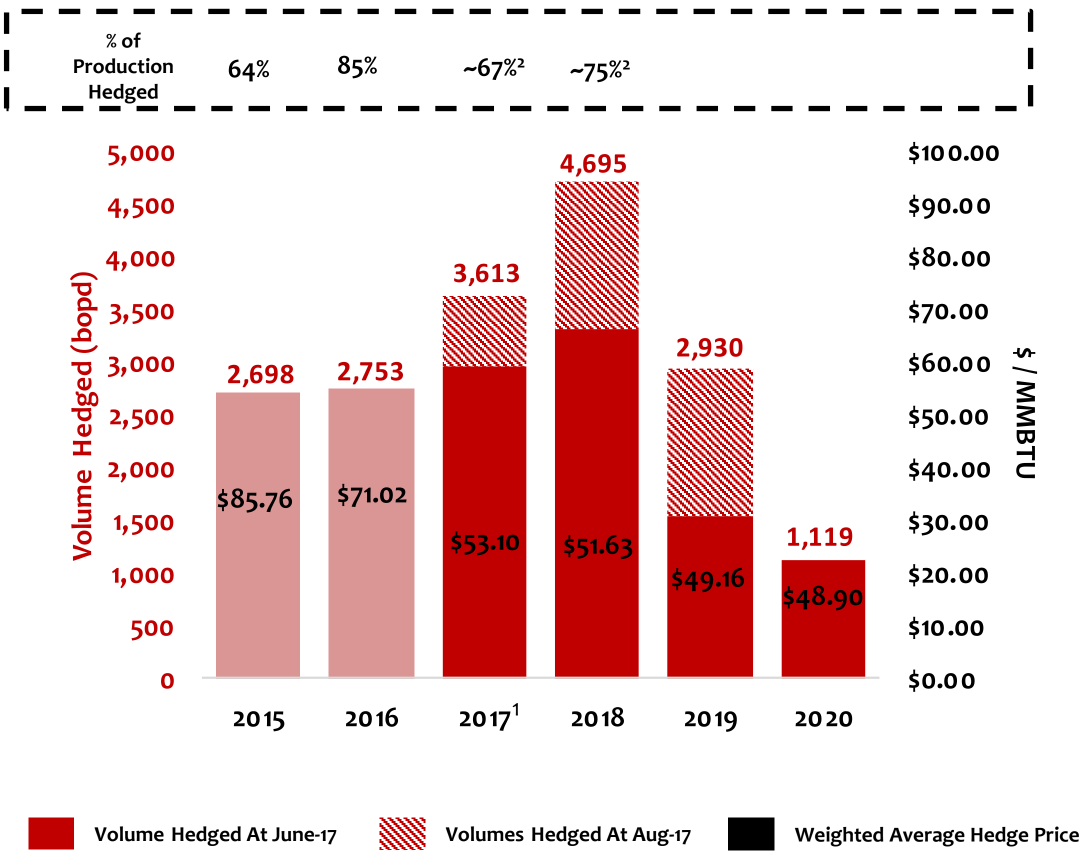
[2]One-time charges totaling $34.0 million; 27.1 million impairment for Poplar Leasehold, $2.7 million one time expense related to acquisition, $2.0 warrant discount recognition due to early payment on second lien, $1.1 million prepayment premium on second lien, $0.6 million non-recurring general and administrative costs, $0.5 stock based compensation, offset by $0.5 million previously recognized income tax benefits

2QFP – 2Q17 Proforma Acquisition

Bolstered Hedge Book to Ensure Cash Flows

- Since inception, Lonestar has implemented a strategy to reduce the effects of volatility of oil and natural gas prices on the Company's results of operations by securing fixed price contracts for a portion of its expected sales volumes
- Hedging Program focuses on Crude Oil (Crude oil was 83% of total wellhead revenues in 1H17)
- On August 1, 2017, Lonestar entered into additional swap agreements, increasing hedges to 67% of Bal ' 17 and 75% of Cal '18 analysts' consensus forecast oil production.

Crude Oil – WTI Based Hedges



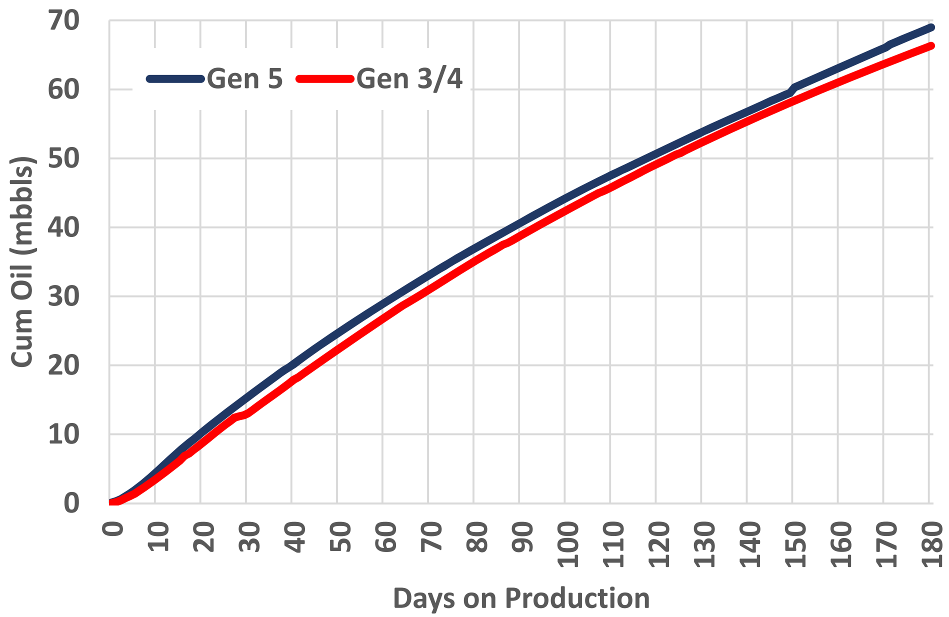
Hedge Book at August 1, 2017

Period	Instrument	Volume	Fixed Price
Bal '17	Oil – WTI Swap	2,666 bbls/day	$52.34
Bal '17	Oil – 3 Way Collar	947 bbls/day	$40.00/$60.00/ $85.00
Bal '17	Gas – NYMEX Swap	7,000 mmbtu/day	$3.36
Cal '18	Oil – WTI Swap	4,195 bbls/day	$51.83
Cal '18	Oil – 2 Way Collar	500 bbls/day	$50.00/$59.45
Cal '19	Oil – WTI Swap	2,930 bbls/day	$49.16
1H20	Oil – WTI Swap	1,119 bbls/day	$48.90

[1] Based on July-17 through Dec-17 hedges [2] Based on analysts' consensus estimates

LaSalle County Performance Update – Burns Ranch

Figure 1: Burns Ranch Production Comparisons



Burns Ranch Area Summary

- **Lonestar completed fracture stimulation operations on January 5, 2017**
  - **Gen 3**- 225 ft stage spacing / 1,567 lbs/ ft / geometric stages (#1H, #2H, #3H)
  - **Gen 4**- 300 ft stage spacing / 1,500 lb/ft / non-geometric stages with diverters (#8H)
  - **Gen 5**- 300 ft stage spacing with BroadBand diverters / 2,020 lb/ft (#9H, #10H)
- **LONE's Gen 5 Completions Are Outperforming Older Completions**

  Figure 1 • **Through 180 days of production, 5% higher cumulative production**

  Figure 2 • **Gen 5 wells Are Being More Aggressively Choke Managed**
    - **Gen 5**- 70,000 bo at ~1,300 GOR
    - **Gen 3**- 70,000 bo with 2,700 GOR, and increasing rapidly

  Figure 3 • **Gen 5 wells Are Achieving Higher Drainage Efficiencies**
    - **Gen 5**- 70,000 bo with 57% drawdown
    - **Gen 3**- 40,000 bo with 57% drawdown
- **LONE has commenced drilling operations on the Burns Ranch #4H & 5H wells**
  - **Planned TD- 18,000 feet with perforated intervals of 9,000 feet**
  - **Lonestar's HBP position was 2,673 net acres at 12/31/16 (67%)**
  - **Upon completion of the #4H & #5H wells, 3,817 net acres will be HBP'd (95%)**

Figure 2: Burns Ranch Cum Oil vs. GOR

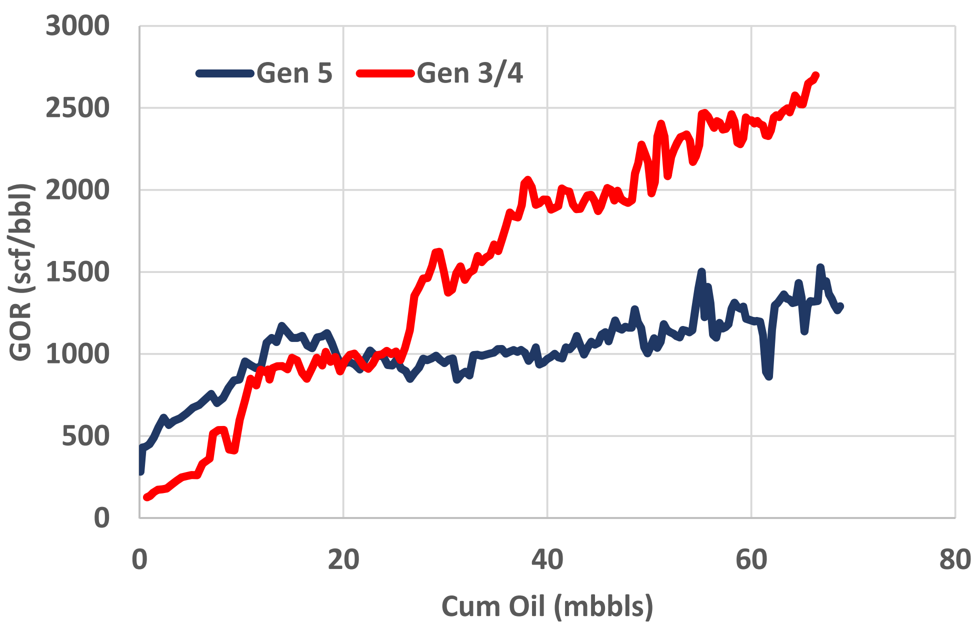
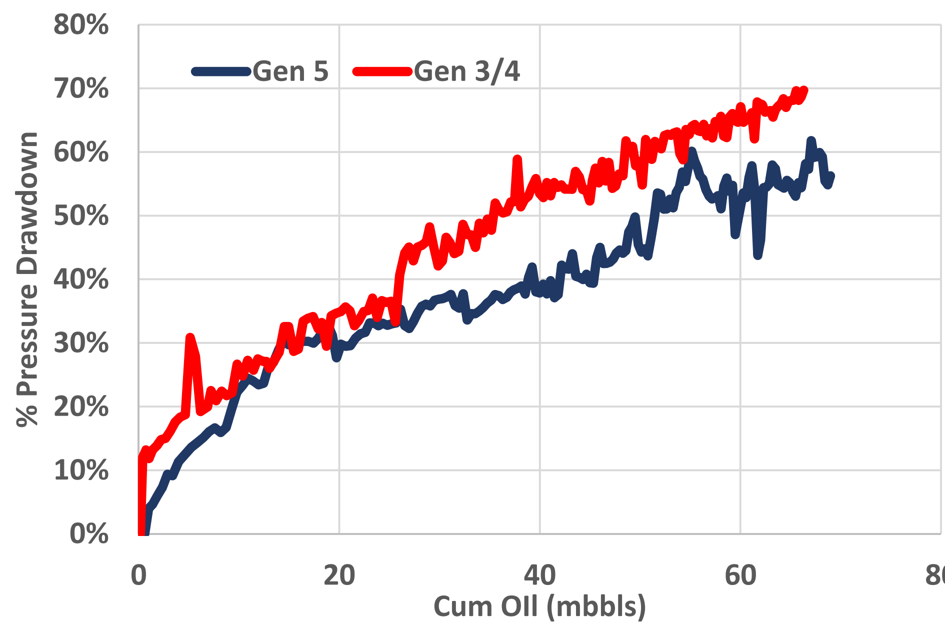


Figure 3: Burns Ranch Cum Oil vs. Pressure Drawdown

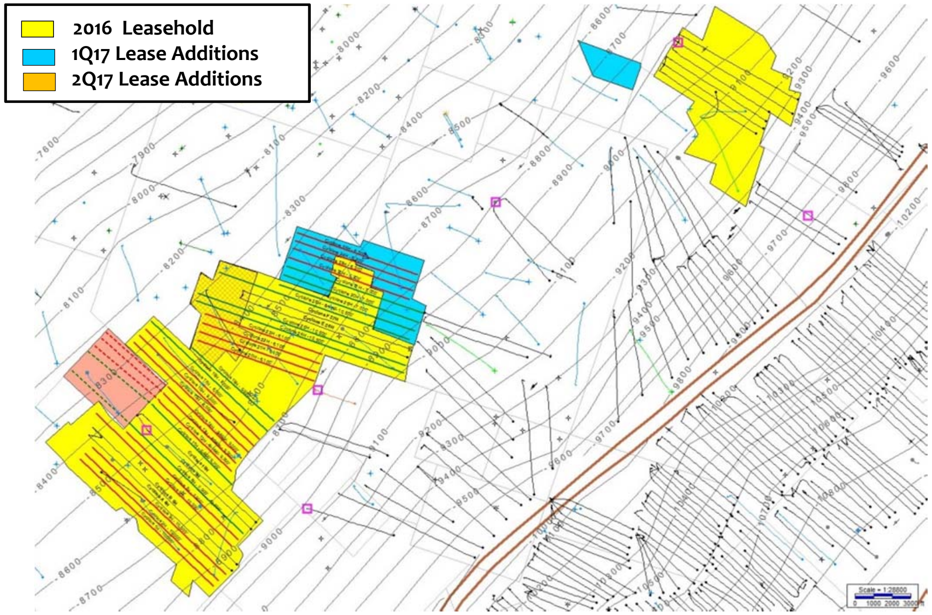


Gonzales County Expansion- Cyclone

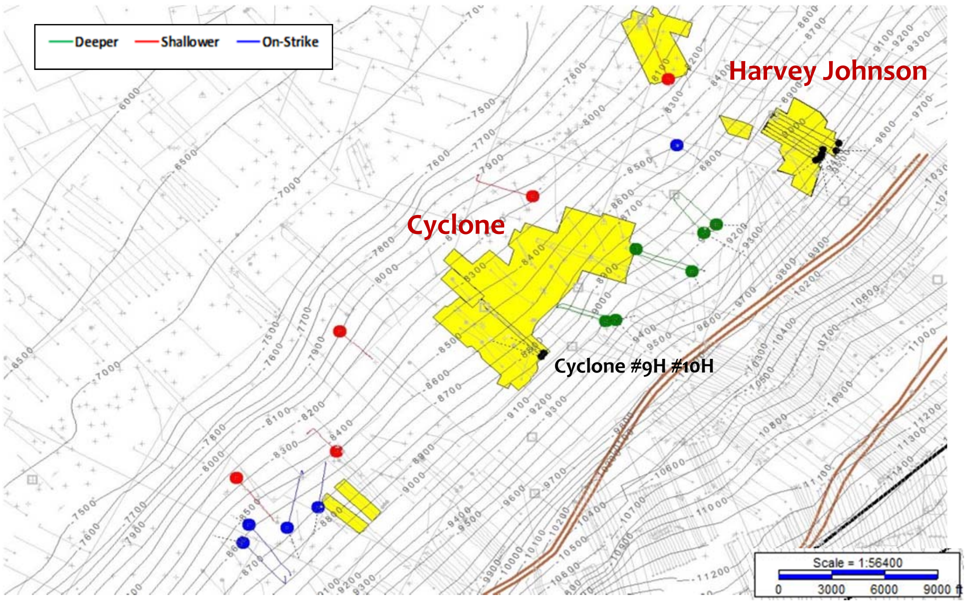
Cyclone Area Summary

- In May 2016, LONE placed the Cyclone #9H & #10H wells online (42% WI/33% NRI)
  - Avg. Lat Length- 6,685' lateral with 1,518 #/ft proppant (with diverters)
    - Avg. Test Rate- 614 BOEPD
    - Avg. Max-30 rate- 504 BOEPD
    - Avg. 12 Mos. Cum- 90,000 Bbls
- In July, 2017 LONE placed Cyclone #4H & #5H wells online (100% WI / 78.5% NRI)
  - Cyclone #4H- 8,706' lateral with 1,820 #/ft – Tested 741 BOEPD
  - Cyclone #5H- 9,286' lateral with 1,820 #/ft- Tested 771 BOEPD
  - Wells choked back, awaiting completion of gas & water pipelines
- In July, Lonestar Completed the Cyclone #26H & #27H wells (100% WI/78.5% NRI)
  - Two 9,000' laterals, fracs scheduled for August, 2017
- Continued Success Bolting-on Leasehold at Low Costs at Cyclone
  - 2016- 2,906 gross / 2.656 net acres- 26 gross / 24 net laterals
  - 1Q17- 3,432 gross / 3,182 net acres- 33 gross / 31 net laterals
  - 2Q17- 3,762 gross / 3,512 net acres- 38 gross / 36 net laterals

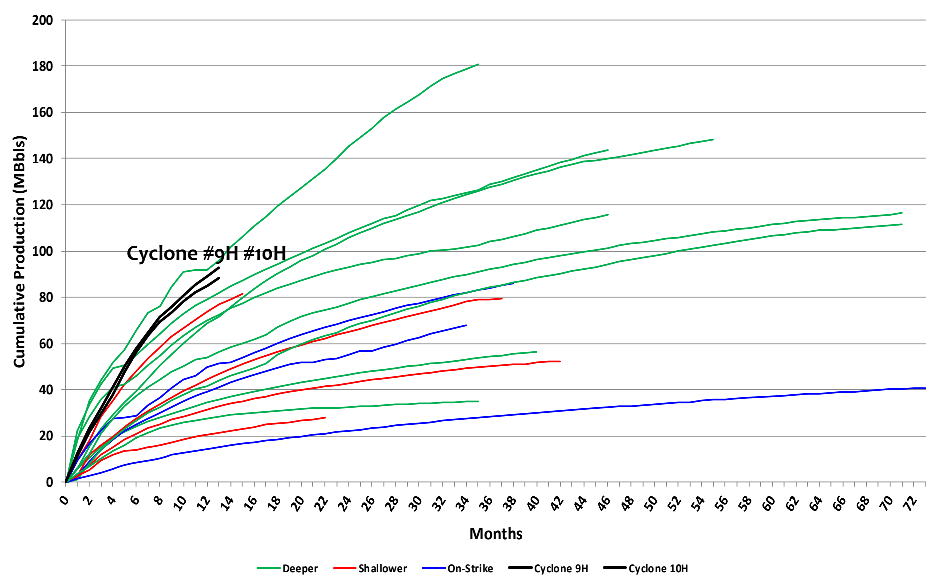
Cyclone Leasehold – Current



Cyclone Offset Wells- Lower Eagle Ford Structure Map



Cum vs. Time- Cyclone Wells vs. Offsets



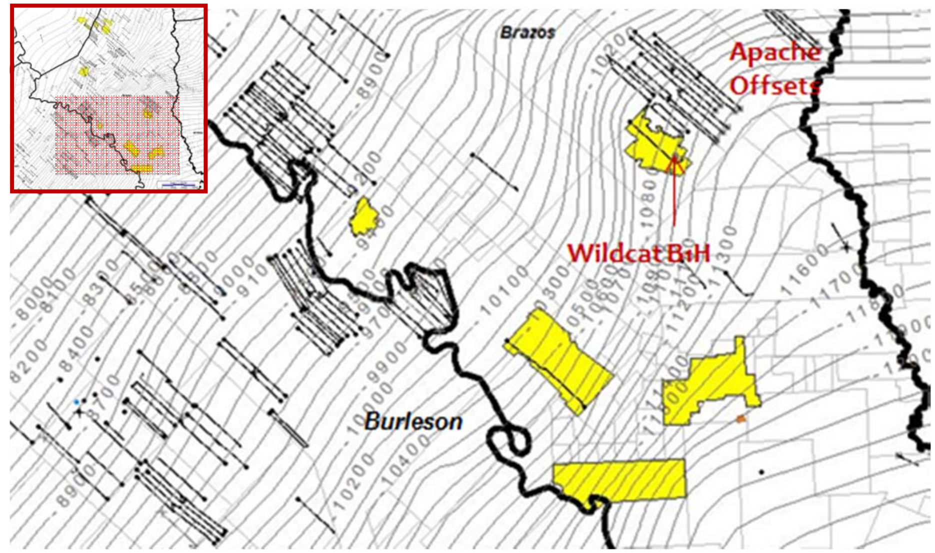
Eastern Region- Wildcat Well Still Cranking

Drilling and Completion Design Evolution

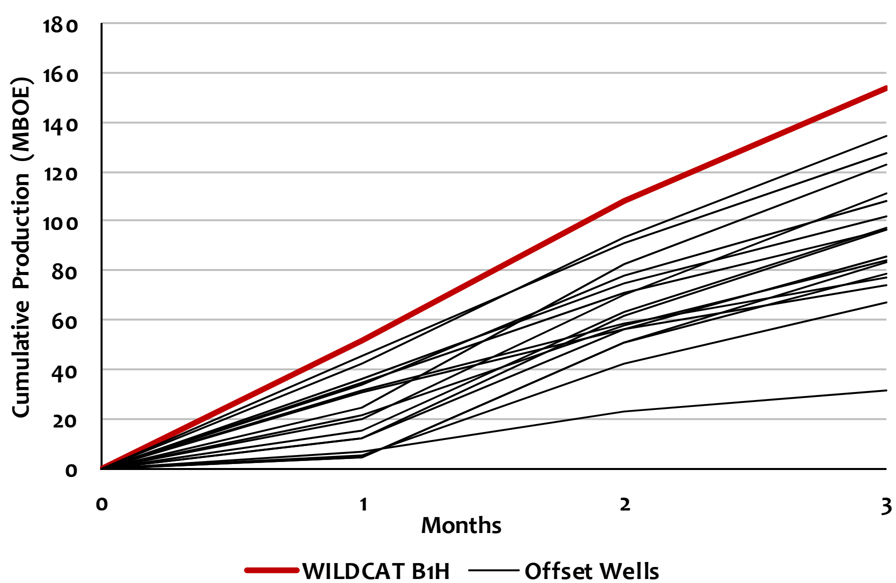
Generation 1	Generation 2	Generation 3
Proppant <2,000#	Proppant >2,000#	20-foot Geotarget Proppant >2,000# Engineered Completion

- **LONE's Gen 3 Completion Featured Several Enhancements**
  - Lonestar pumped @2,100# in engineered stages
  - Lonestar drilled in a petrophysically-derived 20-foot window
  - LONE has aggressively choke-managed the Wildcat B1H (20/64") to maximize oil yield
- **Wildcat B1H Continues to Produce at Robust Rates**
  - 30-day Rate- 2,132 BOEPD (42% oil / 36% NGL / 22% gas)
  - 60-day Rate- 1,867 BOEPD (44% oil / 33% NGL / 23% gas)
  - Expected 90 day cumulative- 158,000 BOE
- **LONE Has Significant Unbooked Inventory in Brazos County**
  - Expect to complete technical analysis in Sept, develop capital plan for area
  - 46 gross / 30 net drilling locations

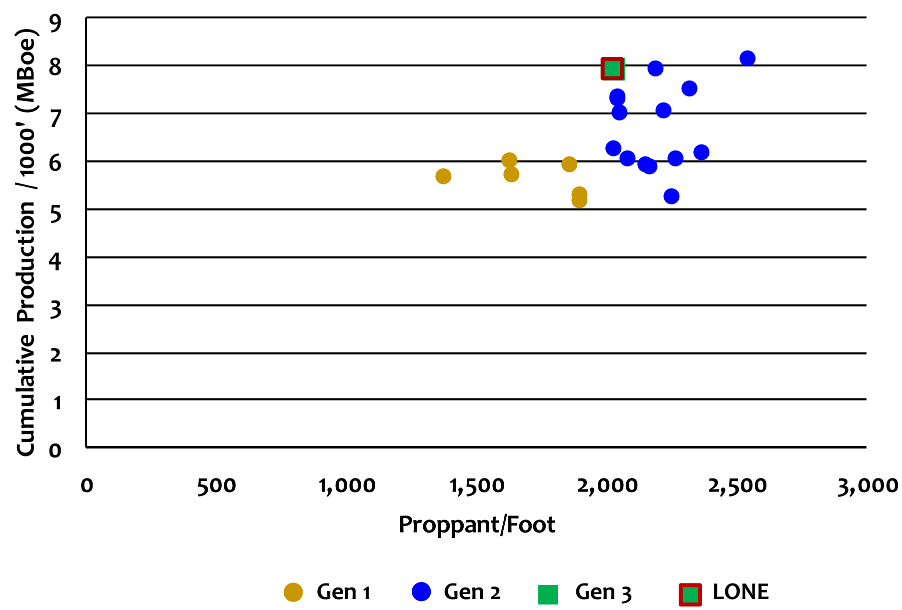
Increased Proppant, Steering has Improved EURs[1](MBOE)



Wildcat B1H Has Outperformed Offsets To Date



LONE's Wildcat B1H Well Has Outperformed Gen 2 Wells [1]

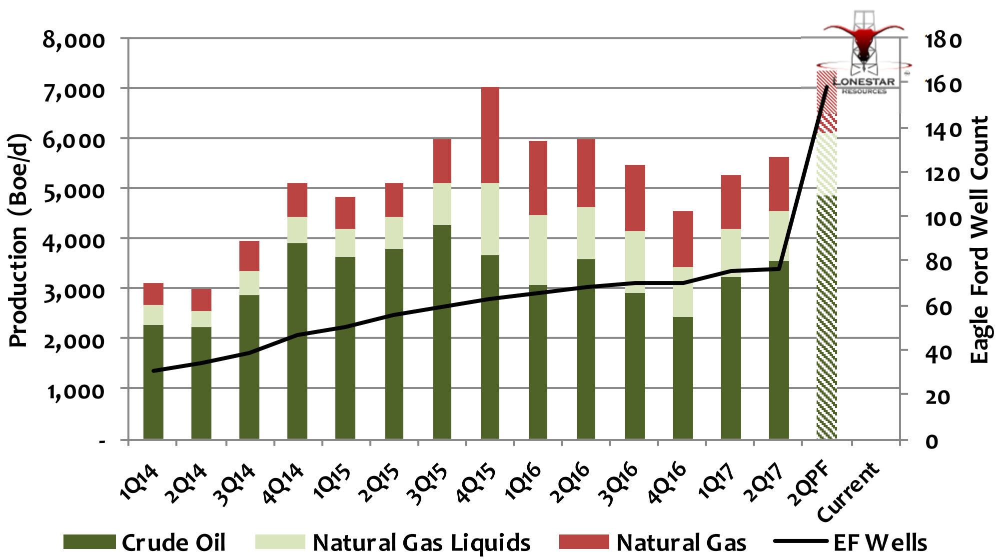


[1] EURs are Lonestar internal estimates

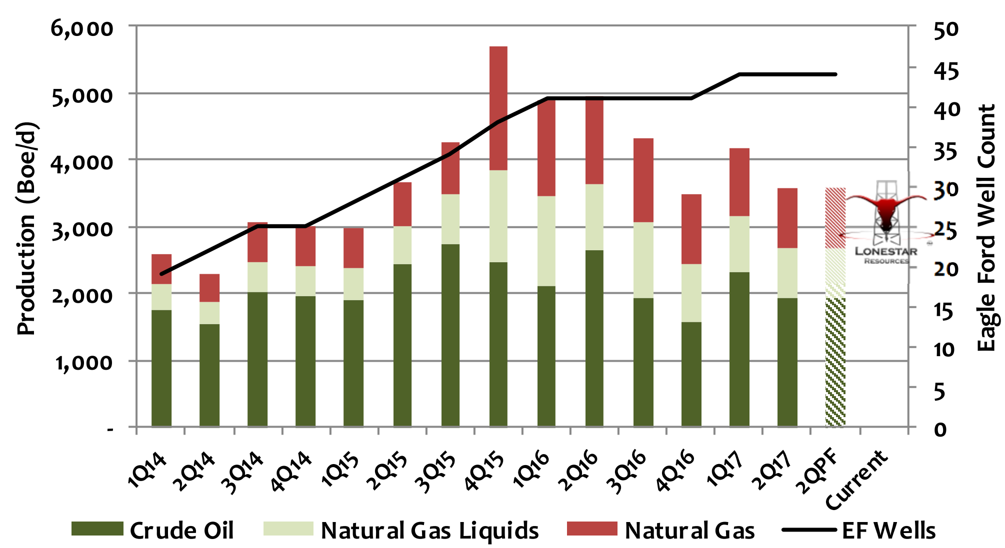
Quarterly Production Summary

LONESTAR RESOURCES

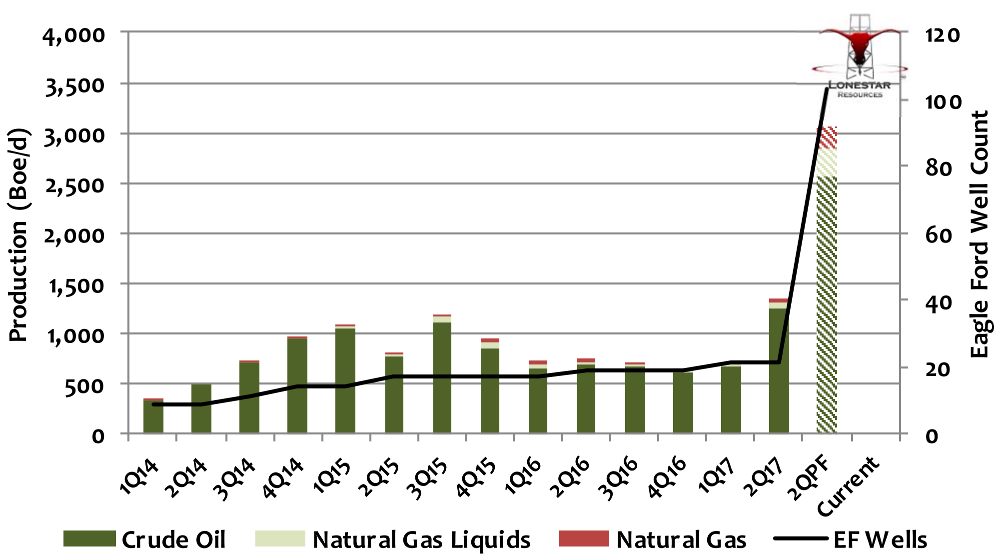
Quarterly Production – Total Eagle Ford



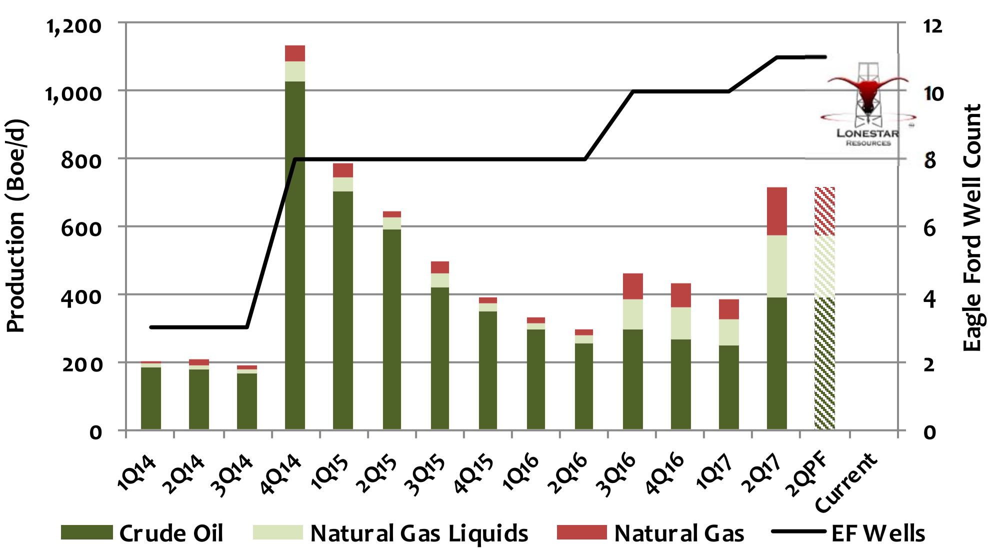
Quarterly Production – Western Eagle Ford



Quarterly Production – Central Eagle Ford



Quarterly Production – Eastern Eagle Ford



2QFP – 2Q17 Proforma Acquisition

Lonestar Resources US, Inc.

Appendix

Non-GAAP Reconciliation

LONESTAR RESOURCES

Reconciliation of Non-GAAP Financial Measures

Adjusted EBITDAX

Adjusted EBITDAX is not a measure of net income as determined by GAAP. Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of the Company's consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. The Company defines Adjusted EBITDAX as net (loss) income before depreciation, depletion, amortization and accretion, exploration costs, non-recurring costs, (gain) loss on sales of oil and natural gas properties, impairment of oil and gas properties, stock-based compensation, interest expense, income tax (benefit) expense, rig standby expense, other income (expense) and unrealized (gain) loss on derivative financial instruments and unrealized (gain) loss on warrants.

Management believes Adjusted EBITDAX provides useful information to investors because it assists investors in the evaluation of the Company's operating performance and comparison of the results of the Company's operations from period to period without regard to its financing methods or capital structure. The Company excludes the items listed above from net income in arriving at Adjusted EBITDAX to eliminate the impact of certain non-cash items or because these amounts can vary substantially from company to company within its industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. The Company's computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table presents a reconciliation of Adjusted EBITDAX to the GAAP financial measure of net income (loss) for each of the periods indicated.

($ in thousands)	1Q14	2Q14	3Q14	4Q14	1Q15	2Q15	3Q15	4Q15	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	2QPF
Net Income (Loss)	**$ 5,045**	**$ (6,976)**	**$ 19,132**	**$ 19,265**	**$ (725)**	**$(20,883)**	**$ 7,381**	**$(13,106)**	**$(11,297)**	**$(12,844)**	**$(11,260)**	**$(58,934)**	**$ 3,066**	**$ (23,457)**	**$ (20,968)**
Income tax expense (benefit)	1,553	(511)	1,508	19,882	(1,120)	(11,028)	4,360	(7,333)	(5,795)	(6,245)	1,684	37,759	1,587	(12,208)	(12,208)
Interest expense (1)	1,553	7,341	5,348	5,708	5,847	5,972	6,666	6,092	6,124	6,174	7,345	9,939	5,032	9,115	9,115
Exploration expense	0	0	0	96	0	51	0	171	0	1	10	371	0	205	205
Depletion, depreciation, amortization and accretion	7,865	9,673	9,217	13,968	12,838	13,307	13,021	19,876	15,195	12,549	10,718	8,607	12,142	12,551	13,774
EBITDAX	**16,016**	**9,527**	**35,205**	**58,919**	**16,840**	**(12,581)**	**31,428**	**5,700**	**4,227**	**(365)**	**8,497**	**(2,258)**	**21,827**	**(13,794)**	**(10,082)**
Rig standby expense (2)	0	0	0	0	0	0	10	653	313	1,584	364	0	0	0	0
Non-recurring costs (3)	501	612	449	138	0	19	25	1,182	323	321	607	308	0	3,127	3,127
Stock-based compensation	448	886	627	(23)	433	433	880	839	95	95	122	135	178	461	461
(Gain) loss on sale of oil and gas properties	0	0	0	0	0	0	0	0	0	(1,531)	53	1,404	142	205	205
Impairment of oil and gas properties	0	0	0	5,478	0	19,328	0	9,295	0	1,938	29,144	2,811	0	27,081	27,081
Unrealized (gain) loss on derivative financial instruments	2,185	6,140	(12,954)	(38,127)	3,768	14,908	(10,668)	720	8,429	13,176	4,600	10,163	(8,339)	(3,770)	(3,770)
Unrealized (gain) loss on warrants	0	0	0	0	0	0	0	0	0	0	611	(1,179)	(2,270)	(613)	(613)
Other (income) expense	0	(464)	44	365	663	(4)	18	389	206	819	(29,362)	1,118	(4)	(46)	(46)
Adjusted EBITDAX	**$ 19,150**	**$ 16,701**	**$ 23,371**	**$ 26,750**	**$ 21,704**	**$ 22,103**	**$ 21,693**	**$ 18,778**	**$ 13,593**	**$ 16,037**	**$ 14,636**	**$ 12,502**	**$ 11,534**	**$ 12,651**	**$ 16,363**

(1) Interest expense consists of Amortization of finance costs and Dividends paid on the preferred stock.

(2) Represents a non-recurring cost associated with a rig contract that expired in July 2016.

(3) Non-recurring costs consists of Acquisitions Costs and General and Administrative Expenses related to the re-domiciliation to the United States, and listing on the NASDAQ.

2QFP – 2Q17 Proforma Acquisition

Glossary

- "bbl" means barrel of oil.
- bbls/d means the number of one stock tank barrel, or 42 US gallons liquid volume of oil or other liquid hydrocarbons per day.
- "Boe" means barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.
- Boe/d means barrels of oil equivalent per day.
- "scf" means standard cubic feet.
- "btu" means British thermal units.
- "M" prefix means thousand.
- "MM" prefix means million.
- "B" prefix means billion.
- "NGL" means Natural Gas Liquids– these products are stripped from the gas stream at 3rd party facilities remote to the field.
- "TEV" means total enterprise value
- "LTM" means last twelve months
- "NTM" means next twelve months
- "HBP" means held by production
- "EPS" means earnings per share
- "Mcf/d" means thousand cubic feet of natural gas per day
- "IRR" means our internal rate of return, calculates the interest rate at which the net present value of all the cash flows (both positive and negative) from a project or investment equal zero
- "EUR" means gross estimated ultimate recoveries for a single well

Note: One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an industry-standard approximate energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.