UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT PURSUANT TO
SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

Date of report (Date of earliest event reported): June 5, 2017

LAREDO PETROLEUM, INC.
(Exact name of registrant as specified in charter)

Delaware	**001-35380**	**45-3007926**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

15 W. Sixth Street, Suite 900, Tulsa, Oklahoma	**74119**
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: **(918) 513-4570**

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging Growth Company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

Item 7.01. Regulation FD Disclosure.

On June 5, 2017, Laredo Petroleum, Inc. (the "Company") posted to its website a Corporate Presentation (the "Presentation"). The Presentation is available on the Company's website, www.laredopetro.com, and is attached to this Current Report on Form 8-K as Exhibit 99.1 and incorporated into this Item 7.01 by reference.

All statements in this Item 7.01 and the Presentation, other than historical financial information, may be deemed to be 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. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance, and actual results or developments may differ materially from those in the forward-looking statements. See the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and the Company's other filings with the SEC for a discussion of other risks and uncertainties. The Company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

In accordance with General Instruction B.2 of Form 8-K, the information furnished under this Item 7.01 of this Current Report on Form 8-K and the exhibit attached hereto are deemed to be "furnished" and shall not be deemed "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall such information and exhibit be deemed incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits*.

Exhibit Number	Description
99.1	Presentation dated June 6, 2017.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

LAREDO PETROLEUM, INC.

Dated: June 5, 2017	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
99.1	Presentation dated June 6, 2017.

EXHIBIT 99.1


LAREDO
PETROLEUM
Bank of America Merrill Lynch
2017 Energy Credit Conference
June 6, 2017

Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of 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 that address activities, events or developments that Laredo Petroleum, Inc. (together with its subsidiaries, the "Company", "Laredo" or "LPI") assumes, plans, expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "may," "estimates," "will," "anticipate," "plan," "project," "intend," "indicator," "foresee," "forecast," "guidance," "should," "would," "could," "goal," "target," "suggest" or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature and are not guarantees of future performance. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including the Company's drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and rate of return and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, availability and cost of drilling equipment and personnel, availability of sufficient capital to execute the Company's business plan, impact of compliance with legislation and regulations, successful results from the Company's identified drilling locations, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and other reports filed with the Securities Exchange Commission ("SEC").

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

The SEC generally permits oil and natural gas companies to disclose proved reserves in filings made with the SEC, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this presentation, the Company may use the terms "unproved reserves," "resource potential," "estimated ultimate recovery," "EUR," "development ready," "horizontal productivity confirmed," "horizontal productivity not confirmed" or other descriptions of potential reserves or volumes of reserves which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. "Unproved reserves" refers to the Company's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. "Resource potential" is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play potentially supporting numerous drilling locations. A "resource play" is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. The Company does not choose to include unproved reserve estimates in its filings with the SEC. "Estimated ultimate recovery", or "EUR", refers to the Company's internal estimates of per-well hydrocarbon quantities that may be potentially recovered from a hypothetical and/or actual well completed in the area. Actual quantities that may be ultimately recovered from the Company's interests are unknown. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability and cost of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals and other factors, as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of ultimate recovery from reserves may change significantly as development of the Company's core assets provide additional data. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including Adjusted EBITDA. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. For a reconciliation of Adjusted EBITDA to the nearest comparable measure in accordance with GAAP, please see the Appendix.

1Q-17 Highlights

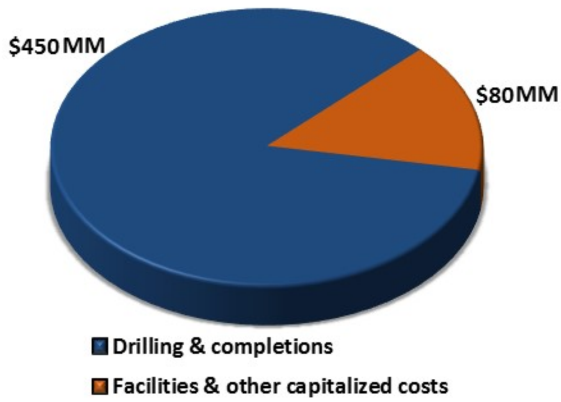
- Grew production ~13% from 1Q-16
- Completed 13 Hz wells with an average lateral length of ~9,900’
- Conducted drilling operations on 5 Hz wells with anticipated lateral lengths between 14,000’ and 15,600’
- Reduced unit LOE to $3.60 per BOE, down 26% from 1Q-16
- Recognized $5.8 MM in cash benefits from LMS field infrastructure investments
- Grew transported volumes on Medallion-Midland Basin system by 79% from 1Q-16

2017 Capital and Operating Expectations

2017 Drilling & Completions

- Operating 4 Hz rigs
- Drilling and completing ~70 Hz wells
- ~85% targeting the UWC & MWC
- ~95% average working interest
- Developed as an average of 4 - 5 well packages

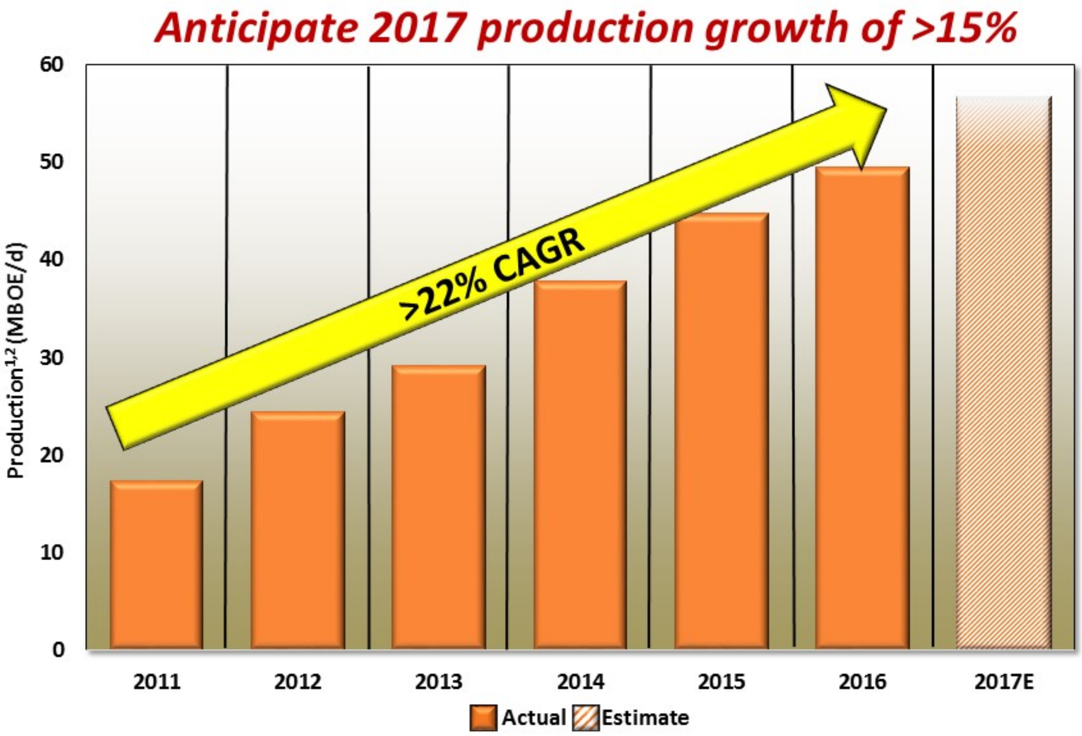
2017 Capital Budget [1]
$530 MM



2017 lateral length expected to average ~10,000'

[1] Does not include acquisitions or investments in Medallion-Midland Basin system

Consistent Production Growth



[1] Production numbers prior to 2014 have been converted to 3-stream using an 18% uplift. 2014 results have been converted to 3-stream using actual gas plant economics
[2] 2011 - 2013 adjusted for Granite Wash divestiture, closed August 1, 2013

Capitalizing on Contiguous Acreage Position

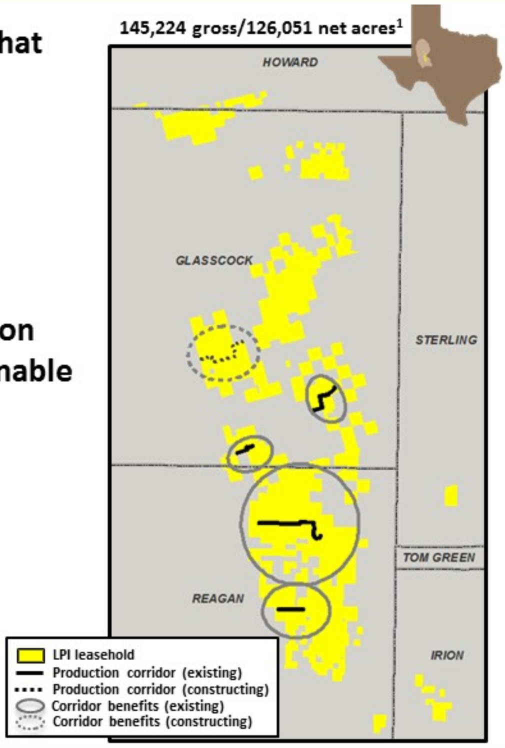
- **The company has identified >2,000 locations that support lateral lengths of 10,000'+ on its contiguous acreage**

- **The expected average lateral length for wells drilled in 2017 is ~10,000'**

- **Centralized infrastructure in multiple production corridors and the ability to drill long laterals enable increased capital and operational efficiencies**

~85% of acreage HBP, enabling a concentrated development plan along production corridors

145,224 gross/126,051 net acres[1]



[1] As of 3/31/17

Multiple Targeted Horizons

2017 Drilling Targets: Upper Wolfcamp, Middle Wolfcamp, Lower Wolfcamp, Cline

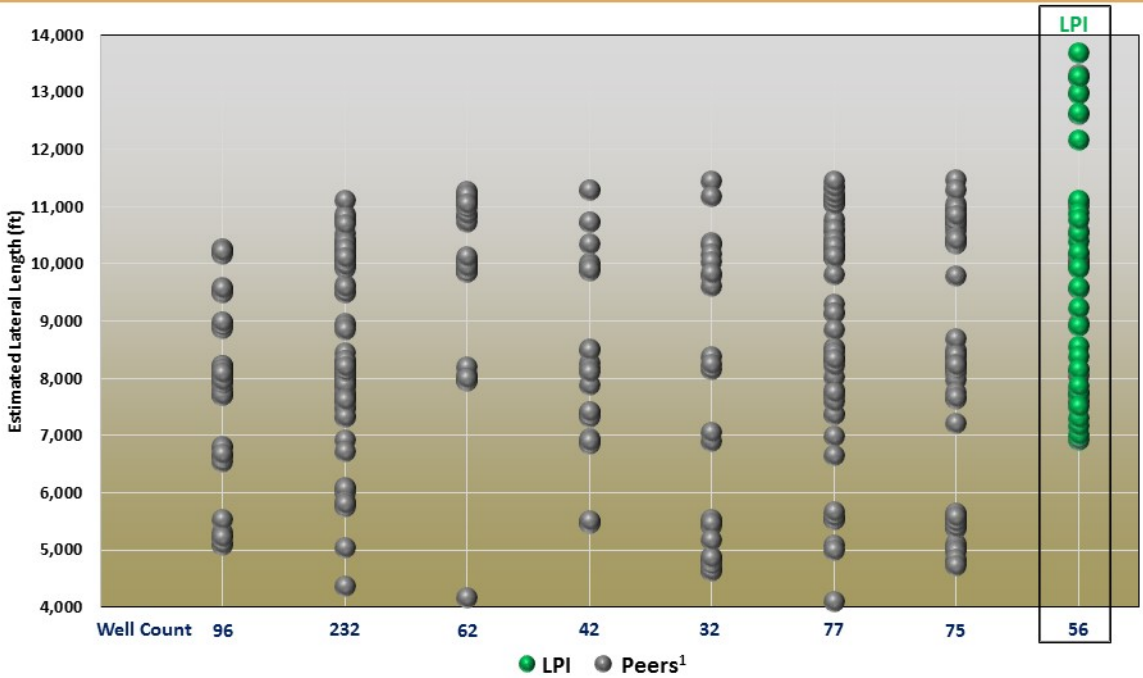
4,500 gross ft. of prospective zones

	Hz Wells Drilled	Thickness	3-Stream (STMMBOE)[1]	Identified Landing Points
Clearfork				
Upper/Middle Spraberry				
Lower Spraberry	2	~415'	90	2 - 3
Dean				
Upper Wolfcamp	128	~405'	72	2 - 3
Middle Wolfcamp	72	~620'	69	2 - 3
Lower Wolfcamp	30	~520'	69	1
Canyon	2	~470'	40	1
Penn Shale				
Cline	58	~330'	47	2
Strawn	2	~75'	n/a	1
Atoka, Barnett, Woodford	1	~375'	41	1

[1] Representative of the estimated mean 3-stream (STMMBOE) per section, measured in stock tank million barrels of oil equivalent
Note: As of 3/31/17

LAREDO PETROLEUM

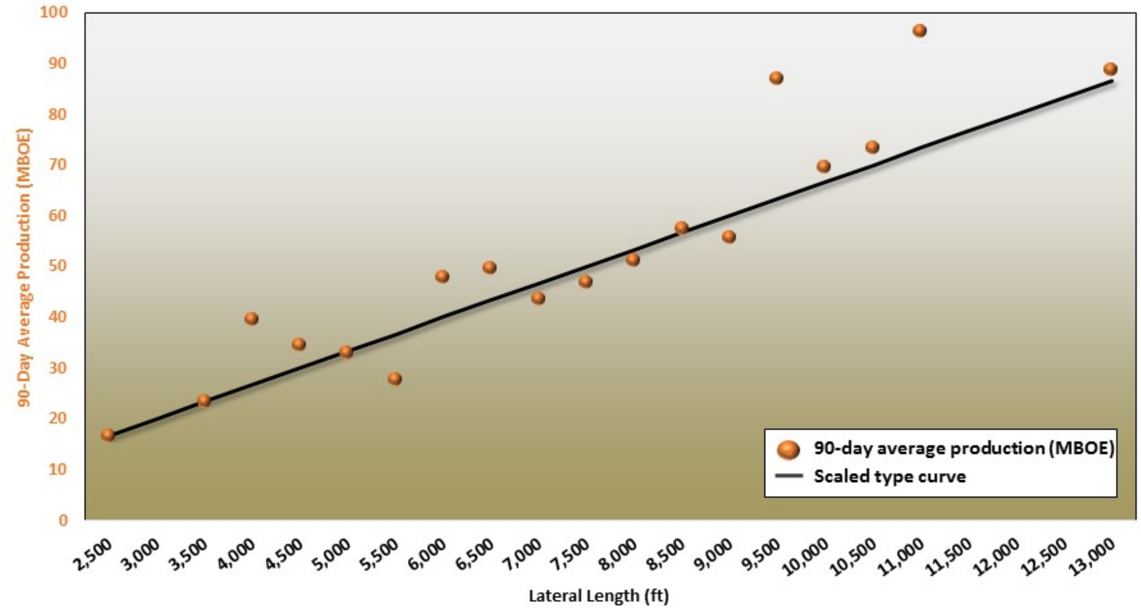
Peer-Leading Long-Lateral Execution



LPI has drilled 7 of the 12 longest laterals in the Midland Basin

[1] Peers: Callon, Diamondback, Encana, Energen, Parsley, Pioneer & RSP Permian
Note: Data is from IHS Enerdeq for the period of 04/01/2016 – 3/31/2017 for Glasscock, Howard, Irion, Midland, Reagan and Martin & Upton counties, TX wells with lateral length greater than 4,000'

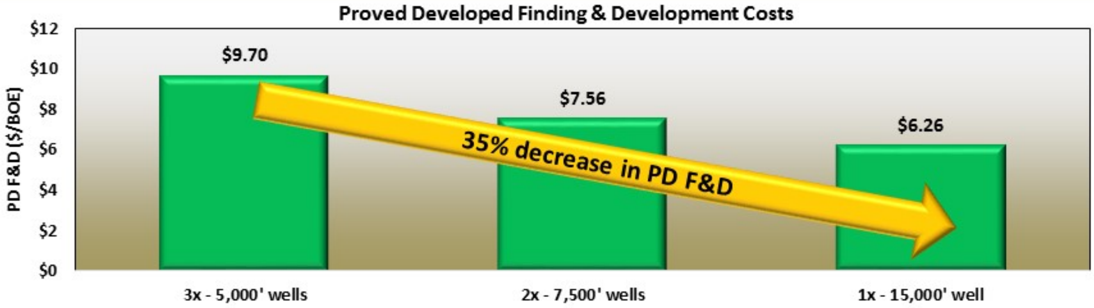
Laredo's Long Laterals Maintain Productivity

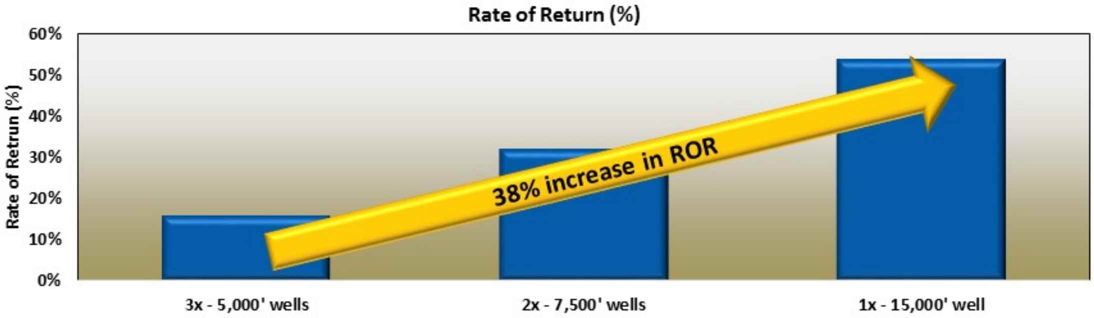


Laterals longer than 10,000' show NO productivity loss

Note: 1.3 MMBOE UWC/MWC 10,000' type curve utilized, scaled to each respective lateral length

Economic Benefits of Longer Laterals

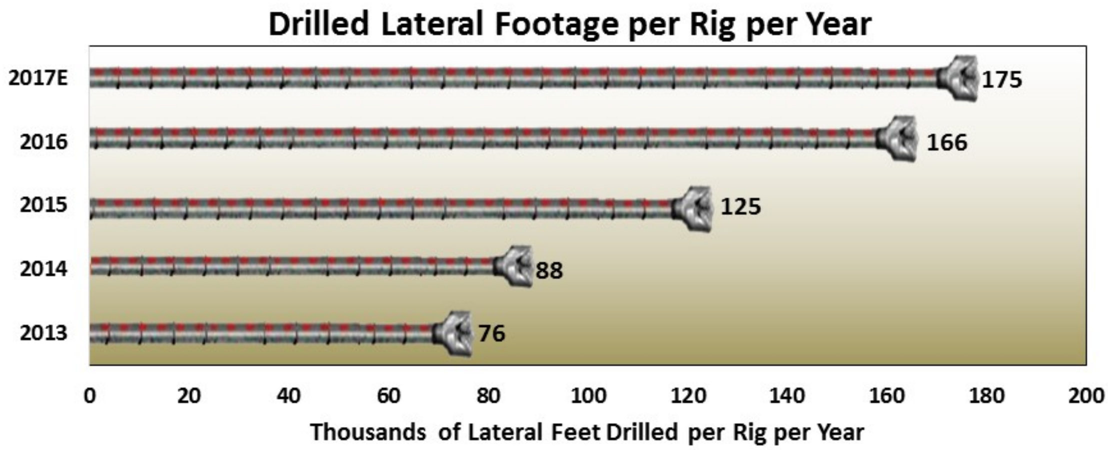




Longer laterals develop equivalent resources for reduced capital, yielding a 35% improvement in PD F&D

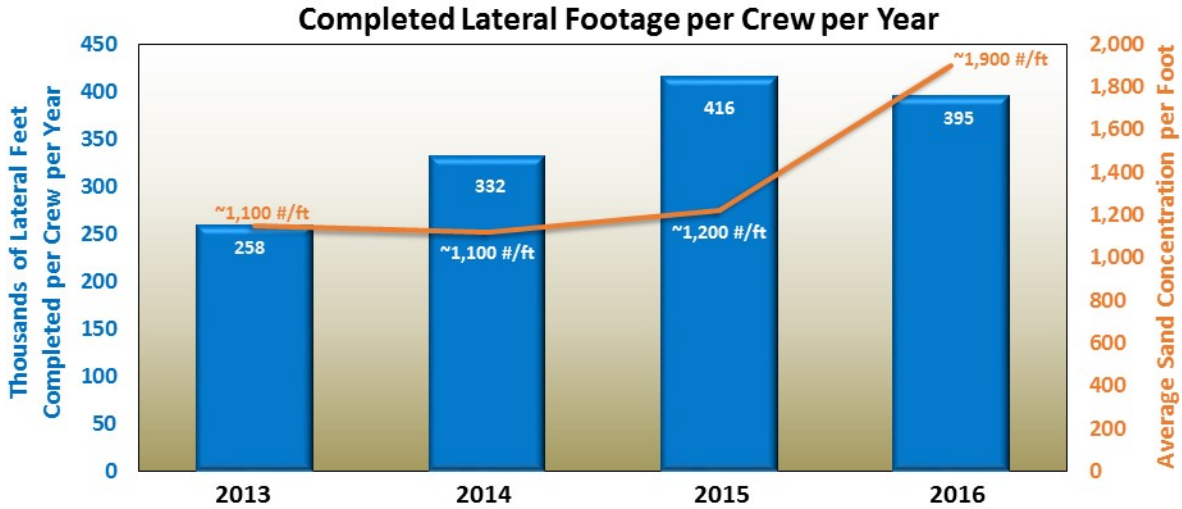
Note: Utilizing 75% NRI and EUR of 1.3 MMBOE per 10,000' lateral
Utilizing flat benchmark of WTI: $56.10/Bbl & HH: $3.00/Mcf and flat realized pricing of WTI: $50.49/Bbl, HH: $2.16/Mcf & NGLs: $17.95/Bbl

Drilling Efficiencies Maintain Lower Well Costs



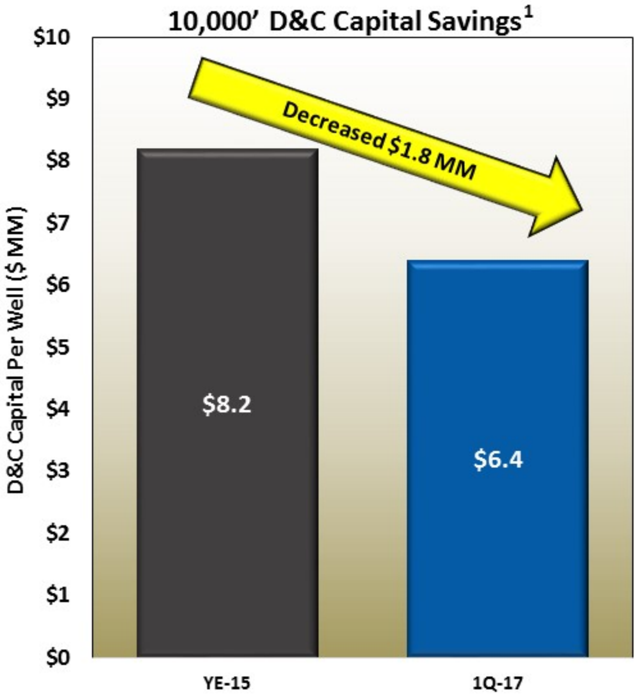
Significant drilling efficiency improvements realized without material increases in capex per rig, improving capital efficiency

Completions Efficiencies Drive Lower Well Costs



Significant completions efficiency improvements realized while optimizing completion designs and improving well performance

Drilling & Completions Efficiencies Drive Savings

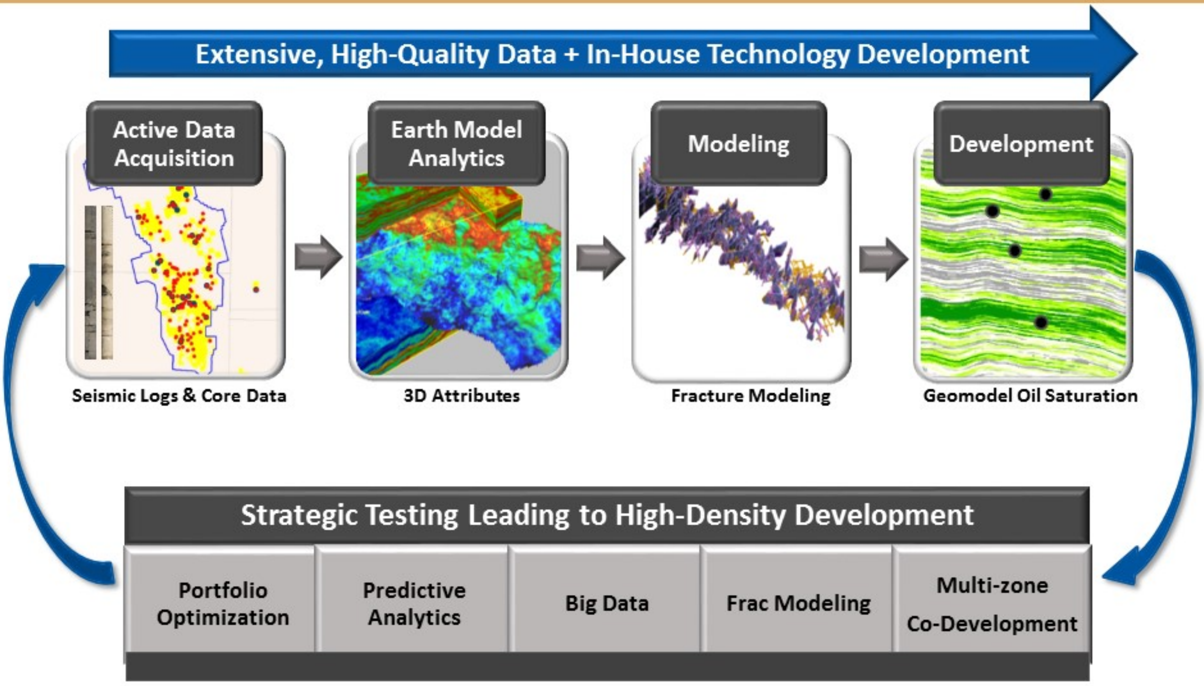


- **Cost-efficient development:**
  - **Longer laterals**
  - **Multi-well packages**
  - **Zipper fracing**
  - **High-spec rigs**

Focused on capital efficient drilling & completion operations

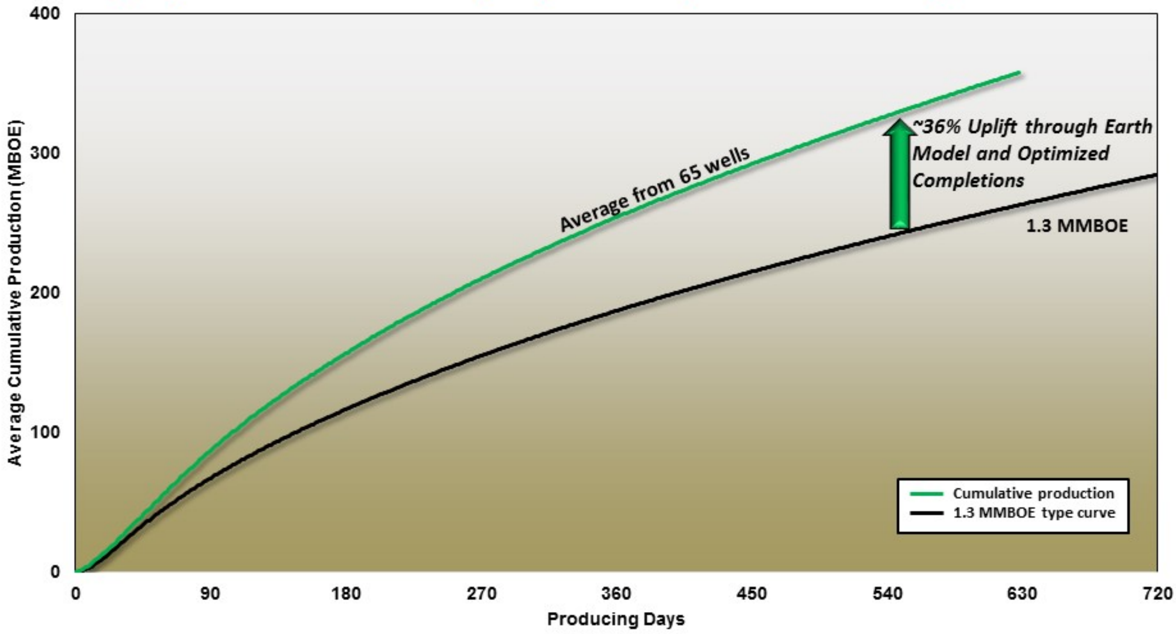
[1] Representative of multi-well pad costs
Note: D&C capital includes: $1 MM for 1,800 lb/ft sand, pad preparation, well-site metering, heater treaters, separation equipment & artificial lift equipment

Accelerating Learning to Enhance Shareholder Returns



Earth Model and Completions Optimization Benefits

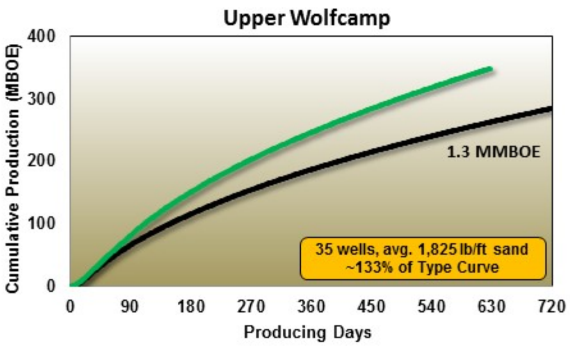
Wells utilizing the Earth Model and optimized completions have performed at an average of ~136% of 1.3 MMBOE Type Curve[1]

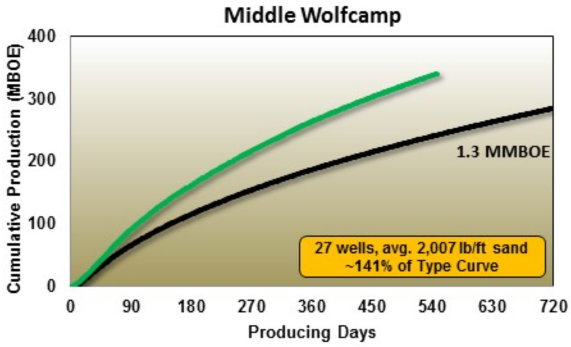


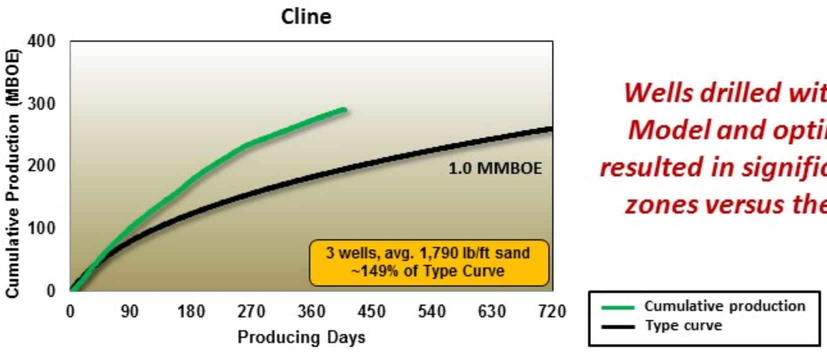
[1] Average cumulative production data through 4/26/17. This includes 65 Hz UWC/MWC wells have utilized both the Earth Model and optimized completions with avg. ~1,900 lb/ft sand

Note: Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

Multivariate Earth Model Enhancing Production



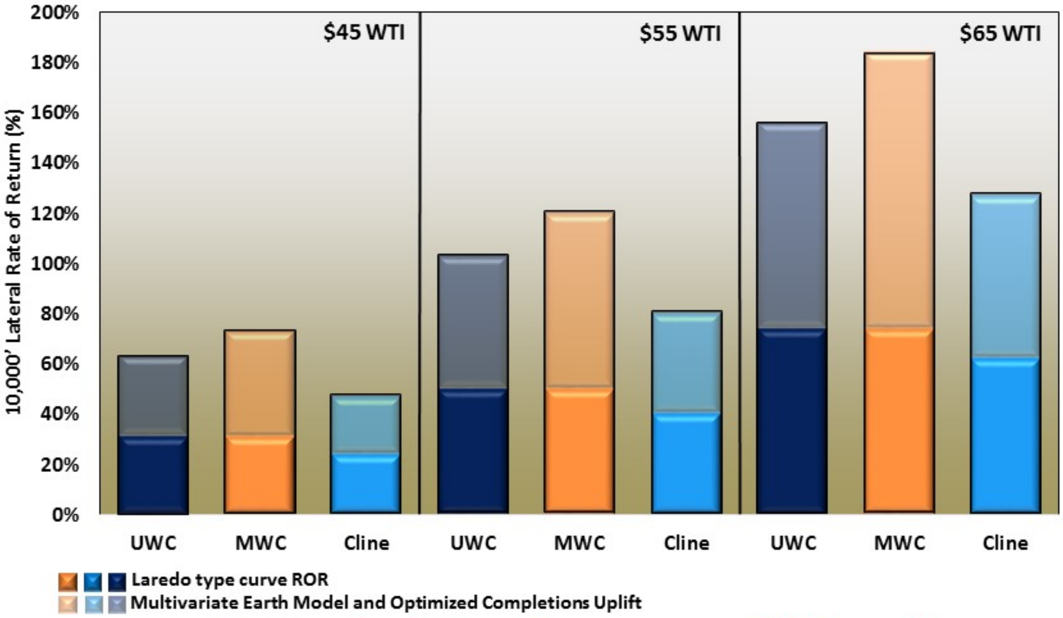




Wells drilled with the multivariate Earth Model and optimized completions have resulted in significant outperformance in all zones versus the Company's type curves

Note: Average cumulative production data through 4/26/17. Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

Multivariate Earth Model Driving Meaningful Uplift in Returns

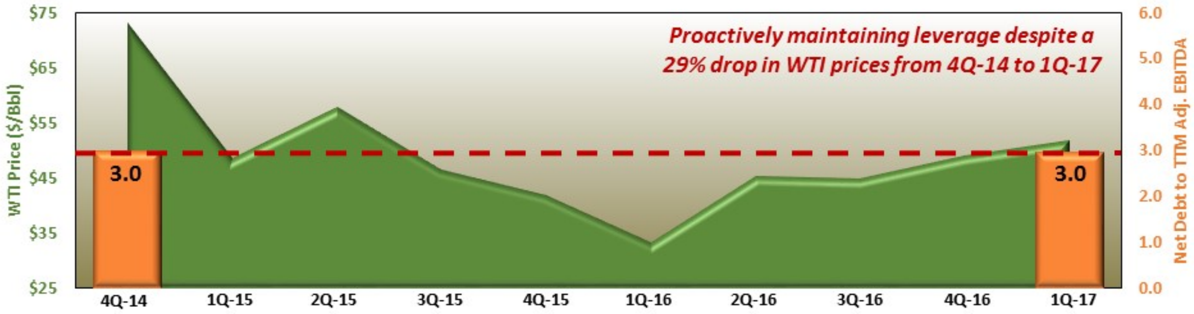


Demonstrated performance uplifts in each zone yield significant return improvements

Note: Rate of returns calculated using benchmark prices of WTI: $45.00/Bbl, $55.00/Bbl, $65.00/Bbl & HH: $3.00/Mcf, $3.25/Mcf, $3.50/Mcf and realized pricing of WTI: $40.95/Bbl, $50.05/Bbl, $59.15/Bbl & HH: $2.10/Mcf, $2.28/Mcf, $2.45/Mcf & NGLs: $14.40/Bbl, $17.60/Bbl, $20.80/Bbl
ROR includes static capital for 10,000' laterals and uplift reflective of current multivariate Earth Model and optimized completions outperformance above type curve by target and can change based on observed performance

Laredo's Productivity Improvements: 2014 vs 2017

Historical Oil Price and Net Debt to Adjusted EBITDA

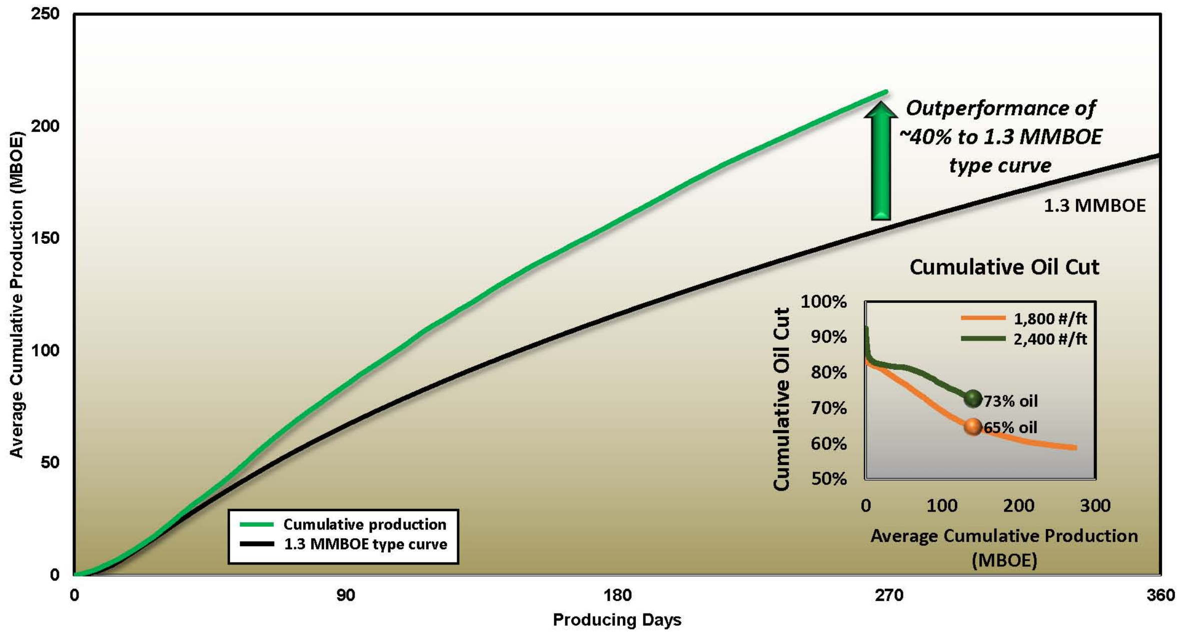


1 Hz Rig	Wells/Year	Avg Lateral Length (ft)	D&C/1,000'[1]	Lateral Ft/Rig/Yr	Lbs/Ft Sand[2]	EUR/1,000'[3]	LOE ($/BOE)
2014	~12	~7,300	~$987/ft	~88,000	1,100	~110	$6.98
2017	~18	~10,000	~$640/ft	~175,000	1,800	~130	$3.60[4]
2014 vs 2017	+50%	+37%	-35%	+99%	+64%	+18%	-48%

1 Based on type curve D&C cost. $7.4 MM for 7,500' lateral in 2014 and $6.4. MM for 10,000' lateral in 2017
2 Based on type curve. Does not include average proppant used to-date for 2017, which would include some 2,400 lb/ft tests
3 Based on comparative 10,000' lateral type curves for 2014 and 2017. Does not include recent well performance above type curve
4 2017 LOE/BOE is for 1Q17

Latest Optimization Tests Continue to Improve

13 wells utilizing the multivariate Earth Model and optimized completions with 2,400 lb/ft sand are yielding results significantly greater than type curve[1]

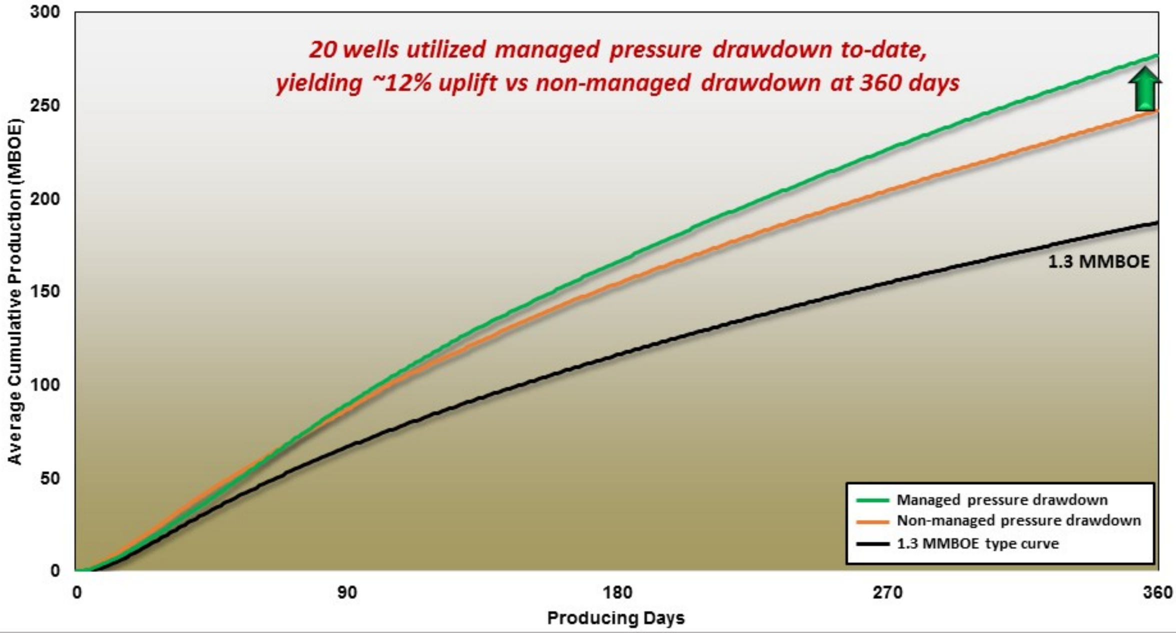


[1] Average cumulative production data through 4/26/17. This includes 13 Hz UWC/MWC wells have utilized both the Earth Model and optimized completions with avg. 2,400 lb/ft sand

Note: Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

Managed Pressure Drawdown Enhances Value

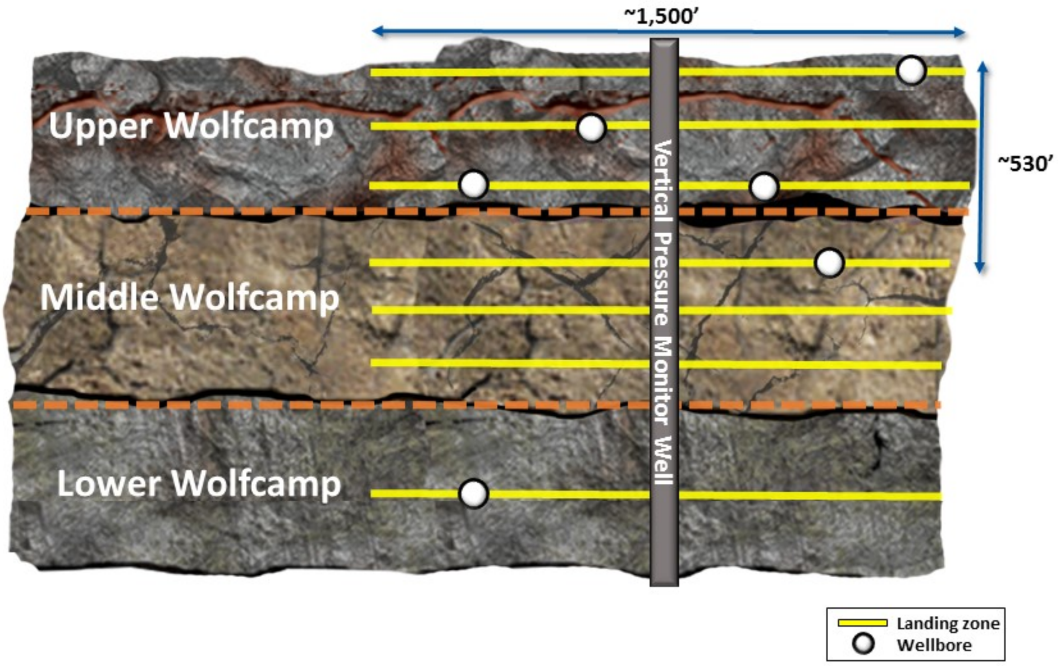
Managed pressure drawdown increases net present value $300,000 - $400,000 in the first year of production



[1] Average cumulative production data through 4/26/17. 20 wells utilized the managed pressure drawdown, 19 wells utilized the non-managed pressure drawdown. All wells utilized 1,800 lb/ft of proppant and optimized completions
Note: Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

Testing Co-Development of Landing Points

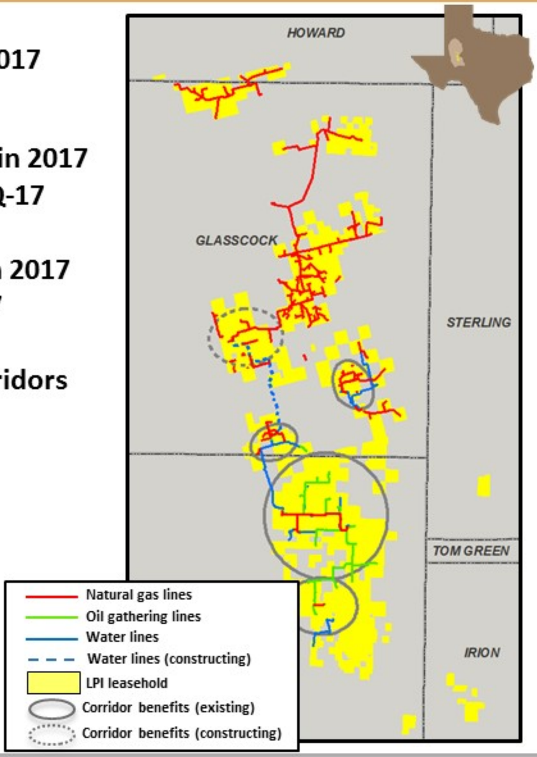
Potential to add additional high-value inventory



Prior Investments in Infrastructure Providing Tangible Benefits

- Expect to receive $27.8 MM total benefits for 2017
  - ~$5.8 MM total benefits in 1Q-17[1]
- Anticipate reducing >100,000 water truckloads in 2017
  - Eliminated ~25,000 water truckloads in 1Q-17
- Anticipate reducing ~65,000 crude truckloads in 2017
  - Eliminated ~12,000 oil truckloads in 1Q-17
- ~200 horizontal wells served by production corridors with potential for >2,500 more[2]

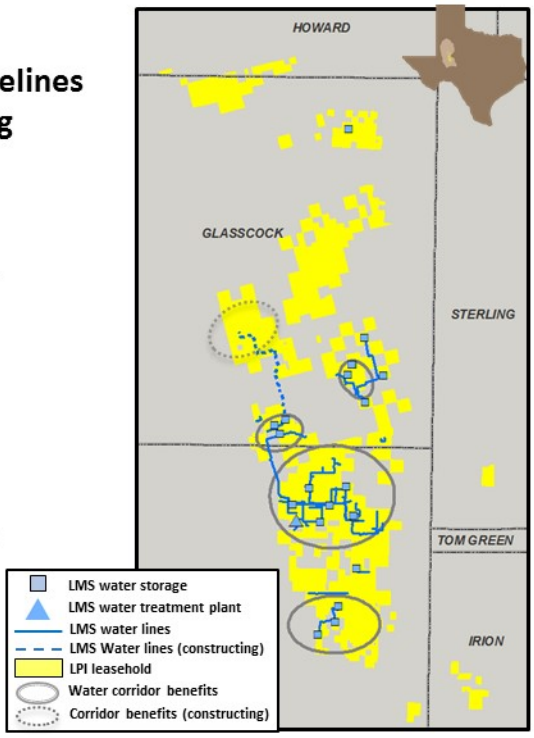
In 1Q-17, Laredo's infrastructure assets gathered on pipe 73% of gross operated oil production & 65% of total produced water



[1] Benefits defined as capital savings, LOE savings, price uplift and LMS net operating income
[2] Includes Western Glasscock production corridor, which is currently under construction
Note: Infrastructure includes crude gathering/transportation, water gathering, distribution & recycle, natural gas gathering and centralized gas lift compression

Significant Benefits through Water Infrastructure Investments

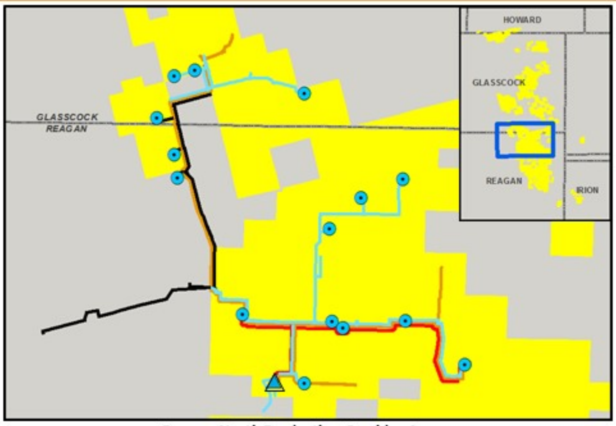
- Water infrastructure consists of:
  - 78 miles of total water gathering pipelines
  - Recycling plant capable of processing 30,000 BWPD
  - Linked water storage assets with >8 MMBW capacity
  - Total storage capacity of 12 MMBW
  - Access to ~340 wells with ~510,000 BWPD refresh rate
- Enables drilling of multi-well pads
- Yields significant capital and LOE savings
- Minimizes trucking



Water Infrastructure Capital and LOE Savings

- 3.1 MMBW (65%) of total 1Q-17 produced water was gathered on pipe
  - Expected to increase to ~75% for FY 2017
- 1.4 MMBW (30%) of total 1Q-17 produced water was recycled by LMS
  - Expected to increase to ~57% for FY 2017
- 3.5 MMBW (30%) of water for completions in 1Q-17 was supplied with recycled water
  - Expected to average ~20% in 2017

LMS Service	LPI Financial Benefits (1Q-17)		
	Category	($/BW)	($ MM)
Produced Water (Gathered vs Trucked)	Capital & LOE savings	$0.62	$1.9
Produced Water (Recycled vs Disposed)	Capital & LOE savings	$0.23	$0.3
Frac Water (Recycled vs Fresh)	Capital savings	$0.20	$0.7



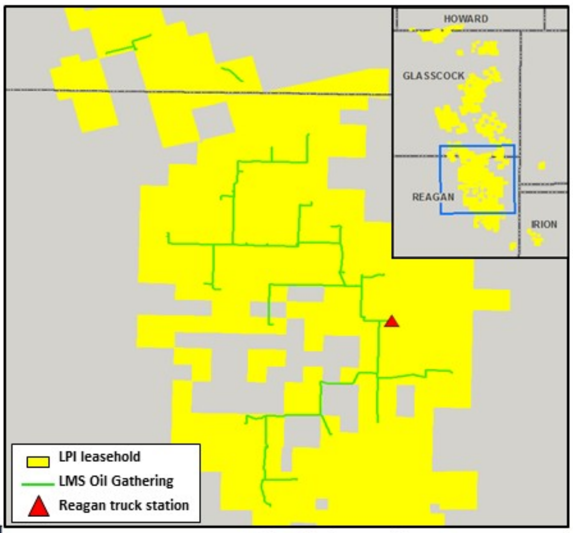
Reagan North Production Corridor Area

LMS' water gathering system is expected to eliminate >100,000 truckloads of water in 2017

Note: 2017 estimates as of 5/1/2017

LMS Crude Gathering System Benefits

- 44 miles of crude oil gathering lines
- 2.2 MMBO (73%) of gross operated production in 1Q-17 was gathered on pipe
- Reduces time from production to sales
- Benefits of system increase as trucking costs rise



Reagan North Production Corridor Area

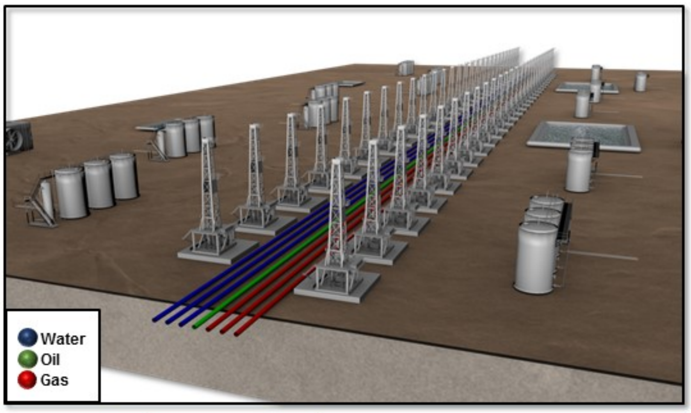
LMS Service	LPI Financial Benefits (1Q-17)		
	Category	($/Bbl)	($ MM)
Produced Oil (Gathered vs Trucked)	3rd-Party Income	$0.66	$1.5
Produced Oil (Gathered vs Trucked)	Increased Revenues	$0.55	$1.2

LMS expects to eliminate ~65,000 truckloads of oil in 2017

Note: 2017 estimates as of 5/1/2017

Corridor Financial Benefits

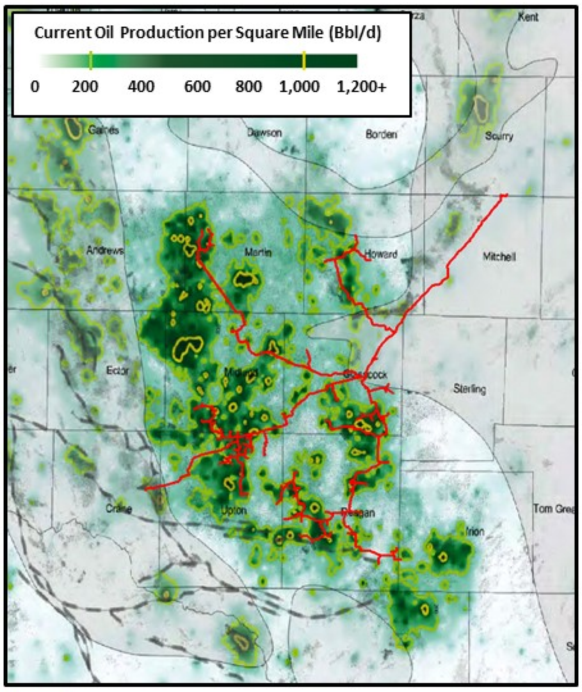
Production corridors reduced unit LOE by $0.46/BOE in 1Q-17 to $3.60/BOE



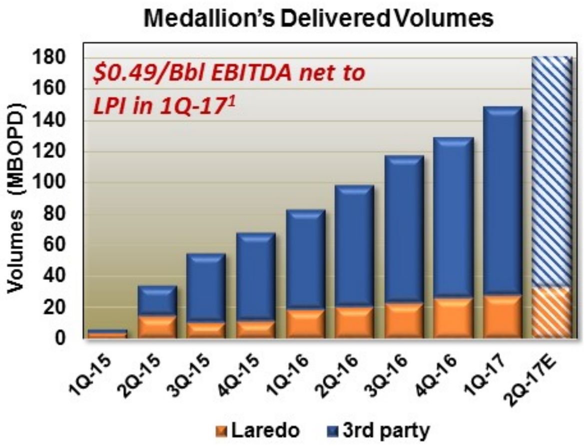
LMS Service	2016 Benefits Actual ($ MM)	1Q-17 Benefits Actual ($ MM)	2017 Benefits Estimated ($ MM)[1]	LPI Financial Benefits
Crude Gathering	$10.4	$2.7	$14.1	Increased revenues & 3rd-party income
Centralized Gas Lift	$0.9	$0.2	$1.0	LOE savings
Produced Water (Gathered vs Trucked)	$9.6	$1.9	$8.4	Capital & LOE savings
Produced Water (Recycled vs Disposed)	$2.0	$0.3	$2.1	Capital & LOE savings
Frac Water (Recycled vs Fresh)	$1.1	$0.7	$2.2	Capital savings
Corridor Benefit	**$24.1**	**$5.8**	**$27.8**	

[1] Benefits estimates as of 4/29/2017

Medallion-Midland Basin: The Premier Pipeline in the Permian



Medallion–Midland Basin system



The Medallion-Midland Basin system grew transported volumes 79% from 1Q-16 to 1Q-17

[1] Includes G&A
Note: Heat map generated by RS Energy Group, 2016

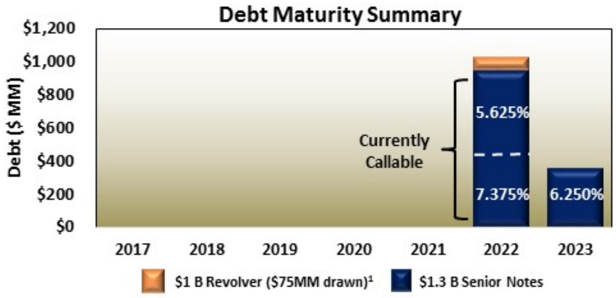
LAREDO PETROLEUM

Maintaining Strong Financial Position

Laredo has always taken a proactive stance towards reducing risk throughout the company

- **Well positioned financially with strong liquidity and no term-debt maturities until 2022**
- **Majority of acreage is held by production**
- **No long-term rig or service commitments**
- **Not vertically integrated**

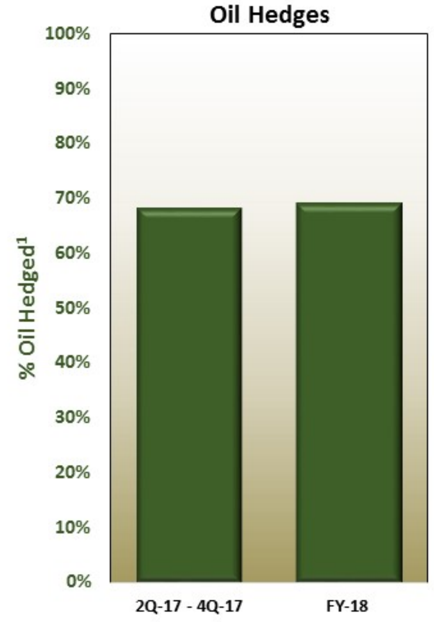
- **No debt due until 2022**
  - **$950 million of notes currently callable at Laredo's option**
- **$945 million of liquidity[1]**

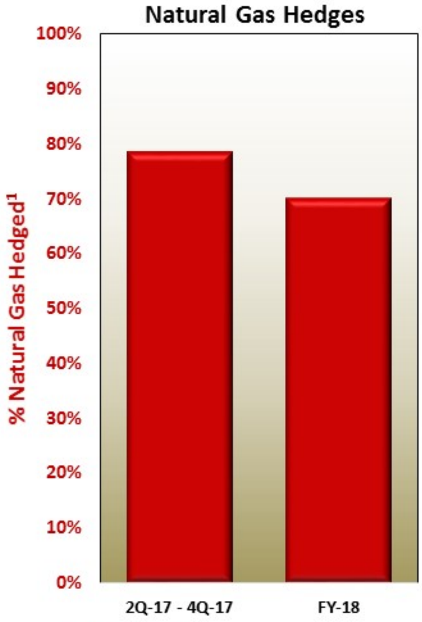


[1] As of 5/2/17, with $1 B Borrowing Base in place with amended and restated Senior Secured Credit Facility

Disciplined Hedging Program

Volumes Protected by Floors





Providing cash flow stability while retaining meaningful price upside opportunity

	2Q-17 - 4Q-17	FY-18
Weighted-Avg. Floor Price[2] NYMEX	$55.82	$46.34

Weighted-Avg. Floor Price[2]		2Q-17 - 4Q-17	FY-18
	WAHA	$2.75	$2.50
	HH[3]	$3.10	$2.95

Note: Hedged volumes are presented on a net basis and do not include 2Q-17 - 4Q-17 NGL hedges of 333,000 Bbl of ethane or 281,250 Bbl of propane

[1] For percent hedged, utilizing actual 2016 production plus 15% growth for FY-17 and flat 2017 production for FY-18.

[2] Oil derivatives are settled based on the month's average daily NYMEX price of WTI Light Sweet Crude Oil and natural gas derivatives are settled based on Inside FERC index price for West Texas WAHA for the calculation period

[3] Based on WAHA basis to Henry Hub (HH) as of 05/22/17

LAREDO PETROLEUM

Oil, Natural Gas & Natural Gas Liquids Hedges

OIL[1]	2Q-17 - 4Q-17	2018
Puts:		
Hedged volume (Bbls)	790,625	2,616,875
Weighted average price ($/Bbl)	$60.00	$54.01
Swaps:		
Hedged volume (Bbls)	1,512,500	
Weighted average price ($/Bbl)	$51.54	
Collars:		
Hedged volume (Bbls)	2,860,000	4,088,000
Weighted average floor price ($/Bbl)	$56.92	$41.43
Weighted average ceiling price ($/Bbl)	$60.23	$60.00
Total volume with a floor (Bbls)	5,163,125	6,704,875
Weighted-average floor price ($/Bbl)	$55.82	$46.34

NATURAL GAS[2]		
Put		
Hedged volume (MMBtu)	6,030,000	8,220,000
Weighted average floor price ($/MMBtu)	$2.50	$2.50
Collars:		
Hedged volume (MMBtu)	14,327,500	15,585,500
Weighted average floor price ($/MMBtu)	$2.86	$2.50
Weighted average ceiling price ($/MMBtu)	$3.54	$3.35
Total volume with a floor (MMBtu)	20,357,500	23,805,500
Weighted-average floor price ($/MMBtu)	$2.75	$2.50

NATURAL GAS LIQUIDS[3]		
Swaps - Ethane:		
Hedged volume (Bbls)	333,000	
Weighted average price ($/Bbl)	$11.24	
Swaps - Propane:		
Hedged volume (Bbls)	281,250	
Weighted average price ($/Bbl)	$22.26	
Total volume with a floor (Bbls)	614,250	

Note: Open positions as of 4/1/2017 and including new hedges through 5/22/2017
Hedged volumes are presented on a net basis
[1] Oil derivatives are settled based on the month's average daily NYMEX price of WTI Light Sweet Crude Oil
[2] Natural gas derivatives are settled based on Inside FERC index price for West Texas Waha for the calculation period
[3] Natural gas liquids derivatives are settled based on the month's daily average of OPIS Mt. Belvieu Purity Ethane and TET Propane

LAREDO PETROLEUM

2Q-17 Guidance

	2Q-17
Production (MBOE/d)	55 - 58
Product % of total production:	
Crude oil	45% - 47%
Natural gas liquids	26% - 27%
Natural gas	27% - 28%
Price Realizations (pre-hedge):	
Crude oil (% of WTI)	~88%
Natural gas liquids (% of WTI)	~29%
Natural gas (% of Henry Hub)	~68%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$3.50 - $4.00
Midstream expenses ($/BOE)	$0.20 - $0.30
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.50%
General and administrative expenses:	
Cash ($/BOE)	$3.00 - $3.50
Non-cash stock-based compensation ($/BOE)	$1.75 - $2.00
Depletion, depreciation and amortization ($/BOE)	$7.25 - $7.75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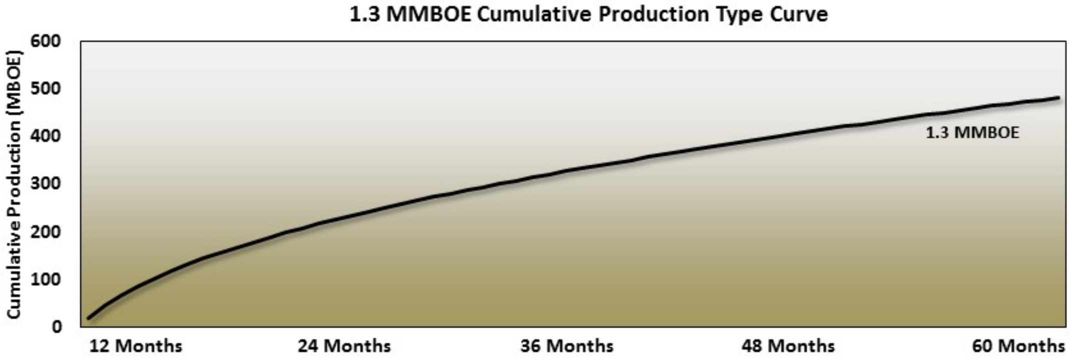
PETROLEUM
Appendix

UWC & MWC 1.3 MMBOE Cumulative Production Type Curve



Months	Cumulative Production (MBOE)	Cumulative % Oil
12	189	60%
24	288	56%
36	363	54%
48	426	52%
60	482	51%

Previously increased UWC & MWC type curve due to well performance uplifts from the multivariate Earth Model optimized drilling and completions

Note: 10,000' lateral length with 1,800 lb/ft completions

2016 & 2017 YTD Actuals

		1Q-16	2Q-16	3Q-16	4Q-16	FY-16	1Q-17
Production	Production (3-Stream)						
	MBOE	4,204	4,338	4,718	4,889	18,149	4,716
	BOE/D	46,202	47,667	51,276	53,141	49,586	52,405
	% oil	48%	46%	46%	46%	47%	45%
Realized Pricing	3-Stream Prices						
	Gas ($/Mcf)	$1.31	$1.31	$2.07	$2.13	$1.73	$2.31
	NGL ($/Bbl)	$8.50	$12.24	$11.54	$14.79	$11.91	$16.49
	Oil ($/Bbl)	$27.51	$39.37	$39.10	$43.98	$37.73	$46.91
	Avg. Price ($/BOE)	$17.40	$23.64	$24.34	$27.82	$23.50	$29.42
Unit Cost Metrics	3-Stream Unit Cost Metrics						
	Lease Operating ($/BOE)	$4.88	$4.43	$3.85	$3.56	$4.15	$3.60
	Midstream ($/BOE)	$0.14	$0.27	$0.22	$0.26	$0.22	$0.19
	General & Administrative ($/BOE)						
	Cash	$3.72	$3.32	$3.49	$3.28	$3.45	$3.47
	Non-cash stock-based compensation	$0.91	$1.41	$2.05	$1.98	$1.61	$1.96
	DD&A ($/BOE)	$9.87	$7.88	$7.45	$7.68	$8.17	$7.23

2015 Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15
Production	Production (3-Stream)					
	MBOE	4,274	4,234	4,124	3,714	16,346
	BOE/D	47,487	46,532	44,820	40,368	44,782
	% oil	51%	46%	45%	45%	47%
Realized Pricing	3-Stream Prices					
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27
	Avg. Price ($/BOE)	$27.64	$29.65	$25.37	$22.47	$26.41
Unit Cost Metrics	3-Stream Unit Cost Metrics					
	Lease Operating ($/BOE)	$7.58	$6.90	$6.09	$5.83	$6.63
	Midstream ($/BOE)	$0.37	$0.38	$0.26	$0.43	$0.36
	General & Administrative ($/BOE)					
	Cash	$3.99	$3.99	$3.89	$4.29	$4.03
	Non-cash stock-based compensation	$1.12	$1.49	$1.67	$1.75	$1.50
	DD&A ($/BOE)	$16.83	$17.03	$16.19	$18.01	$16.99

2014 Two-Stream to Three-Stream Conversions

		1Q-14	2Q-14	3Q-14	4Q-14	FY-14
Production	Production (2-Stream)					
	MBOE	2,434	2,607	3,033	3,655	11,729
	BOE/D	27,041	28,653	32,970	39,722	32,134
	% oil	58%	58%	59%	60%	59%
	Production (3-Stream)					
	MBOE	2,902	3,113	3,614	4,330	13,959
	BOE/D	32,358	33,829	38,798	46,379	37,882
	% oil	49%	49%	50%	51%	50%
Realized Pricing	2-Stream Prices					
	Gas ($/Mcf)	$7.04	$6.08	$5.80	$4.46	$5.72
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	Avg. Price ($/BOE)	$71.17	$70.13	$65.78	$49.70	$64.62
	3-Stream Prices					
	Gas ($/Mcf)	$4.00	$3.73	$3.25	$3.00	$3.45
	NGL ($/Bbl)	$32.88	$28.79	$29.21	$19.65	$27.00
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	Avg. Price ($/BOE)	$59.70	$58.80	$55.41	$41.94	$52.81
Unit Cost Metrics	2-Stream Unit Cost Metrics					
	Lease Operating ($/BOE)	$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream ($/BOE)	$0.35	$0.59	$0.40	$0.50	$0.46
	General & Administrative ($/BOE)					
	Cash	$9.58	$8.88	$6.89	$4.25	$7.07
	Non-cash stock-based compensation	$1.78	$2.46	$2.04	$1.70	$1.97
	DD&A ($/BOE)	$20.38	$20.35	$21.08	$21.85	$21.01
	3-Stream Unit Cost Metrics					
	Lease Operating ($/BOE)	$7.48	$6.55	$7.05	$6.88	$6.98
	Midstream ($/BOE)	$0.29	$0.50	$0.34	$0.43	$0.39
	General & Administrative ($/BOE)					
	Cash	$8.05	$7.44	$5.78	$3.59	$5.94
	Non-cash stock-based compensation	$1.48	$2.06	$1.72	$1.43	$1.65
	DD&A ($/BOE)	$17.03	$17.23	$17.91	$18.72	$17.83

Note: 2014 conversion based on management estimates. Utilizes an 18% volume uplift, for converting from 2-stream to 3-stream volumes

EBITDA Reconciliation

LPI Adjusted EBITDA *(in thousands)*		1Q-17
Net income	$	68,276
Plus:		
Depletion, depreciation and amortization	$	34,112
Impairment expense	$	-
Non-cash stock-based compensation, net of amounts capitalized	$	9,224
Accretion expense	$	928
Mark-to-market on derivatives:		
Gain on derivatives, net	$	(36,671)
Cash settlements received for matured derivatives, net	$	7,451
Cash settlements received for early termination of derivatives, net	$	-
Cash premiums paid for derivatives	$	(2,107)
Interest expense	$	22,720
Loss on disposal of assets, net	$	214
Income from equity method investee	$	(3,068)
Proportionate Adjusted EBITDA of equity method investee[1]	$	6,365
Adjusted EBITDA	$	107,444

[1]Medallion Adjusted EBITDA *(in thousands)*		1Q-17
Income from equity method investee	$	3,068
Adjusted for proportionate share of:		
Depreciation and amortization	$	3,297
Proportionate Adjusted EBITDA of equity method investee	$	6,365