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): March 1, 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))

Item 7.01. Regulation FD Disclosure.

On March 1, 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 March 1, 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: March 1, 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 March 1, 2017.

EXHIBIT 99.2

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, 2015 and other reports filed with the Securities Exchange Commission ("SEC") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2016 to be filed with the 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.

2016 Highlights

- Grew production 11% in 2016 and funded drilling program with operating cash flow
- Increased proved developed reserves organically by approximately 40% at a PD F&D cost of $5.12 per BOE
- Reduced LOE 37% during 2016 with 4Q-16 unit LOE decreasing to $3.56 per BOE
- Decreased leverage from 3.3x net debt/TTM Adj. EBITDA in 1Q-16 to 2.9x at YE-2016

Prior Investments Creating Value

- **Multi-zone, contiguous acreage position enabling development efficiencies**
  - 2016 average completed lateral length of ~10,000' driving higher rates of return
- **Data powering the multivariate Earth Model**
  - Increasing UWC & MWC type curves as a result of long-term production outperformance from multivariate Earth Model optimized drilling and completions
  - Most recent well results currently averaging ~36% higher than the new 1.3 MMBOE type curve
- **Production corridors lowering operating costs**
  - Production corridors benefited LOE by $0.51/BOE in the fourth quarter of 2016
- **Medallion-Midland Basin system growing transported volumes**
  - Medallion-Midland Basin system more than doubled delivered volumes in 2016 and is expected to grow >75% exit-to-exit in 2017

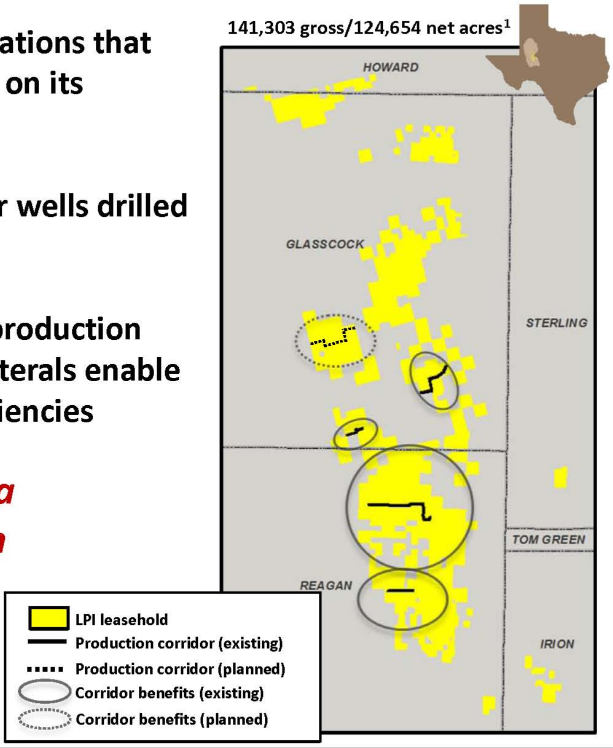
Prior strategic investments and continuous performance improvements yield repeatable benefits

Capitalizing on Contiguous Acreage Position

- The company has identified >2,000 locations that support lateral lengths of 10,000+ feet on its contiguous acreage
- The expected average lateral length for wells drilled in 2017 will be ~10,000 feet
- 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[1]

141,303 gross/124,654 net acres[1]



[1] As of 1/31/17

Multiple Targeted Horizons

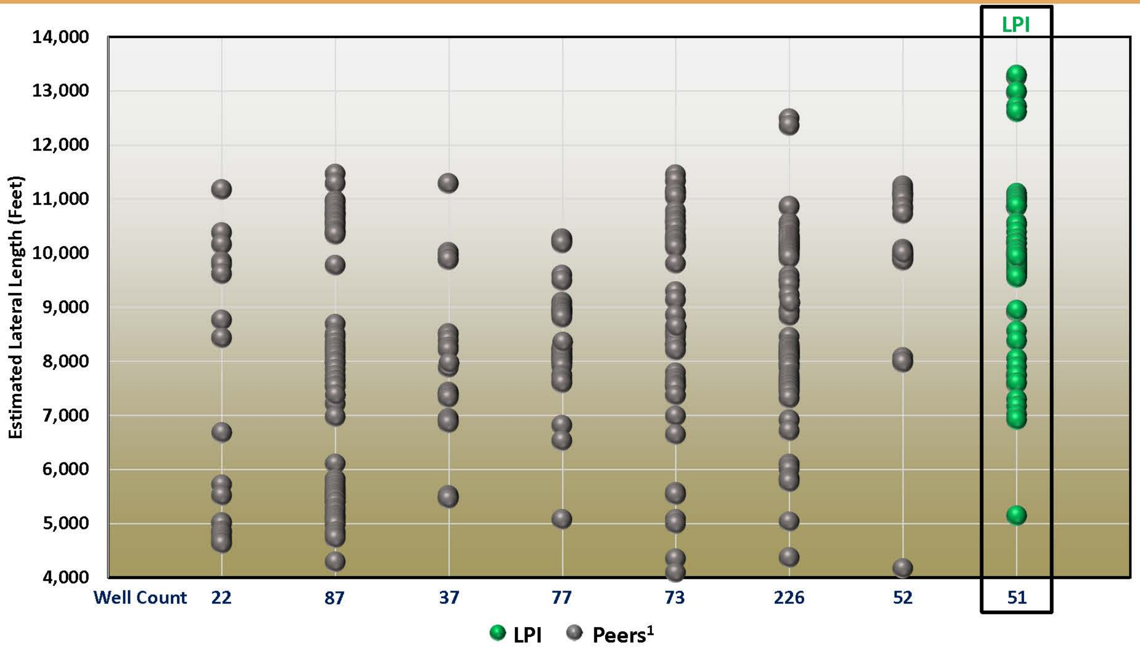
Primary targets
Secondary targets

4,500 gross ft. of prospective zones

	Hz Wells Drilled	Thickness	OOIP[1]	Identified Landing Points
Clearfork				
Upper/Middle Spraberry				
Lower Spraberry	2	~415'	90	2 - 3
Dean				
Upper Wolfcamp	127	~405'	72	2 - 3
Middle Wolfcamp	61	~620'	69	2 - 3
Lower Wolfcamp	30	~520'	69	1
Canyon	2	~470'	40	1
Penn Shale				
Cline	57	~330'	47	2
Strawn				
Atoka, Barnett, Woodford	1	~375'	41	1

[1] Representative of the estimated mean original oil in place (OOIP) per section, measured in stock tank million barrels of oil equivalent
Note: As of 12/31/16

Peer-Leading Long-Lateral Execution

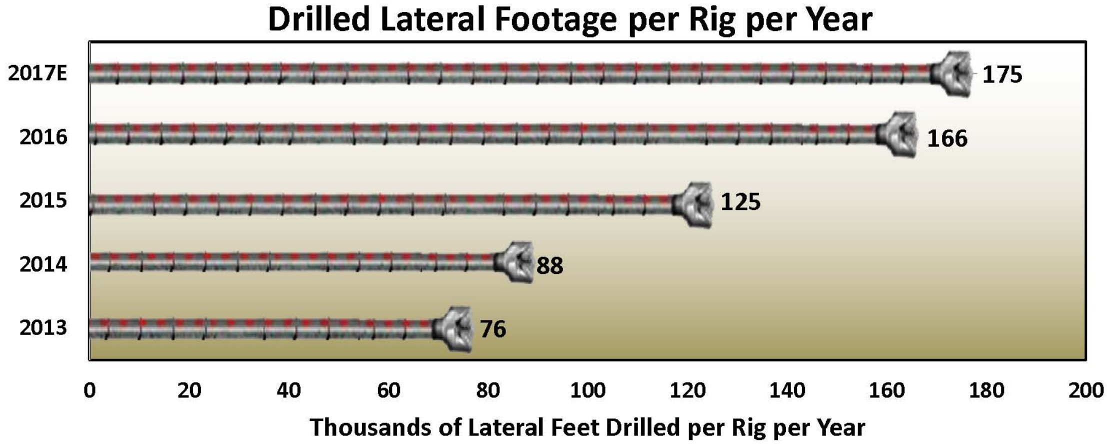


Contiguous acreage position enables drilling of longer laterals

[1] Peers: Callon, Diamondback, Encana, Energen, Parsley, Pioneer & RSP Permian

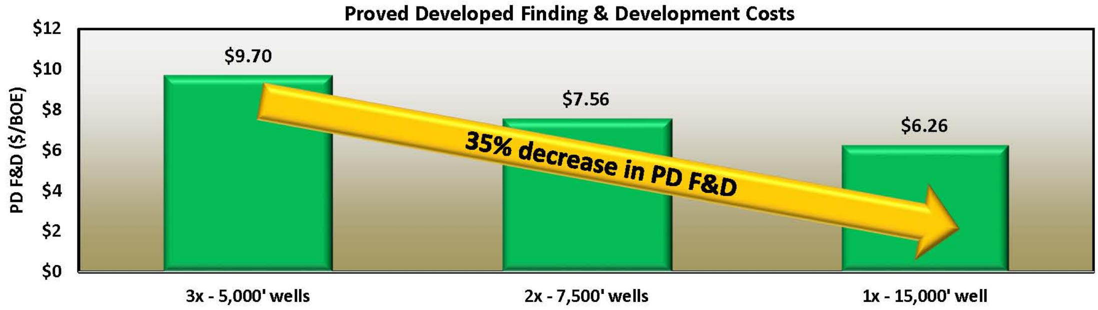
Note: Data is from IHS Enerdeq for the period of 01/01/2016 – 12/31/2016 for Glasscock, Howard, Irion, Midland, Reagan and Martin & Upton counties, TX

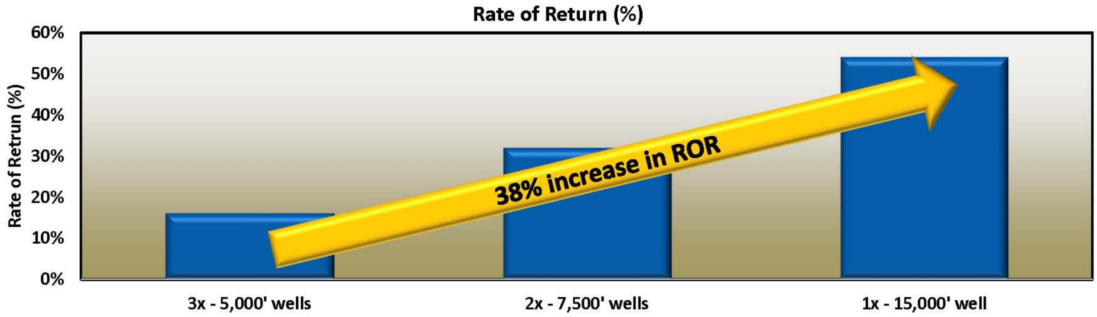
Drilling Efficiencies Drive Lower Well Costs



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

Economic Benefits of Longer Laterals

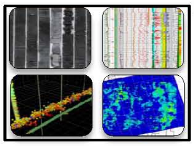


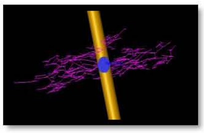


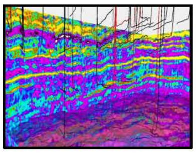
Longer laterals develop equivalent resources for reduced capital, yielding capital efficiency and rate of return improvements

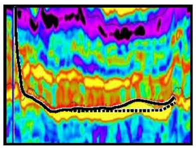
Note: Utilizing 75% NRI and EUR of 1.3 MMBOE per 10,000' lateral (updated type curve as of 2/15/17)
Utilizing flat benchmark of WTI: $56.10/Bbl & HH: $3.00/Mcf and flat realized pricing of WTI: $50.49/Bbl, HH: $2.16/Mcf & NGLs: $17.95/Bbl

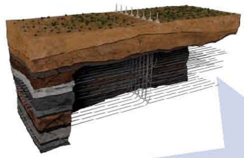
Laredo's Technology Workflow











Technical Data Sets
- Production
- Pressure
- Rock properties
- Stress

Integration
- Prior Knowledge
- Data Collation
- New Well Results
- Paradigms

Technology & Analysis
- Frac Modeling
- Reservoir Simulation
- Multivariate Analytics

Results
- Role of Interference
- Optimized Completions
- Optimized Well Spacing
- Optimized Well Trajectory

Actions
- Predicted Well Performance
- Ranked Zones
- Ranked Wells
- Holistic Development Plan

Earth Modeling is one of a number of technologies being applied at Laredo to enhance shareholder value

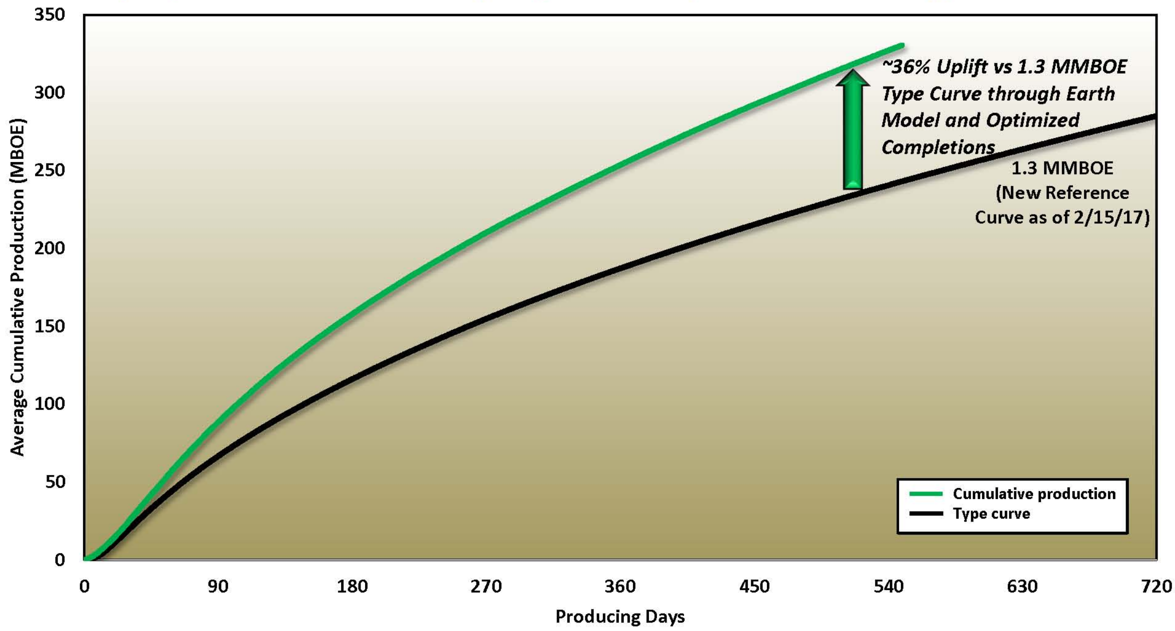
Evolving Beyond the Earth Model

	2015	2016	2017
Project duration	• 12-18 months	• 6-12 months	• 2-4 weeks
LPI acreage coverage	• ~50%	• ~80%	• 100% & offset acreage
# zones	• 2	• 4	• 5
Focus	• Seismic Inversion	• Expanded attributes	• Improved data
Completions	• None	• Intermediate • e.g. proppant loading	• Detailed • e.g. choke management
Well normalization	• Basic • e.g. completion length	• Intermediate • e.g. well spacing	• Enhanced • e.g. development timing
GTI Data	• No	• No	• Yes

Enhanced multivariate analysis of key production drivers

Earth Model and Completion Optimization Benefits

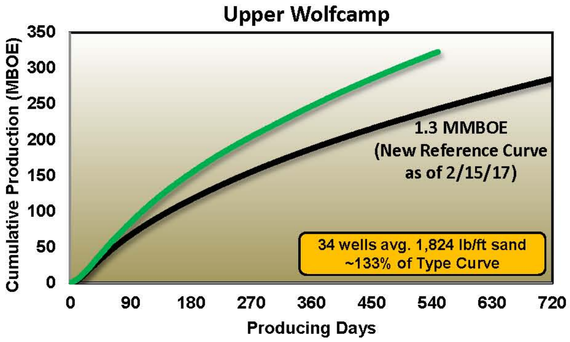
Wells utilizing the Earth Model and optimized completions have performed at an average of ~136% of 1.3 MMBOE Type Curve[1]

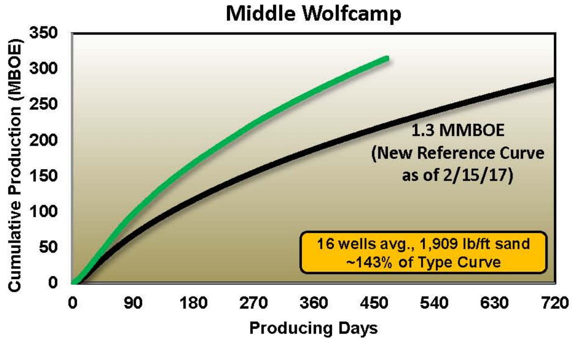


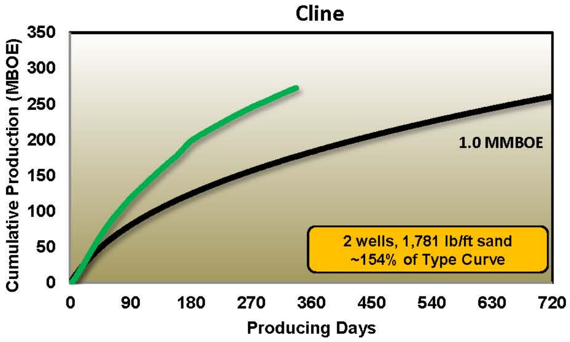
[1] Average cumulative production data through 2/6/17. This includes 50 Hz UWC/MWC wells have utilized both the Earth Model and optimized completions with 1,851 lb/ft sand

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



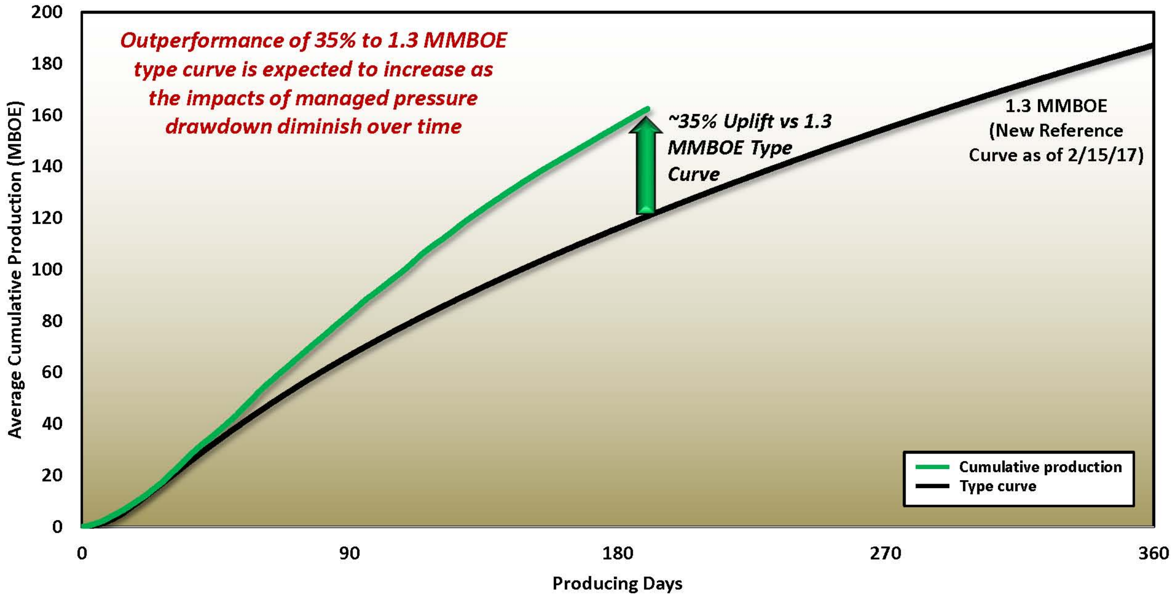




Wells drilled with the Multivariate Earth Model and optimized drilling and completions have resulted in significant outperformance versus the Company's type curves

Note: Average cumulative production data through 2/6/17. Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

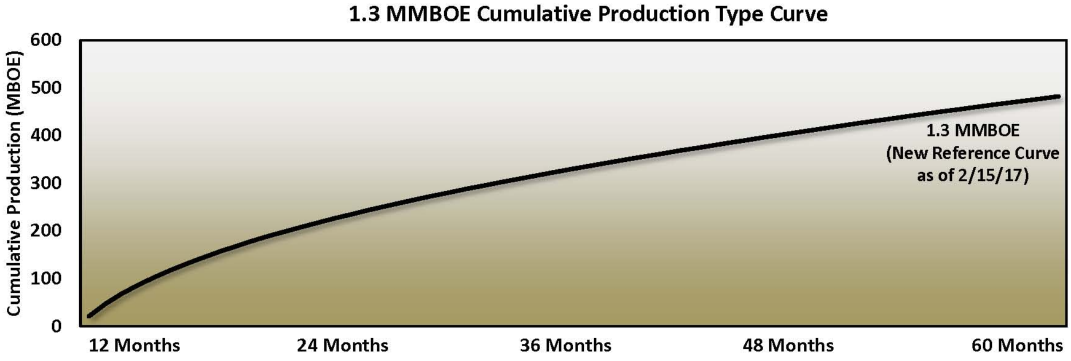
Latest Optimization Tests Significantly Exceeding Type Curve



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

Note: Production through 2/6/2017 for SUGG A 171-172/173, SUGG A 208-209/207, SUGG A 185 utilizing 2,400 lb/ft sand

New UWC & MWC 1.3 MMBOE Cumulative Production Type Curve

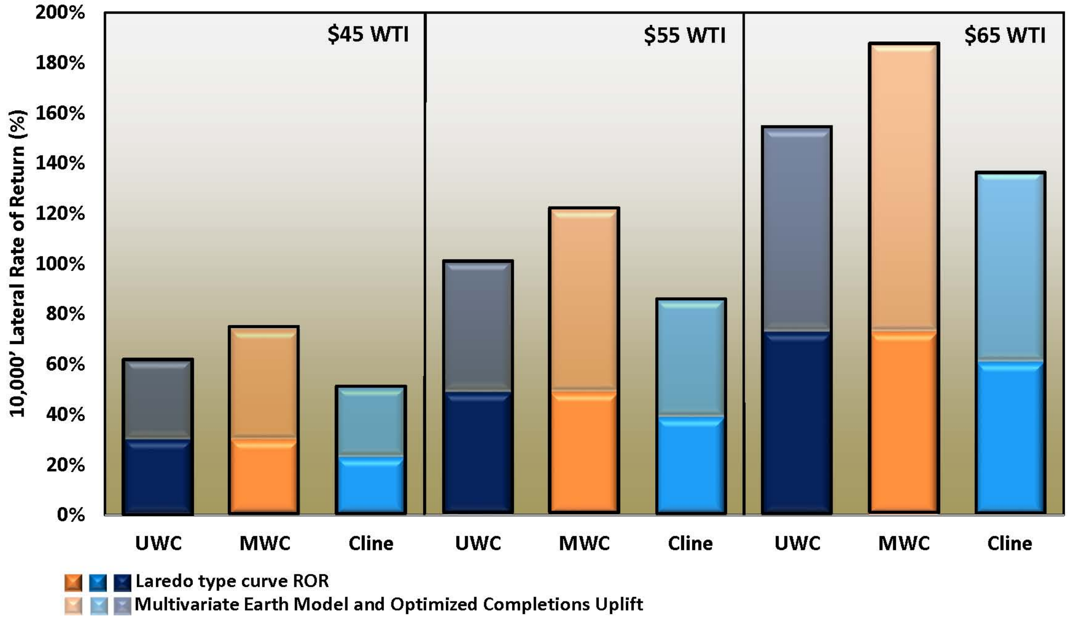


Months	Cumulative Production (MBOE)	Cumulative % Oil
12	189	60%
24	288	56%
36	363	54%
48	426	52%
60	482	51%

Increasing 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

Multivariate Earth Model Driving Meaningful Uplift in Returns



Demonstrated performance uplifts in each zone yield significant return improvements

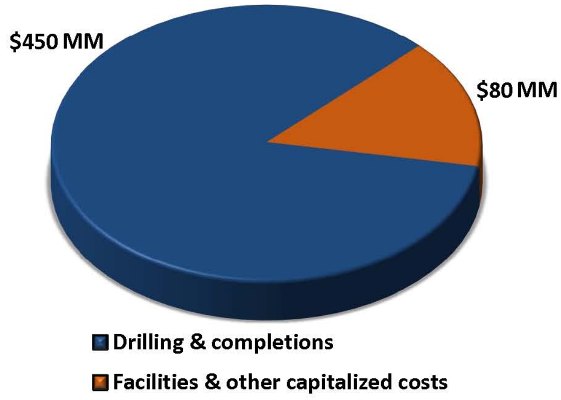
Note: Rate of returns calculated using benchmark prices of WTI: $45.00/Bbl, $55.00/Bbl, $65.00/Bbl & HH: $3.00/Mcf, $3.25/Mcf, $3.50/Mcf and realized pricing of WTI: $40.50/Bbl, $49.50/Bbl, $58.50/Bbl & HH: $2.16/Mcf, $2.34/Mcf, $2.52/Mcf & NGLs: $14.40/Bbl, $17.60/Bbl, $20.80/Bbl
ROR includes static 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

2017 Budget Expectations

2017 Drilling & Completions

- Operating 4 Hz rigs
- Drilling and completing ~70 Hz wells
- ~85% targeting the UWC & MWC
- ~95% average working interest
- Hz wells average ~10,000' lateral length
- Developed as 4-5 well packages

2017 Capital Budget [1]
$530 MM



Over 98% of wells planned for 2017 are expected to be developed as multi-well packages

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

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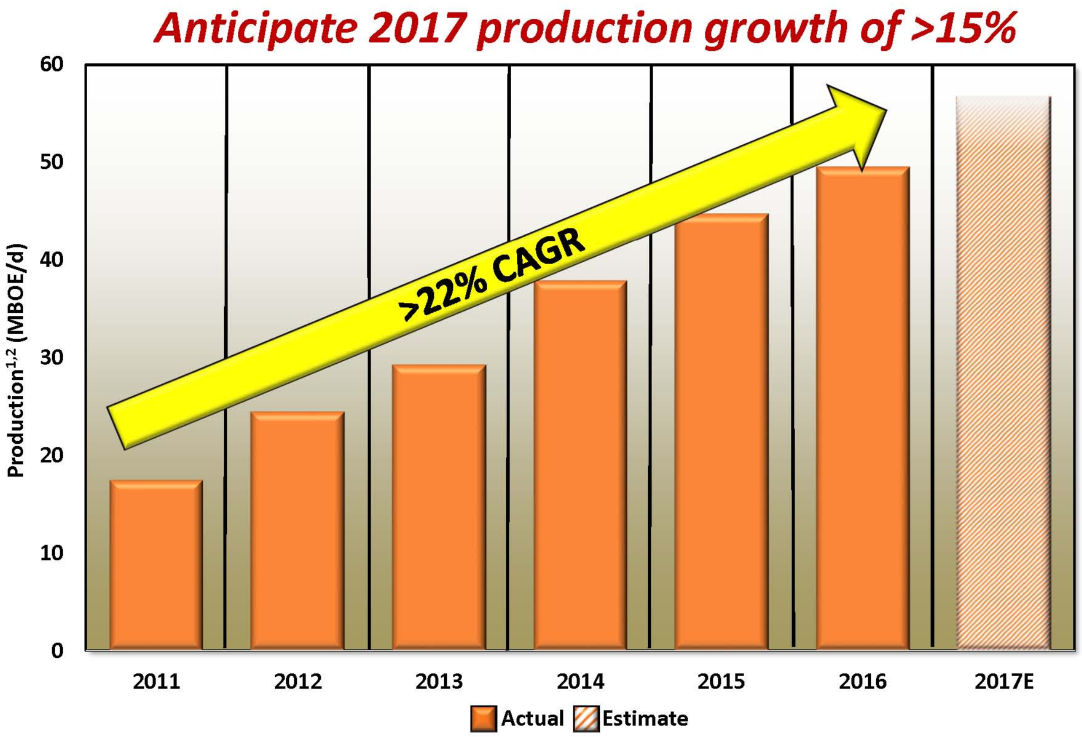
Consistent Production Growth

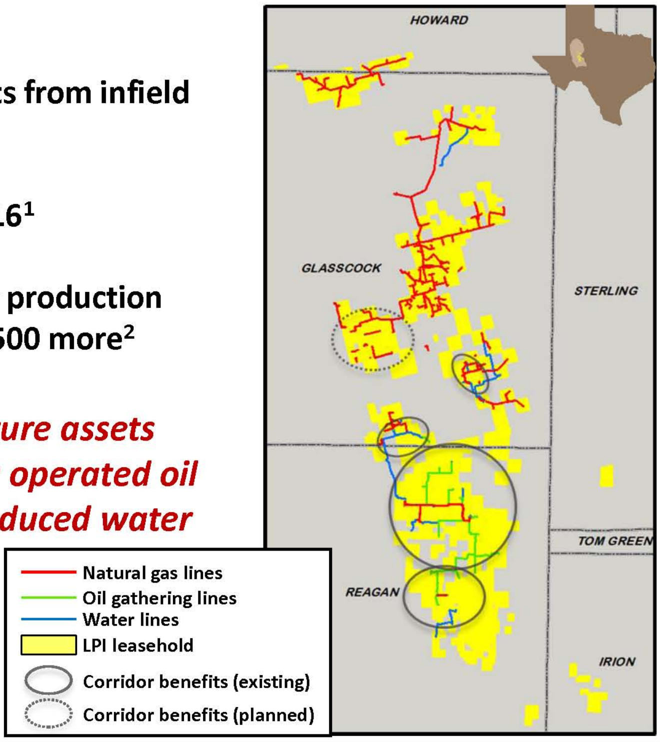


[1] Production numbers prior to 2014 have been converted to 3-stream using an 18% uplift. 2014 results have been converted to 3-stream using actual gas plant economics
[2] 2011 - 2013 adjusted for Granite Wash divestiture, closed August 1, 2013

Prior Investment in Infrastructure Providing Tangible Benefits

- ~$5.5 MM total realized benefits from infield infrastructure in 4Q-16[1]
- ~$24 MM total benefits for FY-16[1]
- ~195 horizontal wells served by production corridors with potential for >2,500 more[2]

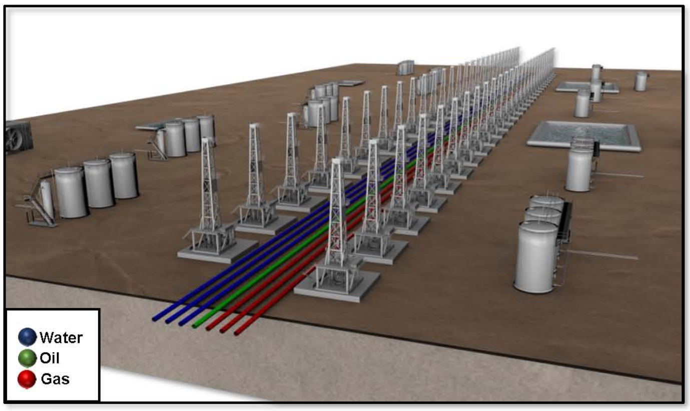
In 4Q-16, Laredo infrastructure assets gathered on pipe 73% of gross operated oil production & 65% of total produced water



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

Corridor Financial Benefits

~$1.3 MM benefit over life of each 10,000' corridor well, with ~25% of the benefit received in the first six months[1]



LMS Service	2016 Benefits Actual ($ MM)	2017 Benefits Estimated ($ MM)[1]	LPI Financial Benefits
Crude Gathering	$10.4	$14.1	Increased revenues & 3rd-party income
Centralized Gas Lift	$0.9	$0.9	LOE savings
Frac Water (Recycled vs Fresh)	$1.1	$1.8	Capital savings
Produced Water (Recycled vs Disposed)	$2.0	$2.4	Capital & LOE savings
Produced Water (Gathered vs Trucked)	$9.6	$8.7	Capital & LOE savings
Corridor Benefit	**$24.1**	**$27.9**	

[1] Benefits estimates as of December 31, 2016

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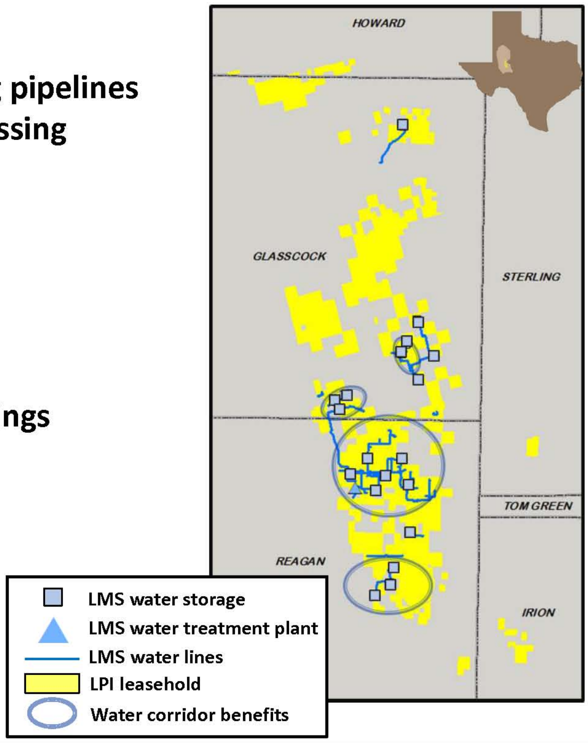
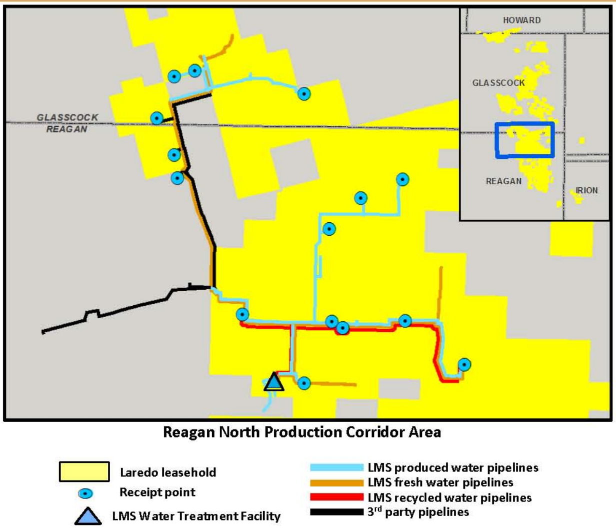
Significant Benefits through Water Infrastructure Investments

- Water infrastructure consists of:
  - 78 miles of total water gathering pipelines
  - Recycling plant capable of processing 30,000 BWPD
  - Linked water storage assets with >5 MMBW capacity
- Enables drilling of multi-well pads
- Yields significant capital and LOE savings
- Minimizes trucking



Water Infrastructure Capital and LOE Savings

- 11.3 MMBW (61%) of total 2016 produced water was gathered on pipe
  - Expected to increase to ~75% in 2017
- 6.3 MMBW (34%) of total 2016 produced water was recycled by LMS
  - Expected to increase to ~57% in 2017
- 4.4 MMBW (15%) of water for completions in 2016 was supplied with recycled water
  - Expected to increase to ~20% in 2017



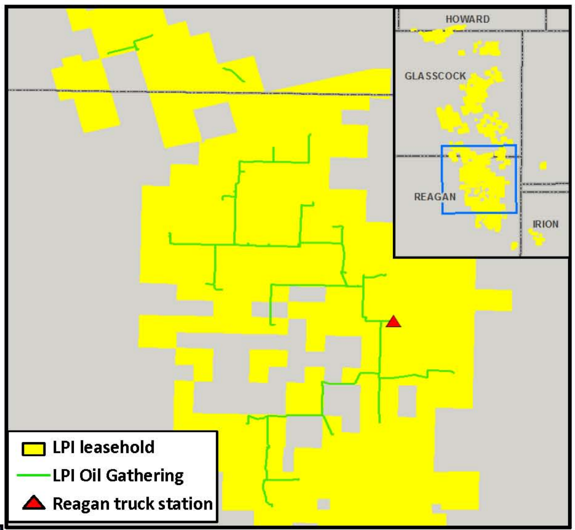
Reagan North Production Corridor Area

LMS Service	LPI Financial Benefits (2016)		
	Category	($/BW)	($ MM)
Produced Water (Recycled vs Disposed)	Capital & LOE savings	$0.32	$2.0
Produced Water (Gathered vs Trucked)	Capital & LOE savings	$0.85	$9.6
Frac Water (Recycled vs Fresh)	Capital savings	$0.26	$1.1

Laredo's water gathering system displaced ~95,000 truckloads of water in 2016

LMS Crude Gathering System Benefits

- **44 miles of crude oil gathering lines**
- **7.4 MMBO (64%) of gross operated production in 2016 was gathered on pipe**
- **Eliminated ~41,000 truckloads of oil in 2016**
- **Reduces time from production to sales**
- **Benefits of system increase as trucking costs rise**



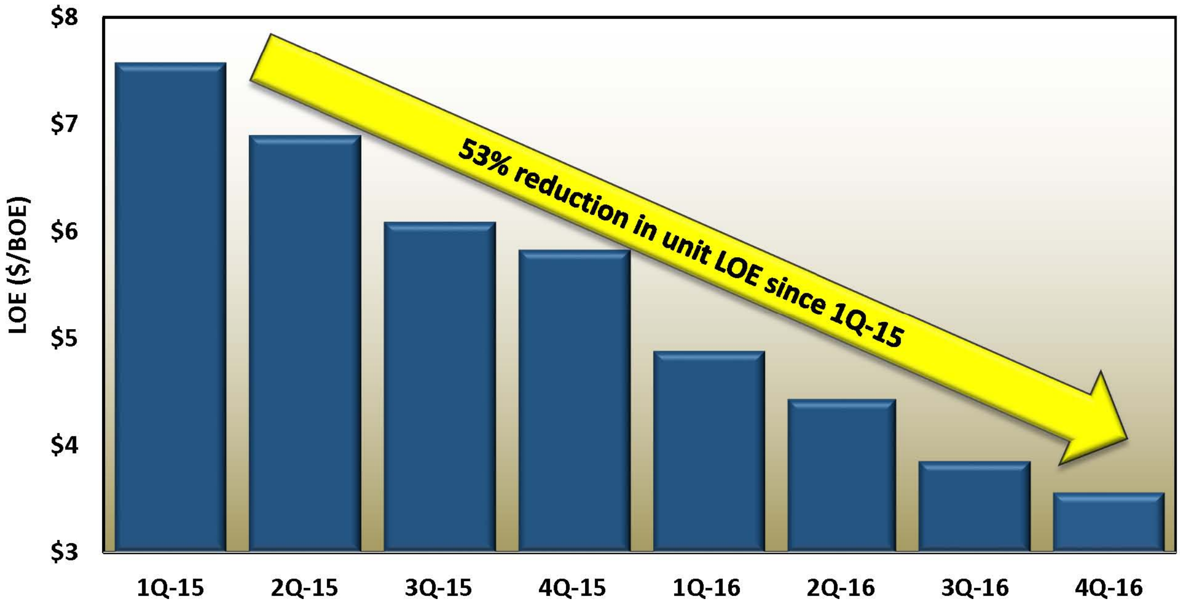
Reagan North Production Corridor Area

LMS Service	LPI Financial Benefits (2016)		
	Category	($/Bbl)	($ MM)
Produced Oil (Gathered vs Trucked)	LMS Operating Income	$0.57	$4.3
Produced Oil (Gathered vs Trucked)	Realized prices	$0.83	$6.2

LMS is anticipated to gather ~85% of Laredo's gross operated oil production in 2017

Note: 2017 estimates as of 2/7/2016

Consistent Unit LOE Reduction



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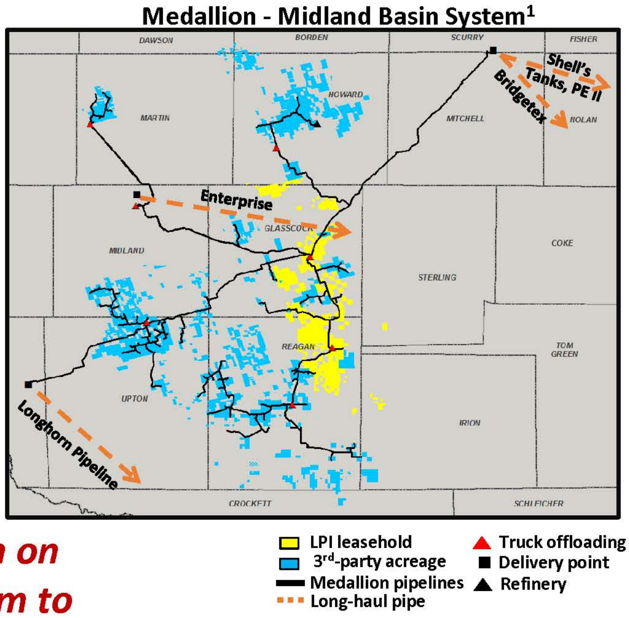
Medallion-Midland Basin System

	YE-15	YE-16
Throughput (MBOPD)	67.6	134.3
Miles of Pipeline	~460	~650[2]
System Deliverability (MBOPD)	125	550
# of AMI or Firm Commitment Acres	~1.8 MM	~2.0 MM
# of Dedicated Producers	8	10
# of Dedicated or Firm Commitment Acres	>290,000	>520,000

Medallion - Midland Basin System[1]

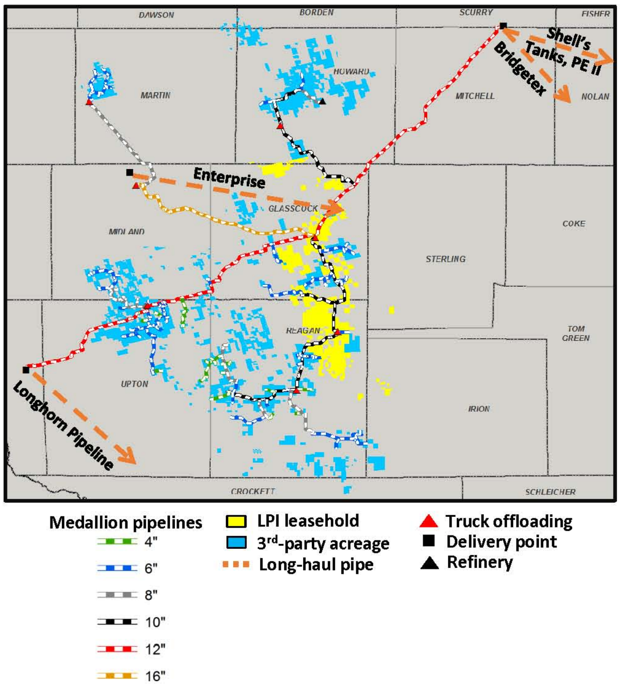


Laredo has firm transportation on Medallion-Midland Basin system to Colorado City and firm transportation of ~30 MBOPD gross to the Gulf Coast

[1]As of 1/17/17
[2]60 miles currently under construction

Medallion-Midland Basin System Scale

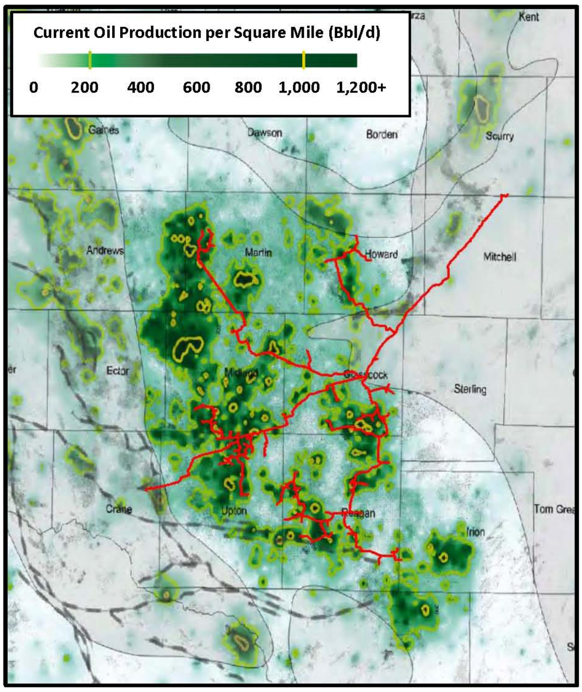
- **Majority of system is large-diameter pipe to multiple delivery points**
  - 16-inch line to Midland delivery point with 200,000 BOPD capacity
  - 12-inch line to Colorado City delivery point with 150,000 BOPD capacity
  - 12-inch line to Crane delivery point with 150,000 BOPD capacity



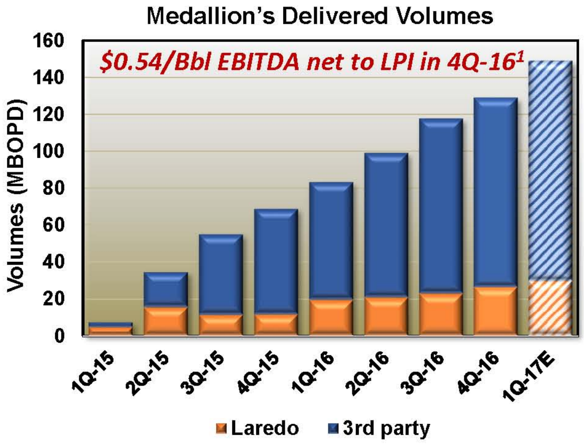
More than 500 miles of the systems' pipelines are 6" or larger, enabling the delivery of ~550,000 barrels of oil to multiple delivery points

[1] As of 1/17/17
[2] 60 miles currently under construction

Medallion-Midland Basin: The Premier Pipeline in the Permian



Medallion–Midland Basin system

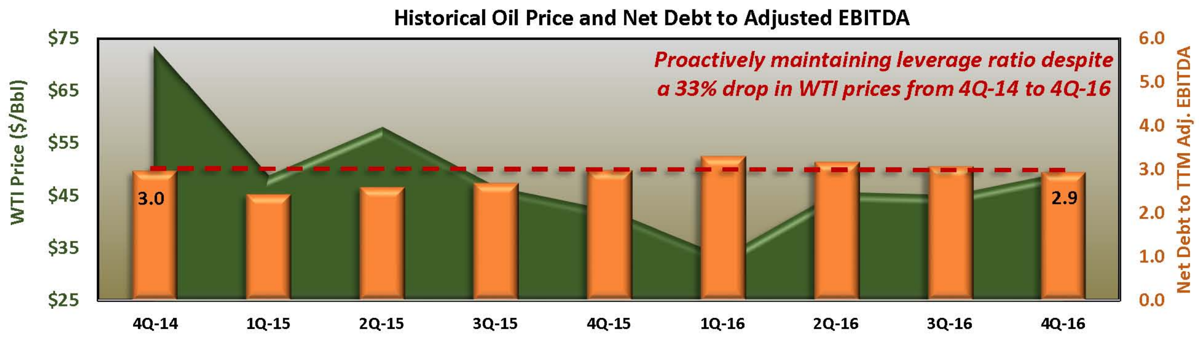


The Medallion-Midland Basin system is expected to grow >75% exit-to-exit in 2017

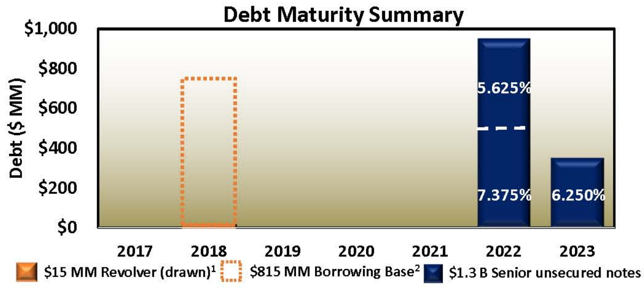
[1] Includes G&A

Note: Heat map generated by RS Energy Group

Maintaining Strong Financial Position

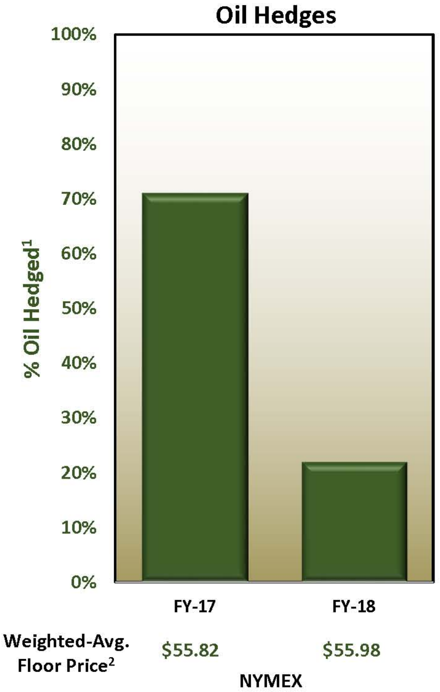


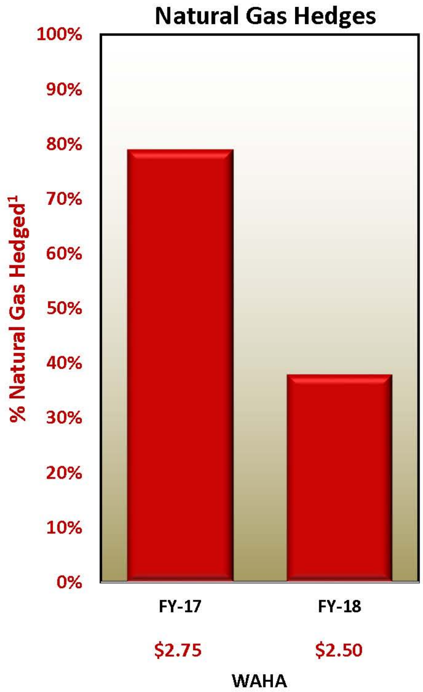
- No term debt due until 2022
  - $950 million of notes callable at Laredo's option in 2017
- $824 MM of liquidity[1]



[1] As of 2/14/17
[2] As of October 2016 redetermination; Medallion interest is not pledged to borrowing base

Disciplined Hedging Program

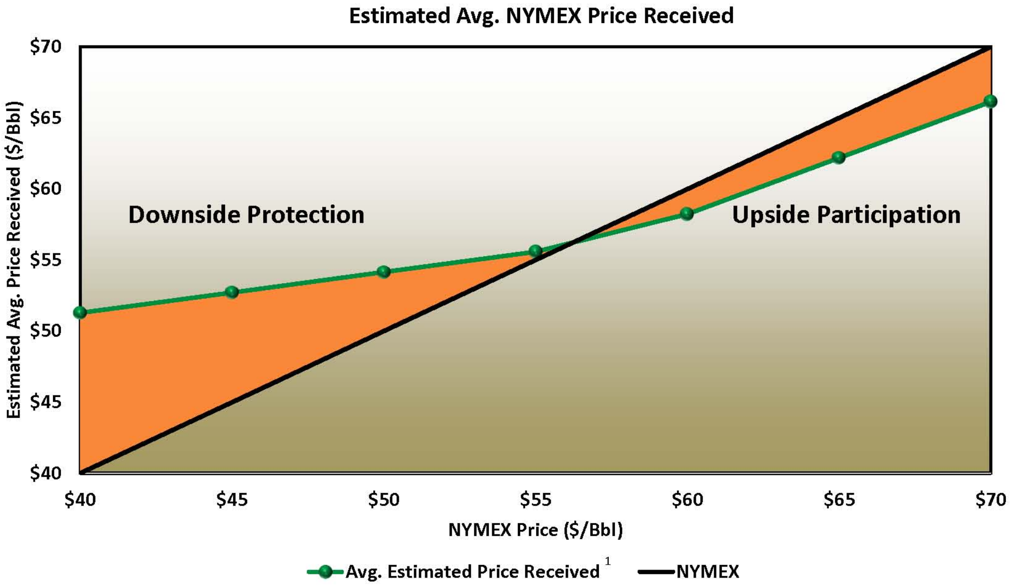




Hedging program provides price protection while retaining substantial upside

[1] Utilizing midpoint of current 2016 production for FY-17 and FY-18 percent hedged
[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
Note: Does not include 2017 NGL hedges of 444,000 Bbl of ethane or 375,000 Bbl of propane

Oil Hedges Retain Meaningful Upside in 2017



2017 oil hedges provide significant downside protection while maintaining upside exposure to an increase in the price of oil

[1] Includes hedged and unhedged barrels
Note: Assumes 15% YoY production growth in 2017

2017 Guidance

	1Q-17	2Q-17
Production (MBOE/d)...	52 - 54	55 - 58
Product % of total production:		
Crude oil..	44% - 46%	45% - 47%
Natural gas liquids..	27% - 28%	*
Natural gas..	27% - 28%	*
Price Realizations (pre-hedge):		
Crude oil (% of WTI)..	~90%	*
Natural gas liquids (% of WTI)...	~32%	*
Natural gas (% of Henry Hub)...	~72%	*
Operating Costs & Expenses:		
Lease operating expenses ($/BOE)...	$3.50 - $4.00	*
Midstream expenses ($/BOE)..	$0.20 - $0.30	*
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)..............	6.75%	*
General and administrative expenses:		
Cash ($/BOE)..	$3.35 - $3.85	*
Non-cash stock-based compensation ($/BOE)..	$2.00 - $2.25	*
Depletion, depreciation and amortization ($/BOE)...	$7.50 - $8.00	*

*Will be provided in conjunction with first-quarter 2017 earnings release


LAREDO
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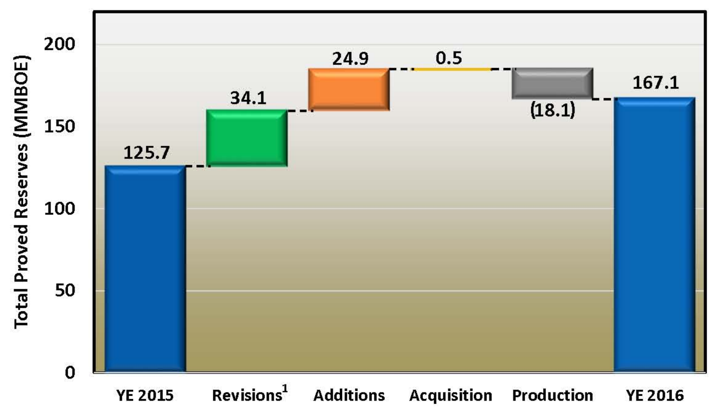
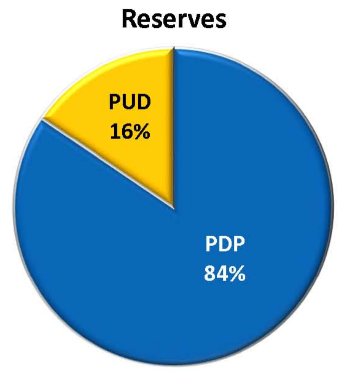
Appendix

YE-16 Proved Reserves





Grew proved developed reserves organically by ~40% at a PD F&D cost of $5.12 per BOE

Note: Assuming current commodity price environment, service costs and rig cadence as of 2/15/17

[1] Includes reserves from locations developed in 2016 that had previously been booked as PUD reserves but were subsequently removed

Oil, Natural Gas & Natural Gas Liquids Hedges

OIL[1]	2017	2018
Puts:		
Hedged volume (Bbls)	1,049,375	1,049,375
Weighted average price ($/Bbl)	$60.00	$60.00
Swaps:		
Hedged volume (Bbls)	2,007,500	1,095,000
Weighted average price ($/Bbl)	$51.54	$52.12
Collars:		
Hedged volume (Bbls)	3,796,000	
Weighted average floor price ($/Bbl)	$56.92	
Weighted average ceiling price ($/Bbl)	$86.00	
Total volume with a floor (Bbls)	6,852,875	2,144,375
Weighted-average floor price ($/Bbl)	$55.82	$55.98

NATURAL GAS[2]		
Put		
Hedged volume (MMBtu)	8,040,000	8,220,000
Weighted average floor price ($/MMBtu)	$2.50	$2.50
Collars:		
Hedged volume (MMBtu)	19,016,500	4,635,500
Weighted average floor price ($/MMBtu)	$2.86	$2.50
Weighted average ceiling price ($/MMBtu)	$3.54	$3.60
Total volume with a floor (MMBtu)	27,056,500	12,855,500
Weighted-average floor price ($/MMBtu)	$2.75	$2.50

NATURAL GAS LIQUIDS[3]		
Swaps - Ethane:		
Hedged volume (Bbls)	444,000	
Weighted average price ($/Bbl)	$11.24	
Swaps - Propane:		
Hedged volume (Bbls)	375,000	
Weighted average price ($/Bbl)	$22.26	
Total volume with a floor (Bbls)	819,000	

Note: Open positions as of 01/01/17
[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

Hydraulic Fracture Test Site (HFTS)

$23.1 MM high-profile, joint-industry project led by Laredo and the Gas Technology Institute (GTI)

Laredo's Project Contribution

- Selected as operator
- Conducted on Laredo's acreage
- No cost to Laredo
- On-time, on-budget
- Strong linkage to completions optimization

Site Host

Research Team

Sponsors

➔ *In-Progress*
☑ *Complete*

Key Initiatives

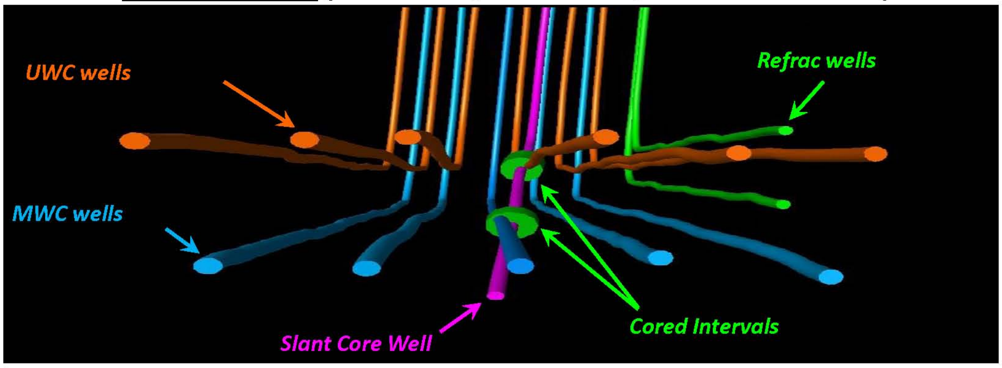
➔ Slant Well Fracture & Proppant Analysis
➔ Hydraulic Fracture Modeling
➔ Fracture Attribute Studies

Data Sets Acquired

☑ Drilling, Coring & Logging Slant Well
☑ Pilot Hole Logs & Sidewall Cores
☑ Offset Well Refracs (μ-seismic & tracers)
☑ Horizontal DFIT's
☑ Radioactive Tracers & Fluid Tracers
☑ Microseismic Monitoring
☑ Cross-Well Seismic
☑ Surface Seismic Monitoring
☑ Colored Proppant Cluster Indicators
☑ Inter-well Pressure Monitoring
☑ Fiber Optic Production Logging
☑ Environmental Sampling
☑ Oil Fingerprinting / Fluid Sampling

Advanced Hydraulic Fracture Data Collected on Laredo Leasehold

HFTS GTI LAYOUT (6 UWC wells, 5 MWC wells, UWC & MWC refracs)



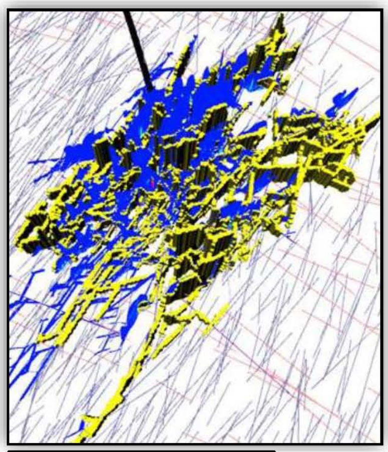
HYDRAULICALLY FRACTURED CORE

Recovered core showing complexity of hydraulically created fractures

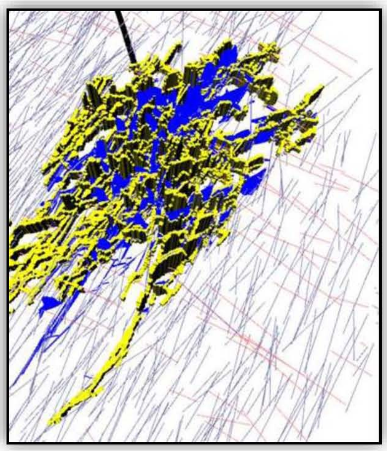
- ~600 feet recovered
- UWC & MWC
- Natural fractures
- Hydraulic fractures
- Proppant recovered

Cutting-edge completions data being integrated into the multivariate Earth Model

Advanced Fracture Modeling



Increasing connected propped fractures

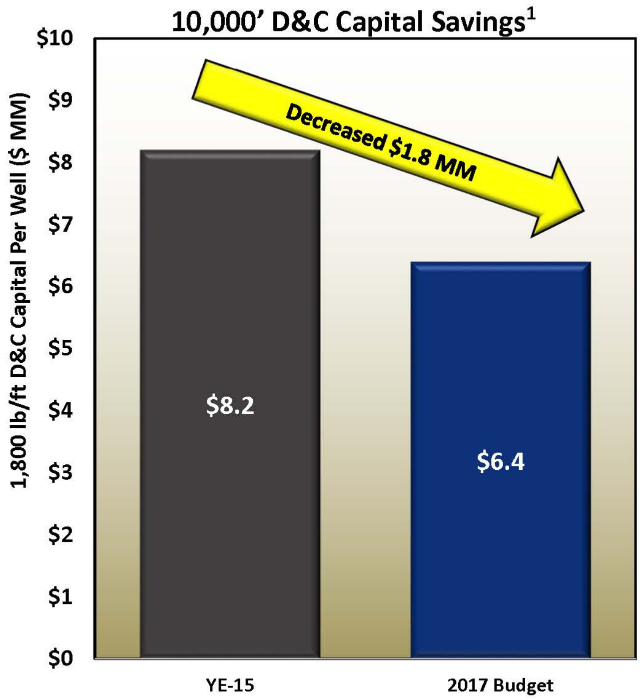


Hydraulic propped fractures

Hydraulic unpropped fractures

Utilizing multivariate Earth Model analysis to optimize completions designs

Drilling & Completion Costs



- Efficiency gains partially offset recent increases in service costs
- D&C capital includes:
  - $1 MM for 1,800 lb/ft sand
  - Pad preparation
  - Well-site metering
  - Heater treaters
  - Separation equipment
  - Artificial lift equipment

Focused on capital efficient drilling & completion operations

[1] Representative of multi-well pad costs

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

2015 & 2016 YTD Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15	1Q-16	2Q-16	3Q-16	4Q-16	FY-16
Production	Production (3-Stream)										
	MBOE	4,274	4,234	4,124	3,714	16,346	4,204	4,338	4,718	4,889	18,149
	BOE/D	47,487	46,532	44,820	40,368	44,782	46,202	47,667	51,276	53,141	49,586
	% oil	51%	46%	45%	45%	47%	48%	46%	46%	46%	47%
Realized Pricing	3-Stream Prices										
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93	$1.31	$1.31	$2.07	$2.13	$1.73
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86	$8.50	$12.24	$11.54	$14.79	$11.91
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27	$27.51	$39.37	$39.10	$43.98	$37.73
	Avg. Price ($/BOE)	$27.64	$29.65	$25.37	$22.47	$26.41	$17.40	$23.64	$24.34	$27.82	$23.50
Unit Cost Metrics	3-Stream Unit Cost Metrics										
	Lease Operating ($/BOE)	$7.58	$6.90	$6.09	$5.83	$6.63	$4.88	$4.43	$3.85	$3.56	$4.15
	Midstream ($/BOE)	$0.37	$0.38	$0.26	$0.43	$0.36	$0.14	$0.27	$0.22	$0.26	$0.22
	General & Administrative ($/BOE)										
	Cash	$3.99	$3.99	$3.89	$4.29	$4.03	$3.73	$3.32	$3.49	$3.28	$3.45
	Non-cash stock-based compensation	$1.12	$1.49	$1.67	$1.75	$1.50	$0.90	$1.41	$2.05	$1.98	$1.61
	DD&A ($/BOE)	$16.83	$17.03	$16.19	$18.01	$16.99	$9.87	$7.88	$7.45	$7.68	$8.17

EBITDA Reconciliation

LPI Adjusted EBITDA *(in thousands)*		4Q-16		FY 2016
Net income	$	(18,421)	$	(260,739)
Plus:				
Depletion, depreciation and amortization	$	37,526	$	148,339
Impairment expense	$	-	$	162,027
Non-cash stock-based compensation, net of amounts capitalized	$	9,667	$	29,229
Accretion of asset retirement obligations	$	896	$	3,483
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	$	43,642	$	87,425
Cash settlements received for matured derivatives, net	$	37,655	$	195,281
Cash settlements received for early termination derivatives, net	$	-	$	80,000
Cash premiums paid for derivatives	$	(2,697)	$	(89,669)
Interest expense	$	23,004	$	93,298
Write-off debt issuance costs	$	-	$	842
Loss on disposal of assets, net	$	411	$	790
Income from equity method investee	$	(3,144)	$	(9,403)
Proportionate Adjusted EBITDA of equity method investee(1)	$	6,386	$	20,367
Adjusted EBITDA	$	134,925	$	461,270

1Medallion Adjusted EBITDA *(in thousands)*		4Q-16		FY 2016
Income from equity method investee	$	3,144	$	9,403
Adjusted for proportionate share of:				
Depreciation and amortization	$	3,242	$	10,964
Proportionate Adjusted EBITDA of equity method investee	$	6,386	$	20,367

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