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): November 2, 2016

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 2.02. Results of Operations and Financial Condition.

On November 2, 2016, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter ended September 30, 2016. Copies of the Company's press release and Presentation (as defined below) are furnished as Exhibit 99.1 and Exhibit 99.2, respectively, to this Current Report on Form 8-K and are incorporated herein by reference. The Company plans to host a teleconference and webcast on November 3, 2016, at 7:30 a.m. Central Time to discuss these results and management's outlook. To access the call, please dial 1-877-930-8286 or 1-253-336-8309 for international callers, and use conference code 99103479. A replay of the call will be available through Thursday, November 10, 2016, by dialing 1-855-859-2056, and using conference code 99103479. The webcast may be accessed at the Company's website, www.laredopetro.com, under the tab "Investor Relations."

In accordance with General Instruction B.2 of the Form 8-K, the information furnished under this Item 2.02 of this Current Report on Form 8-K and the exhibits 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 exhibits be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

Item 7.01. Regulation FD Disclosure.

On November 2, 2016, the Company furnished the press release described above in Item 2.02 of this Current Report on Form 8-K. A copy of the press release is attached hereto as Exhibit 99.1 and incorporated into this Item 7.01 by reference.

On November 2, 2016, the Company also posted to its website certain financial and operating results and other information regarding the Company (the "Presentation"). The Presentation is available on the Company's website, www.laredopetro.com, and is attached hereto as Exhibit 99.2 and incorporated into this Item 7.01 by reference.

All statements in the press release, teleconference 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. 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 the Form 8-K, the information furnished under Item 7.01 of this Current Report on Form 8-K and the exhibits 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 exhibits be deemed incorporated by reference in 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	Press release dated November 2, 2016.
99.2	Presentation dated November 2, 2016.

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.

Date: November 2, 2016	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President & Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
99.1	Press release dated November 2, 2016.
99.2	Presentation dated November 2, 2016.

EXHIBIT 99.1

15 West 6th Street, Suite 900 · Tulsa, Oklahoma 74119 · (918) 513-4570 · Fax: (918) 513-4571
www.laredopetro.com

Laredo Petroleum Announces 2016 Third-Quarter Financial and Operating Results

Raises Estimated 2016 Production Growth Rate to ~10%

TULSA, OK - November 2, 2016 - Laredo Petroleum, Inc. (NYSE: LPI) (“Laredo” or “the Company”) today announced its 2016 third-quarter results, reporting net income attributable to common stockholders of $9.5 million, or $0.04 per diluted share. Adjusted Net Income, a non-GAAP financial measure, for the third quarter of 2016 was $28.4 million, or $0.12 per diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the third quarter of 2016 was $118.0 million. Please see supplemental financial information at the end of this news release for reconciliations of non-GAAP financial measures.

2016 Third-Quarter Highlights

- Produced a Company record 51,276 barrels of oil equivalent (“BOE”) per day and increased anticipated production growth for full-year 2016 to approximately 10%
- Completed 10 horizontal development wells with an average completed lateral length of approximately 10,900 feet, including four wells drilled with lateral lengths greater than 13,000 feet
- Reduced unit lease operating expenses (“LOE”) to $3.85 per BOE, down approximately 37% from the third-quarter 2015 rate of $6.09 per BOE and down approximately 13% from the second-quarter 2016 rate of $4.43 per BOE
- Recognized approximately $6.0 million in cash benefits from Laredo Midstream Services, LLC (“LMS”) field infrastructure investments through reduced costs and increased revenue
- Grew transported volumes on the Medallion-Midland Basin pipeline system (defined below) to 117,862 barrels of oil per day (“BOPD”) on average for the quarter, an increase of approximately 114% from 55,164 BOPD in the third quarter of 2015
- Received approximately $41.6 million of net cash settlements, net of premiums paid, on commodity derivatives that matured during third-quarter 2016, increasing the average sales price for oil by $18.47 per barrel and for natural gas by $0.24 per thousand cubic feet compared to pre-hedged average sales prices

"Third quarter results again demonstrated the benefits of the Company's prior strategic investments in data and infrastructure," commented Randy A. Foutch, Chairman and Chief Executive Officer. "Continued refinement of

Laredo's multivariate Earth Model analysis of data collected throughout eight years of development activity has enabled the identification of multiple landing points per zone and optimized completions driving recent results, on average, more than 30% above type curve in the Upper and Middle Wolfcamp and Cline shale zones. Field infrastructure investments have helped lower unit LOE almost 50% since the beginning of 2015. To take advantage of these tremendous capital efficiency improvements and accelerate value creation, Laredo is adding a fourth horizontal rig beginning in mid November. We anticipate the additional cash flows will be protected by Laredo's outstanding hedge position and the increased activity is being accomplished without increasing the Company's capital budget."

Operational Update

In the third quarter of 2016, Laredo produced a Company record 51,276 BOE per day. The Company completed 10 horizontal development wells with an average working interest of approximately 98%, including seven with a completed lateral length greater than 10,000 feet and nine utilizing 2,400 pounds of proppant per lateral foot. Production and capital efficiency again benefited from Laredo's contiguous acreage position which enables the drilling of longer laterals and the continued refinement of the multivariate Earth Model analysis to optimize completions.

Laredo's industry-leading data collection efforts are driving recent production results as multivariate Earth Model analysis continues to incorporate additional geoscience and engineering parameters that optimize both well placement and completion design. The ongoing Hydraulic Fracture Test Site project on Laredo leasehold with the Gas Technology Institute is a $23 million joint industry project in which Laredo led operational and data collection efforts. The project has generated a world-class dataset proprietary to consortium members, including collecting approximately 600 feet of core through hydraulically fractured rock. As the Company utilizes this data in multivariate Earth Model analysis and in conjunction with completions and reservoir modeling, this process will further the evolution of Laredo's development planning. This integrated modeling is moving completion design beyond perforation cluster spacing and proppant loading to include fracture geometry, growth and behavior, enabling the testing of multiple completion designs to maximize capital efficiency and project value.

The Company has implemented a managed drawdown protocol that both limits initial choke settings and restricts the amount the choke is opened as the well produces. While this can reduce initial production ("IP") rates and delay assigning peak production rates, it is intended to enhance primary fracture conductivity, thereby improving production and recoveries over the life of the well. Laredo is evaluating the effect of managed drawdown and the associated benefit to well economics.

Seven of the 10 horizontal wells completed in the third quarter of 2016 were completed late in the quarter and have not achieved peak IP rates although the Company is very encouraged with preliminary production data. These seven wells all utilized optimized completions with 2,400 pounds of proppant per lateral foot and included four wells with drilled lateral lengths of greater than 13,000 feet. Three of the 10 horizontal wells completed in the third quarter of 2016 have generated sufficient production data to compare to Company type curves.

The G.Schwartz 17-8-1NC, drilled in the Cline shale with a completed lateral length of approximately 9,900 feet, utilized the Earth Model to optimize the completion and used 1,800 pounds of proppant per lateral foot. The well produced a 30-day peak IP rate of 1,639 BOE per day and is currently performing at 140% of the 1.0 million BOE 10,000-foot Cline type curve, adjusted for lateral length. Enhanced production from the application of multivariate Earth Model analysis and optimized completions, coupled with more efficient development drilling, is enabling the development of the Cline shale at returns approaching those achieved in the Upper and Middle Wolfcamp zones.

The Sugg-A-208-209-1SU and Sugg-E-208-207-1NM were drilled in the Upper Wolfcamp and Middle Wolfcamp formations, respectively, utilizing multivariate Earth Model analysis to optimize completions and testing 2,400 pounds of proppant per lateral foot. The Sugg-A-208-209-1SU had a completed lateral length of approximately 7,600 feet and is currently performing at 161% of type curve, adjusted for lateral length. The Sugg-E-208-207-1NM had a completed lateral length of approximately 7,500 feet and is currently performing at 140% of type curve. The Company is encouraged by the early results of higher proppant loads in these wells and will evaluate longer-term data as completion optimization techniques are further refined.

Laredo continues to materially reduce unit LOE which decreased to $3.85 per BOE from $6.09 per BOE in the third quarter of 2015. Investments in water handling infrastructure along production corridors and an intense focus on best practices to reduce well failures have contributed to the operational cost improvements.

Laredo entered the fourth quarter of 2016 operating three horizontal rigs and subsequently added a fourth horizontal rig that is expected to spud its first well in mid November. The Company does not expect the addition of this rig to impact production in the fourth quarter of 2016. Drilling cost savings realized throughout 2016 are expected to fund the additional capital expenditures associated with the increased rig count, leaving the Company's 2016 capital budget unchanged at $420 million.

The Company expects to complete 10 horizontal wells during the fourth quarter of 2016 with an average lateral length of approximately 9,200 feet and an average working interest of approximately 95%. Four of the wells have been completed and are anticipated to contribute meaningfully to production during the quarter. The remaining six wells are being drilled and completed as a package that is expected to begin flowback late in the fourth quarter of 2016.

Laredo Midstream Services Update

Laredo's development strategy of investing in field infrastructure along production corridors and concentrating drilling around those corridors continues to drive material financial and operating benefits for the Company. LMS' oil and water gathering assets enable the use of highly efficient multi-well packages that reduce capital and operating costs and average cycle time per well. Execution of these multi-well packages would be impractical without the ability of LMS to gather large volumes of oil and water by pipe. During the third quarter of 2016, LMS gathered 69% of the Company's gross operated oil production and 67% of total produced water and generated approximately $6.0 million of total cash benefit for the Company. Savings related to LMS infrastructure reduced unit LOE by approximately 12%, or $0.52 per BOE during the third quarter of 2016.

Transported volumes on the Medallion Gathering & Processing, LLC pipeline system ("Medallion-Midland Basin pipeline system"), in which LMS owns a 49% interest, grew to an average of 117,862 BOPD, an increase of approximately 114% from the third quarter of 2015 and up 19% from the second quarter of 2016. The system is expected to be transporting approximately 140,000 BOPD by the end of 2016 and to grow transported volumes 50% to 60% by the end of 2017.

2016 Capital Program

During the third quarter of 2016, Laredo invested approximately $79 million in exploration and development activities, approximately $116 million of the $125 million purchase price in a previously announced bolt-on land acquisition and approximately $17 million in infrastructure held by LMS, including the Medallion-Midland Basin pipeline system.

Liquidity

At September 30, 2016, the Company had cash and equivalents of approximately $30 million and undrawn capacity under the senior secured credit facility of $745 million.

On October 24, 2016, in connection with the regular semi-annual redetermination of the Company's senior secured credit facility, lenders reaffirmed the Company's borrowing base at $815 million with the Company's elected commitment remaining unchanged at $815 million. At November 1, 2016, the Company had cash and equivalents of approximately $10 million and undrawn capacity under the senior secured credit facility of $745 million, resulting in total liquidity of approximately $755 million.

Commodity Derivatives

Laredo maintains an active hedging program to reduce the variability in its anticipated cash flow due to fluctuations in commodity prices. At September 30, 2016, the Company had hedges in place for the fourth quarter of 2016 for 1,861,350 barrels of oil at a weighted-average floor price of $67.13 per barrel and 4,692,000 million British thermal units ("MMBtu") of natural gas at a weighted-average floor price of $3.00 per MMBtu. In addition, the Company had a meaningful level of anticipated production hedged for 2017 and 2018.

At September 30, 2016, for 2017, the Company had hedges in place covering 5,684,875 barrels of oil at a weighted-average floor price of $57.01 per barrel, 18,771,000 MMBtu of natural gas at a weighted-average floor price of $2.65 per MMBtu, 444,000 barrels of ethane at $11.24 per barrel and 375,000 barrels of propane at $22.26 per barrel. Subsequently, the Company hedged an additional 1,168,000 barrels of oil and 3,723,000 MMBtu of natural gas for 2017 and currently has 6,852,875 barrels of oil hedged for 2017 at a weighted-average floor price of $55.82 per barrel and 22,494,000 MMBtu of natural gas hedged for 2017 at a weighted-average floor price of $2.70 per MMBtu. A large portion of the Company's 2017 oil hedges retain the potential benefit of an increase in the price of oil with 3,796,000 barrels structured as collars with a weighted-average ceiling price of $86.00 per barrel and 1,049,375 barrels covered by puts and do not have a ceiling.

At September 30, 2016, for 2018, the Company had hedges in place covering 2,144,375 barrels of oil at a weighted-average floor price of $55.98 per barrel and 12,855,500 MMBtu of natural gas at a weighted-average floor price of $2.50 per MMBtu.

Fourth-Quarter 2016 Guidance

The table below reflects the Company's guidance for the fourth quarter of 2016:

	4Q-2016
Production (MMBOE)	4.7 - 4.9
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)	~87%
Natural gas liquids (% of WTI)	~30%
Natural gas (% of Henry Hub)	~72%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$3.75 - $4.25
Midstream expenses ($/BOE)	$0.20 - $0.30
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.25%
General and administrative expenses:	
Cash ($/BOE)	$3.25 - $3.75
Non-cash stock-based compensation ($/BOE)	$2.00 - $2.25
Depletion, depreciation and amortization ($/BOE)	$7.75 - $8.25

Conference Call Details

On Thursday, November 3, 2016, at 7:30 a.m. CT, Laredo will host a conference call to discuss its third-quarter 2016 financial and operating results and management's outlook, the content of which is not part of this earnings release. A slide presentation providing summary financial and statistical information that will be discussed on the call will be posted to the Company's website and available for review. The Company invites interested parties to listen to the call via the Company's website at www.laredopetro.com, under the tab for "Investor Relations." Portfolio managers and analysts who would like to participate on the call should dial 877.930.8286, using conference code 99103479, approximately 10 minutes prior to the scheduled conference time. International participants should dial 253.336.8309, also using conference code 99103479. A telephonic replay will be available approximately two hours after the call on November 3, 2016 through Thursday, November 10, 2016. Participants may access this replay by dialing 855.859.2056, using conference code 99103479.

About Laredo

Laredo Petroleum, Inc. is an independent energy company with headquarters in Tulsa, Oklahoma. Laredo's business strategy is focused on the acquisition, exploration and development of oil and natural gas properties and the transportation of oil and natural gas from such properties, primarily in the Permian Basin of West Texas.

Additional information about Laredo may be found on its website at www.laredopetro.com.

Forward-Looking Statements

This press release and any oral statements made regarding the subject of this release, including in the conference call referenced herein, contains forward-looking statements as defined under 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 facts, that address activities that Laredo assumes, plans, expects, believes, intends, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. The forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

General risks relating to Laredo include, but are not limited to, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2015, and those set forth from time to time in other filings with the Securities Exchange Commission ("SEC"). These documents are available through Laredo's website at www.laredopetro.com under the tab "Investor Relations" or through the SEC's Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. Any of these factors could cause Laredo's actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement.

The SEC generally permits oil and natural gas companies, in filings made with the SEC, to disclose proved reserves, 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 press release and the conference call, the Company may use the terms "resource potential" and "estimated ultimate recovery," or "EURs," each of which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. These terms refer to the Company's internal estimates of unbooked hydrocarbon quantities that may be potentially added to proved reserves, largely from a specified resource play. 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. EURs are based on the Company's previous operating experience in a given area and publicly available information relating to the operations of producers who are conducting operations in these areas. Unbooked resource potential or EURs do not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities of reserves that may be ultimately recovered from the Company's interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, decreases in oil and natural gas prices, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, negative revisions to reserve estimates and other factors as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves may change significantly as development of the Company's core assets provides additional data. In addition, our 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.

Laredo Petroleum, Inc.
Condensed consolidated statements of operations

(in thousands, except per share data)	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales	$ 114,805	$ 104,607	$ 290,473	$ 348,279
Midstream service revenues	2,488	1,873	5,921	4,908
Sales of purchased oil	42,441	43,860	116,670	130,178
Total revenues	159,734	150,340	413,064	483,365
Costs and expenses:				
Lease operating expenses	18,177	25,112	57,920	86,698
Production and ad valorem taxes	7,066	7,895	21,483	26,481
Midstream service expenses	1,039	1,092	2,826	4,263
Minimum volume commitments	1,582	—	1,582	5,235
Costs of purchased oil	44,232	46,961	121,190	132,578
General and administrative	26,105	22,913	66,058	67,976
Restructuring expenses	—	—	—	6,042
Accretion of asset retirement obligations	883	599	2,587	1,771
Depletion, depreciation and amortization	35,158	66,777	110,813	210,831
Impairment expense	—	906,850	162,027	1,397,327
Total costs and expenses	134,242	1,078,199	546,486	1,939,202
Operating income (loss)	25,492	(927,859)	(133,422)	(1,455,837)
Non-operating income (expense):				
Gain (loss) on derivatives, net	6,850	142,580	(43,783)	141,836
Income from equity method investee	265	2,104	6,259	4,585
Interest expense	(23,077)	(23,348)	(70,294)	(79,732)
Loss on early redemption of debt	—	—	—	(31,537)
Other, net	(45)	(2)	(1,078)	(1,549)
Non-operating income (expense), net	(16,007)	121,334	(108,896)	33,603
Income (loss) before income taxes	9,485	(806,525)	(242,318)	(1,422,234)
Income tax (expense) benefit:				
Deferred	—	(41,258)	—	176,945
Total income tax (expense) benefit	—	(41,258)	—	176,945
Net income (loss)	$ 9,485	$ (847,783)	$ (242,318)	$ (1,245,289)
Net income (loss) per common share:				
Basic	$ 0.04	$ (4.01)	$ (1.09)	$ (6.38)
Diluted	$ 0.04	$ (4.01)	$ (1.09)	$ (6.38)
Weighted-average common shares outstanding:				
Basic	234,639	211,204	221,303	195,081
Diluted	238,108	211,204	221,303	195,081

Laredo Petroleum, Inc.
Condensed consolidated balance sheets

(in thousands)	September 30, 2016	December 31, 2015
Assets:	(unaudited)	(unaudited)
Current assets	$ 190,396	$ 332,232
Property and equipment, net	1,305,642	1,200,255
Other noncurrent assets	260,410	280,800
Total assets	$ 1,756,448	$ 1,813,287
Liabilities and stockholders' equity:		
Current liabilities	$ 160,255	$ 216,815
Long-term debt, net	1,353,232	1,416,226
Other noncurrent liabilities	55,860	48,799
Stockholders' equity	187,101	131,447
Total liabilities and stockholders' equity	$ 1,756,448	$ 1,813,287

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

(in thousands)	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net income (loss)	$ 9,485	$ (847,783)	$ (242,318)	$ (1,245,289)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Deferred income tax expense (benefit)	—	41,258	—	(176,945)
Depletion, depreciation and amortization	35,158	66,777	110,813	210,831
Impairment expense	—	906,850	162,027	1,397,327
Loss on early redemption of debt	—	—	—	31,537
Non-cash stock-based compensation, net of amounts capitalized	9,651	6,877	19,562	17,933
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(6,850)	(142,580)	43,783	(141,836)
Cash settlements received for matured derivatives, net	44,307	66,142	157,626	175,879
Cash settlements received for early terminations of derivatives, net	—	—	80,000	—
Cash premiums paid for derivatives	(2,709)	(1,248)	(86,972)	(3,918)
Amortization of debt issuance costs	1,044	1,111	3,231	3,612
Other, net	750	(1,247)	(8,654)	(3,366)
Cash flows from operations before changes in working capital	90,836	96,157	239,098	265,765
Changes in working capital	16,088	14,079	6,653	(43,216)
Changes in other noncurrent liabilities and fair value of performance unit awards	(101)	963	(297)	2,955
Net cash provided by operating activities	106,823	111,199	245,454	225,504
Cash flows from investing activities:				
Capital expenditures:				
Acquisitions of oil and natural gas properties	(115,600)	—	(115,600)	—
Oil and natural gas properties	(79,693)	(115,843)	(276,735)	(490,351)
Midstream service assets	(806)	(1,100)	(4,231)	(35,237)
Other fixed assets	(150)	(1,998)	(982)	(8,539)
Investment in equity method investee	(16,031)	(48,516)	(58,712)	(63,011)
Proceeds from dispositions of capital assets, net of selling costs	15	65,226	365	65,261
Net cash used in investing activities	(212,265)	(102,231)	(455,895)	(531,877)
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility	94,682	10,000	214,682	310,000
Payments on Senior Secured Credit Facility	(135,000)	—	(279,682)	(475,000)
Issuance of March 2023 Notes	—	—	—	350,000
Redemption of January 2019 Notes	—	—	—	(576,200)
Proceeds from issuance of common stock, net of offering costs	156,742	—	276,052	754,163
Other, net	69	(158)	(1,405)	(9,508)
Net cash provided by financing activities	116,493	9,842	209,647	353,455
Net increase (decrease) in cash and cash equivalents	11,051	18,810	(794)	47,082
Cash and cash equivalents, beginning of period	19,309	57,593	31,154	29,321
Cash and cash equivalents, end of period	$ 30,360	$ 76,403	$ 30,360	$ 76,403

Laredo Petroleum, Inc.
Selected operating data

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(unaudited)		(unaudited)	
Sales volumes:				
Oil (MBbl)	2,150	1,844	6,168	5,954
NGL (MBbl)	1,272	1,150	3,491	3,234
Natural gas (MMcf)	7,766	6,778	21,600	20,663
Oil equivalents (MBOE)[(1)(2)]	4,718	4,124	13,260	12,632
Average daily sales volumes (BOE/D)[(2)]	51,276	44,820	48,392	46,270
% Oil	46%	45%	47%	47%
Average sales prices:				
Oil, realized ($/Bbl)[(3)]	$ 39.10	$ 42.88	$ 35.42	$ 45.03
NGL, realized ($/Bbl)[(3)]	$ 11.54	$ 10.36	$ 10.84	$ 12.12
Natural gas, realized ($/Mcf)[(3)]	$ 2.07	$ 2.01	$ 1.58	$ 1.98
Average price, realized ($/BOE)[(3)]	$ 24.34	$ 25.37	$ 21.91	$ 27.57
Oil, hedged ($/Bbl)[(4)]	$ 57.57	$ 76.74	$ 57.76	$ 72.69
NGL, hedged ($/Bbl)[(4)]	$ 11.54	$ 10.36	$ 10.84	$ 12.12
Natural gas, hedged ($/Mcf)[(4)]	$ 2.31	$ 2.37	$ 2.18	$ 2.34
Average price, hedged ($/BOE)[(4)]	$ 33.15	$ 41.11	$ 33.27	$ 41.19
Average costs per BOE sold:				
Lease operating expenses	$ 3.85	$ 6.09	$ 4.37	$ 6.86
Production and ad valorem taxes	1.50	1.91	1.62	2.10
Midstream service expenses	0.22	0.26	0.21	0.34
General and administrative:				
Cash	3.49	3.89	3.51	3.96
Non-cash stock-based compensation	2.05	1.67	1.48	1.42
Depletion, depreciation and amortization	7.45	16.19	8.36	16.69
Total	$ 18.56	$ 30.01	$ 19.55	$ 31.37

(1) BOE is calculated using a conversion rate of six Mcf per one Bbl.

(2) The volumes presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

(3) Realized oil, NGL and natural gas prices are the actual prices realized at the wellhead adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The prices presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

(4) Hedged prices reflect the after-effect of our hedging transactions on our average sales prices. Our calculation of such after-effects includes current period settlements of matured derivatives in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments that settled in the period. The prices presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

Laredo Petroleum, Inc.
Costs incurred

Costs incurred in the acquisition, exploration and development of oil, NGL and natural gas assets are presented below:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	**2016**	**2015**	**2016**	**2015**
	(unaudited)		(unaudited)	
Property acquisition costs:				
Evaluated[1]	$ 5,905	$ —	$ 5,905	$ —
Unevaluated	110,800	—	110,800	—
Exploration	6,718	7,803	33,750	16,157
Development costs[2]	72,411	64,451	225,103	381,641
Total costs incurred	$ 195,834	$ 72,254	$ 375,558	$ 397,798

(1) Evaluated property acquisition costs include $1.1 million in asset retirement obligations for the three and nine months ended September 30, 2016.

(2) Development costs include $0.3 million in asset retirement obligations for the three months ended September 30, 2016 and 2015 and $0.5 million and $1.3 million for the nine months ended September 30, 2016 and 2015, respectively.

Laredo Petroleum, Inc.
Supplemental reconciliation of GAAP to non-GAAP financial measures

Non-GAAP financial measures

The non-GAAP financial measures of Adjusted Net Income and Adjusted EBITDA, as defined by us, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP measures should be considered in conjunction with net income or loss and other performance measures prepared in accordance with GAAP, such as operating income or loss or cash flow from operating activities. Adjusted Net Income or Adjusted EBITDA should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss or any other GAAP measure of liquidity or financial performance.

Adjusted Net Income (Unaudited)

Adjusted Net Income is a non-GAAP financial measure we use to evaluate performance, prior to deferred income taxes, gains or losses on derivatives, cash settlements of matured derivatives, cash settlements on early terminated derivatives, cash premiums paid for derivatives, impairment expense, restructuring expenses, loss on early redemption of debt, buyout of minimum volume commitment, gains or losses on disposal of assets, write-off of debt issuance costs and bad debt expense and after applying adjusted income tax expense. We believe Adjusted Net Income helps investors in the oil and natural gas industry to measure and compare our performance to other oil and natural gas companies by excluding from the calculation items that can vary significantly from company to company depending upon accounting methods, the book value of assets and other non-operational factors.

Including a higher weighted average shares outstanding in the denominator of a diluted per-share computation results in an anti-dilutive per share amount when an entity is in a loss position. As such, our net income (loss) (GAAP) per common share calculation utilizes the same denominator for both basic and diluted net income (loss) per common share. However, our calculation of Adjusted Net Income (non-GAAP) results in income for all periods presented. Therefore, we believe it appropriate and more conservative to calculate an Adjusted diluted weighted average shares outstanding utilizing our fully dilutive weighted average shares. As such, as of September 30, 2016 we present a line item that calculates Adjusted diluted Adjusted Net Income per common share. Additionally, as of December 31, 2015 we changed the methodology for calculating Adjusted Net Income by applying a tax rate of 36% to all periods. Accordingly, the prior periods' Adjusted Net Income has been modified for comparability.

The following presents a reconciliation of Net income (loss) (GAAP) to Adjusted Net Income (non-GAAP):

(in thousands, except for per share data, unaudited)	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Net income (loss)	$ 9,485	$ (847,783)	$ (242,318)	$ (1,245,289)
Plus:				
Deferred income tax expense (benefit)	—	41,258	—	(176,945)
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(6,850)	(142,580)	43,783	(141,836)
Cash settlements received for matured derivatives, net	44,307	66,142	157,626	175,879
Cash settlements received for early terminations of derivatives, net	—	—	80,000	—
Cash premiums paid for derivatives	(2,709)	(1,248)	(86,972)	(3,918)
Impairment expense	—	906,850	162,027	1,397,327
Restructuring expenses	—	—	—	6,042
Loss on early redemption of debt	—	—	—	31,537
Buyout of minimum volume commitment	—	—	—	3,014
Loss on disposal of assets, net	78	94	379	1,937
Write-off of debt issuance costs	—	—	842	—
Bad debt expense	—	107	—	107
	44,311	22,840	115,367	47,855
Adjusted income tax expense	(15,952)	(8,222)	(41,532)	(17,228)
Adjusted Net Income	$ 28,359	$ 14,618	$ 73,835	$ 30,627
Net income (loss) per common share:				
Basic	$ 0.04	$ (4.01)	$ (1.09)	$ (6.38)
Diluted	$ 0.04	$ (4.01)	$ (1.09)	$ (6.38)
Adjusted Net Income per common share:				
Basic	$ 0.12	$ 0.07	$ 0.33	$ 0.16
Adjusted diluted	$ 0.12	$ 0.07	$ 0.33	$ 0.15
Weighted-average common shares outstanding:				
Basic	234,639	211,204	221,303	195,081
Diluted	238,108	211,204	221,303	195,081
Adjusted diluted	238,108	214,382	223,197	198,069

Adjusted EBITDA (Unaudited)

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for deferred income tax expense or benefit, depletion, depreciation and amortization, bad debt expense, impairment expense, non-cash stock-based compensation, accretion of asset retirement obligations, restructuring expenses, gains or losses on derivatives, cash settlements received for matured derivatives, cash settlements on early terminated derivatives, cash premiums paid for derivatives, interest expense, write-off of debt issuance costs, gains or losses on disposal of assets, loss on early redemption of debt, buyout of minimum volume commitment, income from equity method investee and proportionate Adjusted EBITDA of equity method investee. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures and working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods, book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and

- is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting.

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies and the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

As of September 30, 2016, we changed the methodology for calculating Adjusted EBITDA by including adjustments for both accretion of asset retirement obligations and our proportionate share of our equity method investee's Adjusted EBITDA. Accordingly, the prior periods' Adjusted EBITDA has been modified for comparability.

The following presents a reconciliation of Net income (loss) (GAAP) to Adjusted EBITDA (non-GAAP):

	Three months ended September 30,		Nine months ended September 30,	
(in thousands, unaudited)	**2016**	**2015**	**2016**	**2015**
Net income (loss)	$ 9,485	$ (847,783)	$ (242,318)	$ (1,245,289)
Plus:				
Deferred income tax expense (benefit)	—	41,258	—	(176,945)
Depletion, depreciation and amortization	35,158	66,777	110,813	210,831
Bad debt expense	—	107	—	107
Impairment expense	—	906,850	162,027	1,397,327
Non-cash stock-based compensation, net of amounts capitalized	9,651	6,877	19,562	17,933
Accretion of asset retirement obligations	883	599	2,587	1,771
Restructuring expenses	—	—	—	6,042
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(6,850)	(142,580)	43,783	(141,836)
Cash settlements received for matured derivatives, net	44,307	66,142	157,626	175,879
Cash settlements received for early terminations of derivatives, net	—	—	80,000	—
Cash premiums paid for derivatives	(2,709)	(1,248)	(86,972)	(3,918)
Interest expense	23,077	23,348	70,294	79,732
Write-off of debt issuance costs	—	—	842	—
Loss on disposal of assets, net	78	94	379	1,937
Loss on early redemption of debt	—	—	—	31,537
Buyout of minimum volume commitment	—	—	—	3,014
Income from equity method investee	(265)	(2,104)	(6,259)	(4,585)
Proportionate Adjusted EBITDA of equity method investee[1]	5,194	3,295	13,981	5,774
Adjusted EBITDA	$ 118,009	$ 121,632	$ 326,345	$ 359,311

(1) Proportionate Adjusted EBITDA of Medallion, our equity method investee, is calculated as follows:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands, unaudited)	**2016**	**2015**	**2016**	**2015**
Income from equity method investee	$ 265	$ 2,104	$ 6,259	$ 4,585
Adjusted for proportionate share of:				
Depreciation and amortization	4,929	1,191	7,722	2,666
Buyout of minimum volume commitment	—	—	—	(1,477)
Proportionate Adjusted EBITDA of equity method investee	$ 5,194	$ 3,295	$ 13,981	$ 5,774

\# # #

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16-20

EXHIBIT 99.2

Forward-Looking / Cautionary Statements

This presentation and all oral statements made in connection herewith contain 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").

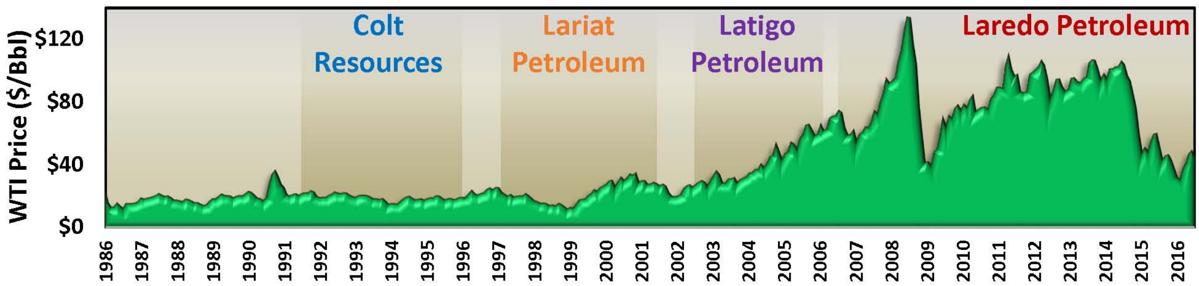
Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

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.

Led By Experienced Management Team

- Each member of the senior management team has more than 30 years of energy industry experience
- Randy Foutch has founded four successful exploration and production companies and operated through a range of oil price environments

Historical Oil Price and Company Timeline



Prior Investments Creating Value

- **Data powering the multivariate Earth Model**
  - **Multivariate Earth Model optimized drilling and completions have yielded well results averaging ~35% higher than 1+ MM BOE type curves**

- **Production corridors lowering operating and capital costs**
  - **Production corridors benefited LOE ~$0.67/BOE in the first nine months of 2016**
  - **10,000' UWC and MWC drilling and completions costs decreased ~$2 MM in 2016**

- **Medallion-Midland Basin Pipeline System growing transported volumes**
  - **Medallion-Midland Basin Pipeline is expected to double delivered volumes in 2016 and grow 50% - 60% in 2017**

Prior strategic investments and continuous performance improvements yield repeatable benefits

3Q-16 Highlights

- **Company record production**
  - **Produced 51,276 BOE/d, above the top end of updated production guidance**

- **Strong well results**
  - **Initial two results of 2,400 #/ft of proppant are exceeding the UWC and MWC type curves by 61% and 40%, respectively**

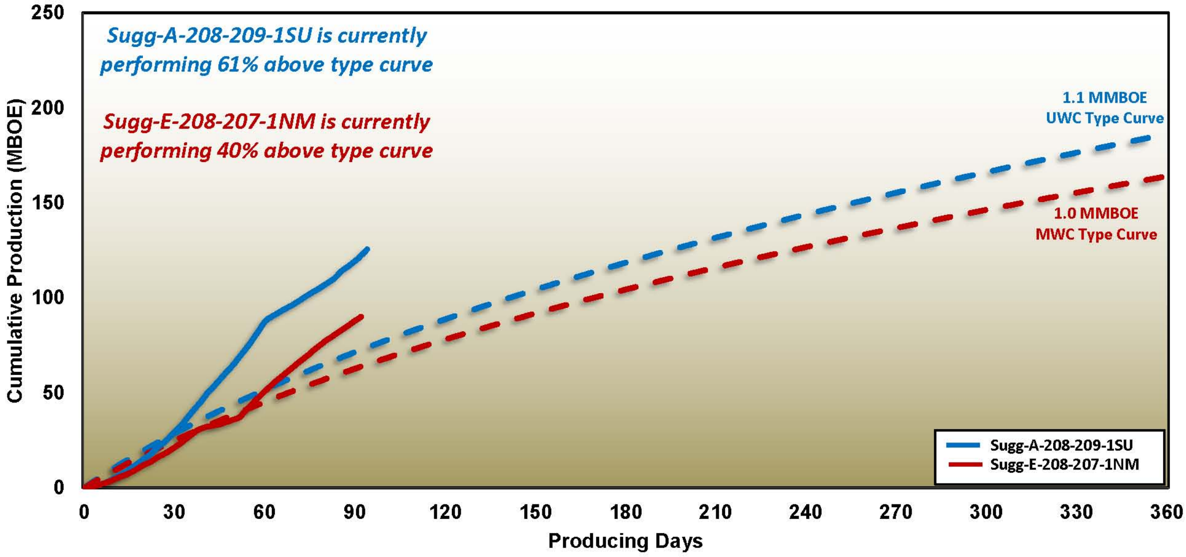
- **Lower costs**
  - **Reduced unit LOE by 37% YoY to $3.85/BOE from $6.09/BOE in 3Q-15**
  - **Recognized ~$6.0 MM of total realized benefits from prior LMS field infrastructure investments through reduced costs and increased revenue**

- **Exceptional hedges**
  - **Received $41.6 MM of net cash settlements on commodity derivatives, net of premiums paid, increasing the average realized sales price by $18.47/Bbl for oil and $0.24/Mcf for natural gas**

Anticipate full-year 2016 production growth of ~10% YoY

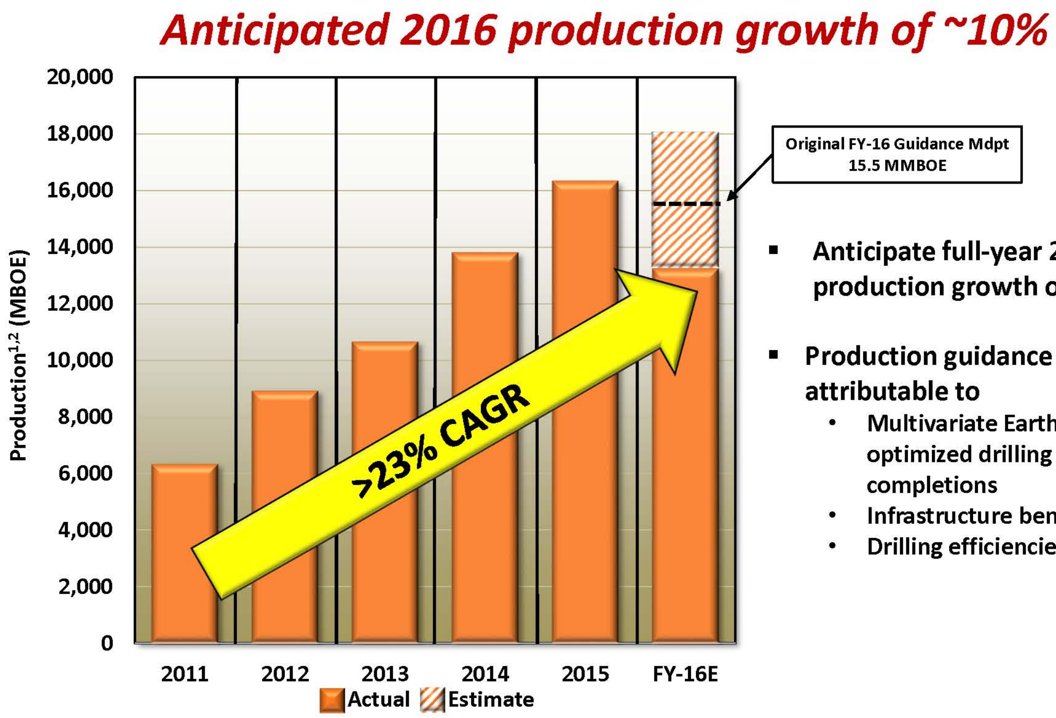
Latest Optimization Tests Significantly Exceeding Type Curve

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



Note: Includes the two 3Q-16 wells with 30 day peak initial production data; wells were both drilled utilizing the multivariate Earth Model drilling and optimized completions with ~2,400 #/ft of sand. Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

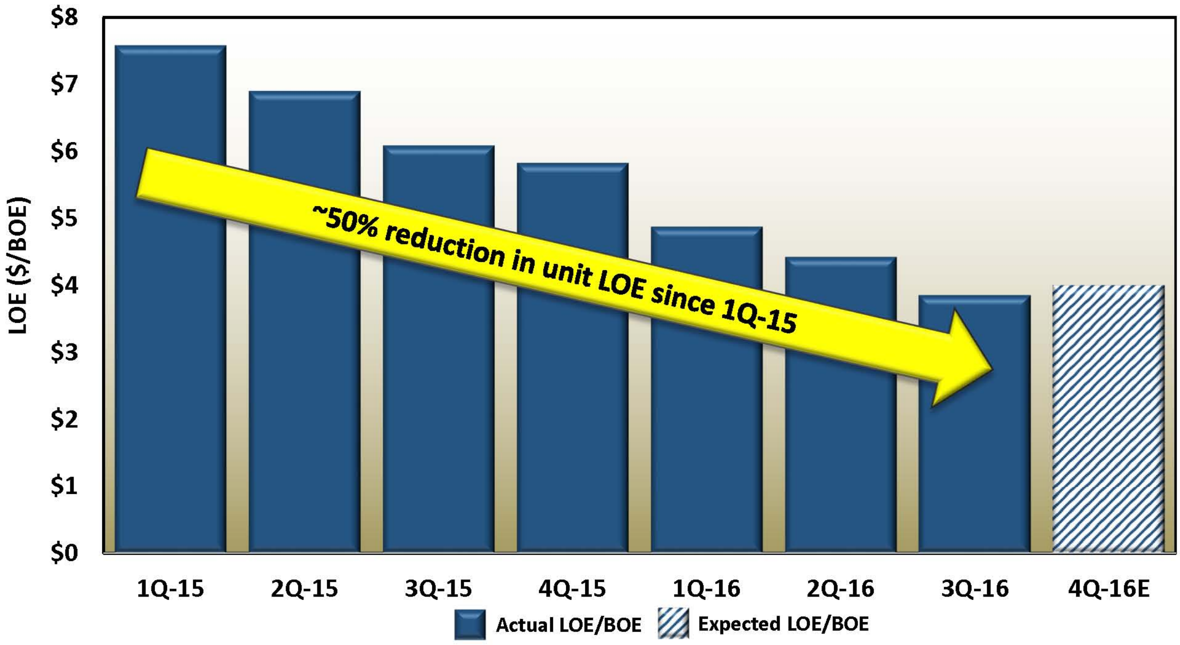
Raising FY-16 Production Estimate



- Anticipate full-year 2016 production growth of ~10% YoY
- Production guidance increases attributable to
  - Multivariate Earth Model optimized drilling and completions
  - Infrastructure benefits
  - Drilling efficiencies

[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

Significant Unit LOE Reduction Since 2015

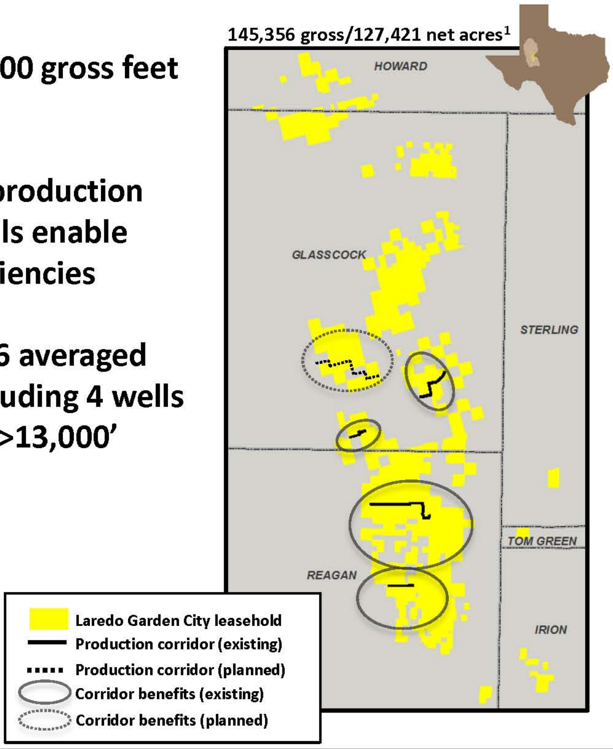


Capitalizing on Contiguous Acreage Position

- Contiguous acreage position with ~4,500 gross feet of prospective zones
- Centralized infrastructure in multiple production corridors and ability to drill long laterals enable increased capital and operational efficiencies
- 10 horizontal wells completed in 3Q-16 averaged >10,900' completed lateral length, including 4 wells each drilled with a total lateral length >13,000'

>80% of acreage HBP, enabling a concentrated development plan along production corridors[1]

145,356 gross/127,421 net acres[1]



[1] As of 9/30/16

Multiple Targeted Horizons

Primary targets: Lower Spraberry, Upper Wolfcamp, Middle Wolfcamp, Cline
Secondary targets: Lower Wolfcamp, Canyon, Atoka, Barnett, Woodford

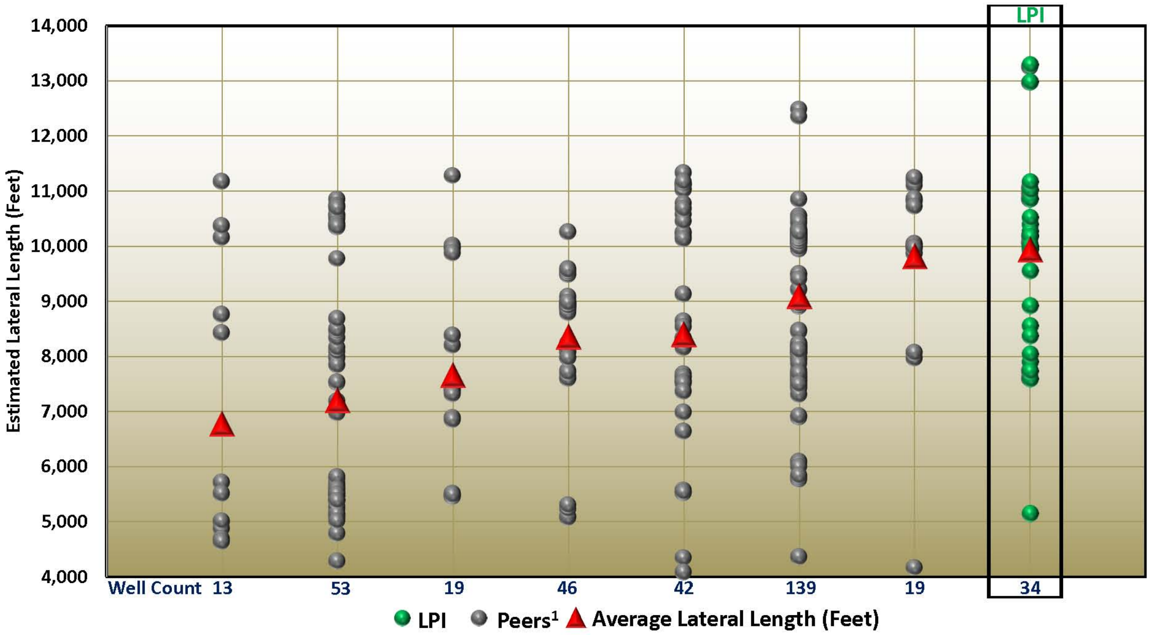
4,500 gross ft of prospective zones

Zone	Hz Wells Drilled	Thickness	OOIP[1]	Identified Landing Points
Clearfork				
Upper/Middle Spraberry				
Lower Spraberry	2	~415'	90	2 - 3
Dean				
Upper Wolfcamp	122	~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	58	~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

LAREDO PETROLEUM

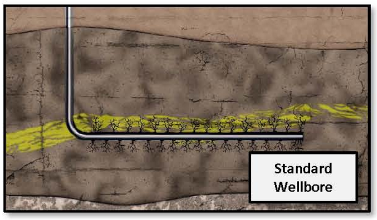
Peer-Leading Long-Lateral Execution



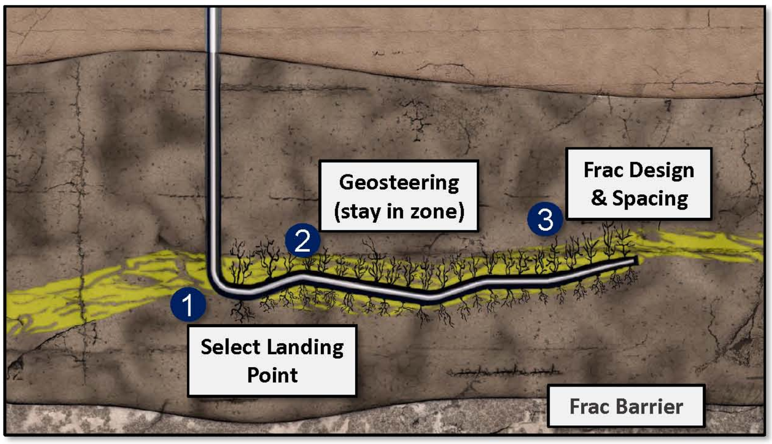
Contiguous acreage position enables drilling of longer laterals

[1] Peers include: Callon, Diamondback, Encana, Energen, Parsley, Pioneer & RSP Permian; data includes 01/01/16 - 10/27/16 for Glasscock, Howard, Irion, Midland, Reagan and Martin & Upton counties, TX

Multivariate Earth Model Drives Performance



Earth Model is facilitating the landing and steering of the wellbore and optimizing the completion to provide significant production uplift



Completion Optimization

- **Proppant:**
  - **Standard: 1,800 #/ft**
  - **Testing: 2,400 #/ft**
- **Cluster Spacing:**
  - **Standard: 54' spacing**
  - **Testing: 30' & 15' spacing**

Hydraulic Fracture Test Site (HFTS)

$23 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

LAREDO PETROLEUM

Research Team

gti | Bureau of Economic Geology | The University of Texas at Austin

Sponsors

U.S. Department of Energy | NETL | devon | HALLIBURTON | EnCana | Total | ConocoPhillips | Core Lab | Discovery Natural Resources | Shell | Energen

Key Initiatives

➔ *In-Progress*
☑ *Complete*

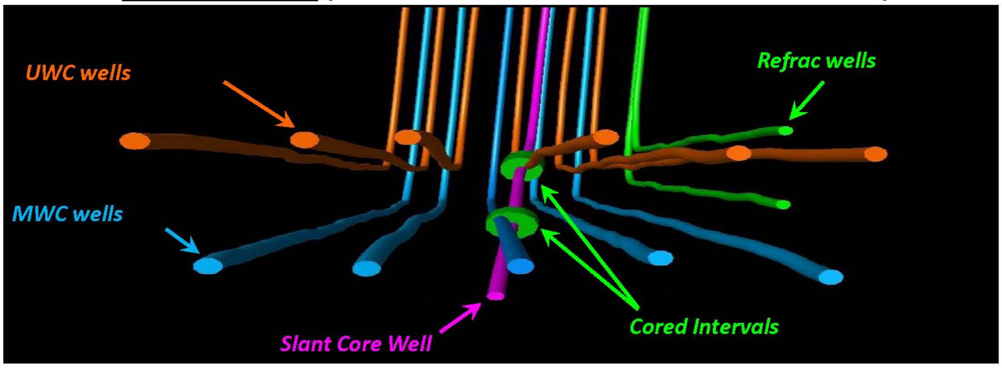
- ➔ Slant Well Fracture & Proppant Analysis
- ➔ Hydraulic Fracture Modeling
- ➔ Fracture Attribute Studies

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

Evolving Beyond the Earth Model

Enhanced analysis of key production drivers

2015

- 12-18 months project duration
- ~50% of LPI acreage
- Focus on UWC & MWC
- Focus on seismic inversion
- Basic well normalization (e.g. completion length)

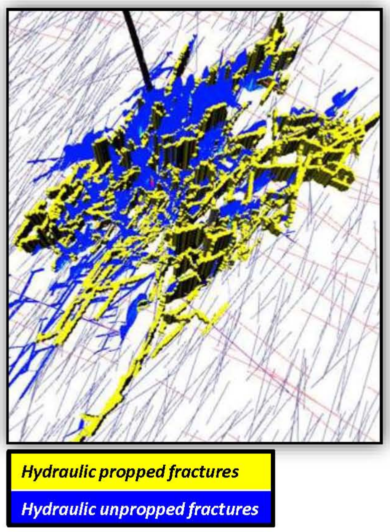
2016

- 6-12 months project duration
- ~80% of LPI acreage
- Expanded from UWC to Cline
- Expanded seismic attributes
- Added detailed completions & proppant loading data
- Improved well normalization (e.g. well spacing)

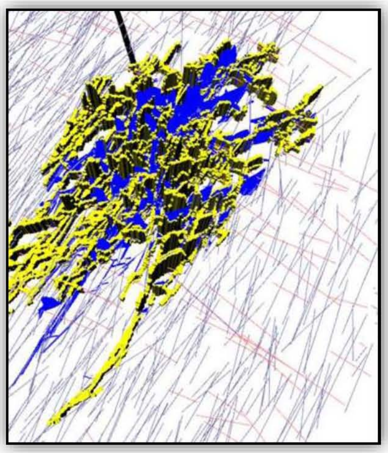
2017

- 2-4 weeks project duration
- ~100% of LPI + offset acreage
- Lower Spraberry to Cline
- Improved inversion variables
- Detailed completions & choke management variables
- Enhanced well normalization (e.g. development timing)
- Integrating GTI project data

Advanced Fracture Modeling

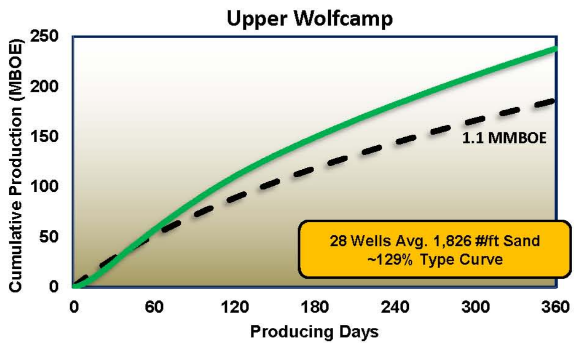


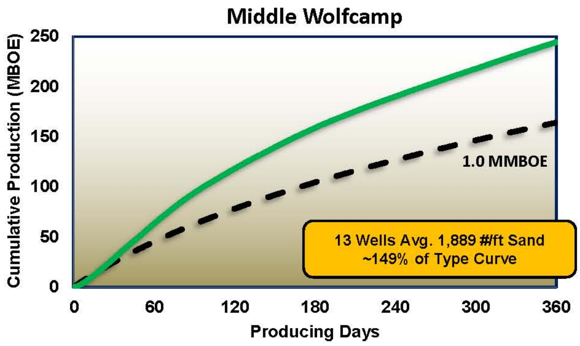
Increasing connected propped fractures

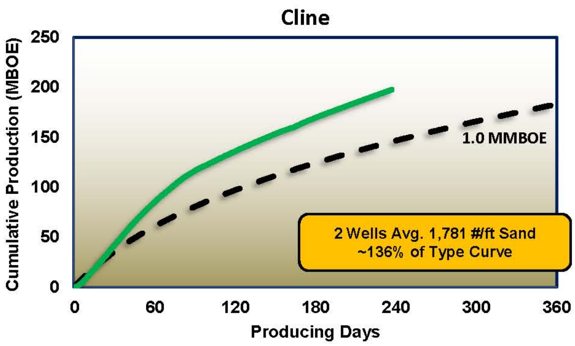


Utilizing multivariate Earth Model analysis to optimize completions designs

Multivariate Earth Model Enhancing Production





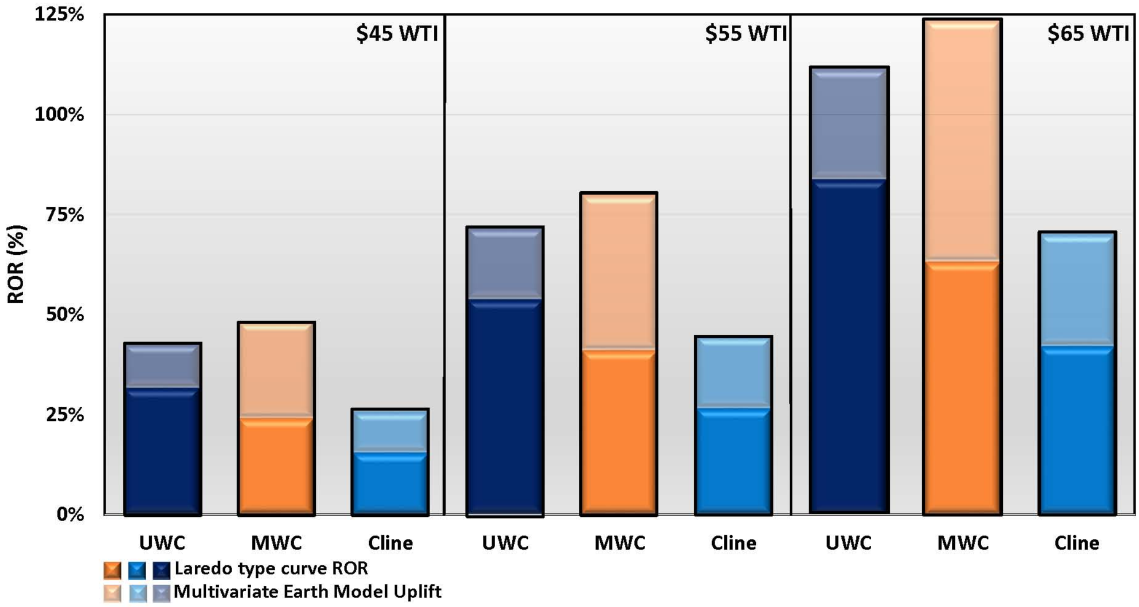


Wells drilled with multivariate Earth Model optimized drilling and completions have resulted in significant outperformance versus the Company's type curves

Cumulative production

Type curve

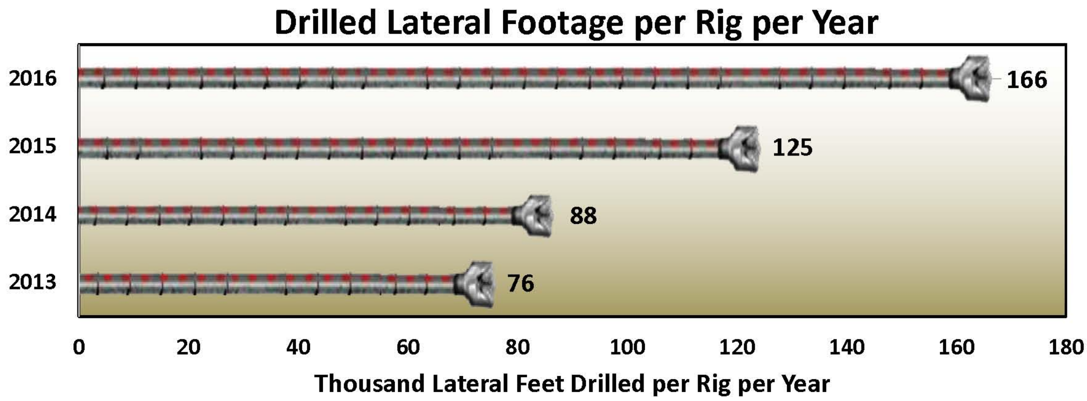
Multivariate Earth Model Driving Meaningful Uplift in Returns



Demonstrated performance uplifts in each zone yield significant return improvements

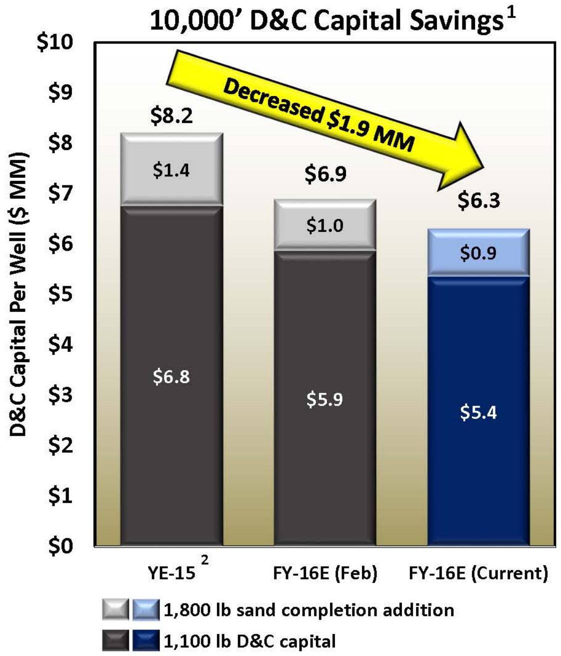
Note: Rate of returns calculated using benchmark prices of WTI: $45.00/Bbl, $55.00/Bbl, $65.00/Bbl & HH: $3.00/Mcf, $3.25/Mcf, $3.50/Mcf and realized pricing of WTI: $39.23/Bbl, $47.95/Bbl, $56.67/Bbl & HH: $2.16/Mcf, $2.34/Mcf, $2.52/Mcf & NGLs: $11.58/Bbl, $14.15/Bbl, $16.72/Bbl

Drilling Efficiencies Drive Lower Well Costs



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

Decreasing D&C Costs



- **D&C costs for recent Upper and Middle Wolfcamp wells have been in the mid $5 million range**

- **D&C capital includes:**
  - Pad preparation
  - Well-site metering
  - Heater treaters
  - Separation equipment
  - Artificial lift equipment

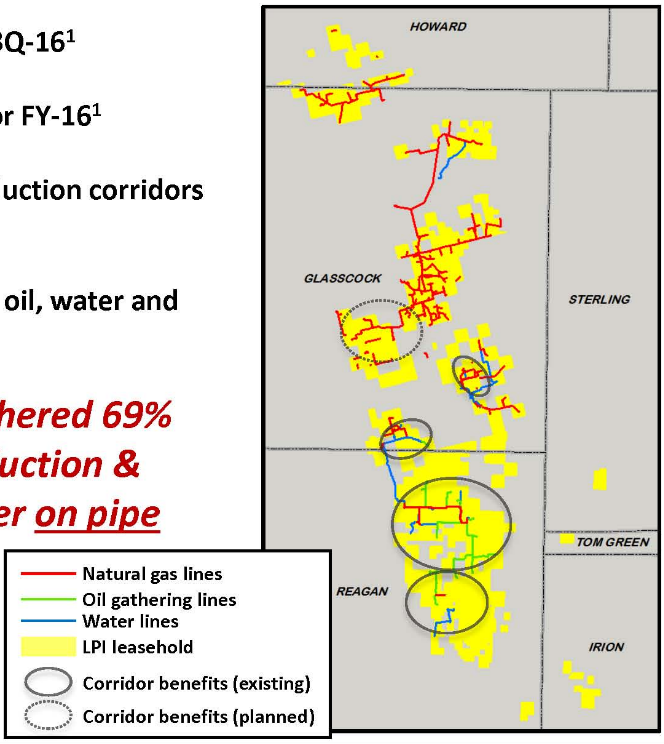
23+% average D&C capital savings YTD in all zones

[1] Representative of 2-well pad costs
[2] YE-15 well cost estimates for FY-16

Prior Investment in Infrastructure Providing Tangible Benefits

- >$6.0 MM total realized benefits in 3Q-16[1]
- ~$25 MM total estimated benefits for FY-16[1]
- ~195 horizontal wells served by production corridors with potential for >2,500 more[2]
- Invested ~$150 MM to date in crude oil, water and natural gas midstream assets

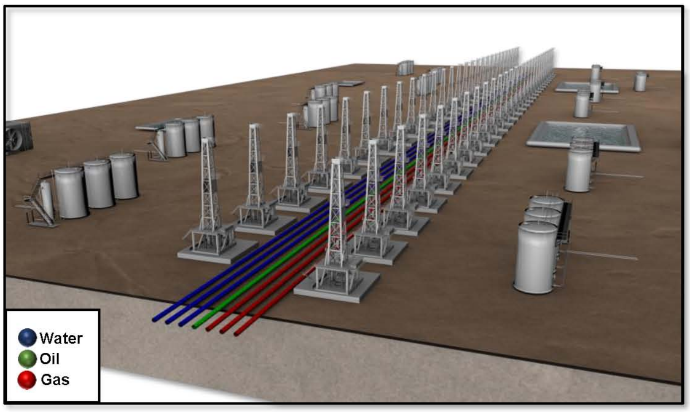
In 3Q-16, infrastructure gathered 69% of gross operated oil production & 67% of total produced water on pipe



[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

~$1.6 million benefit over life of each 10,000' corridor well, with ~25% of the benefit received in the first six months[1]



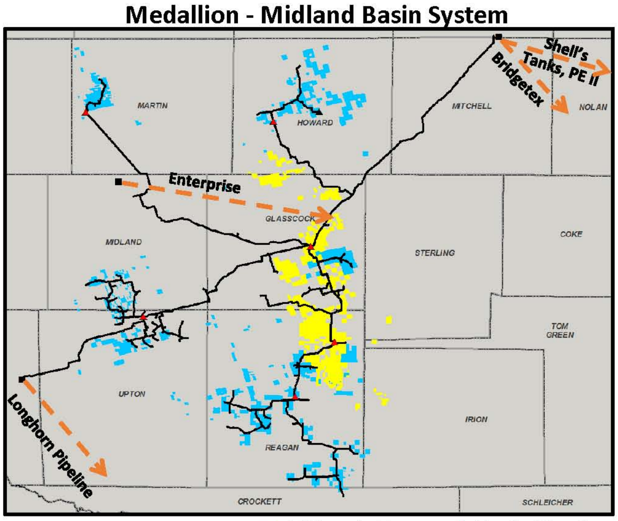
LMS Service	3Q-16 Benefits Actual ($ MM)	2016 Benefits Estimated ($ MM)[1]	LPI Financial Benefits
Crude Gathering	$3.1	$11.4	Increased revenues & 3rd-party income
Centralized Gas Lift	$0.2	$0.9	LOE savings
Frac Water (Recycled vs Fresh)	$0.4	$1.1	Capital savings
Produced Water (Recycled vs Disposed)	$0.4	$2.0	Capital & LOE savings
Produced Water (Gathered vs Trucked)	$1.9	$9.3	Capital & LOE savings
Corridor Benefit	**$6.0**	**$24.7**	

[1] Benefits estimates as of October 27, 2016

Medallion-Midland Basin Crude Oil System

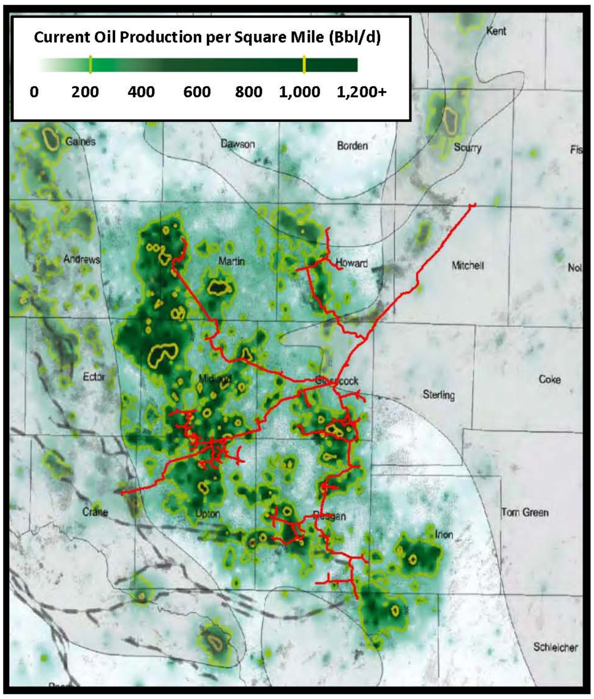
- ~500 miles with >325,000 net acres dedicated to system
- $0.48/Bbl 3Q-16 cash flow margin net to LPI
- YE-16 estimated exit rate of 140,000 BOPD
- ~2 MM acres either under AMI or supporting firm commitments

Medallion - Midland Basin System

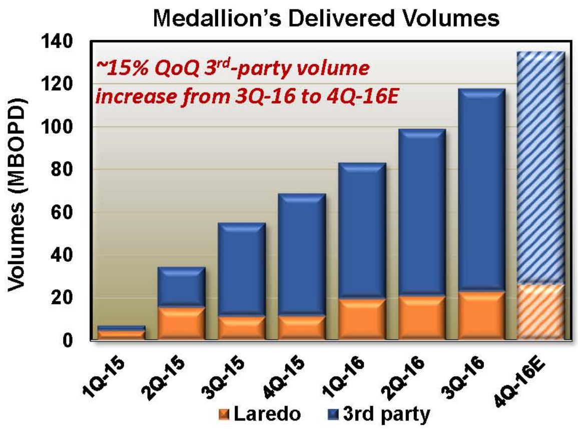


Access to multiple delivery points provides optionality to various crude markets, avoiding potential bottlenecks out of the Midland Basin

Medallion-Midland Basin: The Premier Pipeline in the Permian



— Medallion–Midland Basin pipelines

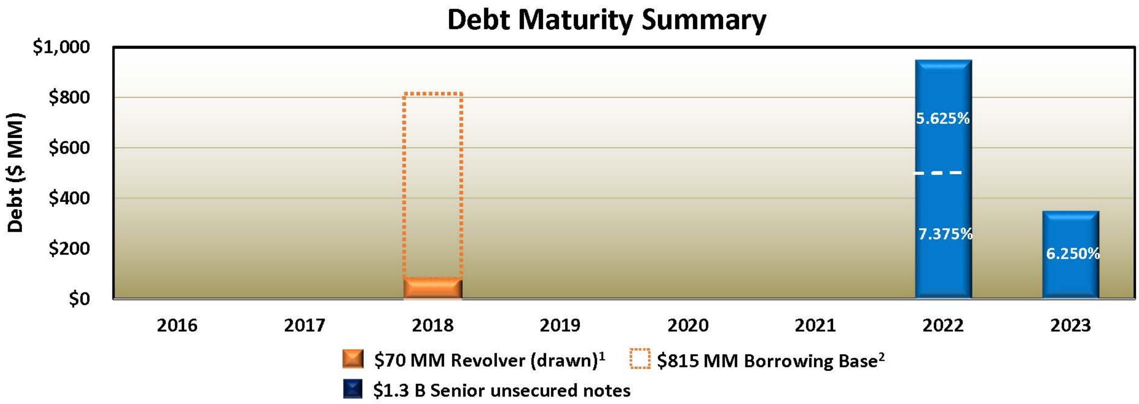


Access to the most productive parts of the Midland Basin drives significant growth on the Medallion-Midland Basin Pipeline

Note: Heat map generated by RS Energy Group

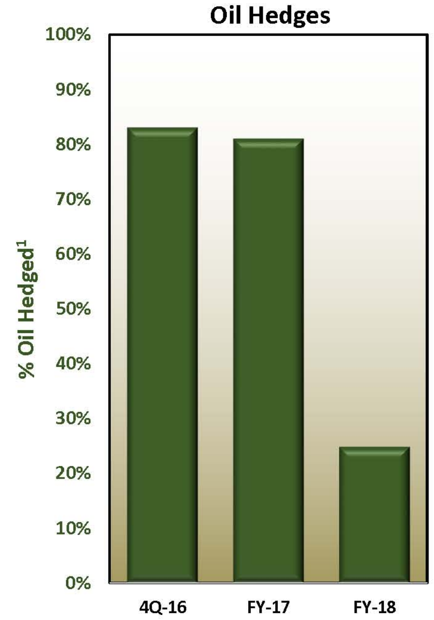
Strong Financial Position

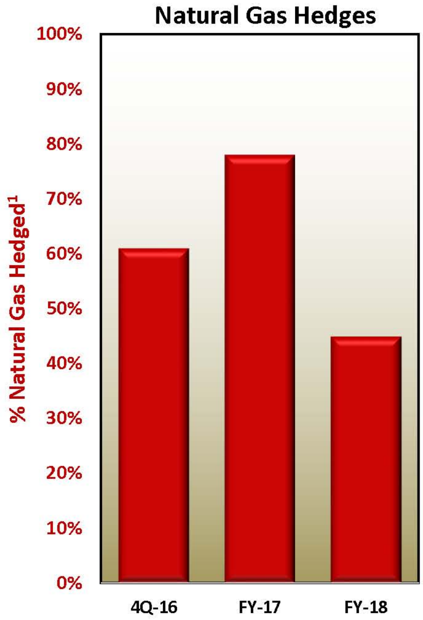
- ~$755 million of liquidity[1]
- No term debt due until 2022
  - $950 million of notes callable at Laredo's option in 2017
- Top-tier, multi-year hedge position



[1] As of 11/01/16
[2] As of October 2016 redetermination; Medallion interest is not pledged to borrowing base

Top-Tier, Multi-Year Hedge Position





	4Q-16	FY-17	FY-18	4Q-16	FY-17	FY-18
Weighted-Avg. Floor Price[2]	$67.13	$55.82	$55.98	$3.00	$2.70	$2.50

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

Fourth-Quarter 2016 Guidance

	4Q-2016
Production (MMBOE)	4.7 - 4.9
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)	~87%
Natural gas liquids (% of WTI)	~30%
Natural gas (% of Henry Hub)	~72%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$3.75 - $4.25
Midstream expenses ($/BOE)	$0.20 - $0.30
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.25%
General and administrative expenses:	
Cash ($/BOE)	$3.25 - $3.75
Noncash stock-based compensation ($/BOE)	$2.00 - $2.25
Depletion, depreciation and amortization ($/BOE)	$7.75 - $8.25


LAREDO
PETROLEUM
Appendix

Oil, Natural Gas & Natural Gas Liquids Hedges

OIL[1]	4Q-16	2017	2018
Puts:			
Hedged volume (Bbls)	549,000	1,049,375	1,049,375
Weighted average price ($/Bbl)	$42.95	$60.00	$60.00
Swaps:			
Hedged volume (Bbls)	395,600	2,007,500	1,095,000
Weighted average price ($/Bbl)	$84.82	$51.54	$52.12
Collars:			
Hedged volume (Bbls)	916,750	3,796,000	
Weighted average floor price ($/Bbl)	$73.98	$56.92	
Weighted average ceiling price ($/Bbl)	$89.62	$86.00	
Total volume with a floor (Bbls)	1,861,350	6,852,875	2,144,375
Weighted-average floor price ($/Bbl)	$67.13	$55.82	$55.98

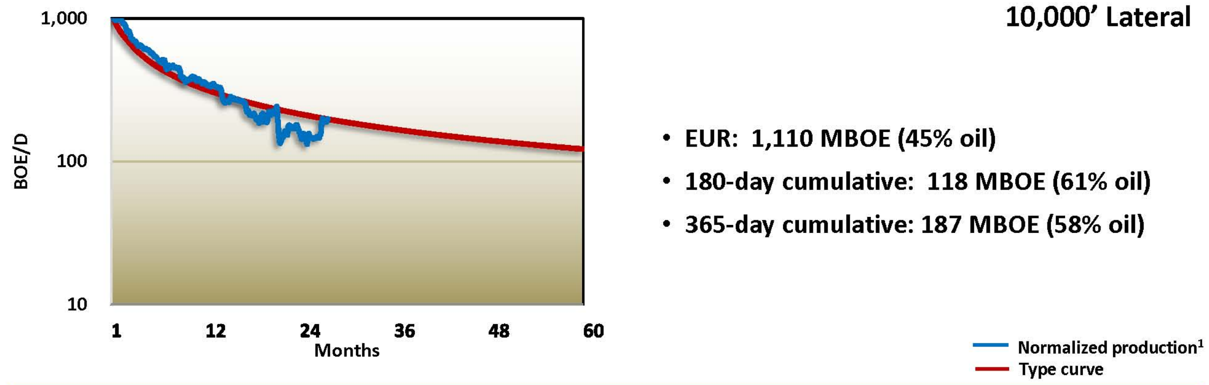
NATURAL GAS[2]	4Q-16	2017	2018
Put			
Hedged volume (MMBtu)		8,040,000	8,220,000
Weighted average floor price ($/MMBtu)		$2.50	$2.50
Collars:			
Hedged volume (MMBtu)	4,692,000	14,454,000	4,635,500
Weighted average floor price ($/MMBtu)	$3.00	$2.82	$2.50
Weighted average ceiling price ($/MMBtu)	$5.60	$3.54	$3.60
Total volume with a floor (MMBtu)	4,692,000	22,494,000	12,855,500
Weighted-average floor price ($/MMBtu)	$3.00	$2.70	$2.50

NATURAL GAS LIQUIDS[3]	4Q-16	2017	2018
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 09/30/16, including hedges placed through 11/01/16
[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

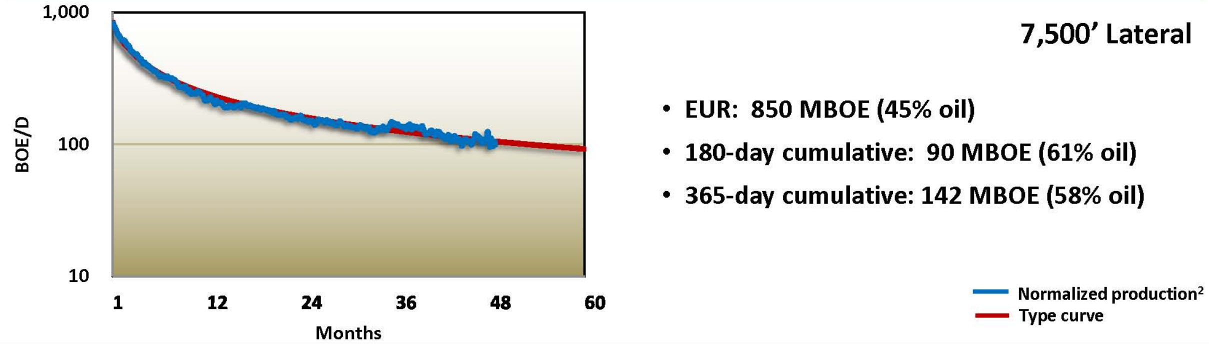
Upper Wolfcamp Type Curves

10,000' Lateral



- **EUR: 1,110 MBOE (45% oil)**
- **180-day cumulative: 118 MBOE (61% oil)**
- **365-day cumulative: 187 MBOE (58% oil)**

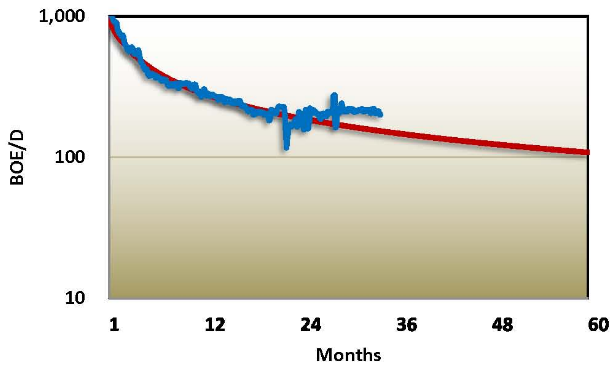
7,500' Lateral



- **EUR: 850 MBOE (45% oil)**
- **180-day cumulative: 90 MBOE (61% oil)**
- **365-day cumulative: 142 MBOE (58% oil)**

[1] Data includes horizontal wells with lateral lengths >8,500' and 31 stages
[2] Data includes horizontal wells with lateral lengths >6,000' and 24 stages
Note: Production data as of 10/07/16, utilizing 73% residue shrink & 116 Bbl/MMcf yield

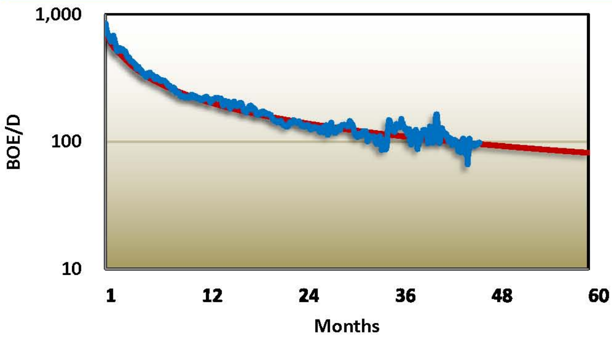
Middle Wolfcamp Type Curves



10,000' Lateral

- EUR: 1,000 MBOE (51% oil)
- 180-day cumulative: 104 MBOE (62% oil)
- 365-day cumulative: 165 MBOE (59% oil)

Normalized production[1]
Type curve



7,500' Lateral

- EUR: 750 MBOE (51% oil)
- 180-day cumulative: 79 MBOE (62% oil)
- 365-day cumulative: 125 MBOE (59% oil)

Normalized production[2]
Type curve

[1] Data includes horizontal wells with lateral lengths >8,500' and 31 stages
[2] Data includes horizontal wells with lateral lengths >6,000' and 24 stages
Note: Production data as of 10/07/16, utilizing 73% residue shrink & 116 Bbl/MMcf yield

2015 & 2016 (YTD) Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15	1Q-16	2Q-16	3Q-16
Production	Production (3-Stream)								
	BOE/D	47,487	46,532	44,820	40,368	44,782	46,202	47,667	51,276
	% oil	51%	46%	45%	45%	47%	48%	46%	46%
Realized Pricing	3-Stream Prices								
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93	$1.31	$1.31	$2.07
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86	$8.50	$12.24	$11.54
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27	$27.51	$39.37	$39.10
Unit Cost Metrics	3-Stream Unit Cost Metrics								
	Lease Operating ($/BOE)	$7.58	$6.90	$6.09	$5.83	$6.63	$4.88	$4.43	$3.85
	Midstream ($/BOE)	$0.37	$0.38	$0.26	$0.43	$0.36	$0.14	$0.27	$0.22
	G&A ($/BOE)	$5.11	$5.48	$5.56	$6.04	$5.53	$4.63	$4.73	$5.54
	DD&A ($/BOE)	$16.83	$17.03	$16.19	$18.01	$16.99	$9.87	$7.88	$7.45

2014 Two-Stream to Three-Stream Conversions

		1Q-14	2Q-14	3Q-14	4Q-14	FY-14
Production	**Production (2-Stream)**					
	BOE/D	**27,041**	**28,653**	**32,970**	**39,722**	**32,134**
	% oil	**58%**	**58%**	**59%**	**60%**	**59%**
	Production (3-Stream)					
	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	$82.83
	3-Stream Prices					
	Gas ($/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	$82.83
Unit Cost Metrics	**2-Stream Unit Cost Metrics**					
	Lease Operating ($/BOE)	$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream ($/BOE)	$0.35	$0.59	$0.40	$0.50	$0.46
	G&A ($/BOE)	$11.36	$11.34	$8.93	$5.95	$9.04
	DD&A ($/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	$0.39
	G&A ($/BOE)	$9.50	$9.60	$7.59	$5.10	$7.67
	DD&A ($/BOE)	$17.03	$17.23	$17.91	$18.72	$17.83