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 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))

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

Emerging Growth Company o

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

Item 2.02. Results of Operations and Financial Condition.

On November 1, 2017, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter ended September 30, 2017. Copies of the Company's press release and Presentation (as defined below) are furnished as Exhibit 99.1 and 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 2, 2017, at 7:30 am Central Time to discuss these results. To access the call, please dial 1-877-930-8286 or 1-253-336-8309 for international callers, and use conference code 2277457. A replay of the call will be available through Thursday, November 9, 2017, by dialing 1-855-859-2056, and using conference code 2277457. 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 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 1, 2017, 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 1, 2017, the Company also posted to its website a Corporate Presentation (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 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 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	Press release dated November 1, 2017 announcing financial and operating results.
99.2	Presentation dated November 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.

Date: November 1, 2017	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President & Chief Financial Officer

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Laredo Petroleum Announces 2017 Third-Quarter Financial and Operating Results

TULSA, OK - November 1, 2017 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or "the Company") today announced its 2017 third-quarter results, reporting net income attributable to common stockholders of $11.0 million, or $0.05 per diluted share. Adjusted Net Income, a non-GAAP financial measure, for the third quarter of 2017 was $33.1 million, or $0.13 per adjusted diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the third quarter of 2017 was $130.9 million. Please see supplemental financial information at the end of this news release for reconciliations of non-GAAP financial measures.

2017 Third-Quarter Highlights

- Produced a Company record 60,011 barrels of oil equivalent ("BOE") per day, an increase of approximately 17% from the third quarter of 2016
- Reduced unit lease operating expenses ("LOE") to a Company record $3.55 per BOE, a decrease of approximately 8% from the third quarter of 2016 and down approximately 6% from second-quarter 2017
- Increased Adjusted EBITDA to $130.9 million, up 11% from the third quarter of 2016 and an increase of approximately 15% from second-quarter 2017
- Recognized approximately $7.6 million in cash benefits from Laredo Midstream Services, LLC ("LMS") field infrastructure investments through reduced costs and increased revenue

"Throughout the third quarter, our operations team precisely executed a challenging testing program for both drilling and completions activities while managing through a broad list of issues derived from one of the worst hurricanes to impact the energy industry in decades," said Randy A. Foutch, Chairman and Chief Executive Officer. "As a result, we achieved record production volumes and drove operating costs on a unit basis to the lowest level in Company history while meaningfully advancing our understanding of ultimate development opportunities to maximize the total net asset value of the Company."

"Laredo has always taken a balanced approach to value creation in every aspect of its business. Preserving meaningful operational and financial flexibility in an ever changing environment ensures today’s investments are truly value-enhancing. Consistent with the infrastructure investments that are key to efficient operations and reduced operating costs, the recent divestiture of our Medallion pipeline interest returned three times our investment in four years while preserving the marketing and cost-saving benefits. In a similar vein, accelerated field testing that applies knowledge derived from our multivariate earth model is expected to further enhance our field development plan. We are very encouraged with many of our initial test results and are now building the production history necessary to fully understand and evaluate the economic impacts that drive net asset values. The efficiencies driven by these investments, coupled with a disciplined capital program, are expected to result in a double-digit oil production growth rate over the next two years, while operating within cash flow by the end of 2019 and enhancing the Company’s return on average capital employed."

Operational Update

The Company's solid performance from base production coupled with initial volumes from 15 new horizontal wells that came online during the third quarter of 2017 resulted in Company record production of 60,011 BOE per day. The 15 new wells during the quarter had an average completed lateral length of approximately 9,900 feet, including three with drilled lateral lengths longer than 15,000 feet. The longer laterals utilized increased water for completion and therefore require a longer flowback period and have not yet achieved peak rates. As a result, both oil and total production came within the Company's quarterly guidance range, although at the lower end.

The three wells drilled with lateral lengths greater than 15,000 feet likely represent the longest laterals drilled to date throughout the Midland Basin. Laredo drilled and completed each of these ultra-long wells without any impact to operations. The wells were part of a five-well package drilled on the Company's Reagan North production corridor. The production corridor was instrumental in facilitating the completions and increasing the expected returns of the project. The five-well package required the delivery of approximately 3.8 million barrels of water to the location, of which 27% was supplied by LMS' recycled water facilities.

Both the operational efficiency and production results of longer laterals confirm Laredo's expectations that incorporating 15,000-foot laterals into the Company's development plan can enhance capital efficiency. The success of these wells provides significant confidence for drilling additional ultra-long lateral locations that exist within Laredo's contiguous acreage block. Laredo currently has approximately 500 land-ready locations in its high-return Upper and Middle Wolfcamp formations that can be developed with 15,000-foot laterals.

Laredo decreased unit LOE to a Company record $3.55 per BOE, down approximately 6% from the previous quarter. The Company has recorded five consecutive quarters of unit LOE below $4.00 per BOE, driven primarily by Laredo's investments in field infrastructure through its wholly-owned subsidiary, LMS. As the number of horizontal wells benefiting from production corridor services has grown from 195 at the beginning of 2017 to 240 through third-quarter 2017, infrastructure driven LOE savings have increased 28% from the first quarter of 2017.

The Company remains focused on testing various vertical, horizontal and tangential spacing combinations within specific well packages to maximize efficiencies and resource development. These tests are focused on increasing the inventory of premium locations in the Upper and Middle Wolfcamp formations through the co-development of the six to eight combined landing points that Laredo has identified in these formations. Should these tests add locations, recovery factors and capital efficiencies are expected to benefit, increasing value per section.

The nine-well Sugg-Graham package, completed in the first and second quarters of 2017, continues to perform well, outperforming the Company's Upper/Middle Wolfcamp three-stream type curve by 30% and the oil type curve by 18%. The results support tighter spacing between landing points, in a chevroned pattern, between the Upper and Middle Wolfcamp formations and the potential for additional premium locations in those formations. Effective horizontal spacing of approximately 440 feet and vertical spacing of approximately 200 feet between some wells in the package could result in a 50% increase in locations in the Upper and Middle Wolfcamp formations around the Company's production corridors. Laredo's six-well package on the Company's Western Glasscock production corridor, expected to be completed during the fourth quarter of 2017, will further test tighter effective spacing in the Upper Wolfcamp formation.

A key component of increasing well density is enhancing fracture complexity and concentration around the wellbore. Laredo has tested various completion designs to accomplish this and, based on production results and microseismic data, is completing a significant number of wells with 30-foot cluster intervals. The Company expects to continue to test additional completion designs related to perforation cluster spacing, including 15-foot cluster spacing and varying the number of clusters per stage.

Through the third quarter of 2017, Laredo has utilized proprietary analytics and modeling to optimize completions on 96 horizontal wells. On average, these wells are outperforming the Company's type curves by 36%. Importantly, this outperformance has remained consistent as Laredo has expanded testing to additional landing points within the Upper and Middle Wolfcamp formations. Tests also incorporate increased proppant density of 2,400 pounds per lateral foot. This group of 22 wells using 2,400 pounds of proppant per foot is currently outperforming Laredo's type curves by 42%, including the 13 wells with the longest production history that are outperforming the Company's type curves by 49%.

Laredo continues to evaluate the economics of multiple spacing and completion tests and is incorporating the analysis into the Company's overall development plan. In 2017, Laredo anticipates a total of 11 of the Company's multi-well packages will test spacing concepts, co-development of landing points and additional landing points. Completions tests have been integrated into these packages to determine the impact of proppant density, cluster interval spacing, stage length and proprietary concepts in spacing design. The primary goal is to enhance long-term value through efficient resource recovery while retaining the ability to appropriately adjust well package elements of spacing and completion design as service costs and commodity prices fluctuate.

In the third quarter of 2017, Laredo continued to experience higher well costs as service cost increases seen at the end of second-quarter 2017 continued throughout the third quarter. Laredo is currently budgeting $7.7 million for an Upper/Middle Wolfcamp 10,000-foot horizontal well, completed with 1,800 pounds of sand per lateral foot and utilizing 30-foot perforation cluster spacing. The Company is actively pursuing initiatives to reduce well costs, including self-sourcing local sand supplies and increasing the number of clusters per stage to reduce costs associated with tighter cluster spacing.

In the fourth quarter of 2017, Laredo expects to complete 20 wells, 12 of which are expected to meaningfully impact fourth quarter production, with an average lateral length of approximately 9,400 feet and an average working interest of 99%. The Company is currently operating four horizontal development rigs. During the third quarter of 2017, Laredo employed a fifth rig to drill a core test to further its data analysis efforts and has released the rig subsequent to the end of the quarter.

The Company is focused on driving efficiencies in its drilling and completion operations through the development of multi-well packages on its production corridors. It is expected that these efficiencies will result in a continued increase in work-in-progress wells from the third-quarter 2017 level of 21 wells. The Company's goal is to manage the number of work-in-progress wells, focus on return on capital and better align capital spending with cash flow.

Laredo Midstream Services Update

LMS-owned field infrastructure provided combined benefits from increased revenue and cost savings of $7.6 million in the third quarter of 2017. Without the benefits generated by LMS' water infrastructure and centralized gas lift infrastructure, unit LOE would have increased by an estimated $0.51 per BOE in third-quarter 2017.

Efficient use of water resources is a priority for the Company, and through LMS, Laredo has invested in water infrastructure since 2013. The Company gathered 72% of its produced water by pipe and recycled 30% of its produced water in the third quarter of 2017. Additionally, LMS supplied 46% of the water needed for Laredo's third-quarter 2017 completions with recycled water or fresh water from LMS-owned water wells. In total, LMS' water infrastructure assets delivered approximately $4.5 million in operating and capital cost savings in the third quarter of 2017.

LMS' oil gathering assets generated approximately $2.8 million in benefits to the Company through a combination of increased realized prices and operating income from third-party shippers. Approximately 81% of Laredo's gross operated production was gathered on pipe and 81% was transported on the Medallion-Midland Basin pipeline system.

The Company expects that the sale of the Company's interest in Medallion, announced subsequent to the end of the third quarter of 2017, will have no impact on Laredo's future operating cost structure or realized oil pricing.

2017 Capital Program

During the third quarter of 2017, Laredo invested approximately $156 million in exploration and development activities, including approximately $46 million in wells expected to be completed in the fourth quarter of 2017. Other expenditures incurred during the quarter included approximately $4 million in bolt-on land acquisitions and lease extensions, approximately $4 million in infrastructure held by LMS and approximately $7 million in capitalized employee-related costs.

Through the third quarter of 2017, the Company has incurred total expenditures of approximately $442 million, exclusive of investments in the Medallion-Midland Basin pipeline system, which Laredo divested subsequent to the end of third-quarter 2017.

The Company has increased its 2017 capital budget to $630 million from the previously anticipated $530 million. The new budget reflects service cost inflation, additional completion optimization testing and data collection. Approximately $90 million of expected costs incurred in 2017 are associated with wells drilled in multi-well packages that will benefit production in 2018.

Liquidity

At September 30, 2017, the Company had cash and cash equivalents of approximately $21 million and undrawn capacity under the senior secured credit facility of $845 million, resulting in total liquidity of approximately $866 million.

On October 20, 2017, in connection with the semi-annual redetermination of the Company's senior secured credit facility, lenders reaffirmed the Company's borrowing base at $1 billion.

At October 31, 2017, subsequent to the closing of the sale of LMS' interest in the Medallion-Midland Basin pipeline system, the Company had cash and equivalents of approximately $735 million and available capacity under the senior secured credit facility of $1 billion, resulting in total available liquidity of approximately $1.735 billion. Approximately $521 million of this amount will be utilized to satisfy the redemption of the Company's 7.375% senior notes, which is expected to be completed on November 29, 2017.

Commodity Derivatives

Laredo maintains a disciplined hedging program to reduce the variability in its anticipated cash flow due to fluctuations in commodity prices. At September 30, 2017, the Company had hedges in place for the remainder of 2017 for 1,727,300 barrels of oil at a weighted-average floor price of $55.82 per barrel and for 6,803,200 million British thermal units ("MMBtu") of natural gas at a weighted-average floor price of $2.75 per MMBtu. All natural gas hedges the Company has in place are priced at the WAHA hub. Additionally, Laredo had hedged 111,000 barrels of ethane at $11.24 per barrel and 93,750 barrels of propane at $22.26 per barrel.

At September 30, 2017, for 2018, the Company had hedged 9,515,375 barrels of oil at a weighted-average floor price of $47.42 per barrel. All of the Company's 2018 oil hedges enable Laredo to benefit from an increase in the price of oil from current levels with 4,088,000 barrels structured as collars with a weighted-average ceiling price of $60.00 per barrel and 5,427,375 barrels hedged with puts and thus do not have a ceiling. The Company has also hedged 23,805,500 MMBtu of natural gas for 2018 at a weighted-average floor price of $2.50 per MMBtu, priced at the WAHA hub. Additionally, Laredo has basis swaps for 2018 for 3,650,000 barrels of oil to hedge the Midland-West Texas Intermediate ("WTI") basis differential at WTI less $0.56 per barrel.

At September 30, 2017, for 2019, the Company had hedged 730,000 barrels of oil with puts having a weighted-average floor price of $50.00 per barrel.

Guidance

The Company is reiterating its anticipated full-year 2017 production growth guidance range of 16% - 19% as compared to 2016. The table below reflects the Company’s guidance for the fourth quarter of 2017.

	4Q-2017
Production (MBOE/d)	61 - 64
Product % of total production:	
Crude oil	43% - 45%
Natural gas liquids	27% - 29%
Natural gas	27% - 29%
Price Realizations (pre-hedge):	
Crude oil (% of WTI)	~94%
Natural gas liquids (% of WTI)	~39%
Natural gas (% of Henry Hub)	~67%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$3.50 - $4.00
Midstream expenses ($/BOE)	$0.20 - $0.30
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.25%
General and administrative expenses:	
Cash ($/BOE)	$2.50 - $3.00
Non-cash stock-based compensation ($/BOE)	$1.50 - $1.75
Depletion, depreciation and amortization ($/BOE)	$7.25 - $7.75

Conference Call Details

On Thursday, November 2, 2017, at 7:30 a.m. CT, Laredo will host a conference call to discuss its third-quarter 2017 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 2277457, approximately 10 minutes prior to the scheduled conference time. International participants should dial 253.336.8309, also using conference code 2277457. A telephonic replay will be available approximately two hours after the call on November 2, 2017 through Thursday, November 9, 2017. Participants may access this replay by dialing 855.859.2056, using conference code 2277457.

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 gathering of oil and liquids-rich 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, contain 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, the increase in service costs, the impact of the Medallion sale, hedging activities, possible impacts of pending or potential litigation and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2016, 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 costs 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, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales	$ 157,558	$ 114,805	$ 438,131	$ 290,473
Midstream service revenues	2,446	2,488	8,148	5,921
Sales of purchased oil	45,814	42,441	135,546	116,670
Total revenues	205,818	159,734	581,825	413,064
Costs and expenses:				
Lease operating expenses	19,594	18,177	56,690	57,920
Production and ad valorem taxes	9,558	7,066	26,811	21,483
Midstream service expenses	1,174	1,039	2,986	2,826
Costs of purchased oil	47,385	44,232	141,661	121,190
General and administrative	25,000	26,105	72,605	66,058
Depletion, depreciation and amortization	41,212	35,158	113,327	110,813
Impairment expense	—	—	—	162,027
Other operating expenses	1,443	2,465	3,906	4,169
Total costs and expenses	145,366	134,242	417,986	546,486
Operating income (loss)	60,452	25,492	163,839	(133,422)
Non-operating income (expense):				
Gain (loss) on derivatives, net	(27,441)	6,850	38,127	(43,783)
Income from equity method investee**	2,371	265	7,910	6,259
Interest expense	(23,697)	(23,077)	(69,590)	(70,294)
Other, net	(658)	(45)	127	(1,078)
Non-operating expense, net	(49,425)	(16,007)	(23,426)	(108,896)
Income (loss) before income taxes	11,027	9,485	140,413	(242,318)
Income tax:				
Deferred	—	—	—	—
Total income tax	—	—	—	—
Net income (loss)	$ 11,027	$ 9,485	$ 140,413	$ (242,318)
Net income (loss) per common share:				
Basic	$ 0.05	$ 0.04	$ 0.59	$ (1.09)
Diluted	$ 0.05	$ 0.04	$ 0.57	$ (1.09)
Weighted-average common shares outstanding:				
Basic	239,306	234,639	239,017	221,303
Diluted	244,887	238,108	244,693	221,303

Laredo Petroleum, Inc.
Condensed consolidated balance sheets

(in thousands)	September 30, 2017	December 31, 2016
	(unaudited)	(unaudited)
Assets:		
Current assets	$ 142,465	$ 154,777
Property and equipment, net	1,631,319	1,366,867
Other noncurrent assets**	292,542	260,702
Total assets	$ 2,066,326	$ 1,782,346
Liabilities and stockholders' equity:		
Current liabilities	$ 223,260	$ 187,945
Long-term debt, net	1,440,968	1,353,909
Other noncurrent liabilities	55,873	59,919
Stockholders' equity	346,225	180,573
Total liabilities and stockholders' equity	$ 2,066,326	$ 1,782,346

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2017	2016	2017	2016
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net income (loss)	$ 11,027	$ 9,485	$ 140,413	$ (242,318)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depletion, depreciation and amortization	41,212	35,158	113,327	110,813
Impairment expense	—	—	—	162,027
Non-cash stock-based compensation, net of amounts capitalized	8,966	9,651	26,877	19,562
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	27,441	(6,850)	(38,127)	43,783
Cash settlements received for matured derivatives, net	13,635	44,307	34,791	157,626
Cash settlements received for early terminations of derivatives, net	—	—	4,234	80,000
Cash premiums paid for derivatives	(1,448)	(2,709)	(13,542)	(86,972)
Other, net	786	1,794	(1,134)	(5,423)
Cash flows from operations before changes in working capital and other noncurrent liabilities	101,619	90,836	266,839	239,098
Increase in working capital	13,656	16,088	5,502	6,653
Decrease in other noncurrent liabilities	(125)	(101)	(290)	(297)
Net cash provided by operating activities	115,150	106,823	272,051	245,454
Cash flows from investing activities:				
Capital expenditures:				
Acquisitions of oil and natural gas properties	—	(115,600)	—	(115,600)
Oil and natural gas properties	(148,946)	(79,693)	(381,165)	(276,735)
Midstream service assets	(5,563)	(806)	(11,680)	(4,231)
Other fixed assets	(921)	(150)	(3,604)	(982)
Investment in equity method investee**	(24,572)	(16,031)	(24,572)	(58,712)
Proceeds from dispositions of capital assets, net of selling costs	687	15	64,128	365
Net cash used in investing activities	(179,315)	(212,265)	(356,893)	(455,895)
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility	65,000	94,682	155,000	214,682
Payments on Senior Secured Credit Facility	(15,000)	(135,000)	(70,000)	(279,682)
Proceeds from issuance of common stock, net of offering costs	—	156,742	—	276,052
Other, net	(41)	69	(12,012)	(1,405)
Net cash provided by financing activities	49,959	116,493	72,988	209,647
Net (decrease) increase in cash and cash equivalents	(14,206)	11,051	(11,854)	(794)
Cash and cash equivalents, beginning of period	35,024	19,309	32,672	31,154
Cash and cash equivalents, end of period	$ 20,818	$ 30,360	$ 20,818	$ 30,360

Laredo Petroleum, Inc.
Selected operating data

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
	(unaudited)		(unaudited)	
Sales volumes:				
Oil (MBbl)	2,425	2,150	7,027	6,168
NGL (MBbl)	1,491	1,272	4,187	3,491
Natural gas (MMcf)	9,630	7,766	26,154	21,600
Oil equivalents (MBOE)(1)(2)	5,521	4,718	15,573	13,260
Average daily sales volumes (BOE/D)(1)	60,011	51,276	57,044	48,392
% Oil	44%	46%	45%	47%
Average sales prices(1):				
Oil, realized ($/Bbl)(3)	$ 45.44	$ 39.10	$ 44.67	$ 35.42
NGL, realized ($/Bbl)(3)	$ 18.58	$ 11.54	$ 16.32	$ 10.84
Natural gas, realized ($/Mcf)(3)	$ 2.04	$ 2.07	$ 2.14	$ 1.58
Average price, realized ($/BOE)(3)	$ 28.54	$ 24.34	$ 28.13	$ 21.91
Oil, hedged ($/Bbl)(4)	$ 50.72	$ 57.57	$ 49.08	$ 57.76
NGL, hedged ($/Bbl)(4)	$ 17.98	$ 11.54	$ 15.90	$ 10.84
Natural gas, hedged ($/Mcf)(4)	$ 2.10	$ 2.31	$ 2.17	$ 2.18
Average price, hedged ($/BOE)(4)	$ 30.80	$ 33.15	$ 30.07	$ 33.27
Average costs per BOE sold(1):				
Lease operating expenses	$ 3.55	$ 3.85	$ 3.64	$ 4.37
Production and ad valorem taxes	1.73	1.50	1.72	1.62
Midstream service expenses	0.21	0.22	0.19	0.21
General and administrative:				
Cash	2.90	3.49	2.94	3.51
Non-cash stock-based compensation, net of amounts capitalized	1.62	2.05	1.73	1.48
Depletion, depreciation and amortization	7.46	7.45	7.28	8.36
Total	$ 17.47	$ 18.56	$ 17.50	$ 19.55

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

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

(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.

(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.

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)	**2017**	**2016**	**2017**	**2016**
	(unaudited)		(unaudited)	
Property acquisition costs:				
Evaluated[1]	$ —	$ 5,905	$ —	$ 5,905
Unevaluated	—	110,800	—	110,800
Exploration costs	7,136	6,718	28,337	33,750
Development costs[2]	160,359	72,411	397,255	225,103
Total costs incurred	$ 167,495	$ 195,834	$ 425,592	$ 375,558

(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 $0.4 million and $0.3 million in asset retirement obligations for the three months ended September 30, 2017 and 2016, respectively, and $0.6 million and $0.5 million for the nine months ended September 30, 2017 and 2016, 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, mark-to-market on derivatives, cash premiums paid for derivatives, impairment expense, gains or losses on disposal of assets, write-off of debt issuance costs and other non-recurring income and expenses 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, for the nine months ended September 30, 2016, our net loss (GAAP) per common share calculation utilizes the same denominator for both basic and diluted net loss per common share. However, our calculation of Adjusted Net Income (non-GAAP) results in income for the period presented. Therefore, we believe it appropriate and more conservative to calculate an Adjusted diluted weighted-average common shares outstanding utilizing our fully dilutive weighted-average common shares. As such, for each of the three and nine months ended September 30, 2017 and 2016, we present a line item that calculates Adjusted Net Income per Adjusted diluted common share.

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

	Three months ended September 30,		Nine months ended September 30,	
(in thousands, except per share data, unaudited)	**2017**	**2016**	**2017**	**2016**
Net income (loss)	$ 11,027	$ 9,485	$ 140,413	$ (242,318)
Plus:				
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	27,441	(6,850)	(38,127)	43,783
Cash settlements received for matured derivatives, net	13,635	44,307	34,791	157,626
Cash settlements received for early terminations of derivatives, net	—	—	4,234	80,000
Cash premiums paid for derivatives	(1,448)	(2,709)	(13,542)	(86,972)
Impairment expense	—	—	—	162,027
Loss on disposal of assets, net	991	78	400	379
Write-off of debt issuance costs	—	—	—	842
Adjusted net income before adjusted income tax expense	51,646	44,311	128,169	115,367
Adjusted income tax expense	(18,593)	(15,952)	(46,141)	(41,532)
Adjusted Net Income	$ 33,053	$ 28,359	$ 82,028	$ 73,835
Net income (loss) per common share:				
Basic	$ 0.05	$ 0.04	$ 0.59	$ (1.09)
Diluted	$ 0.05	$ 0.04	$ 0.57	$ (1.09)
Adjusted Net Income per common share:				
Basic	$ 0.14	$ 0.12	$ 0.34	$ 0.33
Adjusted diluted	$ 0.13	$ 0.12	$ 0.34	$ 0.33
Weighted-average common shares outstanding:				
Basic	239,306	234,639	239,017	221,303
Diluted	244,887	238,108	244,693	221,303
Adjusted diluted	244,887	238,108	244,693	223,197

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, impairment expense, non-cash stock-based compensation, net of amounts capitalized, accretion expense, mark-to-market on derivatives, cash premiums paid for derivatives, interest expense, write-off of debt issuance costs, gains or losses on disposal of assets, income or loss from equity method investee, proportionate Adjusted EBITDA of equity method investee and other non-recurring income and expenses. 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.

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

(in thousands, unaudited)	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Net income (loss)	$ 11,027	$ 9,485	$ 140,413	$ (242,318)
Plus:				
Depletion, depreciation and amortization	41,212	35,158	113,327	110,813
Impairment expense	—	—	—	162,027
Non-cash stock-based compensation, net of amounts capitalized	8,966	9,651	26,877	19,562
Accretion expense	951	883	2,822	2,587
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	27,441	(6,850)	(38,127)	43,783
Cash settlements received for matured derivatives, net	13,635	44,307	34,791	157,626
Cash settlements received for early terminations of derivatives, net	—	—	4,234	80,000
Cash premiums paid for derivatives	(1,448)	(2,709)	(13,542)	(86,972)
Interest expense	23,697	23,077	69,590	70,294
Write-off of debt issuance costs	—	—	—	842
Loss on disposal of assets, net	991	78	400	379
Income from equity method investee**	(2,371)	(265)	(7,910)	(6,259)
Proportionate Adjusted EBITDA of equity method investee**[(1)]	6,789	5,194	19,755	13,981
Adjusted EBITDA	$ 130,890	$ 118,009	$ 352,630	$ 326,345

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

(in thousands, unaudited)	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Income from equity method investee	$ 2,371	$ 265	$ 7,910	$ 6,259
Adjusted for proportionate share of:				
Depreciation and amortization	4,418	4,929	11,845	7,722
Proportionate Adjusted EBITDA of equity method investee	$ 6,789	$ 5,194	$ 19,755	$ 13,981

** On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC, which is owned and controlled by an affiliate of The Energy & Minerals Group, completed the previously announced sale of 100% of the ownership interests in Medallion (the "Medallion Sale") to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion, subject to customary post-closing adjustments. LMS' net cash proceeds for its 49% ownership interest in Medallion are $829.6 million, before post-closing adjustments and taxes, but after deduction of its proportionate share of fees and other expenses associated with the Medallion Sale. The Medallion Sale closed pursuant to the membership interest purchase and sale agreement, which provides for potential post-closing additional cash consideration that is structured based on GIP's realized profit at exit. There can be no assurance as to when and whether the additional consideration will be paid.

# # #

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L A R E D O P E T R O L E U M

Corporate Presentation
November 2017

LAREDO PETROLEUM

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, possible impacts of pending or potential litigation 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, impacts of pending or potential litigation, successful results from the Company's identified drilling locations, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and other reports filed with the Securities Exchange Commission ("SEC").

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

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

3Q-17 Highlights

- **Produced a Company record 60,011 BOE/d**
  - **~17% YoY increase**

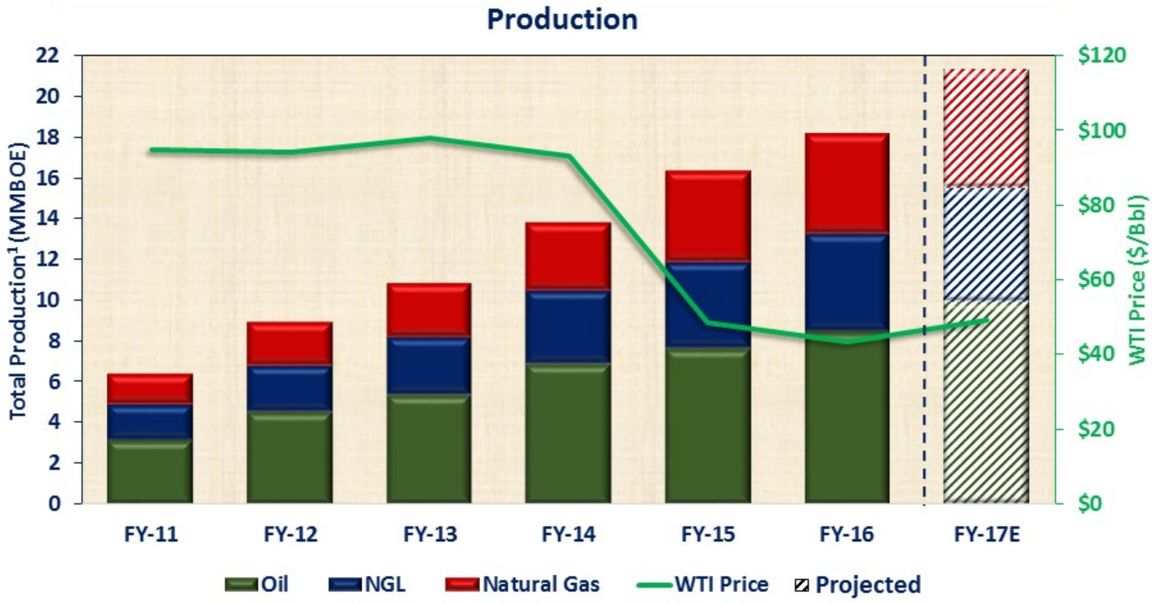
- **Completed three wells greater than 15,000 lateral feet, likely representing the longest laterals drilled to date throughout the Midland Basin**

- **Reduced unit LOE to $3.55/BOE**
  - **~8% YoY decrease**
  - **~6% QoQ decrease**

- **Recognized ~$7.6 MM in cash benefits[1] from LMS field infrastructure investments through reduced costs and increased revenues**

[1]LMS benefits calculated utilizing a 95% WI & 72% NRI

Consistent Growth Despite Commodity Price Decline



16% - 19%
2017E YoY Production Growth

[1] 2011 - 2014 results have been converted to 3-stream using actual gas plant economics. 2011 - 2013 results have been adjusted for Granite Wash divestiture, closed August 1, 2013. 2017 estimated production is utilizing the midpoint of 16% - 19% of production guidance

2017 Capital and Operating Expectations Update

FY-17E Drilling & Completions
4 Hz development rigs
60 - 65 Hz wells drill & complete
~10,000' lateral length average

2017 Capital Budget
Original: $530 MM

2017 Capital Budget
Updated: $630 MM

FY-17 capital increase includes:
- Service cost inflation
  - Base well cost: $7.7 MM[1]
- Completions testing

Work in Progress:
- ~$90 MM of D&C associated with multi-well packages that will benefit 2018 production

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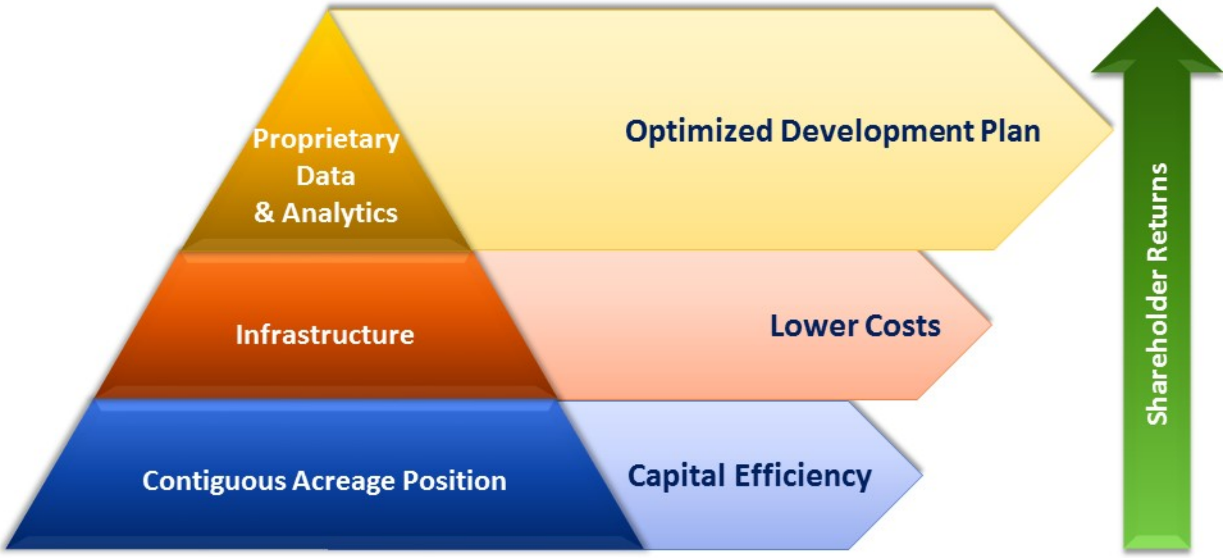
[1]Base well cost representative of current multi-well pad costs for 10,000' UWC/MWC well utilizing 1,800 pounds of sand per foot and 30' cluster spacing
Note: Capital does not include acquisitions or investments in Medallion-Midland Basin system

Steady, Strategic Plan Yields Repeatable Results



A disciplined focus on key value drivers since inception has driven shareholder returns

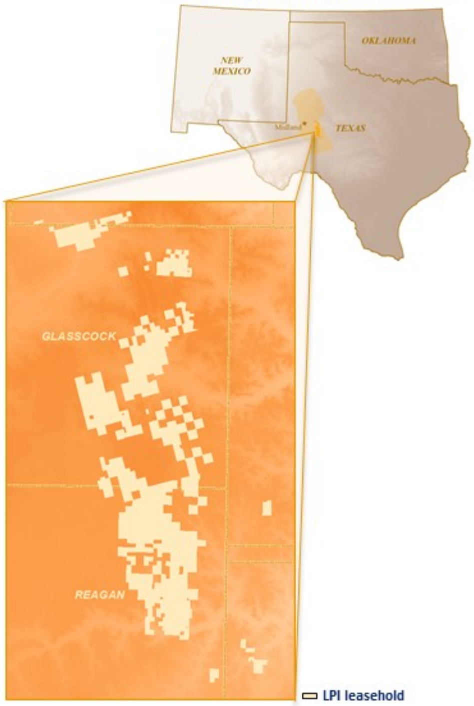
Capitalizing on Our Contiguous Acreage Position

- **The Company has identified ~500 land-ready UWC/MWC locations from its total inventory that support lateral lengths of 15,000'+ on its contiguous acreage**

- **Centralized infrastructure in multiple production corridors and the ability to drill long laterals enable increased capital and operational efficiencies**
  - **Infrastructure benefits have facilitated unit LOE costs below $4.00/BOE for five consecutive quarters**

~86%
HBP acreage, enabling a concentrated development plan along production corridors

145,036 gross/125,466 net acres



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Note: Acreage counts and statistics as of 9/30/17. Map as of 11/01/17

Contiguous Acreage Facilitates Robust Infrastructure Investments

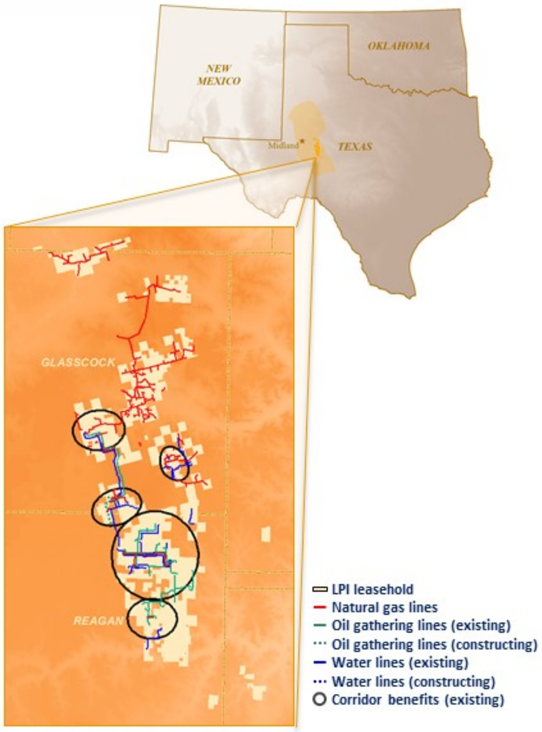
PIPELINE INFRASTRUCTURE

~45 Miles
CRUDE GATHERING

~80 Miles
WATER GATHERING / RECYCLED DISTRIBUTION

~188 Miles
NATURAL GAS GATHERING & DISTRIBUTION

>180,000
Truckloads removed from roads in 2017E due to LMS' water and crude gathering infrastructure



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Note: Statistics and estimates as of 10/25/17. Map as of 11/01/17

Infrastructure Provides Tangible Benefits

Yield capital & LOE savings, plus increased revenues & 3rd-party income
Enable multi-well pad drilling & operational flexibility
Minimize trucking

LMS Corridor Benefit	LPI Benefit	3Q-17 Net Benefits Actual ($ MM)	2017 Net Benefits Estimated ($ MM)
Crude gathering	Increased revenues & 3rd-party income	$2.8	$10.8
Centralized gas lift	LOE savings	$0.2	$0.9
Produced water gathered on pipe	Capital & LOE savings	$2.7	$10.0
Produced water recycled	Capital & LOE savings	$0.4	$1.7
Completions utilizing recycled water	Capital savings	$0.5	$1.6
Completions utilizing LPI fresh water wells	Capital savings	$0.9	$3.2
Corridor Benefits Total		$7.6	$28.3


LMS Water Treatment Plant


LMS Crude Gathering Tanks at Reagan Truck Station


LMS Gas Lift Compressor Station

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Note: Benefits estimates as of 10/25/17. Totals may not foot due to rounding. Calculated utilizing a 95% WI & 72% NRI

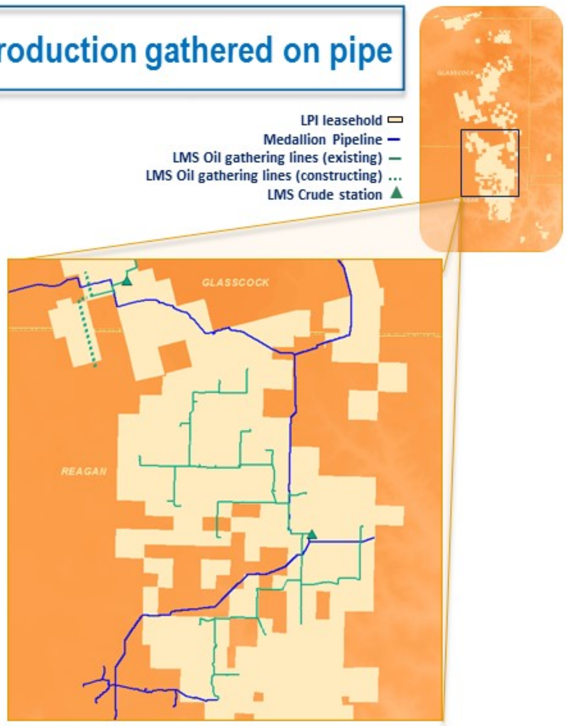
LMS Crude Gathering System Benefits

80% YE-17E gross operated crude production gathered on pipe

Reduces time from production to sales

System benefits increase as trucking costs rise

Provides LPI with increased oil price realizations and LMS with 3rd-party income



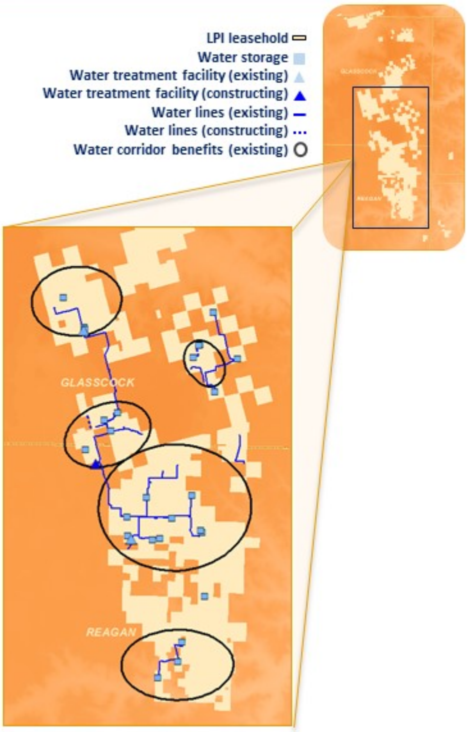
Note: Estimate as of 10/25/17. Map as of 11/01/17

Significant Benefits through Water Infrastructure Investments

>15 MMBW
FY-17E produced water gathered on pipe

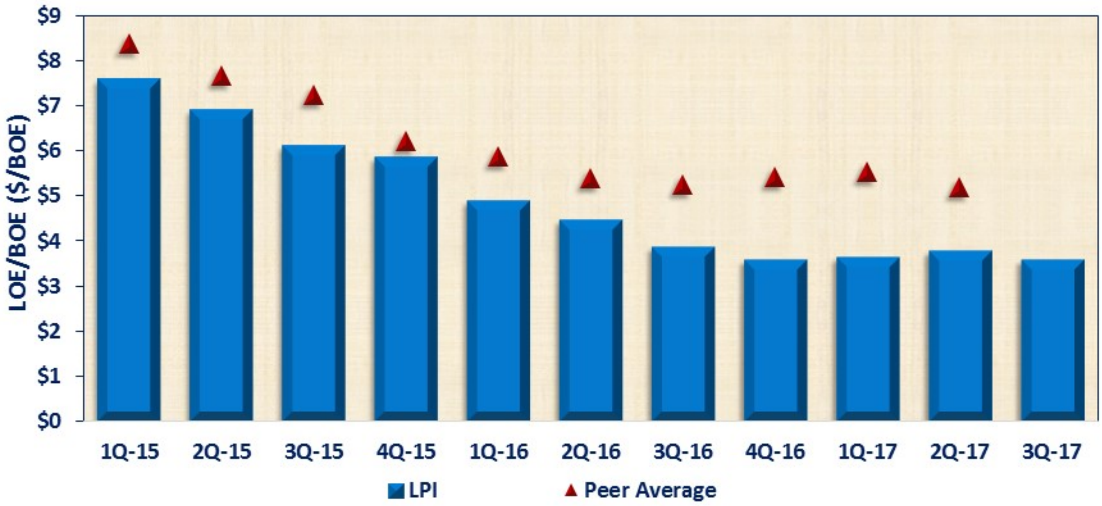
LMS Corridor Benefit	LPI Benefit	YE-17E (% of Total Activity)	Capacity
Produced Water Gathered on Pipe	Capital & LOE savings	~82%	54 MBWPD Recycling Processing[1] & ~15.7 MMBW Storage Capacity
Produced Water Recycled	Capital & LOE savings	~50%	
Completions Utilizing Recycled Water	Capital savings	~28%	
Completions Utilizing LPI Fresh Water Wells	Capital savings	~23%	

~$7.4 MM
YTD LOE reduction generated by LMS' water infrastructure investment[2]



[1]Upon completion of one additional water treatment plant that is currently under construction
[2]YTD numbers reflective of 1Q-17 thru 3Q-17
Note: Statistics and estimates as of 10/25/17. Map as of 11/01/17

Infrastructure Helping to Deliver Peer-Leading LOE



Gap between LPI's unit LOE vs. peers has historically widened as more production is placed on infrastructure corridors

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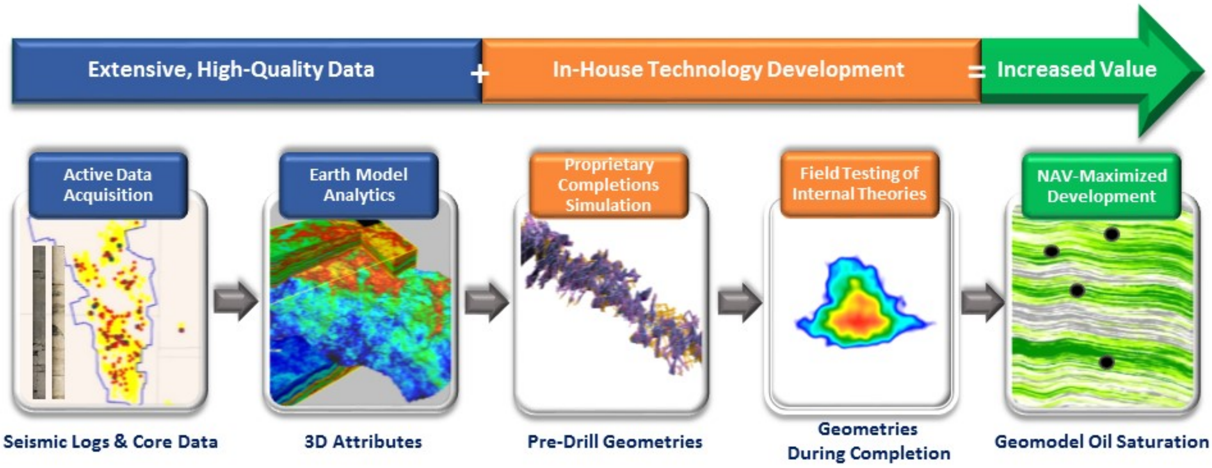
Note: Peers include CPE, CXO, EGN, FANG, PE, PXD & RSPP
3Q-17 peer performance to be updated once reported

Proprietary Modeling Accelerates Value Creation



Proprietary data and workflows accelerate the process of advancing concepts to implementation

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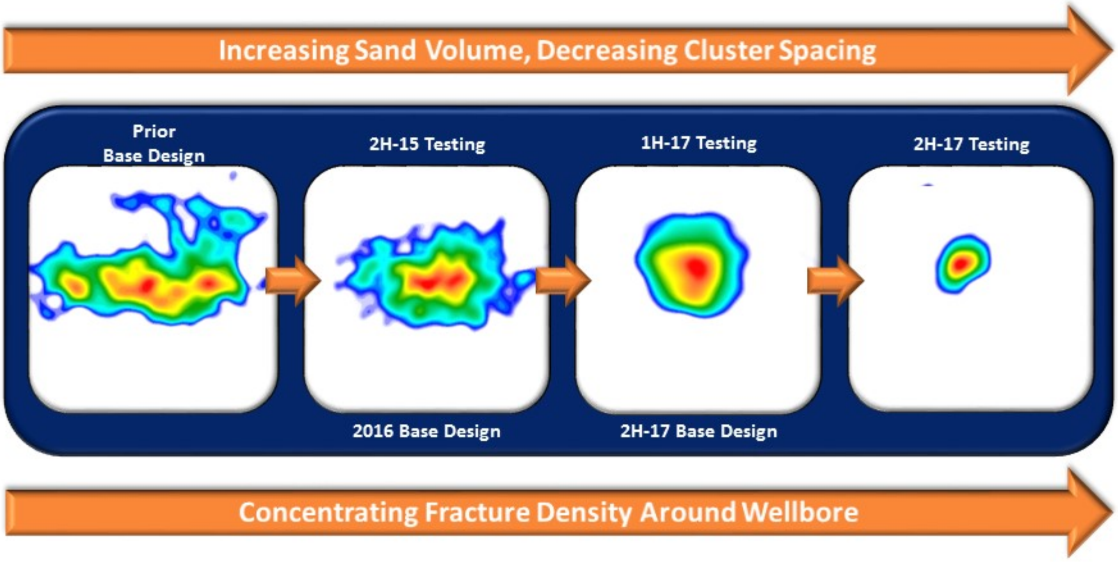
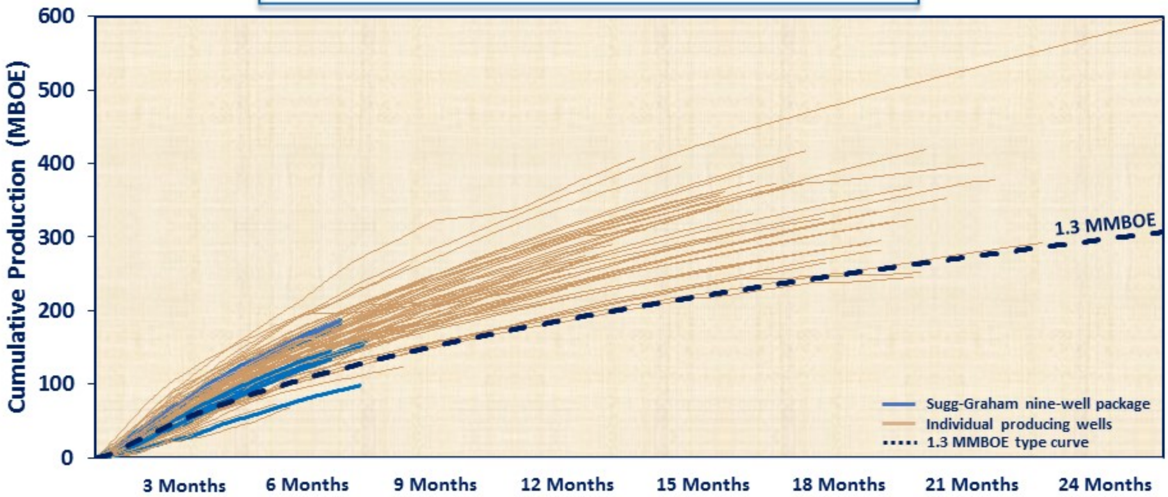
Internal Models Accelerate Completions Design Evolution

Proprietary workflows are shortening time from concept to field implementation, enabling continual optimization of completions designs



Sugg-Graham Nine-Well Package Performing vs. Type Curve

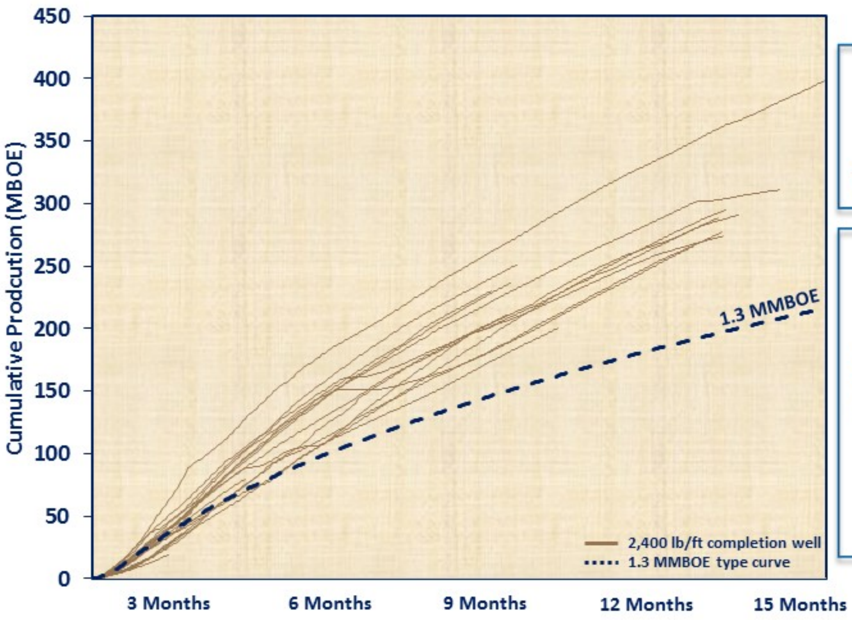
Wells drilled with tighter spacing are exceeding type curve expectations



~36% Outperformance of all 96 wells to 1.3 MMBOE type curve

Note: Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed
Average cumulative production data through 10/25/2017. This includes 96 Hz UWC/MWC & Cline wells that have utilized optimized completions with avg. ~1,900 pounds of sand per lateral foot. Type curve utilizes a weighted-average of 89 Hz UWC/MWC 1.3 MMBOE wells & 7 Hz Cline 1.0 MMBOE wells

2,400 lb/ft Field Tests Confirm Internal Models

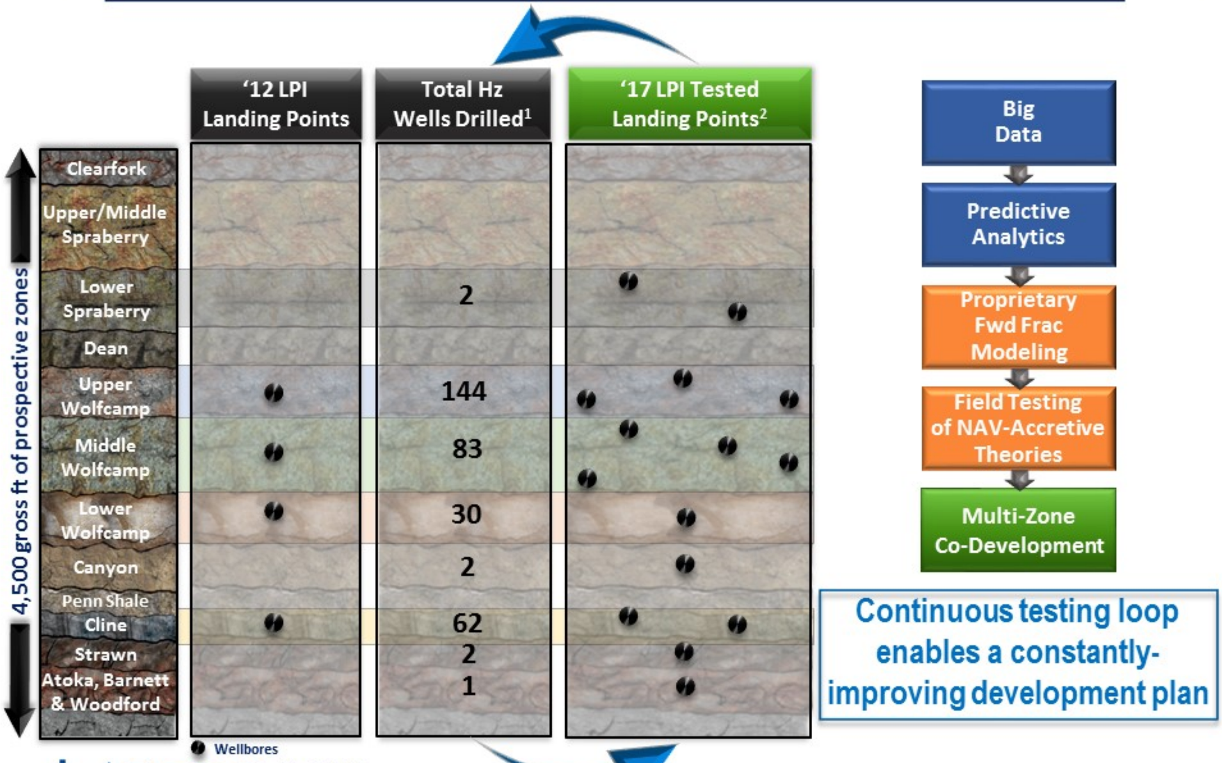


~42%
Outperformance to 1.3 MMBOE type curve

~50%
Pre-drill model uplift prediction when utilizing 2,400 lb/ft completions. Actual field tests are confirming our internal models

Note: Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed
Average cumulative production data through 10/30/17. This includes 22 Hz UWC/MWC wells that have utilized optimized completions with avg. 2,400 pounds of sand per lateral foot

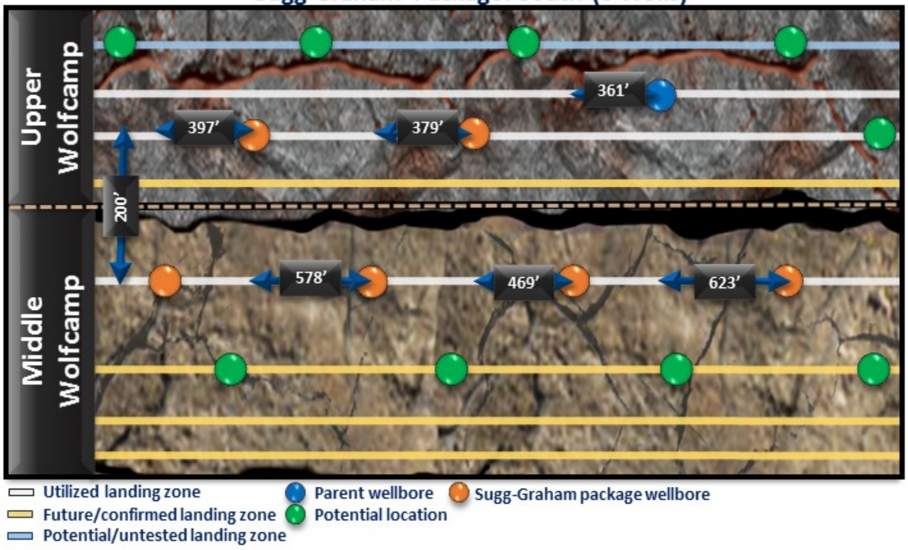
Strategic Testing Leading to High-Quality, Multi-Zone Co-Development



[1]As of 9/30/17
[2]As of 11/01/17
Note: Diagram not to scale

Successfully Increasing Landing Point Density

Sugg-Graham Package: South (6 Wells)

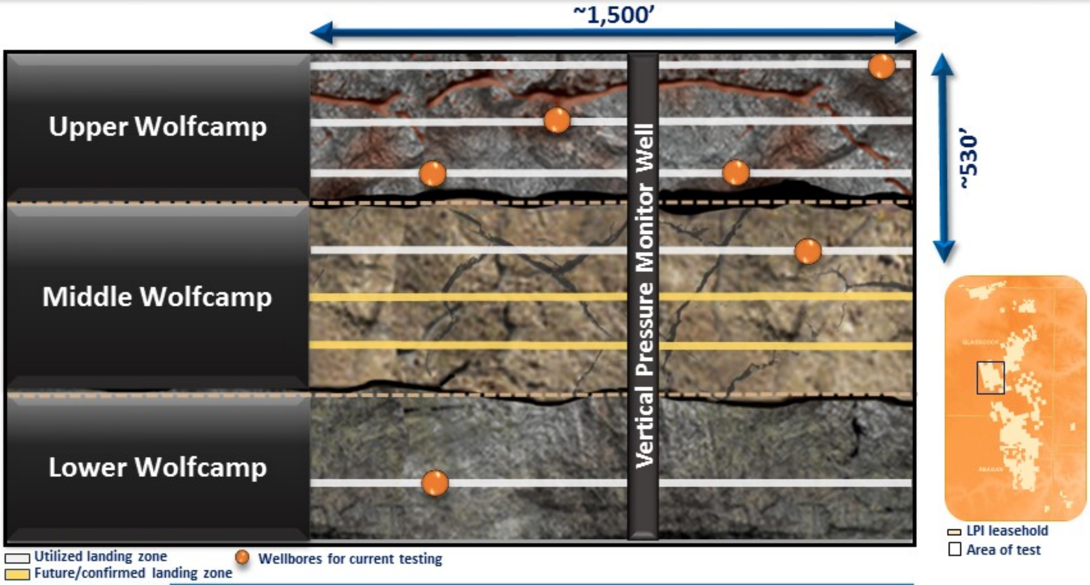


Landing zones potentially added for development from tighter vertical spacing

Tighter multi-zone development provides potential for increasing premium Upper Wolfcamp & Middle Wolfcamp inventory

Testing Co-Development of Landing Points

Potential to add additional high-value inventory in the UWC with current testing



Plan to apply spacing design to other formations, further increasing high-value inventory

Note: Diagram not to scale

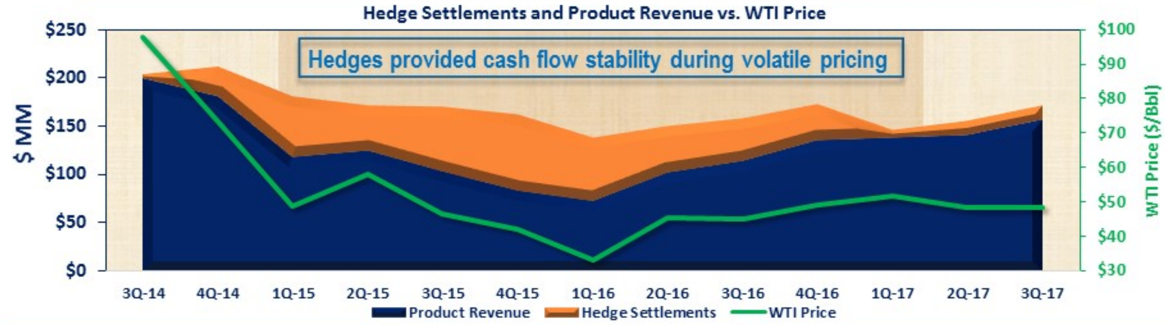
Maintaining Financial Flexibility

~$830 MM
Medallion divestiture net proceeds[1] applied primarily to debt reduction

~$592 MM
Net debt as of 9/30/17, pro forma for the Medallion divestiture[2]

[1] Net proceeds of ~$830 MM after deduction of its proportionate share of fees and other expenses but prior to customary post-closing adjustments and taxes
[2] Please see the Company's press releases dated October 30, 2017 for more details regarding the $500 million 7.375% senior note redemption, which is expected to be completed on November 29, 2017, and detailed pro forma financials as of 09/30/17
[3] As of 10/31/17, with $1 B Borrowing Base in place under amended and restated Senior Secured Credit Facility

Disciplined Risk Management Philosophy Insures Long-Term Value



71%
Current cash margin exceeds pre-price decline cash margin[1]

[1] Current cash margin as a percent of unhedged average realized price
Note: 2014 cash margin has been converted to 3-stream using actual gas plant economics. Current cash margin percentage of realized pricing as of 3Q-17

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Totals	4Q-17	FY-18	FY-19
Oil total floor volume (Bbl)	1,727,300	9,515,375	730,000
Oil wtd-avg floor price ($/Bbl)	$55.82	$47.42	$50.00
Nat gas total floor volume (MMBtu)	6,803,200	23,805,500	
Nat gas wtd-avg floor price ($/MMBtu)	$2.75	$2.50	
NGL total floor volume (Bbl)	204,750		
Oil[1]	**4Q-17**	**FY-18**	**FY-19**
Puts			
Hedged volume (Bbl)	264,500	5,427,375	730,000
Wtd-avg floor price ($/Bbl)	$60.00	$51.93	$50.00
Swaps			
Hedged volume (Bbl)	506,000		
Wtd-avg price ($/Bbl)	$51.54		
Collars			
Hedged volume (Bbl)	956,800	4,088,000	
Wtd-avg floor price ($/Bbl)	$56.92	$41.43	
Wtd-avg ceiling price ($/Bbl)	$60.23	$60.00	
Natural Gas[2]	**4Q-17**	**FY-18**	**FY-19**
Puts			
Hedged volume (MMBtu)	2,010,000	8,220,000	
Wtd-avg floor price ($/MMBtu)	$2.50	$2.50	
Collars			
Hedged volume (MMBtu)	4,793,200	15,585,500	
Wtd-avg floor price ($/MMBtu)	$2.86	$2.50	
Wtd-avg ceiling price ($/MMBtu)	$3.54	$3.35	
Natural Gas Liquids[3]	**4Q-17**	**FY-18**	**FY-19**
Swaps - Ethane:			
Hedged volume (Bbl)	111,000		
Wtd-avg price ($/Bbl)	$11.24		
Swaps - Propane:			
Hedged volume (Bbl)	93,750		
Wtd-avg price ($/Bbl)	$22.26		
Basis Swaps[4]	**4Q-17**	**FY-18**	**FY-19**
Mid/Cush Basis Swaps			
Hedged volume (Bbl)		3,650,000	
Wtd-avg price ($/Bbl)		-$0.56	

[1] Oil derivatives are settled based on the month's average daily NYMEX index price for the first nearby month of the WTI Light Sweet Crude Oil futures contract
[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 average daily OPIS index price for Mt. Belvieu Purity Ethane and TET Propane
[4] Oil basis swaps are settled based on the West Texas Intermediate Midland weighted average price published in Argus Americas Crude and the West Texas Intermediate Cushing Formula Basis price published in Argus Americas Crude
Note: Positions as of 10/31/17

4Q-17 Guidance

	4Q-17
Production (MBOE/d)	61 - 64
Product % of total production:	
Crude oil	43% - 45%
Natural gas liquids	27% - 28%
Natural gas	27% - 29%
Price Realizations (pre-hedge):	
Crude oil (% of WTI)	~94%
Natural gas liquids (% of WTI)	~39%
Natural gas (% of Henry Hub)	~67%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$3.50 - $4.00
Midstream expenses ($/BOE)	$0.20 - $0.30
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.25%
General and administrative expenses:	
Cash ($/BOE)	$2.50 - $3.00
Non-cash stock-based compensation[1] ($/BOE)	$1.50 - $1.75
Depletion, depreciation and amortization ($/BOE)	$7.25 - $7.75

[1]Net of amounts capitalized

Note: Crude oil price realizations reflect a pricing election made in accordance with the terms of a crude oil purchase agreement with Shell Trading (US) Company ("Shell"). However, the pricing terms under the crude oil purchase agreement are the subject of litigation filed against the Company by Shell. The Company believes it has substantive defenses and intends to vigorously defend its position. Please see Note 11.a. in the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 for more information regarding the litigation

APPENDIX

UWC & MWC 1.3 MMBOE Cumulative Production Type Curve

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

45%
Total oil recovered in the first five years

Note: 10,000' lateral length with 1,800 pounds of sand per foot completions at 54' perf cluster spacing

2016 & 2017 YTD Actuals

	1Q-16	2Q-16	3Q-16	4Q-16	FY-16	1Q-17	2Q-17	3Q-17
Sales Volumes								
3-Stream Sales Volumes								
MBOE	4,204	4,338	4,718	4,889	18,149	4,716	5,336	5,521
BOE/d	46,202	47,667	51,276	53,141	49,586	52,405	58,632	60,011
% oil	48%	46%	46%	46%	47%	45%	47%	44%
Pricing								
3-Stream Realized Prices								
Oil ($/Bbl)	$27.51	$39.37	$39.10	$43.98	$37.73	$46.91	$42.00	$45.44
NGL ($/Bbl)	$8.50	$12.24	$11.54	$14.79	$11.91	$16.49	$13.82	$18.58
Gas ($/Mcf)	$1.31	$1.31	$2.07	$2.13	$1.73	$2.31	$2.09	$2.04
Avg. price ($/BOE)	$17.40	$23.64	$24.34	$27.82	$23.50	$29.42	$26.58	$28.54
Unit Cost Metrics								
3-Stream Unit Cost Metrics ($/BOE)								
Lease operating expenses	$4.88	$4.43	$3.85	$3.56	$4.15	$3.60	$3.77	$3.55
Midstream	$0.14	$0.27	$0.22	$0.26	$0.22	$0.19	$0.17	$0.21
Production & ad val taxes	$1.53	$1.84	$1.50	$1.45	$1.58	$1.86	$1.59	$1.73
General & administrative								
Cash	$3.72	$3.33	$3.49	$3.28	$3.45	$3.47	$2.50	$2.90
Non-cash stock-based compensation[1]	$0.91	$1.40	$2.05	$1.98	$1.61	$1.96	$1.63	$1.62
DD&A	$9.87	$7.88	$7.45	$7.68	$8.17	$7.23	$7.12	$7.46

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[1]Net of amounts capitalized

2015 Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15
Sales Volumes	3-Stream Sales Volumes					
	MBOE	4,274	4,234	4,124	3,714	16,346
	BOE/d	47,487	46,532	44,820	40,368	44,782
	% oil	51%	46%	45%	45%	47%
Pricing	3-Stream Realized Prices					
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93
	Avg. price ($/BOE)	$27.64	$29.65	$25.37	$22.47	$26.41
Unit Cost Metrics	3-Stream Unit Cost Metrics ($/BOE)					
	Lease operating expenses	$7.58	$6.90	$6.09	$5.83	$6.63
	Midstream	$0.37	$0.38	$0.26	$0.43	$0.36
	Production & ad val taxes	$2.13	$2.24	$1.91	$1.73	$2.01
	General & administrative					
	Cash	$3.99	$4.00	$3.89	$4.27	$4.03
	Non-cash stock-based compensation[1]	$1.12	$1.48	$1.67	$1.77	$1.50
	DD&A	$16.83	$17.03	$16.19	$18.01	$16.99

[1]Net of amounts capitalized

2014 Actuals: Two-Stream to Three-Stream Conversions

		1Q-14	2Q-14	3Q-14	4Q-14	FY-14
Sales Volumes	2-Stream Sales Volumes					
	MBOE	2,434	2,607	3,033	3,654	11,729
	BOE/d	27,041	28,653	32,970	39,722	32,134
	% oil	58%	58%	59%	60%	59%
	3-Stream Sales Volumes					
	MBOE	2,912	3,078	3,569	4,267	13,827
	BOE/d	32,358	33,829	38,798	46,379	37,882
	% oil	49%	49%	50%	51%	50%
Pricing	2-Stream Realized Prices					
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	Gas ($/Mcf)	$7.04	$6.08	$5.80	$4.46	$5.72
	Avg. Price ($/BOE)	$71.17	$70.13	$65.77	$49.70	$62.86
	3-Stream Realized Prices					
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	NGL ($/Bbl)	$32.88	$28.79	$29.21	$19.65	$27.00
	Gas ($/Mcf)	$4.00	$3.73	$3.25	$3.00	$3.45
	Avg. Price ($/BOE)	$59.48	$59.40	$55.89	$42.57	$53.32
Unit Cost Metrics	2-Stream Unit Cost Metrics ($/BOE)					
	Lease operating expenses	$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream	$0.35	$0.59	$0.40	$0.50	$0.46
	Production & ad val taxes	$5.12	$5.05	$4.14	$3.33	$4.29
	General & administrative					
	Cash	$9.58	$8.88	$6.89	$4.27	$7.07
	Non-cash stock-based compensation[1]	$1.78	$2.45	$2.04	$1.69	$1.97
	DD&A	$20.38	$20.35	$21.08	$21.85	$21.01
	3-Stream Unit Cost Metrics ($/BOE)					
	Lease operating expenses	$7.48	$6.55	$7.05	$6.88	$6.98
	Midstream	$0.29	$0.50	$0.34	$0.43	$0.39
	Production & ad val taxes	$4.28	$4.27	$3.52	$2.85	$3.64
	General & Administrative					
	Cash	$8.01	$7.52	$5.85	$3.66	$6.00
	Non-cash stock-based compensation[1]	$1.49	$2.08	$1.74	$1.44	$1.67
	DD&A	$17.03	$17.23	$17.91	$18.72	$17.83

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[1]Net of amounts capitalized

Note: 2014 2-stream to 3-stream conversion based on actual gas plant economics