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): February 14, 2018

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 February 14, 2018, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter and year ended December 31, 2017. Copies of the Company's press release and Presentation (as defined below) are furnished as Exhibit 99.1 and 99.3, 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 February 15, 2018 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 2795428. A replay of the call will be available through Thursday, February 22, 2018, by dialing 1-855-859-2056, and using conference code 2795428. 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 February 14, 2018, 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 February 14, 2018, the Company also furnished a press release announcing that its board of directors has authorized a $200 million share repurchase program. The press release 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.

On February 14, 2018, 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 99.3 and incorporated into this Item 7.01 by reference.

All statements in the press releases, 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 February 14, 2018 announcing financial and operating results.
99.2	Press release dated February 14, 2018 announcing share repurchase program.
99.3	Presentation dated February 14, 2018.

SIGNATURES

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

LAREDO PETROLEUM, INC.

Dated: February 14, 2018	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President & Chief Financial Officer

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Laredo Petroleum Announces 2017 Fourth-Quarter and Full-Year Financial and Operating Results

TULSA, OK - February 14, 2018 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or the "Company") today announced its 2017 fourth-quarter and full-year results. For the fourth quarter of 2017, the Company reported net income attributable to common stockholders of $408.6 million, or $1.70 per diluted share, which includes a $405.9 million gain on the sale of Laredo's investment in the Medallion-Midland Basin pipeline system. Adjusted Net Income, a non-GAAP financial measure, for the fourth quarter of 2017 was $44.8 million, or $0.19 per adjusted diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the fourth quarter of 2017, was $133.8 million.

For the year ended December 31, 2017, the Company reported net income attributable to common stockholders of $549.0 million, or $2.29 per diluted share. Adjusted Net Income for the year ended December 31, 2017 was $144.7 million, or $0.60 per adjusted diluted share, and Adjusted EBITDA was $486.4 million. Please see supplemental financial information at the end of this news release for reconciliation of the non-GAAP financial measures.

2017 Highlights

- Produced a Company record 58,273 barrels of oil equivalent ("BOE") per day in full-year 2017, resulting in production growth of approximately 17% from full-year 2016
- Grew proved developed reserves organically by approximately 36% in 2017 at a proved developed finding and development ("F&D") cost, a non-GAAP financial measure, of $7.90 per BOE
- Completed 62 horizontal development wells in 2017 at an average anticipated well-level rate of return on invested capital of greater than 30%
- Increased cash margin per BOE to $20.87 in full-year 2017, an increase of 48% from full-year 2016, doubling the 24% increase in the Company's average realized price per BOE over the same time frame
- Reduced unit lease operating expenses ("LOE") to $3.53 per BOE in full-year 2017, a reduction of approximately 15% from full-year 2016
- Recognized approximately $27.9 million of net cash benefits from Laredo Midstream Services, LLC ("LMS") field infrastructure investments through reduced capital and operating costs and increased revenue
- Realized approximately $830 million in net proceeds from the sale of the Company's interest in the Medallion-Midland Basin pipeline system, enabling the Company to reduce debt by $690 million to a total debt level of $800 million, and net debt to 1.3 times annualized fourth-quarter 2017 Adjusted EBITDA

"During 2017, Laredo's development plan yielded well-level returns on invested capital exceeding 30% while making meaningful progress towards co-developing multiple landing points in our Upper and Middle Wolfcamp formations," stated Randy A. Foutch, Chairman and Chief Executive Officer. "We did experience increased cycle times and decreased capital efficiency in the second half of the year as we optimized completions and tested spacing with the goal of adding additional premium locations. We are confident in our operational abilities and remain committed to progressing towards a high-density development plan that we believe will result in improved long-term value creation."

"We will be announcing separately that our board of directors has authorized a $200 million share repurchase program. We believe having the optionality of repurchasing approximately 10% of our outstanding shares at current market prices represents a highly accretive use of capital. Given our view of the value of the Company's reserves, financial position after our Medallion divestment and the expected efficiencies as we identify additional premium locations in our Upper and Middle Wolfcamp formations, we believe repurchasing our shares accelerates value recognition for our current stockholders."

E&P Update

In the fourth quarter of 2017, Laredo completed 18 horizontal wells averaging approximately 9,500 completed lateral feet. Fourth-quarter 2017 production was a Company record 61,922 BOE per day, an increase of approximately 17% from fourth-quarter 2016.

During the fourth quarter of 2017, the Company completed the six-well Kloesel package, drilled in the western Glasscock portion of our leasehold. The package tested five discrete landing points in a dense-spacing configuration. Initial data is affirming pre-drill modeling and the early oil cut is positive. The package was delayed due to drilling challenges associated with one well testing a higher-pressure landing point and a second well experiencing a problem with its casing. Root causes of both issues have been identified and are not expected to impede further activities in the area.

The performance of the Company's 114 horizontal wells to date that utilized optimized completions combined with proprietary analytics continues to exceed type curve expectations, outperforming the Upper/Middle Wolfcamp three-stream type curve by approximately 34% and the oil type curve by approximately 21%. Production data supports Laredo's modeled expectations that wells will perform, on average, at the Company's 1.3 million BOE type curve as completions and spacing are modified to facilitate higher density development and increase net asset value per two-section spacing unit.

Utilizing the Company's comprehensive dataset, high-resolution geomodels and predictive analytics, Laredo continues to evaluate the spacing density of horizontal wells as they are co-developed in multiple landing points in the Upper and Middle Wolfcamp formations. Results of spacing tests conducted in 2017 suggest development of up to 32 Upper and Middle Wolfcamp locations per spacing unit is possible. Laredo plans to further evaluate this higher-density development design in 2018 and expects approximately 60% of wells brought on production in the second half of 2018 to be developed at this tighter spacing.

Lease operating expenses decreased to $3.22 per BOE in the fourth quarter of 2017, down approximately 9% from third-quarter 2017. The Company continues to receive significant benefits from prior investments in field infrastructure, which reduced unit LOE by an estimated $0.54 per BOE.

Laredo is currently operating three horizontal rigs and expects to complete 16 net horizontal wells with an average completed lateral length of approximately 9,100 feet in the first quarter of 2018. Cold weather early in the first quarter of 2018 disrupted operations, negatively impacting estimated quarterly volumes by 52,000 BOE.

The Company expects well costs in the first quarter of 2018 to begin to trend lower as longer stage lengths, in-basin sand and other completion design changes are implemented. Additionally, Laredo has completed the process of selecting a second full-time completions crew. Pricing quotes from interested parties confirmed the Company's assumptions that current service cost increases are minimal and we believe our average well cost savings goal of $600,000 per well in 2018 can be achieved.

Laredo Midstream Services Update

LMS-owned field infrastructure provided net combined benefits from increased revenue and cost savings of approximately $7.5 million in the fourth quarter of 2017. In addition to financial benefits, LMS assets provide significant operational flexibility, including the ability to offload Laredo's natural gas production to alternative natural gas processing facilities. During the fourth quarter of 2017, LMS-owned natural gas gathering assets enabled the delivery of more than 10 million cubic feet of natural gas per day that would have been flared had the natural gas not had access to alternative processing facilities via LMS-owned gathering assets.

LMS' ownership of assets that gather approximately 50% of the Company's gross operated natural gas production increases Laredo's confidence that temporary residue natural gas delivery issues to the WAHA hub by gas processors will not result in substantial flaring or production curtailments. Although Laredo has not contracted directly for firm transportation capacity of its natural gas, the Company believes that a combination of its processors' firm capacity and the ability to offload LMS-gathered natural gas to alternative processors through the LMS-owned gathering system provides the flexibility needed to avoid substantial production curtailments.

2017 Capital Program

During the fourth quarter of 2017, Laredo invested approximately $160 million in exploration and development activities. Other expenditures incurred during the quarter included approximately $4 million in bolt-on land acquisitions and lease extensions, approximately $10 million in infrastructure held by LMS and approximately $8 million in capitalized employee-related costs.

Liquidity

At December 31, 2017, the Company had cash and cash equivalents of approximately $112 million and undrawn capacity under the senior secured credit facility of $1 billion. At February 13, 2018, the Company had cash and cash equivalents of approximately $46 million and undrawn capacity under the senior secured credit facility of $1 billion, resulting in total liquidity of approximately $1.05 billion.

Commodity Derivatives

Laredo maintains a disciplined hedging program to reduce the variability in its anticipated cash flow due to fluctuations in commodity prices. The Company utilizes a combination of puts, swaps and collars, entering into contracts solely with banks that are part of its senior secured credit facility. Laredo currently has hedges in place for approximately 90% of anticipated oil production in 2018 and has increased oil hedges through 2020. Laredo has also entered into NGL and natural gas hedges through 2018 and basis hedges through 2019. Details of the Company's hedge positions are included in the current Corporate Presentation available on the Company's website at www.laredopetro.com.

Guidance

The Company is reiterating its anticipated full-year 2018 production growth guidance of at least 10% as compared to 2017. The table below reflects the Company's guidance for the first quarter of 2018.

	1Q-2018E
Total production (MBOE/d)	62.0
Oil production (MBO/d)	27.0
Price Realizations (pre-hedge):	
Crude oil (% of WTI)	97%
Natural gas liquids (% of WTI)	28%
Natural gas (% of Henry Hub)	57%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$3.55
Midstream expenses ($/BOE)	$0.20
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.25%
General and administrative expenses:	
Cash ($/BOE)	$2.90
Non-cash stock-based compensation ($/BOE)	$1.65
Depletion, depreciation and amortization ($/BOE)	$7.75

Fourth-Quarter and Full-Year 2017 Earnings Conference Call

Laredo will host a conference call on Thursday, February 15, 2018 at 7:30 a.m. CT (8:30 a.m. ET) to discuss its fourth-quarter and full-year 2017 financial and operating results and management's outlook. Individuals who would like to participate on the call should dial 877.930.8286 (international dial-in 253.336.8309), using conference code 2795428 or listen to the call via the Company's website at www.laredopetro.com, under the tab for "Investor Relations." A telephonic replay will be available approximately two hours after the call on February 15, 2018 through Thursday, February 22, 2018. Participants may access this replay by dialing 855.859.2056, using conference code 2795428.

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 in 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, including, but not limited to, the share repurchase program, which may be suspended or discontinued by the Company at any time, 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, 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") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2017, to be filed with the 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," "type curve," 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, NGL 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 resources 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. "Type curve" refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. 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.*

Laredo Petroleum, Inc.
Condensed consolidated statements of operations

(in thousands, except per share data)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales	$ 183,376	$ 136,012	$ 621,507	$ 426,485
Midstream service revenues	2,369	2,421	10,517	8,342
Sales of purchased oil	54,592	45,881	190,138	162,551
Total revenues	240,337	184,314	822,162	597,378
Costs and expenses:				
Lease operating expenses	18,359	17,407	75,049	75,327
Production and ad valorem taxes	10,991	7,103	37,802	28,586
Midstream service expenses	1,113	1,251	4,099	4,077
Costs of purchased oil	54,247	48,346	195,908	169,536
General and administrative	23,707	25,698	96,312	91,756
Depletion, depreciation and amortization	45,062	37,526	158,389	148,339
Impairment expense	—	—	—	162,027
Other operating expenses	1,025	1,523	4,931	5,692
Total costs and expenses	154,504	138,854	572,490	685,340
Operating income (loss)	85,833	45,460	249,672	(87,962)
Non-operating income (expense):				
Gain (loss) on derivatives, net	(37,777)	(43,642)	350	(87,425)
Income from equity method investee**	575	3,144	8,485	9,403
Interest expense	(19,787)	(23,004)	(89,377)	(93,298)
Loss on early redemption of debt	(23,761)	—	(23,761)	—
Gain on sale of investment in equity method investee**	405,906	—	405,906	—
Other, net	(628)	(379)	(501)	(1,457)
Non-operating income (expense), net	324,528	(63,881)	301,102	(172,777)
Income (loss) before income taxes	410,361	(18,421)	550,774	(260,739)
Income tax expense:				
Current	(1,800)	—	(1,800)	—
Total income tax expense	(1,800)	—	(1,800)	—
Net income (loss)	$ 408,561	$ (18,421)	$ 548,974	$ (260,739)
Net income (loss) per common share:				
Basic	$ 1.71	$ (0.08)	$ 2.30	$ (1.16)
Diluted	$ 1.70	$ (0.08)	$ 2.29	$ (1.16)
Weighted-average common shares outstanding:				
Basic	239,332	238,047	239,096	225,512
Diluted	240,289	238,047	240,122	225,512

Laredo Petroleum, Inc.
Condensed consolidated balance sheets

(in thousands)	December 31, 2017	December 31, 2016
Assets:	(unaudited)	(unaudited)
Current assets	$ 235,382	$ 154,777
Property and equipment, net	1,768,385	1,366,867
Other noncurrent assets, net**	19,522	260,702
Total assets	$ 2,023,289	$ 1,782,346
Liabilities and stockholders' equity:		
Current liabilities	$ 277,419	$ 187,945
Long-term debt, net	791,855	1,353,909
Other noncurrent liabilities	188,436	59,919
Stockholders' equity	765,579	180,573
Total liabilities and stockholders' equity	$ 2,023,289	$ 1,782,346

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

	Three months ended December 31,		Year ended December 31,	
(in thousands)	2017	2016	2017	2016
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net income (loss)	$ 408,561	$ (18,421)	$ 548,974	$ (260,739)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depletion, depreciation and amortization	45,062	37,526	158,389	148,339
Impairment expense	—	—	—	162,027
Gain on sale of investment in equity method investee**	(405,906)	—	(405,906)	—
Loss on early redemption of debt	23,761	—	23,761	—
Non-cash stock-based compensation, net of amounts capitalized	8,857	9,667	35,734	29,229
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	37,777	43,642	(350)	87,425
Cash settlements received for matured derivatives, net	2,792	37,655	37,583	195,281
Cash settlements received for early terminations of derivatives, net	—	—	4,234	80,000
Cash premiums paid for derivatives	(12,311)	(2,697)	(25,853)	(89,669)
Other, net**	3,196	(425)	2,062	(5,848)
Cash flows from operations before changes in assets and liabilities	111,789	106,947	378,628	346,045
(Increase) decrease in current assets and liabilities, net	(2,934)	4,016	2,568	10,669
Decrease (increase) in other noncurrent assets and liabilities, net	4,008	(122)	3,718	(419)
Net cash provided by operating activities	112,863	110,841	384,914	356,295
Cash flows from investing activities:				
Deposit received for potential sale of oil and natural gas properties	—	3,000	—	3,000
Deposit utilized for sale of oil and natural gas properties	(3,000)	—	(3,000)	—
Capital expenditures:				
Acquisitions of oil and natural gas properties	—	(9,060)	—	(124,660)
Oil and natural gas properties	(156,957)	(83,944)	(538,122)	(360,679)
Midstream service assets	(9,207)	(1,009)	(20,887)	(5,240)
Other fixed assets	(1,301)	(6,629)	(4,905)	(7,611)
Investment in equity method investee**	(7,236)	(10,897)	(31,808)	(69,609)
Proceeds from disposition of equity method investee, net of selling costs**	829,615	—	829,615	—
Proceeds from dispositions of capital assets, net of selling costs	29	32	64,157	397
Net cash provided by (used in) investing activities	651,943	(108,507)	295,050	(564,402)
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility	35,000	25,000	190,000	239,682
Payments on Senior Secured Credit Facility	(190,000)	(25,000)	(260,000)	(304,682)
Early redemption of debt	(518,480)	—	(518,480)	—
Proceeds from issuance of common stock, net of offering costs	—	—	—	276,052
Other, net	15	(22)	(11,997)	(1,427)
Net cash (used in) provided by financing activities	(673,465)	(22)	(600,477)	209,625
Net increase in cash and cash equivalents	91,341	2,312	79,487	1,518
Cash and cash equivalents, beginning of period	20,818	30,360	32,672	31,154
Cash and cash equivalents, end of period	$ 112,159	$ 32,672	$ 112,159	$ 32,672

Laredo Petroleum, Inc.
Selected operating data

	Three months ended December 31,		Year ended December 31,	
	2017	2016	2017	2016
	(unaudited)		(unaudited)	
Sales volumes:				
Oil (MBbl)	2,448	2,274	9,475	8,442
NGL (MBbl)	1,613	1,293	5,800	4,784
Natural gas (MMcf)	9,818	7,935	35,972	29,535
Oil equivalents (MBOE)[(1)(2)]	5,697	4,889	21,270	18,149
Average daily sales volumes (BOE/D)[(2)]	61,922	53,141	58,273	49,586
% Oil	43%	46%	45%	47%
Average sales prices[(2)]:				
Oil, realized ($/Bbl)[(3)]	$ 53.57	$ 43.98	$ 46.97	$ 37.73
NGL, realized ($/Bbl)[(3)]	$ 20.53	$ 14.79	$ 17.49	$ 11.91
Natural gas, realized ($/Mcf)[(3)]	$ 1.95	$ 2.13	$ 2.09	$ 1.73
Average price, realized ($/BOE)[(3)]	$ 32.19	$ 27.82	$ 29.22	$ 23.50
Oil, hedged ($/Bbl)[(4)]	$ 54.38	$ 58.92	$ 50.45	$ 58.07
NGL, hedged ($/Bbl)[(4)]	$ 19.53	$ 14.79	$ 16.91	$ 11.91
Natural gas, hedged ($/Mcf)[(4)]	$ 2.08	$ 2.26	$ 2.15	$ 2.20
Average price, hedged ($/BOE)[(4)]	$ 32.48	$ 34.97	$ 30.71	$ 33.73
Average costs per BOE sold[(2)]:				
Lease operating expenses	$ 3.22	$ 3.56	$ 3.53	$ 4.15
Production and ad valorem taxes	1.93	1.45	1.78	1.58
Midstream service expenses	0.20	0.26	0.19	0.22
General and administrative:				
Cash	2.61	3.28	2.85	3.45
Non-cash stock-based compensation, net of amounts capitalized	1.55	1.98	1.68	1.61
Depletion, depreciation and amortization	7.91	7.68	7.45	8.17
Total costs and expenses	$ 17.42	$ 18.21	$ 17.48	$ 19.18
Cash margins per BOE[(2)]:				
Realized	$ 24.23	$ 19.27	$ 20.87	$ 14.10
Hedged	$ 24.52	$ 26.42	$ 22.36	$ 24.33

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

(2) The numbers 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.

(4) Hedged prices reflect the after-effects 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

The following table presents the costs incurred in the acquisition, exploration and development of oil, NGL and natural gas assets:

	Three months ended December 31,		Year ended December 31,	
(in thousands)	**2017**	**2016**	**2017**	**2016**
	(unaudited)		(unaudited)	
Property acquisition costs:				
Evaluated[1]	$ —	$ —	$ —	$ 5,905
Unevaluated	—	9,123	—	119,923
Exploration costs	7,920	7,583	36,257	41,333
Development costs[2]	163,664	73,839	560,919	298,942
Total costs incurred	$ 171,584	$ 90,545	$ 597,176	$ 466,103

(1) Evaluated property acquisition costs include $1.1 million in asset retirement obligations for the year ended December 31, 2016.

(2) Development costs include $0.1 million and $2.0 million in asset retirement obligations for the three months ended December 31, 2017 and 2016, respectively, and $0.7 million and $2.5 million for the years ended December 31, 2017 and 2016, respectively.

Non-GAAP financial measures

The non-GAAP financial measures of Adjusted Net Income, Adjusted EBITDA and proved developed Finding & Development Cost, 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, Adjusted EBITDA and proved developed Finding and Development Cost should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss, standardized measure of discounted future net cash flows 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 income tax expense or benefit, impairment expense, mark-to-market on derivatives, cash premiums paid for derivatives, write-off of debt issuance costs, gain on sale of investment in equity method investee, gains or losses on disposal of assets, loss on early redemption of debt 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 common 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 each of the periods ended December 31, 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 periods 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 periods ended December 31, 2017 and 2016, we present a line item that calculates Adjusted Net Income per Adjusted diluted common share.

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

	Three months ended December 31,		Year ended December 31,	
(in thousands, except for per share data, unaudited)	**2017**	**2016**	**2017**	**2016**
Income (loss) before income taxes	$ 410,361	$ (18,421)	$ 550,774	$ (260,739)
Plus:				
Impairment expense	—	—	—	162,027
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	37,777	43,642	(350)	87,425
Cash settlements received for matured derivatives, net	2,792	37,655	37,583	195,281
Cash settlements received for early terminations of derivatives, net	—	—	4,234	80,000
Cash premiums paid for derivatives	(12,311)	(2,697)	(25,853)	(89,669)
Write-off of debt issuance costs	—	—	—	842
Gain on sale of investment in equity method investee**	(405,906)	—	(405,906)	—
Loss on disposal of assets, net	906	411	1,306	790
Loss on early redemption of debt	23,761	—	23,761	—
Adjusted net income before adjusted income tax expense	57,380	60,590	185,549	175,957
Adjusted income tax expense(1)	(12,624)	(21,812)	(40,821)	(63,345)
Adjusted Net Income	$ 44,756	$ 38,778	$ 144,728	$ 112,612
Net income (loss) per common share:				
Basic	$ 1.71	$ (0.08)	$ 2.30	$ (1.16)
Diluted	$ 1.70	$ (0.08)	$ 2.29	$ (1.16)
Adjusted Net Income per common share:				
Basic	$ 0.19	$ 0.16	$ 0.61	$ 0.50
Adjusted diluted	$ 0.19	$ 0.16	$ 0.60	$ 0.49
Weighted-average common shares outstanding:				
Basic	239,332	238,047	239,096	225,512
Diluted	240,289	238,047	240,122	225,512
Adjusted diluted	240,289	243,507	240,122	228,676

(1) Adjusted income tax expense is calculated by applying a statutory tax rate of 22% for each of the periods ended December 31, 2017 in response to recent changes in the tax code, and 36% for each of the periods ended December 31, 2016.

Adjusted EBITDA (Unaudited)

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for income tax expense or benefit, depletion, depreciation and amortization, bad debt expense, 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 our 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, 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, the 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 table presents a reconciliation of net income (loss) (GAAP) to Adjusted EBITDA (non-GAAP):

	Three months ended December 31,		Year ended December 31,	
(in thousands, unaudited)	**2017**	**2016**	**2017**	**2016**
Net income (loss)	$ 408,561	$ (18,421)	$ 548,974	$ (260,739)
Plus:				
Income tax expense	1,800	—	1,800	—
Depletion, depreciation and amortization	45,062	37,526	158,389	148,339
Impairment expense	—	—	—	162,027
Non-cash stock-based compensation, net of amounts capitalized	8,857	9,667	35,734	29,229
Accretion expense	969	896	3,791	3,483
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	37,777	43,642	(350)	87,425
Cash settlements received for matured derivatives, net	2,792	37,655	37,583	195,281
Cash settlements received for early terminations of derivatives, net	—	—	4,234	80,000
Cash premiums paid for derivatives	(12,311)	(2,697)	(25,853)	(89,669)
Interest expense	19,787	23,004	89,377	93,298
Write-off of debt issuance costs	—	—	—	842
Gain on sale of investment in equity method investee**	(405,906)	—	(405,906)	—
Loss on disposal of assets, net	906	411	1,306	790
Loss on early redemption of debt	23,761	—	23,761	—
Income from equity method investee**	(575)	(3,144)	(8,485)	(9,403)
Proportionate Adjusted EBITDA of equity method investee**[(1)]	2,326	6,386	22,081	20,367
Adjusted EBITDA	$ 133,806	$ 134,925	$ 486,436	$ 461,270

(1) Proportionate Adjusted EBITDA of Medallion, our equity method investee through October 30, 2017, is calculated as follows:

	Three months ended December 31,		Year ended December 31,	
(in thousands, unaudited)	**2017**	**2016**	**2017**	**2016**
Income from equity method investee	$ 575	$ 3,144	$ 8,485	$ 9,403
Adjusted for proportionate share of depreciation and amortization	1,751	3,242	13,596	10,964
Proportionate Adjusted EBITDA of equity method investee	$ 2,326	$ 6,386	$ 22,081	$ 20,367

Proved Developed Finding and Development Cost (Unaudited)

Proved developed finding and development ("F&D") cost is calculated by dividing (x) development costs for the period, by (y) proved developed reserve additions for the period, defined as the change in proved developed reserves, less purchased reserves, plus sold reserves and plus sales volumes during the period. The method we use to calculate our proved developed F&D cost may differ significantly from methods used by other companies to compute similar measures. As a result, our proved developed F&D cost may not be comparable to similar measures provided by other companies. We believe that providing the measure of proved development F&D cost is useful in evaluating the cost, on a per BOE basis, to add proved developed reserves.

However, this measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP. Due to various factors, including timing differences in the addition of proved reserves and the related costs to develop those reserves, proved developed F&D cost do not necessarily reflect precisely the costs associated with particular proved reserves. As a result of various factors that could materially affect the timing and amounts of future increases in proved reserves and the timing and amounts of future costs, we cannot assure you that our future proved developed F&D cost will not differ materially from those presented.

(dollars in millions, except per BOE amount, reserves and sales volumes in MMBOE)	**Proved developed F&D**
Development costs (x)	$ 561
Proved developed reserves:	
As of December 31, 2017	191
As of December 31, 2016	(141)
Change in proved developed reserves	50
Plus sales of proved developed reserves during 2017	—
Plus 2017 sales volumes	21
Proved developed reserve additions (y)	71
Proved developed F&D cost per BOE	$ 7.90

** On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC ("MMH"), which is owned and controlled by an affiliate of the third-party interest holder, The Energy & Minerals Group ("EMG"), completed the sale of 100% of the ownership interests in Medallion to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion (the "Medallion Sale"). LMS' net cash proceeds for its 49% ownership interest in Medallion in 2017 was $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. On February 1, 2018, closing adjustments were finalized and LMS received additional net cash of $1.7 million for total net cash proceeds before taxes of $831.3 million. 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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LAREDO
PETROLEUM, INC.

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Laredo Petroleum Announces $200 Million Share Repurchase Program

TULSA, OK - February 14, 2018 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or the "Company") today announced that its board of directors has authorized a $200 million share repurchase program. The Company may purchase shares in accordance with applicable securities laws from time to time in open market or privately negotiated transactions. The timing, number and value of shares repurchased under the program will be at the discretion of management and the board of directors and will depend on a number of factors, including market conditions, business conditions, the trading price of the Company's common stock and the nature of other investment opportunities available to the Company. The authorization extends through February 16, 2020.

"At current market prices, this program will enable the Company to repurchase approximately 10% of our outstanding shares at, what we believe, is a substantial discount to the true value of the Company." stated Randy A. Foutch, Chairman and Chief Executive Officer. "Our balance sheet strength after the divestment of our interest in the Medallion-Midland Basin pipeline system offers several avenues to accelerate value recognition for our current shareholders. We believe this repurchase program is the most compelling and accretive avenue at this time."

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 in 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 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, including, but not limited to, the share repurchase program, 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, 2016, and those set forth from time to time in other filings with the Securities Exchange

Commission ("SEC") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2017, to be filed with the 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.

Statements in this press release regarding share repurchases that are forward-looking are based on management's estimates, assumptions and projections, and are subject to significant uncertainties and other factors, many of which are beyond our control. Important risk factors could cause future events to differ materially from those currently estimated by management, including, but not limited to the following:

- *Significant disruptions in the equity or debt markets could negatively impact our ability to repurchase shares.*

- *Share repurchases may be suspended or discontinued by the Company at any time.*

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.

# # #

Contact:
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EXHIBIT 99.3

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

Corporate Presentation
February 2018

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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, impacts relating to the Company's share repurchase program (which may be suspended or discontinued by the Company at any time without notice), 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 and Exchange Commission ("SEC") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2017 to be filed with the SEC.

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

The SEC generally permits oil and natural gas companies to disclose proved reserves in filings made with the SEC, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this presentation, the Company may use the terms "unproved reserves," "resource potential," "estimated ultimate recovery," "EUR," "development ready," "type curve" 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. "Type curve" refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

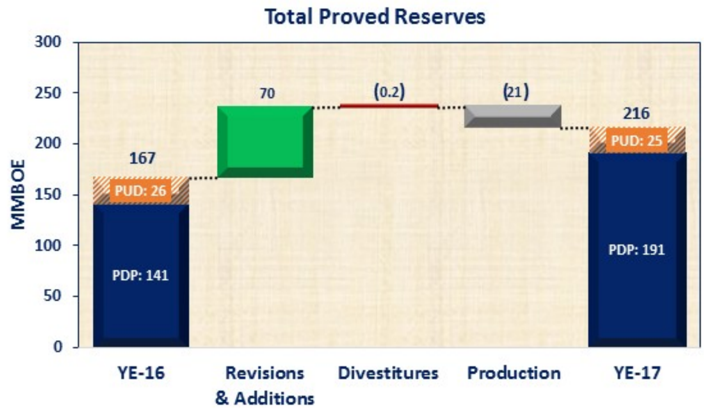
This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including Adjusted EBITDA and Proved F&D Cost. While management believes that such measures are useful for investors, they should not be used as a replacement for financial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

2017 Highlights

- ~17% YoY production growth
  - Company record of 58,273 BOE/d
- ~36% YoY organic PDP reserve growth
  - $7.90/BOE proved F&D cost[1]
- 62 Hz development wells completed
  - >30% average anticipated well-level rate of return on invested capital
- $20.87/BOE FY-17 per unit cash margin
  - 48% YoY increase, doubling the 24% YoY increase of average realized price per BOE
- ~15% YoY decrease in per unit LOE to $3.53/BOE for FY-17
- ~$27.9 MM of net cash benefits from LMS field infrastructure investments through reduced capital and operating costs plus increased revenue
- ~$830 MM of net cash proceeds realized from the Medallion-Midland Basin pipeline system divestiture, achieving three times invested capital

[1] Proved Developed F&D Cost is a non-GAAP financial measure. See the Appendix for information on this calculation

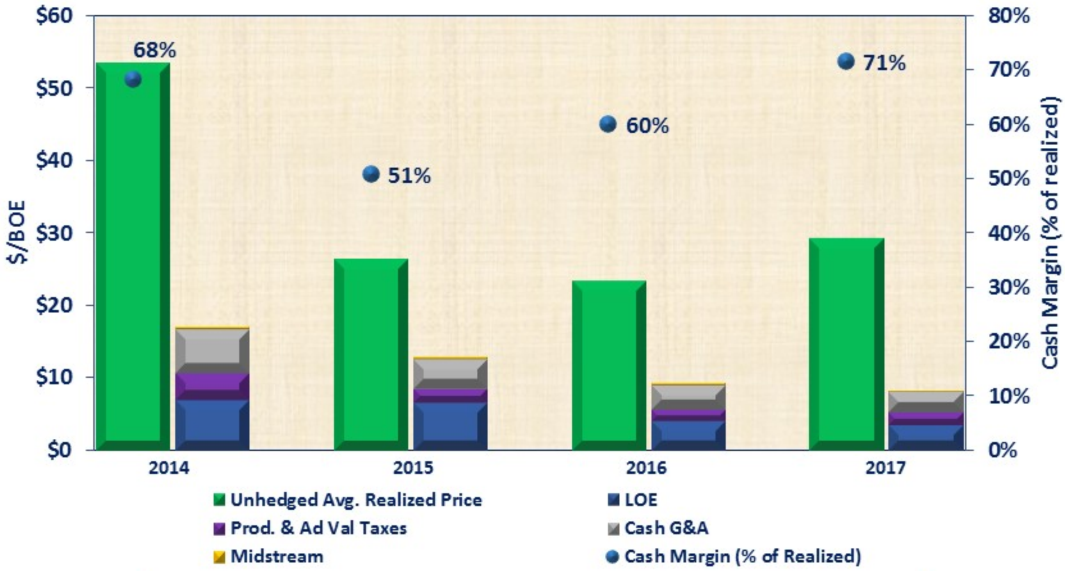
Low-Cost Proved Reserves Growth



36% **Organic growth in proved developed reserves**

2017 proved developed F&D cost **$7.90/BOE**

Improved Cash Margin Percentage During Volatile Pricing



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

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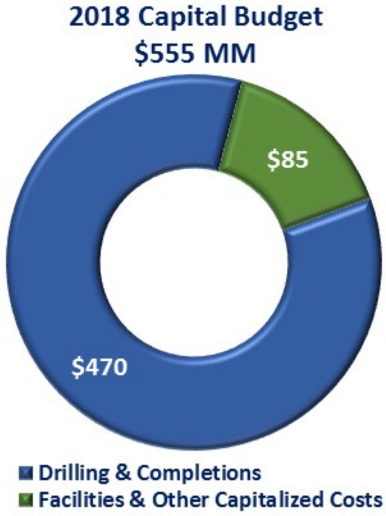
[1] Current cash margin as a percent of unhedged average realized price

Note: 2014 cash margin has been converted to 3-stream using actual gas plant economics

2018 Capital Budget



2018 Drilling & Completions

- Operating 3 - 4 Hz rigs
- Completing 60 - 65 net wells
- ~99% targeting the UWC & MWC
- ~10,400' average Hz lateral length

Expect to operate within cash flow by year-end 2018

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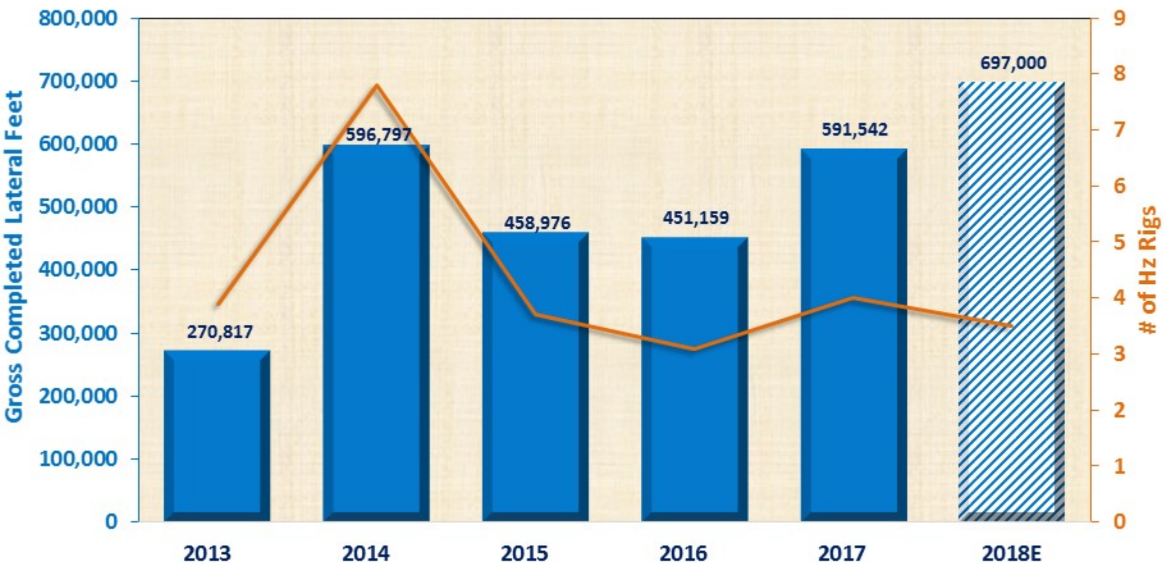
Note: Budget assumes $55/Bbl WTI and $3/MMBtu HH

Operational Efficiencies Enable Us to Do More with Less



~10,400’ **FY-18E average completed lateral length per well**

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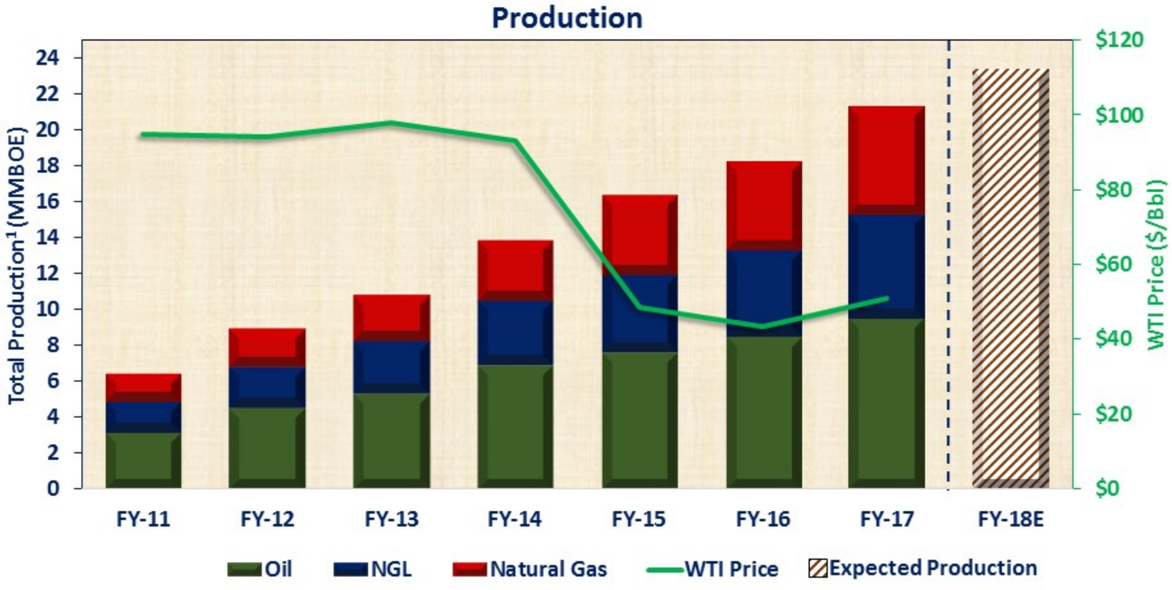
Consistent Growth Through Commodity Price Cycle



>10% FY-18E 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

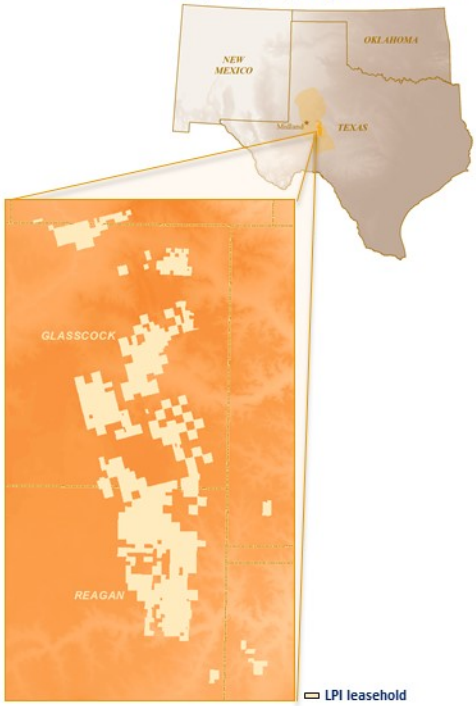
Capitalizing on Our Contiguous Acreage Position

- **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 six consecutive quarters**

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

144,538 gross/124,843 net acres



Infrastructure Provides Tangible Benefits

Yields capital & LOE savings, plus increased revenues & 3rd-party income
Enables multi-well pad drilling & operational flexibility
Minimizes trucking

LMS Corridor Benefit	LPI Benefit	4Q-17 Net Benefits Actual ($ MM)	2017 Net Benefits Actual ($ MM)
Crude gathering	Increased revenues & 3rd-party income	$2.7	$10.6
Centralized gas lift	LOE savings	$0.2	$0.9
Produced water gathered on pipe	Capital & LOE savings	$2.9	$10.2
Produced water recycled	Capital & LOE savings	$0.5	$1.7
Completions utilizing recycled water	Capital savings	$0.4	$1.4
Completions utilizing LPI fresh water wells	Capital savings	$0.7	$3.1
Corridor Benefits Total		$7.5	$27.9


LMS Water Treatment Plant


LMS Crude Gathering Tanks at Reagan Truck Station


LMS Gas Lift Compressor Station

Note: Benefits as of 1/15/18. Totals may not foot due to rounding. Calculated utilizing a 95% WI & 72% NRI

Contiguous Acreage Facilitates Robust Infrastructure Investments

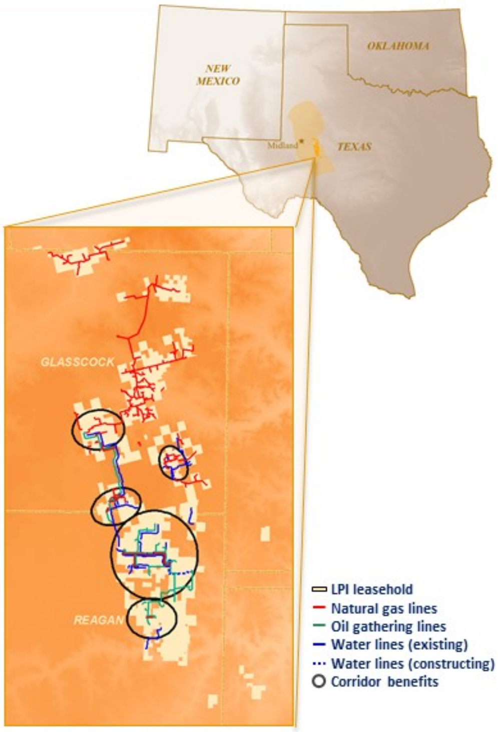
PIPELINE INFRASTRUCTURE

~60 Miles
CRUDE GATHERING

~95 Miles
WATER GATHERING / RECYCLED DISTRIBUTION

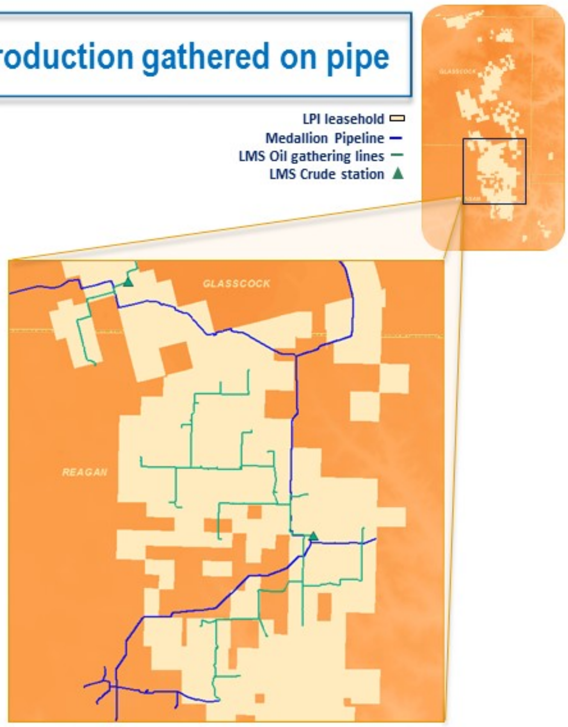
~188 Miles
NATURAL GAS GATHERING & DISTRIBUTION

~185,000
Truckloads removed from roads in 2017 due to LMS' water and crude gathering infrastructure



LMS Crude Gathering System Benefits

81% YE-17 gross operated crude production gathered on pipe



Reduces time from production to sales

System benefits increase as trucking costs rise

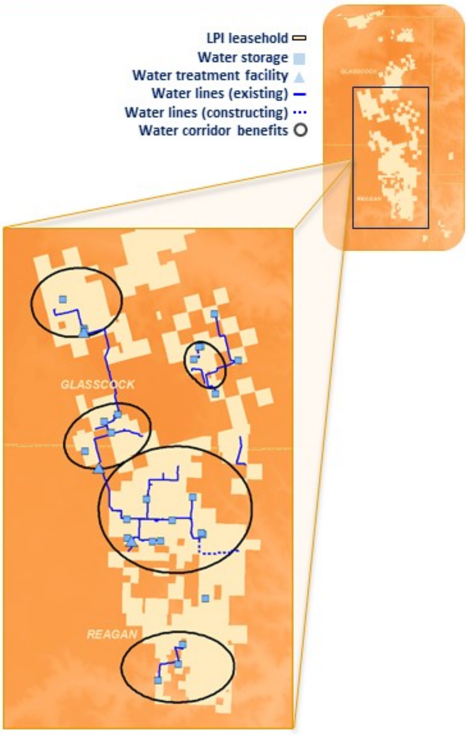
Provides LPI with increased oil price realizations and LMS with 3rd-party income

Note: Statistics and maps as of 12/31/17

Significant Benefits Through Water Infrastructure Investments

15.7 MMBW
FY-17 produced water gathered on pipe

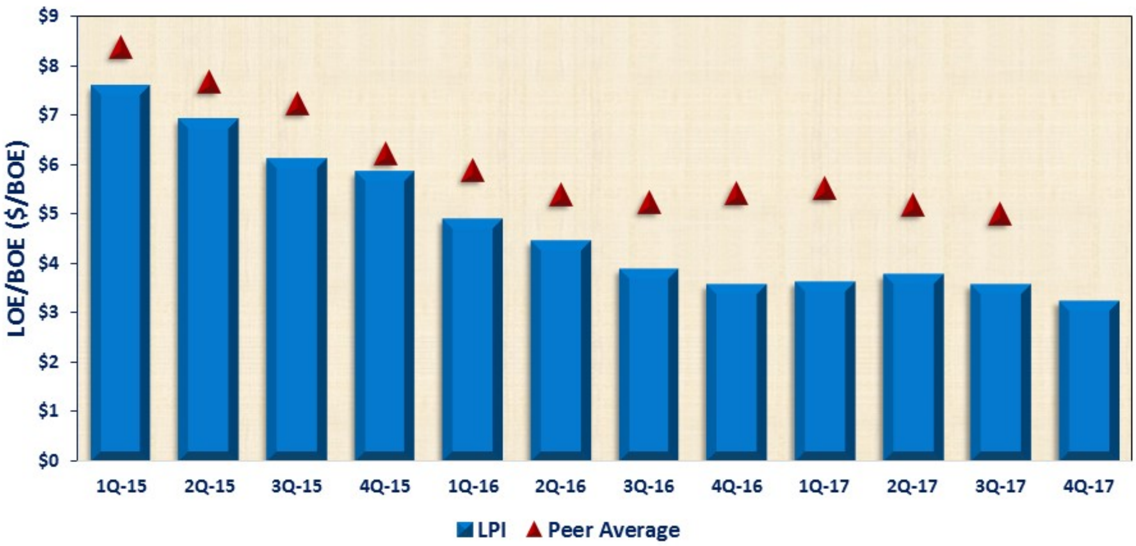
LMS Corridor Benefit	LPI Benefit	YE-17 (% of Total Activity)	Capacity
Produced Water Gathered on Pipe	Capital & LOE savings	78%	
Produced Water Recycled	Capital & LOE savings	44%	54 MBWPD Recycling Processing & ~15.7 MMBW Storage Capacity
Completions Utilizing Recycled Water	Capital savings	15%	
Completions Utilizing LPI Fresh Water Wells	Capital savings	17%	



~$10.2 MM
FY-17 LOE reduction generated by LMS' water infrastructure investments[1]

[1]Calculated utilizing a 95% WI & 72% NRI
Note: Statistics, estimates and maps as of 12/31/17

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

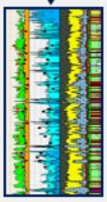
Note: Peers include CPE, CXO, EGN, FANG, PE, PXD & RSPP
4Q-17 peer performance to be updated once reported

Advanced Subsurface Characterization Drives Optimized Development

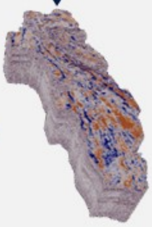
Physics-Based Workflows

Acquire Subsurface data

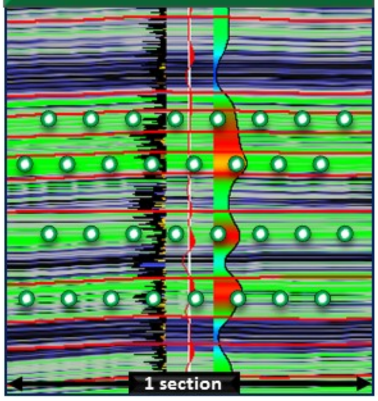
Calibrate Petrophysical model



Integrate spatial data



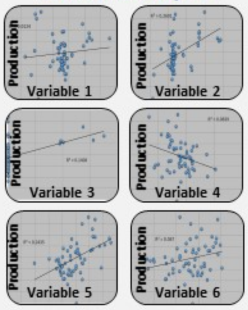
High-Resolution 3D Reservoir Geomodels



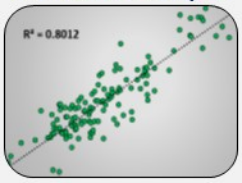
Increased NAV
driven by
high-density development

Improved Analytics

Bivariate analytics



Multivariate analytics



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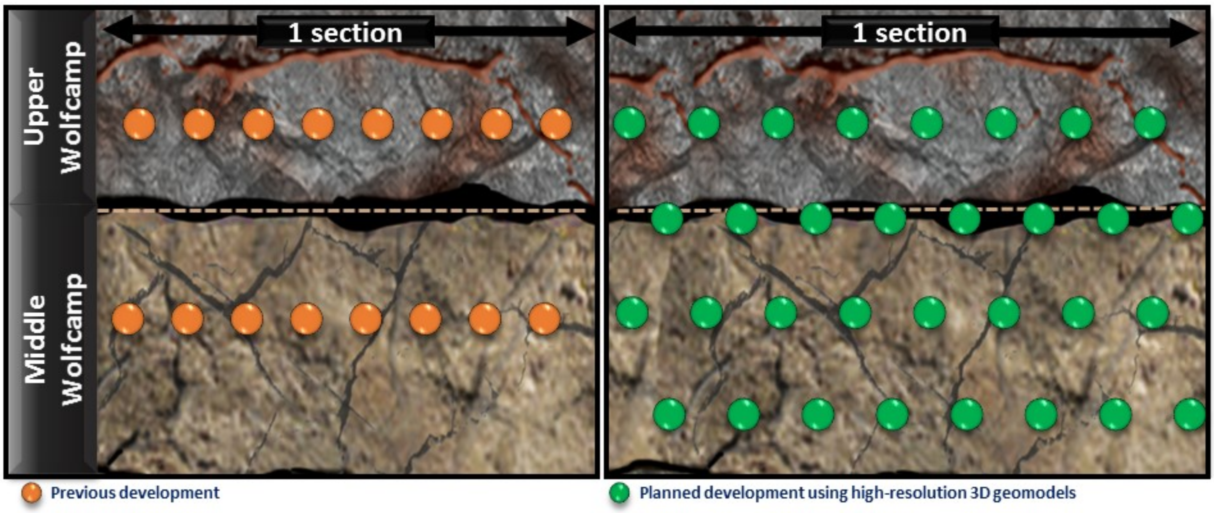
Note: Diagrams are not to scale

Tightened Spacing Increases Premium UWC/MWC Locations

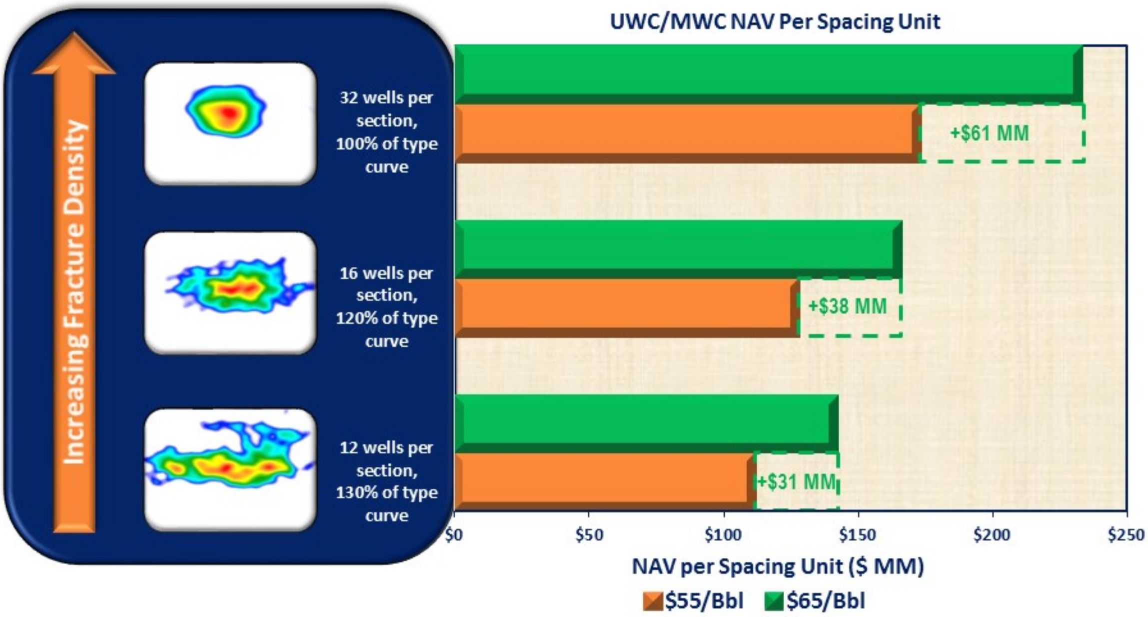


32 locations per section

Results of 2017 spacing tests suggest development possibility of up to 32 UWC/MWC locations per spacing unit

Note: Diagrams are not to scale
Spacing unit comprised of two sections to accommodate 10,000' laterals

Tighter Cluster Spacing Facilitates Higher-Density Development

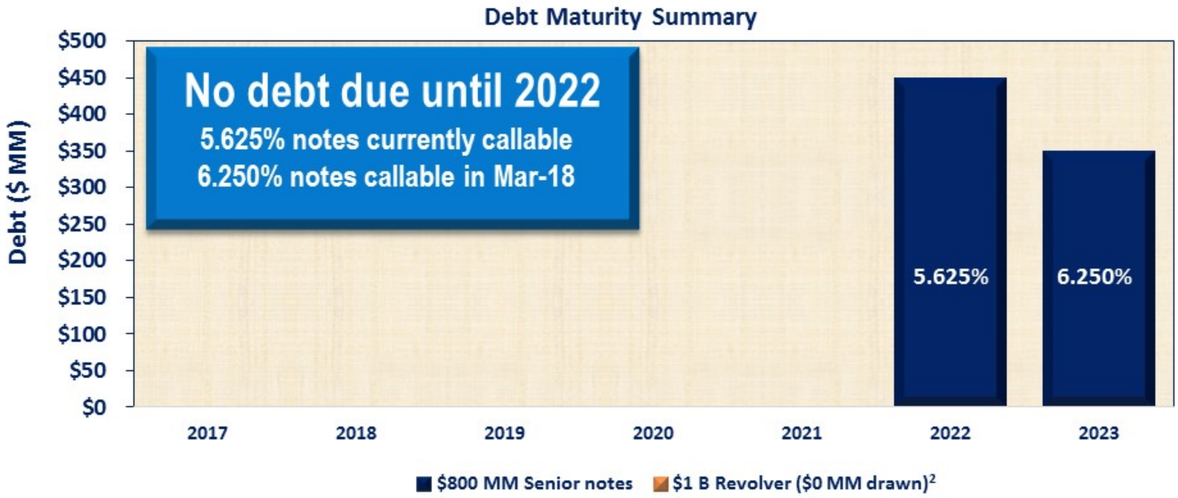


Increased well density drives higher NAV per spacing unit

Note: NAV calculation pricing reflective of WTI benchmark, utilizing $3/Mcf flat HH benchmark and $7.1 MM D&C well cost
Spacing unit comprised of two sections to accommodate 10,000' laterals

Maintaining A Strong Balance Sheet

~1.3x net debt to Adjusted EBITDA[1]



[1] Net debt to Adjusted EBITDA includes net debt as of 12/31/17 and 4Q-17 annualized Adjusted EBITDA. Net debt is calculated as the face value of long-term debt of $800 MM, reduced by cash on hand of $112 MM. Please see the Appendix for a reconciliation of Adjusted EBITDA

[2] As of 2/13/18, with $1 B Borrowing Base in place under Fifth Amended and Restated Senior Secured Credit Facility

Stock Repurchase Program

- **Up to $200 MM stock repurchase approved**
  - **~10% reduction in current common stock outstanding[1]**
- **Plan to utilize cash on hand and senior secured credit facility**
  - **Results in ~1.7x net debt to Adjusted EBITDA post repurchase[2,3]**
- **Program authorized for two years by Board of Directors**

Stock repurchase program represents a highly accretive use of capital

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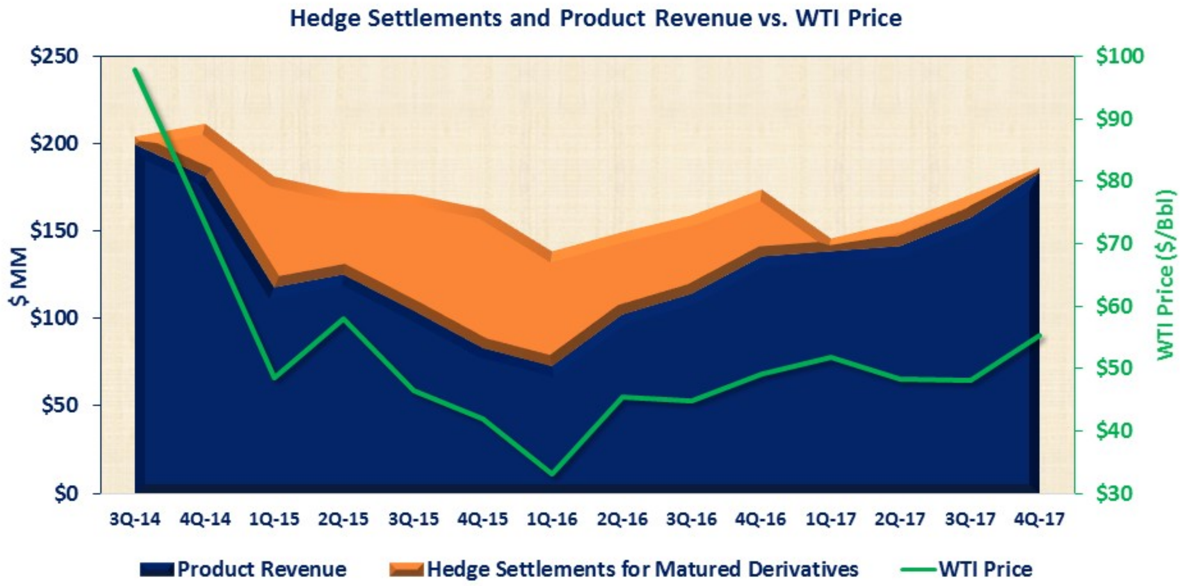
[1] Assumes market prices as of 02/13/18
[2] Assumes all $200 MM utilized for stock repurchase
[3] Net debt to Adjusted EBITDA includes net debt as of 12/31/17 and 4Q-17 annualized Adjusted EBITDA. Net debt is calculated as the face value of long-term debt of $800 MM, reduced by cash on hand of $112 MM.

Disciplined Risk Management Philosophy Protects Long-Term Value



Hedges provide cash flow stability during volatile pricing

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	FY-18	FY-19	FY-20
Oil total floor volume (Bbl)	9,515,375	6,606,500	1,061,400
Oil wtd-avg floor price ($/Bbl)	$47.42	$48.82	$49.70
Nat gas total floor volume (MMBtu)	23,805,500		
Nat gas wtd-avg floor price ($/MMBtu)	$2.50		
NGL total floor volume (Bbl)	1,436,200		

Oil	FY-18	FY-19	FY-20
Puts			
Hedged volume (Bbl)	5,427,375	5,949,500	366,000
Wtd-avg floor price ($/Bbl)	$51.93	$48.31	$45.00
Swaps			
Hedged volume (Bbl)		657,000	695,400
Wtd-avg price ($/Bbl)		$53.45	$52.18
Collars			
Hedged volume (Bbl)	4,088,000		
Wtd-avg floor price ($/Bbl)	$41.43		
Wtd-avg ceiling price ($/Bbl)	$60.00		

Note: 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

Natural Gas Liquids	FY-18	FY-19	FY-20
Swaps - Ethane:			
Hedged volume (Bbl)	567,800		
Wtd-avg price ($/Bbl)	$11.66		
Swaps - Propane:			
Hedged volume (Bbl)	467,600		
Wtd-avg price ($/Bbl)	$33.92		
Swaps – Normal Butane:			
Hedged volume (Bbl)	167,000		
Wtd-avg price ($/Bbl)	$38.22		
Swaps - Isobutane:			
Hedged volume (Bbl)	66,800		
Wtd-avg price ($/Bbl)	$38.33		
Swaps - Natural Gasoline:			
Hedged volume (Bbl)	167,000		
Wtd-avg price ($/Bbl)	57.02		

Note: Natural gas liquids derivatives are for February through December 2018 and are settled based on the month's average daily OPIS index price for Mt. Belvieu Purity Ethane and Non-TET: Propane, Normal Butane, Isobutane and natural gasoline

Basis Swaps	FY-18	FY-19	FY-20
Mid/Cush Basis Swaps			
Hedged volume (Bbl)	3,650,000		
Wtd-avg price ($/Bbl)	-$0.56		
HH/WAHA Basis Swaps			
Hedged volume (MMBtu)	9,125,000	9,125,000	
Wtd-avg price ($/MMBtu)	-$0.62	-$0.70	

Note: 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. Natural gas basis swaps are settled based on the inside FERC index price for West Texas WAHA and NYMEX Henry Hub

Natural Gas - WAHA	FY-18	FY-19	FY-20
Puts			
Hedged volume (MMBtu)	8,220,000		
Wtd-avg floor price ($/MMBtu)	$2.50		
Collars			
Hedged volume (MMBtu)	15,585,500		
Wtd-avg floor price ($/MMBtu)	$2.50		
Wtd-avg ceiling price ($/MMBtu)	$3.35		

Note: Natural gas derivatives are settled based on Inside FERC index price for West Texas WAHA for the calculation period

Note: Positions as of 2/14/18

1Q-18E Guidance

	1Q-18E
Production (MBOE/d)..............................	**62.0**
Crude oil production (MBbl/d)..............................	**27.0**
Price Realizations (pre-hedge):	
Crude oil (% of WTI)..............................	**97%**
Natural gas liquids (% of WTI)..............................	**28%**
Natural gas (% of Henry Hub)..............................	**57%**
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)..............................	**$3.55**
Midstream expenses ($/BOE)..............................	**$0.20**
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)....	**6.25%**
General and administrative expenses:	
Cash ($/BOE)..............................	**$2.90**
Non-cash stock-based compensation[1] ($/BOE)..............................	**$1.65**
Depletion, depreciation and amortization ($/BOE)..............................	**$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 and Note 13.b. in the Company's Annual Report on Form 10-K for the year ended December 31, 2017 to be filed on February 15, 2018 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

2017 Actuals

		1Q-17	2Q-17	3Q-17	4Q-17	FY-17
Sales Volumes	**3-Stream Sales Volumes**					
	MBOE	4,716	5,336	5,521	5,697	21,270
	BOE/d	52,405	58,632	60,011	61,922	58,273
	% oil	45%	47%	44%	43%	45%
Pricing	**3-Stream Realized Prices**					
	Oil ($/Bbl)	$46.91	$42.00	$45.44	$53.57	$46.97
	NGL ($/Bbl)	$16.49	$13.82	$18.58	$20.53	$17.49
	Gas ($/Mcf)	$2.31	$2.09	$2.04	$1.95	$2.09
	Avg. price ($/BOE)	$29.42	$26.58	$28.54	$32.19	$29.22
Unit Cost Metrics	**3-Stream Unit Cost Metrics ($/BOE)**					
	Lease operating expenses	$3.60	$3.77	$3.55	$3.22	$3.53
	Midstream	$0.19	$0.17	$0.21	$0.20	$0.19
	Production & ad val taxes	$1.86	$1.59	$1.73	$1.93	$1.78
	General & administrative					
	Cash	$3.47	$2.50	$2.90	$2.61	$2.85
	Non-cash stock-based compensation[1]	$1.96	$1.63	$1.62	$1.55	$1.68
	DD&A	$7.23	$7.12	$7.46	$7.91	$7.45

[1] Net of amounts capitalized

2015 & 2016 Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15	1Q-16	2Q-16	3Q-16	4Q-16	FY-16
Sales Volumes	3-Stream Sales Volumes										
	MBOE	4,274	4,234	4,124	3,714	16,346	4,204	4,338	4,718	4,889	18,149
	BOE/d	47,487	46,532	44,820	40,368	44,782	46,202	47,667	51,276	53,141	49,586
	% oil	51%	46%	45%	45%	47%	48%	46%	46%	46%	47%
Pricing	3-Stream Realized Prices										
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27	$27.51	$39.37	$39.10	$43.98	$37.73
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86	$8.50	$12.24	$11.54	$14.79	$11.91
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93	$1.31	$1.31	$2.07	$2.13	$1.73
	Avg. price ($/BOE)	$27.64	$29.65	$25.37	$22.47	$26.41	$17.40	$23.64	$24.34	$27.82	$23.50
Unit Cost Metrics	3-Stream Unit Cost Metrics ($/BOE)										
	Lease operating expenses	$7.58	$6.90	$6.09	$5.83	$6.63	$4.88	$4.43	$3.85	$3.56	$4.15
	Midstream	$0.37	$0.38	$0.26	$0.43	$0.36	$0.14	$0.27	$0.22	$0.26	$0.22
	Production & ad val taxes	$2.13	$2.24	$1.91	$1.73	$2.01	$1.53	$1.84	$1.50	$1.45	$1.58
	General & administrative										
	Cash	$3.99	$4.00	$3.89	$4.27	$4.03	$3.72	$3.33	$3.49	$3.28	$3.45
	Non-cash stock-based compensation[1]	$1.12	$1.48	$1.67	$1.77	$1.50	$0.91	$1.40	$2.05	$1.98	$1.61
	DD&A	$16.83	$17.03	$16.19	$18.01	$16.99	$9.87	$7.88	$7.45	$7.68	$8.17

[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 valorem 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 valorem 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

Supplemental Non-GAAP Financial Measure

Proved Developed Finding and Development Cost (Unaudited)

Proved developed finding and development ("F&D") cost per BOE is calculated by dividing (x) development costs for the period, by (y) proved developed reserve additions for the period, defined as the change in proved developed reserves, less purchased reserves, plus sold reserves and plus sales volumes during the period. The method we use to calculate our proved developed F&D cost may differ significantly from methods used by other companies to compute similar measures. As a result, our proved developed F&D cost may not be comparable to similar measures provided by other companies. We believe that providing the measure of proved development F&D cost is useful in evaluating the cost, on a per BOE basis, to added proved developed reserves.

However, this measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP. Due to various factors, including timing differences in the addition of proved reserves and the related costs to develop those reserves, proved developed F&D cost does not necessarily reflect precisely the costs associated with particular proved reserves. As a result of various factors that could materially affect the timing and amounts of future increases in proved reserves and the timing and amounts of future costs, we cannot assure you that our future proved developed F&D cost will not differ materially from those presented.

($ MM, except per BOE amount, reserves and sales volumes in MMBOE)	Proved Developed F&D
Development costs (x)	$561
Proved developed reserves:	
As of December 31, 2017	191
As of December 31, 2016	(141)
Change in proved developed reserves	50
Plus sales of proved developed reserves during 2017	-
Plus 2017 sales volumes	21
Proved developed reserve additions (y)	71
Proved developed F&D cost per BOE	$7.90

Supplemental Non-GAAP Financial Measure

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for income tax expense or benefit, depletion, depreciation & amortization, bad debt expense, 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 our equity method investee & other non-recurring income & 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, working capital, income taxes, franchise taxes & other commitments & 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 & 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, the book value of assets, capital structure & the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate & 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 & as a basis for strategic planning & 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 & non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies & 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.

(in thousands)	Three months ended December 31, 2017
Net income	$408,561
Plus:	
Income tax expense	1,800
Depletion, depreciation & amortization	45,062
Non-cash stock-based compensation, net of amounts capitalized	8,857
Accretion expense	969
Mark-to-market on derivatives:	
(Gain) loss on derivatives, net	37,777
Cash settlements received for matured derivatives, net	2,792
Cash premiums paid for derivatives	(12,311)
Interest expense	19,787
Gain on sale of investment in equity method investee**	(405,906)
Loss on disposal of assets, net	906
Loss on early redemption of debt	23,761
Income from equity method investee**	(575)
Proportionate Adjusted EBITDA of equity method investee**	2,326
Adjusted EBITDA	$133,806

** On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC ("MMH"), which is owned and controlled by an affiliate of the third-party interest holder, The Energy & Minerals Group ("EMG"), completed the sale of 100% of the ownership interests in Medallion to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion (the "Medallion Sale"). LMS' net cash proceeds for its 49% ownership interest in Medallion in 2017 was $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. On February 1, 2018, closing adjustments were finalized and LMS received additional net cash of $1.7 million for total net cash proceeds before taxes of $831.3 million. 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.