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): August 6, 2015

LAREDO PETROLEUM, INC.

(Exact Name of Registrant as Specified in Charter)

Delaware	**001-35380**	**45-3007926**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

15 W. Sixth Street, Suite 900, Tulsa, Oklahoma	**74119**
(Address of Principal Executive Offices)	(Zip Code)

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

Not Applicable

(Former Name or Former Address, if Changed Since Last Report)

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

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

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

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

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

Item 2.02. Results of Operations and Financial Condition.

On August 6, 2015, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter ended June 30, 2015. A copy of the Company's press release is furnished as Exhibit 99.1 to this Current Report on Form 8-K and is incorporated herein by reference. The Company plans to host a teleconference and webcast on August 6, 2015, at 9:00 am Central Time to discuss these results. To access the call, please dial 1-877-930-8286, using the conference code 78876918 or 1-253-336-8309 for international callers, also using the conference code 78876918. A replay of the call will be available through Thursday, August 13, 2015, by dialing 1-855-859-2056, and using conference code 78876918. 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 exhibit attached hereto are deemed to be "furnished" and shall not be deemed "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall such information and exhibit be deemed incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

Item 7.01. Regulation FD Disclosure.

On August 6, 2015, the Company issued 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.

On August 6, 2015, the Company also posted to its website a Corporate Presentation. The presentation is available on the Company's website, www.laredopetro.com, and is attached to this Current Report on Form 8-K as Exhibit 99.2 and incorporated into this Item 7.01 by reference.

All statements in the press release, teleconference and 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 this 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 August 6, 2015 announcing financial and operating results.
99.2	Corporate Presentation.

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: August 6, 2015	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
99.1	Press release dated August 6, 2015 announcing financial and operating results.
99.2	Corporate Presentation.

EXHIBIT 99.1

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

LAREDO PETROLEUM ANNOUNCES 2015 SECOND-QUARTER FINANCIAL AND OPERATING RESULTS

RAISES ESTIMATED 2015 PRODUCTION GROWTH RANGE TO 17% - 19%

TULSA, OK - August 6, 2015 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or "the Company") today announced its 2015 second-quarter results, reporting a net loss attributable to common stockholders of $397.0 million, or $1.88 per diluted share, which includes a pre-tax, non-cash full cost ceiling impairment charge of $488.0 million. Adjusted Net Income, a non-GAAP financial measure, for the second quarter of 2015 was $9.8 million, or $0.05 per diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the second quarter of 2015 was $117.9 million.

2015 Second-Quarter Highlights

- Produced 46,532 barrels of oil equivalent ("BOE") per day, up approximately 38% from the comparable second quarter of 2014
- Generated Adjusted EBITDA of $117.9 million, flat with second-quarter 2014 as production growth and cost controls overcame a 46% decrease in realized oil prices
- Reduced unit cash costs to $13.52 per BOE, a decrease of approximately 28% from the second-quarter 2014 rate of $18.85 per BOE, on a three-stream basis
- Continued growth of the pipeline system managed by Medallion Gathering and Processing, LLC ("Medallion"), which is 49%-owned by Laredo Midstream Services, LLC ("LMS"), as total volumes increased to approximately 35,000 barrels of oil per day ("BOPD") in the second quarter and are expected to be approximately 60,000 BOPD in the third quarter
- Received $46.6 million of cash settlements on derivatives that matured in second-quarter 2015, increasing hedged pricing for oil by $21.62 per barrel and natural gas by $0.47 per thousand cubic feet, from pre-hedged average sales prices

Please see supplemental financial information at the end of this news release for reconciliations of non-GAAP financial measures.

"This quarter we exceeded our guidance for production, reduced capital and unit operating costs, benefitted from more than $46 million in cash flow from our hedge book and continued to invest in the Medallion pipeline system," commented Randy A. Foutch, Laredo Chairman and Chief Executive Officer. "Horizontal wells completed late last year that now have at least 180 days of production are, in aggregate, performing better than type curve and contributed to production coming in above guidance. Our prior investments in data, production corridors and LMS, coupled with our focus on capital efficiency, has enabled the Company to optimize returns. We are further capitalizing on these investments by initiating an 11-well program in one 640-acre section along the Reagan North production corridor, targeting the Upper and Middle Wolfcamp zones with 10,000-foot laterals utilizing cost-efficient multi-well pads."

"Cost reduction measures are now being realized via appreciably lower capital costs, unit lease operating expenses and general and administrative expenses. Additionally, long-term investments in the Medallion pipeline system are proving to be very valuable as third-party operators are recognizing Medallion's ability to access price advantaged markets. Total system volumes on Medallion are now expected to exceed 100,000 barrels of oil per day by year end, as additional operators dedicate acreage to the Medallion system. As Laredo continues to plan and invest for the long-term, we expect to derive additional value for our shareholders from these efforts."

Operational Update

In the second quarter of 2015, Laredo produced 46,532 BOE per day, up approximately 38% from three-stream production of 33,829 BOE per day in the second quarter of 2014. The Company completed 21 horizontal wells in the second quarter of 2015, with an average working interest of approximately 72%, comprised of 10 wells in the Upper Wolfcamp, six in the Lower Wolfcamp, four in the Cline and one in the Canyon. Additionally, the Company completed seven vertical wells with an average working interest of approximately 91%. Laredo expects to complete eight horizontal wells in the third quarter of 2015, with an average working interest of approximately 94%.

During the second quarter of 2015, 12 of the Company's horizontal wells were completed on the JE Cox-Blanco production corridor. By tying the water handling and recycling system from the Reagan North corridor to the JE Cox-Blanco corridor, Laredo demonstrated the flexibility of its infrastructure systems and the ability to handle the approximately 3 million barrels of water associated with the completion operations. Additionally, the oil volumes produced on the corridor are gathered on crude gathering pipelines owned by LMS, increasing operated crude production gathered on LMS pipelines to 45%. These volumes realize a $0.95 per barrel pricing advantage versus oil transported by truck and were instrumental in pushing the Company's crude oil price realizations to approximately 88% of West Texas Intermediate ("WTI").

The longer-term performance of Laredo's horizontal wells continues to support the Company's type curves. Additionally, wells that achieved 180 days of production during the second quarter, on average, performed better than their type curves and improved the aggregate performance of all four zones. Based on 180-day cumulative production, the Company's long-lateral horizontal wells, with at least 24 completed stages, are performing at or above type curve in all four initially targeted zones.

Zone	Wells with 180 days of Production			Wells with 365 days of Production		
	No. of Wells	Avg. Cumulative Production per Well	% of Type Curve	No. of Wells	Avg. Cumulative Production per Well	% of Type Curve
	(long laterals)	*(three-stream MBOE)*		*(long laterals)*	*(three-stream MBOE)*	
Upper Wolfcamp	61	91.2	101%	39	144.9	101%
Middle Wolfcamp	24	87.2	109%	15	131.0	104%
Lower Wolfcamp	21	79.2	100%	10	123.9	98%
Cline	13	98.5	104%	9	144.7	103%

Laredo's focus on operational and capital efficiency, and the resulting positive impact on returns, has enabled the Company to accelerate drilling activity. Laredo is currently operating four horizontal rigs, two of which were added to drill an 11-well project in one section, targeting the Upper and Middle Wolfcamp zones. These wells are all projected to be approximately 10,000-foot laterals drilled on muti-well pads along the Reagan North production corridor. They are expected to be concurrently completed late in the fourth quarter of 2015 and achieve a full quarter of production impact during first-quarter 2016.

Laredo has begun to utilize its Earth Model reservoir characterization process to select landing points and geosteer horizontal wells in areas where the data has been fully processed and integrated. While limited in scope, the Company is encouraged by initial results. The Company will make a determination of the efficacy of the model once a statistically significant number of wells have reached at least 180 days of production.

In the second quarter of 2015, the Company reduced unit cash costs to $13.52 per BOE from $18.85 per BOE during the second quarter of 2014. Unit lease operating costs benefitted primarily from investments in water handling and disposal infrastructure within the Company's production corridors as well as initiatives to reduce fuel and electricity costs in the field. The Company expects to recognize additional savings throughout the year as a result of these investments. General and administrative expenses experienced a substantial decrease from the second quarter of 2014, as savings were realized from the reduction in force and office consolidation the Company implemented in January of 2015.

Laredo Midstream Services Update

In the second quarter of 2015, Medallion, of which LMS is a 49% owner, conducted its first full quarter of operations of the Medallion pipeline system. During the second quarter, the system shipped approximately 3.1 million barrels of oil and in June achieved volumes of more than 38,000 BOPD. Based on third-quarter 2015 nominations, it is expected the pipeline will ship approximately 5.4 million barrels of oil in the third quarter, with the September 2015 nomination expected to exceed 80,000 BOPD.

The Medallion pipeline system continues to grow as third-party operators recognize the value of dedicating properties to the system. In the second quarter, the Laredo Board of Directors approved approximately $28 million to fund the Company's share of proposed expansions that will extend parts of the system to additional third-party acreage dedications and build interconnects to other interbasin pipelines. Additionally, Medallion has been awarded a contract to expand the system to a new third-party producer that is dedicating acreage to the pipeline and Laredo may participate in this project. The expansion will grow the system to more than 400 miles of pipeline with acreage dedications in excess of 290,000 net acres. After giving effect to this expansion, Medallion anticipates transporting volumes of more than 100,000 BOPD by the end of 2015.

2015 Capital Program

During the second quarter of 2015, Laredo invested approximately $114 million in exploration and development activities and approximately $38 million in pipelines and related infrastructure assets held by LMS, including previously approved investments in Medallion. The Company's Board of Directors has approved an increase of the 2015 capital budget to $595 million to fund additional drilling in the second half of the year and additional investments in the Medallion pipeline system.

On August 3, 2015, the Company entered into an agreement to sell non-strategic, and primarily non-operated properties and the associated production. The sale price for these assets is approximately $65 million, subject to customary closing adjustments.

Liquidity

At June 30, 2015, the Company had cash and equivalents of approximately $58 million and undrawn capacity under the senior secured credit facility of $875 million, resulting in total liquidity of approximately $933 million.

Commodity Derivatives

Laredo maintains an active hedging program to reduce the variability in its anticipated cash flow due to fluctuations in commodity prices. At August 5, 2015, the Company had hedges in place for the remaining two quarters of 2015 for 3,847,760 barrels of oil at a weighted-average floor price of $80.99 per barrel, representing approximately 100% of anticipated oil production for the remaining six months of 2015. The Company has also hedged 14,384,000 million British thermal units ("MMBtu") of natural gas for the remaining six months of 2015 at a weighted-average floor price of $3.00 per MMBtu, representing approximately 60% of anticipated natural gas and natural gas liquids heat content for the last half of 2015. Additionally, the Company has basis swaps for the remaining six months of 2015 totaling 1,840,000 barrels of oil to hedge the Midland-WTI basis differential at WTI less $1.95 per barrel.

For 2016, the Company has hedged 5,227,800 barrels of oil at a weighted-average floor price of $77.25 per barrel and 18,666,000 MMBtu of natural gas at a weighted-average floor price of $3.00 per MMBtu. Additionally, for 2017, the Company has hedged 2,628,000 barrels of oil at a weighted-average floor price of $77.22 per barrel and 5,475,000 MMBtu of natural gas at a weighted average floor price of $3.00 per MMBtu.

Guidance

The table below reflects the Company’s guidance for the third and fourth quarters of 2015 and full-year 2015:

	3Q-2015	4Q-2015	FY-2015
Production (MMBOE)	3.9 - 4.1	3.7 - 3.9	16.1 - 16.5
Crude oil % of production	~46%	~46%	~47%
Natural gas liquids % of production	~26%	~26%	~25%
Natural gas % of production	~28%	~28%	~28%
Price Realizations (pre-hedge):			
Crude oil (% of WTI)	~88%	~88%	~87%
Natural gas liquids (% of WTI)	~22%	~22%	~22%
Natural gas (% of Henry Hub)	~70%	~70%	~70%
Operating Costs & Expenses:			
Lease operating expenses ($/BOE)	$6.25 - $7.25	$6.50 - $7.50	$6.50 - $7.50
Midstream expenses ($/BOE)	$0.40 - $0.50	$0.40 - $0.50	$0.40 - $0.50
Production and ad valorem taxes (% of oil and gas revenue)	7.75%	7.75%	7.75%
General and administrative expenses ($/BOE)	$5.75 - $6.75	$5.75 - $6.75	$5.50 - $6.50
Depletion, depreciation and amortization ($/BOE)	$15.50 - $16.50	$15.50 - $16.50	$16.00 - $17.00

Conference Call Details

Laredo has scheduled a conference call today at 9:00 a.m. CT (10:00 a.m. ET) to discuss its second-quarter 2015 financial and operating results and management’s outlook for the future, the content of which is not part of this earnings release. Participants may listen to the call via the Company’s website at www.laredopetro.com, under the tab for “Investor Relations.” The conference call may also be accessed by dialing 1-877-930-8286 and using the conference code 78876918. International participants may access the call by dialing 1-253-336-8309 and using conference code 78876918. It is recommended that participants dial in approximately 10 minutes prior to the start of the conference call. A telephonic replay will be available approximately two hours after the call on August 6, 2015 through Thursday, August 13, 2015. Participants may access this replay by dialing 1-855-859-2056 and using conference code 78876918.

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 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 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.

The preliminary results above are based on the most current information available to management. As a result, our final results may vary from these preliminary estimates. Such variances may be material; accordingly, you should not place undue reliance on these preliminary estimates.

General risks relating to Laredo include, but are not limited to, the decline in prices of oil, NGL 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, 2014, its Quarterly Report on Form 10-Q for the quarter ended March 31, 2015 and those set forth from time to time in other filings 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 ("EDGAR") 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, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. EURs are based on the Company's previous operating experience in a given area and publicly available information relating to the operations of producers who are conducting operations in these areas. Unbooked resource potential or EURs do not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities of reserves that may be ultimately recovered from the Company's interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly *affected by the availability of capital, decreases in oil and natural gas prices, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, negative revisions to reserve estimates and other factors as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves may change significantly as development of the Company's core assets provides additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.*

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Contact:
Ron Hagood: (918) 858-5504 - RHagood@laredopetro.com

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Laredo Petroleum, Inc.
Condensed consolidated statements of operations

(in thousands, except per share data)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales	$ 125,554	$ 182,872	$ 243,672	$ 356,086
Midstream service revenues	1,726	172	3,035	268
Sales of purchased oil	55,051	—	86,318	—
Total revenues	182,331	183,044	333,025	356,354
Costs and expenses:				
Lease operating expenses	29,206	20,179	61,586	41,964
Production and ad valorem taxes	9,500	13,160	18,586	25,610
Midstream service expenses	1,597	1,526	3,171	2,371
Minimum volume commitments	3,579	588	5,235	1,104
Costs of purchased oil	54,417	—	85,617	—
General and administrative	23,208	29,552	45,063	57,206
Restructuring expenses	—	—	6,042	—
Accretion of asset retirement obligations	593	422	1,172	837
Depletion, depreciation and amortization	72,112	53,056	144,054	102,663
Impairment expense	489,599	—	490,477	—
Total costs and expenses	683,811	118,483	861,003	231,755
Operating income (loss)	(501,480)	64,561	(527,978)	124,599
Non-operating income (expense):				
Loss on derivatives, net	(63,899)	(63,125)	(744)	(94,237)
Income (loss) from equity method investee	2,914	(41)	2,481	(25)
Interest expense	(23,970)	(30,657)	(56,384)	(59,643)
Loss on early redemption of debt	(31,537)	—	(31,537)	—
Other	(908)	(11)	(1,547)	(73)
Non-operating expense, net	(117,400)	(93,834)	(87,731)	(153,978)
Loss before income taxes	(618,880)	(29,273)	(615,709)	(29,379)
Income tax benefit:				
Deferred	221,846	10,374	218,203	10,267
Total income tax benefit	221,846	10,374	218,203	10,267
Net loss	$ (397,034)	$ (18,899)	$ (397,506)	$ (19,112)
Net loss per common share:				
Basic	$ (1.88)	$ (0.13)	$ (2.13)	$ (0.14)
Diluted	$ (1.88)	$ (0.13)	$ (2.13)	$ (0.14)
Weighted-average common shares outstanding:				
Basic	211,078	141,298	186,886	141,183
Diluted	211,078	141,298	186,886	141,183

Laredo Petroleum, Inc.
Condensed consolidated balance sheets

(in thousands)	June 30, 2015	December 31, 2014
Assets:	(unaudited)	(unaudited)
Current assets	$ 314,745	$ 365,253
Net property and equipment	3,085,280	3,354,082
Other noncurrent assets	302,004	213,214
Total assets	$ 3,702,029	$ 3,932,549
Liabilities and stockholders' equity:		
Current liabilities	$ 310,074	$ 425,025
Long-term debt	1,425,000	1,801,295
Other noncurrent liabilities	38,008	143,028
Stockholders' equity	1,928,947	1,563,201
Total liabilities and stockholders' equity	$ 3,702,029	$ 3,932,549

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

(in thousands)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net loss	$ (397,034)	$ (18,899)	$ (397,506)	$ (19,112)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Deferred income tax benefit	(221,846)	(10,374)	(218,203)	(10,267)
Depletion, depreciation and amortization	72,112	53,056	144,054	102,663
Impairment expense	489,599	—	490,477	—
Loss on early redemption of debt	31,537	—	31,537	—
Non-cash stock-based compensation, net of amounts capitalized	6,268	6,396	11,056	10,725
Mark-to-market on derivatives:				
Loss on derivatives, net	63,899	63,125	744	94,237
Cash settlements received (paid) for matured derivatives, net	46,596	(4,420)	109,737	(5,851)
Cash settlements received for early terminations of derivatives, net	—	—	—	76,660
Cash premiums paid for derivatives	(1,249)	(1,820)	(2,670)	(3,779)
Amortization of debt issuance costs	1,124	1,305	2,501	2,512
Other	(1,166)	669	(2,119)	1,226
Cash flows from operations before changes in working capital	89,840	89,038	169,608	249,014
Changes in working capital	(3,209)	20,471	(57,295)	(11,710)
Changes in other noncurrent liabilities and fair value of performance unit awards	809	2,473	1,992	2,795
Net cash provided by operating activities	87,440	111,982	114,305	240,099
Cash flows from investing activities:				
Capital expenditures:				
Acquisition of oil and natural gas properties	—	(6,493)	—	(6,493)
Acquisition of mineral interests	—	—	—	(7,305)
Oil and natural gas properties	(130,775)	(225,171)	(374,508)	(412,211)
Midstream service assets	(13,703)	(15,389)	(34,137)	(25,909)
Other fixed assets	(2,622)	(5,067)	(6,541)	(8,436)
Investment in equity method investee	—	(8,171)	(14,495)	(19,471)
Proceeds from dispositions of capital assets, net of costs	—	329	35	597
Net cash used in investing activities	(147,100)	(259,962)	(429,646)	(479,228)
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility	125,000	—	300,000	—
Payments on Senior Secured Credit Facility	—	—	(475,000)	—
Issuance of March 2023 and January 2022 Notes	—	—	350,000	450,000
Redemption of January 2019 Notes	(576,200)	—	(576,200)	—
Proceeds from issuance of common stock, net of offering costs	—	—	754,163	—
Other	(640)	(33)	(9,350)	(9,518)
Net cash (used in) provided by financing activities	(451,840)	(33)	343,613	440,482
Net (decrease) increase in cash and cash equivalents	(511,500)	(148,013)	28,272	201,353
Cash and cash equivalents, beginning of period	569,093	547,519	29,321	198,153
Cash and cash equivalents, end of period	$ 57,593	$ 399,506	$ 57,593	$ 399,506

Laredo Petroleum, Inc.
Selected operating data

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(unaudited)		(unaudited)	
Sales volumes[1]:				
Oil (MBbl)	1,938	1,513	4,110	2,934
NGL (MBbl)	1,095	—	2,084	—
Natural gas (MMcf)	7,205	6,567	13,885	12,643
Oil equivalents (MBOE)[2][3]	4,234	2,607	8,508	5,041
Average daily sales volumes (BOE/D)[3]	46,532	28,653	47,007	27,852
% Oil	46%	58%	48%	58%
Average sales prices[1]:				
Oil, realized ($/Bbl)[4]	$ 50.77	$ 94.47	$ 45.99	$ 93.17
NGL, realized ($/Bbl)[4]	$ 12.85	$ —	$ 13.08	$ —
Natural gas, realized ($/Mcf)[4]	$ 1.82	$ 6.08	$ 1.97	$ 6.54
Average price, realized ($/BOE)[4]	$ 29.65	$ 70.13	$ 28.64	$ 70.63
Oil, hedged ($/Bbl)[5]	$ 72.39	$ 90.55	$ 70.87	$ 90.25
NGL, hedged ($/Bbl)[5]	$ 12.85	$ —	$ 13.08	$ —
Natural gas, hedged ($/Mcf)[5]	$ 2.29	$ 6.04	$ 2.32	$ 6.46
Average price, hedged ($/BOE)[5]	$ 40.36	$ 67.75	$ 41.22	$ 68.73
Average costs per BOE sold[1]:				
Lease operating expenses	$ 6.90	$ 7.74	$ 7.24	$ 8.32
Production and ad valorem taxes	2.24	5.05	2.18	5.08
Midstream service expenses	0.38	0.59	0.37	0.47
General and administrative[6]	5.48	11.34	5.30	11.35
Depletion, depreciation and amortization	17.03	20.35	16.93	20.37
Total	$ 32.03	$ 45.07	$ 32.02	$ 45.59

(1) For periods prior to January 1, 2015, we presented our sales volumes, average sales prices for oil and natural gas and average costs per BOE sold, which combined NGL with the natural gas stream, and did not separately report NGL. This change impacts the comparability of the two periods presented.

(2) Bbl equivalents are calculated using a conversion rate of six Mcf per one Bbl.

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

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

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

(6) General and administrative includes non-cash stock-based compensation, net of amount capitalized, of $6.3 million and $6.4 million for the three months ended June 30, 2015 and 2014, respectively, and $11.1 million and $10.7 million for the six months ended June 30, 2015 and 2014, respectively.

Costs incurred

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

(in thousands)	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
	(unaudited)		(unaudited)	
Property acquisition costs:				
Evaluated	$ —	$ 3,848	$ —	$ 3,873
Unevaluated	—	2,645	—	9,925
Exploration	3,841	8,143	8,354	16,642
Development costs[1]	110,518	220,240	317,190	408,553
Total costs incurred	$ 114,359	$ 234,876	$ 325,544	$ 438,993

(1) The costs incurred for oil and natural gas development activities include $0.5 million and $0.9 million in asset retirement obligations for the three months ended June 30, 2015 and 2014, respectively, and $1.0 million and $1.5 million for the six months ended June 30, 2015 and 2014, respectively.

Laredo Petroleum, Inc.

Supplemental reconciliation of GAAP to non-GAAP financial measures
(Unaudited)

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

Adjusted Net Income is a non-GAAP financial measure used by the Company to evaluate performance, prior to gains or losses on derivatives, cash settlements of matured commodity derivatives, cash settlements on early terminated commodity derivatives, impairment expense, restructuring expenses, loss on early redemption of debt, buyout of minimum volume commitment, gains or losses on disposal of assets, write-off of debt issuance costs and bad debt expense.

The following presents a reconciliation of net loss to Adjusted Net Income:

	Three months ended June 30,		Six months ended June 30,	
(in thousands, except for per share data, unaudited)	2015	2014	2015	2014
Net loss	$ (397,034)	$ (18,899)	$ (397,506)	$ (19,112)
Plus:				
Impairment expense	489,599	—	490,477	—
Restructuring expenses	—	—	6,042	—
Loss on derivatives, net	63,899	63,125	744	94,237
Cash settlements received (paid) for matured commodity derivatives, net	46,596	(4,420)	109,737	(5,851)
Cash settlements received for early terminations of commodity derivatives, net	—	—	—	76,660
Write-off of debt issuance costs	—	—	—	124
Loss on disposal of assets, net	1,081	205	1,843	226
Loss on early redemption of debt	31,537	—	31,537	—
Buyout of minimum volume commitment	3,014	—	3,014	—
	238,692	40,011	245,888	146,284
Income tax adjustment(1)	(228,861)	(20,619)	(231,622)	(57,889)
Adjusted Net Income	$ 9,831	$ 19,392	$ 14,266	$ 88,395
Adjusted Net Income per common share:				
Basic	$ 0.05	$ 0.14	$ 0.08	$ 0.63
Diluted	$ 0.05	$ 0.14	$ 0.08	$ 0.63
Weighted-average common shares outstanding:				
Basic	211,078	141,298	186,886	141,183
Diluted	211,078	141,298	186,886	141,183

(1) The income tax adjustment is calculated by applying the tax rate of 36% for the three and six months ended June 30, 2015, respectively, and 35% for the three and six months ended June 30, 2014, respectively.

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 and amortization, bad debt expense, impairment expense, non-cash stock-based compensation, restructuring expenses, gains or losses on derivatives, cash settlements of matured commodity derivatives, cash settlements on early terminated commodity derivatives, premiums paid for derivatives that matured during the period, interest expense, write-off of debt issuance costs, gains or losses on disposal of assets, loss on early redemption of debt and buyout of minimum volume commitment. 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 loss to Adjusted EBITDA:

	Three months ended June 30,		Six months ended June 30,	
(in thousands, unaudited)	**2015**	**2014**	**2015**	**2014**
Net loss	$ (397,034)	$ (18,899)	$ (397,506)	$ (19,112)
Plus:				
Deferred income tax benefit	(221,846)	(10,374)	(218,203)	(10,267)
Depletion, depreciation and amortization	72,112	53,056	144,054	102,663
Impairment expense	489,599	—	490,477	—
Non-cash stock-based compensation, net of amounts capitalized	6,268	6,396	11,056	10,725
Restructuring expenses	—	—	6,042	—
Loss on derivatives, net	63,899	63,125	744	94,237
Cash settlements received (paid) for matured commodity derivatives, net	46,596	(4,420)	109,737	(5,851)
Cash settlements received for early terminations of commodity derivatives, net	—	—	—	76,660
Premiums paid for derivatives that matured during the period[1]	(1,249)	(1,820)	(2,670)	(3,779)
Interest expense	23,970	30,657	56,384	59,643
Write-off of debt issuance costs	—	—	—	124
Loss on disposal of assets, net	1,081	205	1,843	226
Loss on early redemption of debt	31,537	—	31,537	—
Buyout of minimum volume commitment	3,014	—	3,014	—
Adjusted EBITDA	$ 117,947	$ 117,926	$ 236,509	$ 305,269

(1) Reflects premiums incurred previously or upon settlement that are attributable to instruments settled in the respective periods presented.

EXHIBIT 99.2

Forward-Looking / Cautionary Statements

This presentation (which includes oral statements made in connection with this presentation) contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical fact, included in this presentation that address activities, events or developments that Laredo Petroleum, Inc. (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 as to the Company's drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and rate of return and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, availability and cost of drilling equipment and personnel, availability of sufficient capital to execute the Company's business plan, impact of compliance with legislation and regulations, successful results from the Company's identified drilling locations, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company's Annual Report on Form 10-K for the year ended December 31, 2014, its Quarterly Report on Form 10-Q for the quarter ended March 31, 2015 and other reports filed with the Securities Exchange Commission ("SEC").

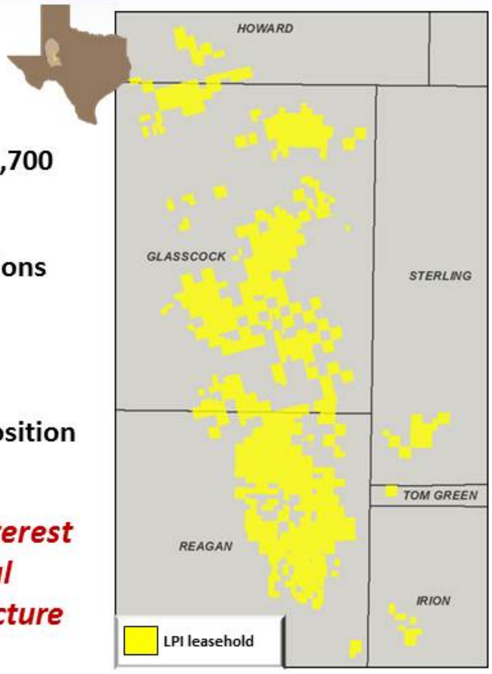
Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

The SEC generally permits oil and 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 presentation, the Company may use the terms "unproved reserves", "resource potential", "estimated ultimate recovery", "EUR", "development ready", "horizontal commerciality confirmed", "horizontal commerciality 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. 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, 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.

High-Quality Contiguous Acreage

- 179,713 Gross/149,921 net acres[1]
- ~4.3 billion barrels of resource potential on >7,700 identified locations
- ~3,200 operated Development Ready Hz locations with >90% average WI
- ~95% average WI in operated wells[1]
- Current drilling plan preserves core acreage position

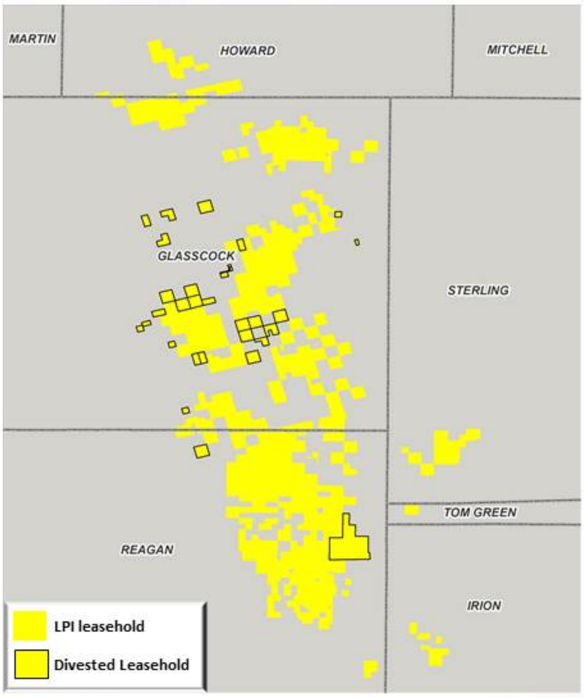
Contiguous acreage with high working interest enables Laredo to achieve operational efficiencies by leveraging data, infrastructure and maximizing resource recovery



[1] As of 6/30/15

Divestiture of Non-Strategic Properties

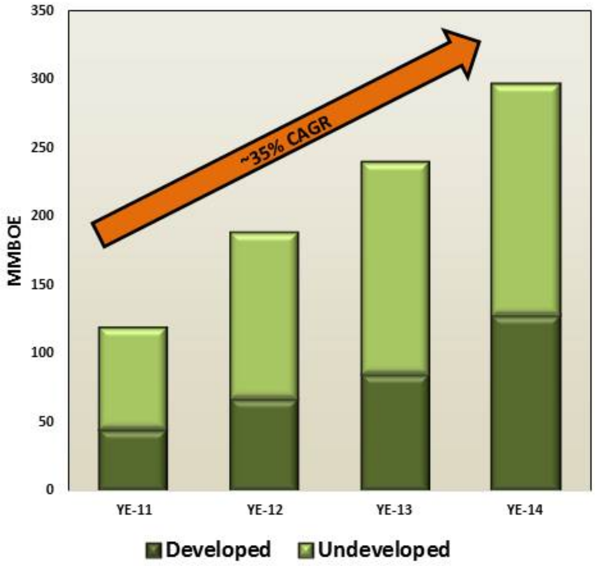
- **Recently announced agreement to sell non-strategic properties**
  - **Expected to close September 2015**
- **~5,882 net acres**
  - **Primarily non-operated**
- **Sales proceeds of ~$65 million[1]**
- **Proceeds utilized to fund 11-well project on Reagan North Corridor**
  - **Leverages LMS infrastructure**
  - **10,000' laterals targeting Upper and Middle Wolfcamp**
  - **Locations selected utilized the Earth Model**

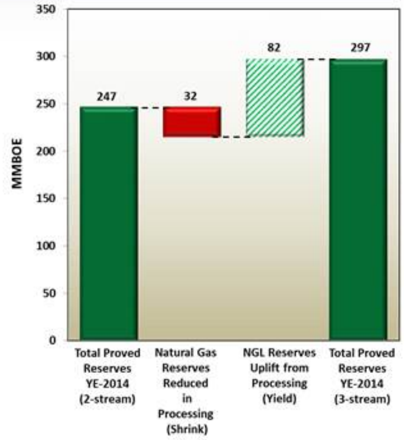


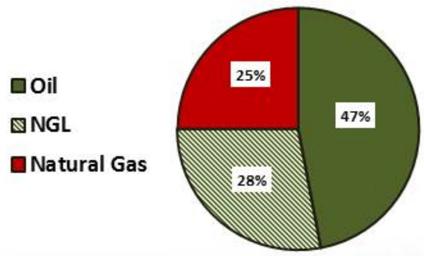
[1] Subject to customary closing conditions

2014 Reserve Summary

Permian Year-End Reserves[1]

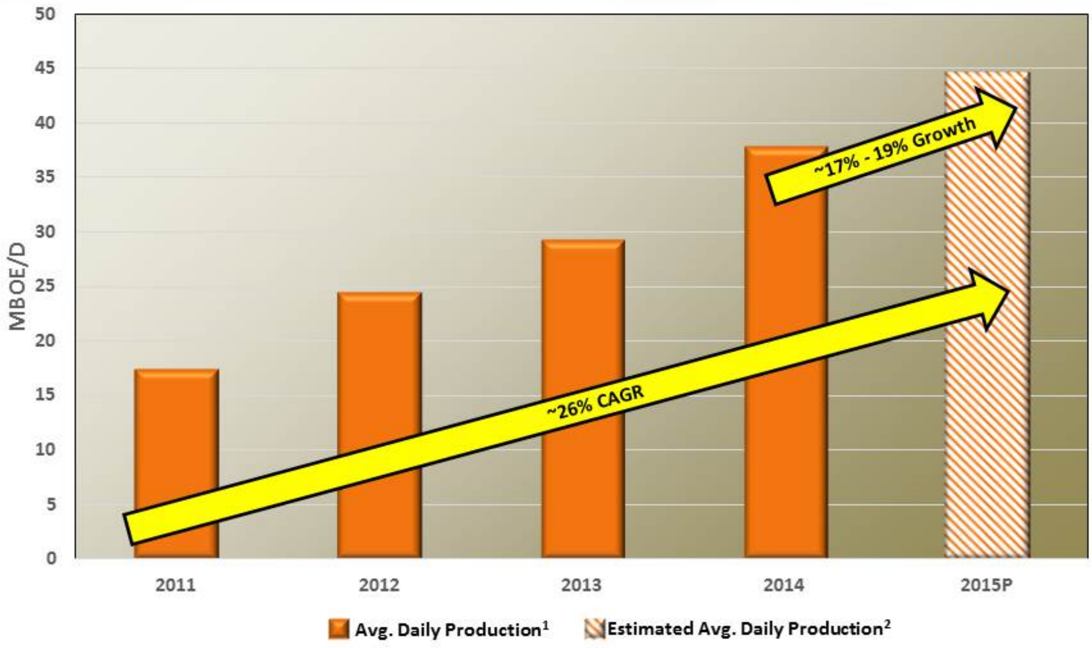






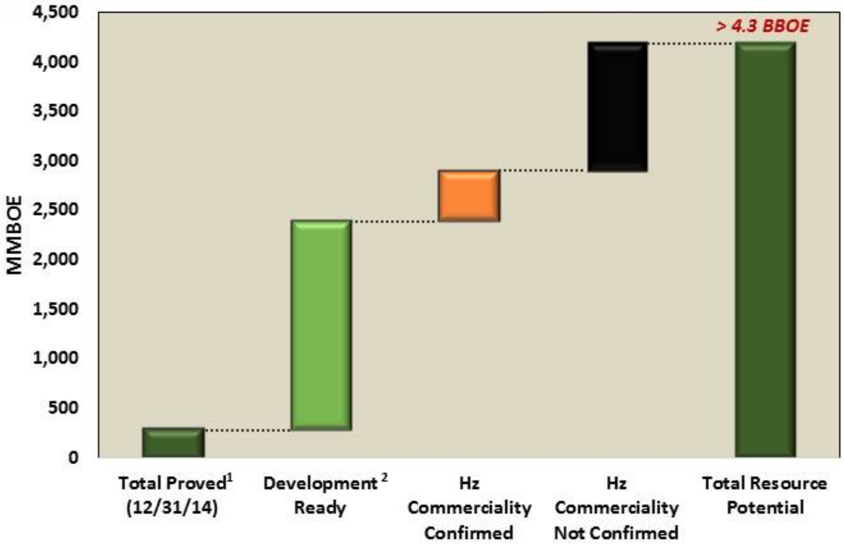
[1] *Based on YE-2014 2-stream proved reserves, prepared by Ryder Scott. Internally converted to 3-stream based on actual gas plant economics of 30% shrink and a yield of 127 Bbl of NGL per MMcf. Annual reserve volumes prior to 2014* have been converted to 3-stream using an 18% uplift

2015 Estimated Production Growth



[1] Quarterly production numbers prior to 2014 have been converted to 3-stream using an 18% uplift. 2014 quarterly results have been converted to 3-stream using actual gas plant economics
[2] Based on midpoint of guidance of 16.1 MMBOE – 16.5 MMBOE for full-year 2015

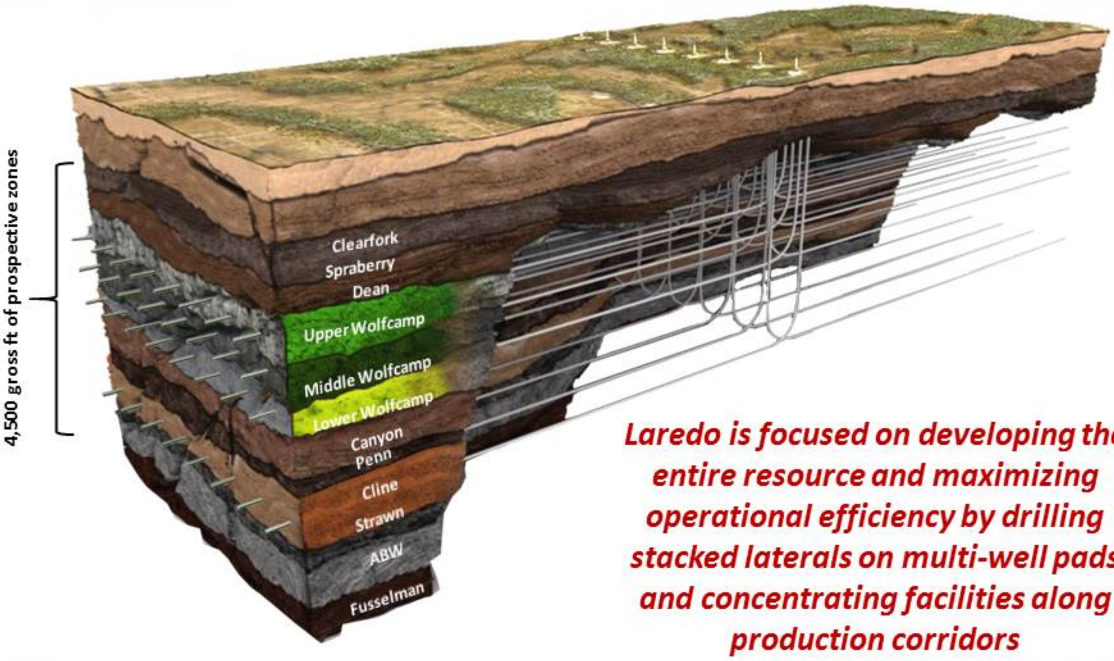
Identified Resource Potential



Approximately 4.3 billion barrels of resource potential from an inventory of ~7,700 low-risk drilling locations

[1] *Based on YE-2014 2-stream proved reserves, prepared by Ryder Scott. Internally converted to 3-stream based on actual gas plant economics of 30% shrink and a yield of 127 Bbl of NGL per MMcf*
[2] *Additional development ready resource not already included in Total Proved reserves*

Developing to Maximize NPV



Laredo is focused on developing the entire resource and maximizing operational efficiency by drilling stacked laterals on multi-well pads and concentrating facilities along production corridors

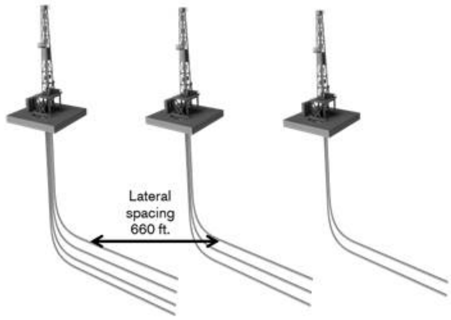
Not to scale

Efficient Development of the Entire Resource

Stacked Lateral Multi-Well Pads

# of pads completed	Four-stacked	Three-stacked	Two-stacked
	2	11	23

87 wells total[1]



As of Q2 '15, Laredo has completed 87 wells on 36 multi-well pads

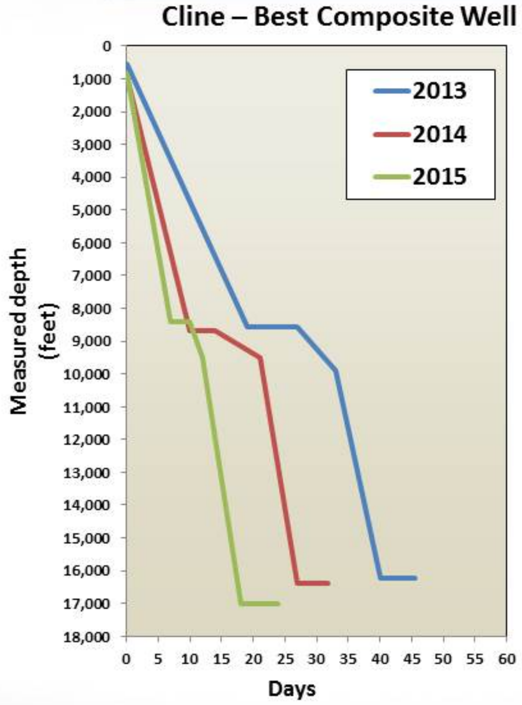
Horizontal Wells on Multi-Well Pads	
2013	13
2014	56
2015	18

- Average cost savings on a multi-well pad ~$400K / well
- Reduces cycle-time
- Reduces surface footprint

Laredo capitalizes on its large contiguous land position to be extremely efficient on surface footprint to develop all zones

[1] Independent wellbores

Best Composite Well: Cline Example



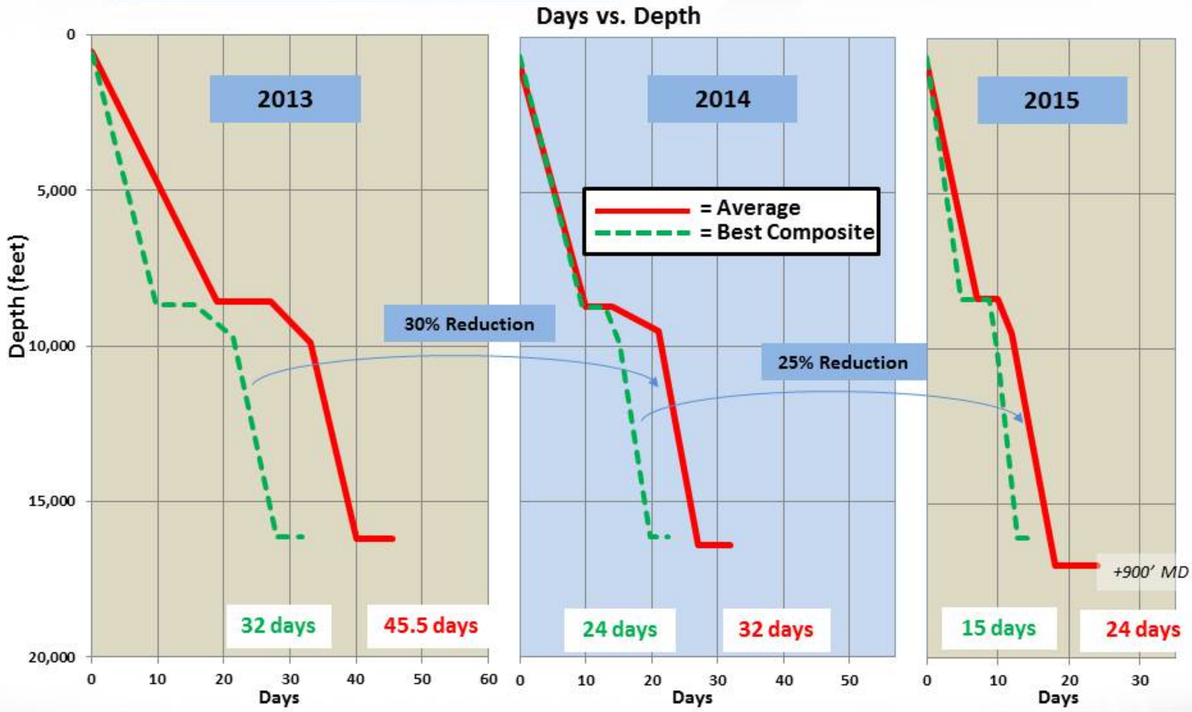
Composite well goals

- Continuous improvement
- Identification of best practices
- Implementation of best practices

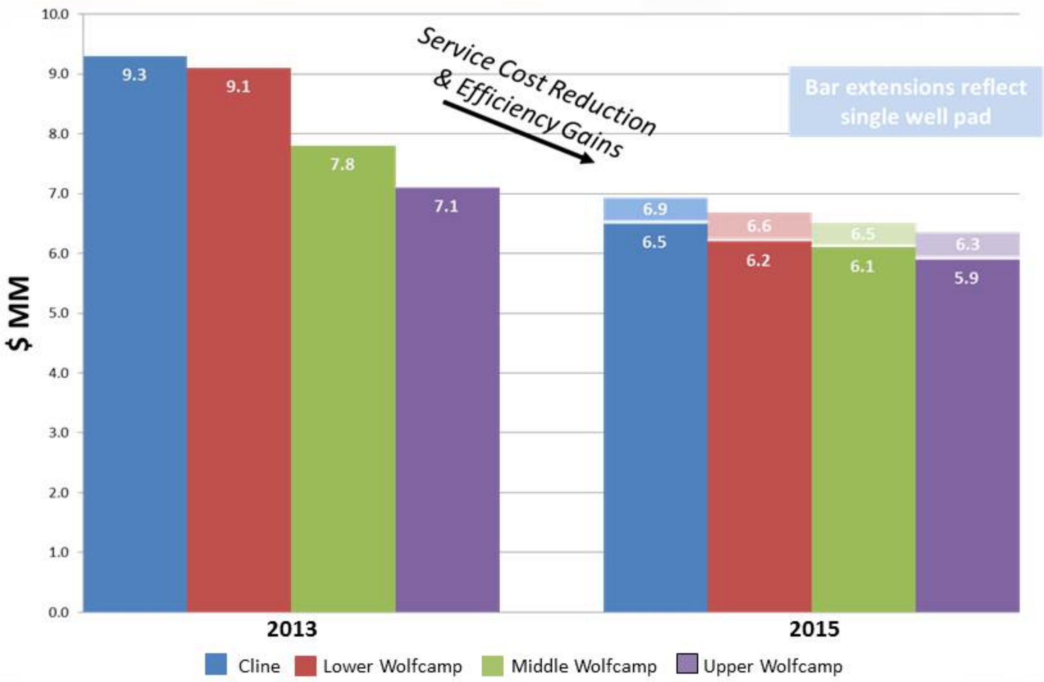
Composite well process

- Well divided into key sections
- Best performance key sections identified
- Best practices identified
  - Operational practices
  - Operating parameters
- Lessons learned applied to future wells
  - Incorporated in well plans
  - Weekly meetings/discussions
  - Operating parameter Monitoring

Substantial Reduction in Drill Times (Cline Example)

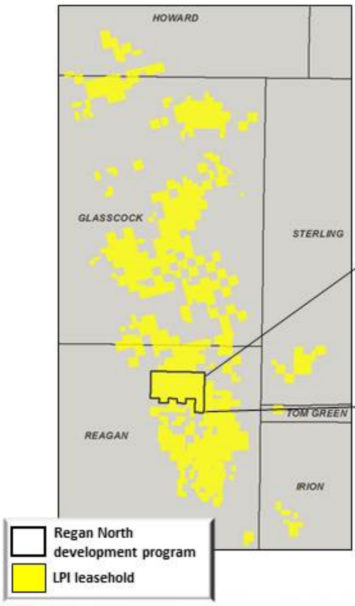


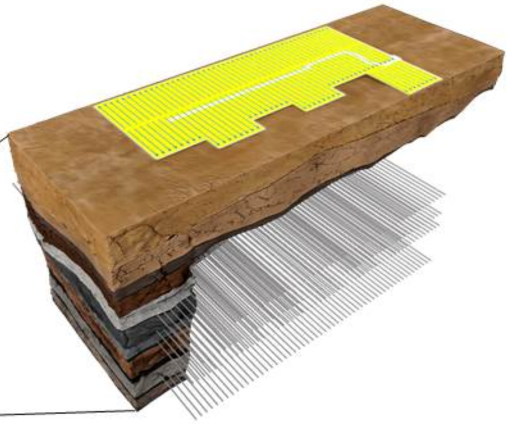
Well Cost Evolution (7,500' Laterals)



Contiguous Acreage Enables Efficient Development

Centralization of infrastructure provides benefits of ~$1.2 MM per well



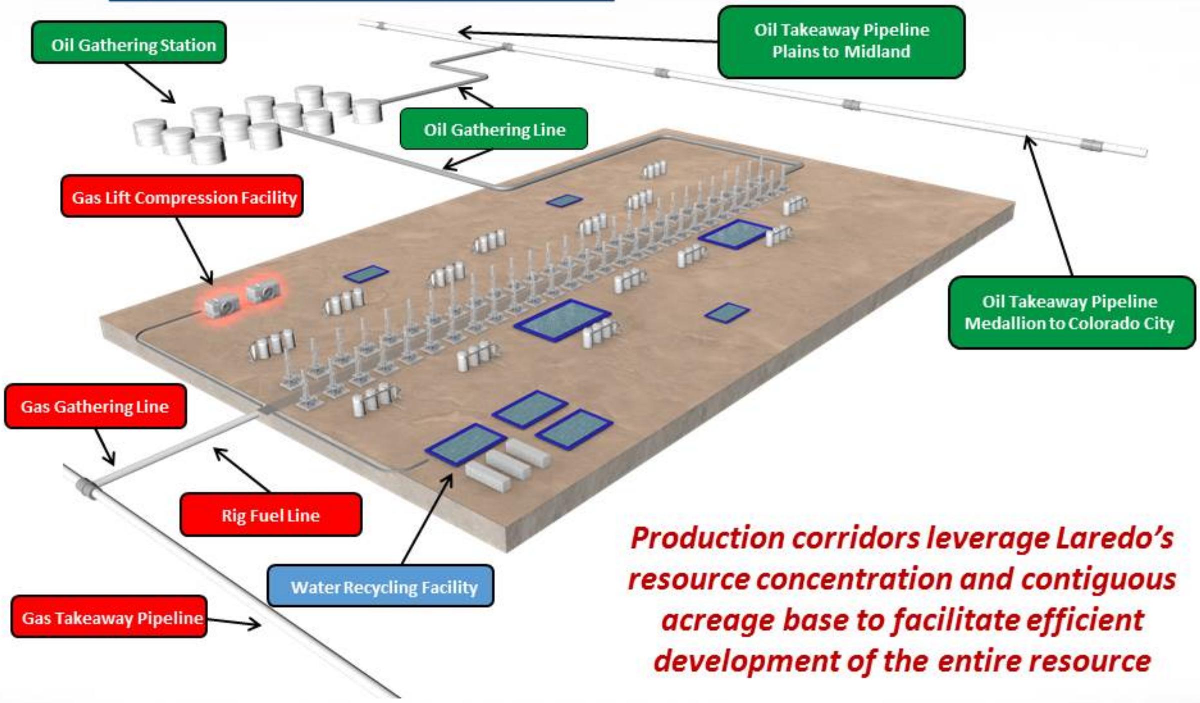


A four-well completion requires[1]:

- 1,000,000 barrels of water in two weeks
- Takeaway capacity for ~82,500 BOE per month during peak production
- Takeaway capacity for ~93,000 barrels of water per month during peak production

[1] Assumes two 7,500' Upper Wolfcamp and two 7,500' Middle Wolfcamp horizontal wells

Infrastructure Integrated with Complete Development Plan



Production corridors leverage Laredo's resource concentration and contiguous acreage base to facilitate efficient development of the entire resource

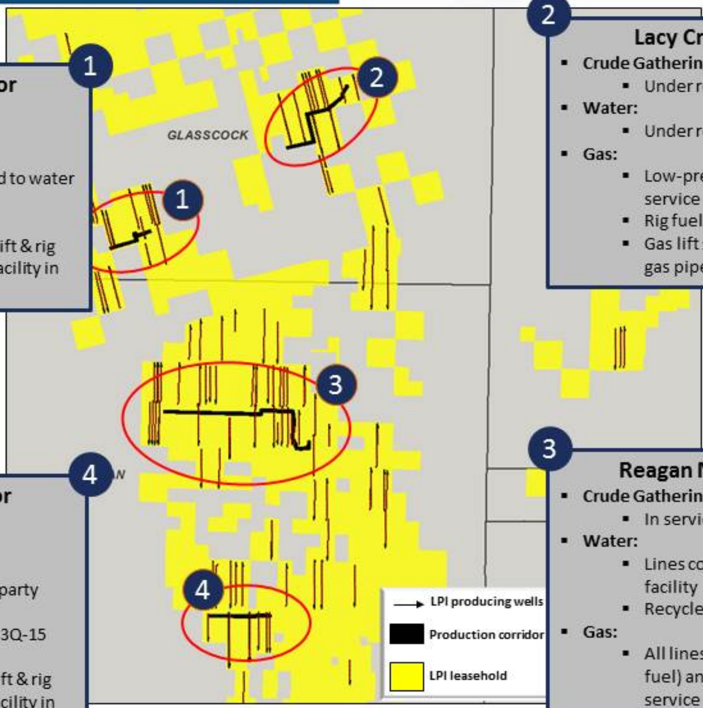
Production Corridor Status

1 JE Cox/Blanco Corridor

- **Crude Gathering:**
  - In service
- **Water:**
  - In service and connected to water recycle facility
- **Gas:**
  - All lines (gathering, gas lift & rig fuel) and compression facility in service

2 Lacy Creek Corridor

- **Crude Gathering:**
  - Under review
- **Water:**
  - Under review
- **Gas:**
  - Low-pressure gas gathering in service
  - Rig fuel line in service
  - Gas lift supply from EnLink lean gas pipeline in service



4 Reagan South Corridor

- **Crude Gathering:**
  - In service
- **Water:**
  - Lines constructed to 3rd- party SWD
  - Expected in service date 3Q-15
- **Gas:**
  - All lines (gathering, gas lift & rig fuel) and compression facility in service

3 Reagan North Corridor

- **Crude Gathering:**
  - In service
- **Water:**
  - Lines constructed to recycle facility
  - Recycle facility in service
- **Gas:**
  - All lines (gathering, gas lift & rig fuel) and compression facility in service

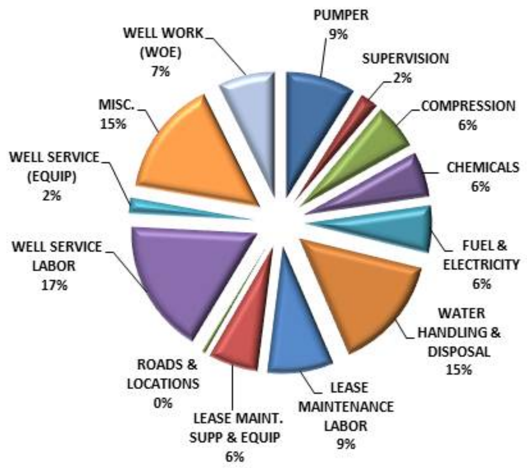
Reagan North Corridor

Per well estimated benefits of corridor investment (capital savings, LOE savings and price uplift)

Natural gas for rig fuel, displaces higher cost diesel	**$37,500**
Approximately 40% total investment pays out before well is even producing	
Flowback and produced water savings over life of well	**$253,000**
85% of savings in initial flowback of load water used in completion	
Per well payout occurs at <25% load recovery	
Natural gas for gas lift for first 3 years of well life	**$81,000**
Crude oil gathering price uplift to LPI over life of well	**$356,250**
Crude oil gathering revenue to LMS over life of well	**$281,250**
Reduced gas gathering expense over life of well	**$225,000**
Total estimated benefit of Reagan North Production Corridor *for each well*	**$1,234,000**

$553 million in total estimated benefits from investment of $44 million

Lease Operating Expenses (LOE)

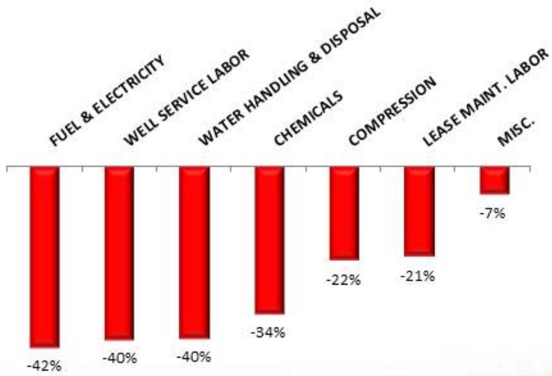


Current Expense Breakdown

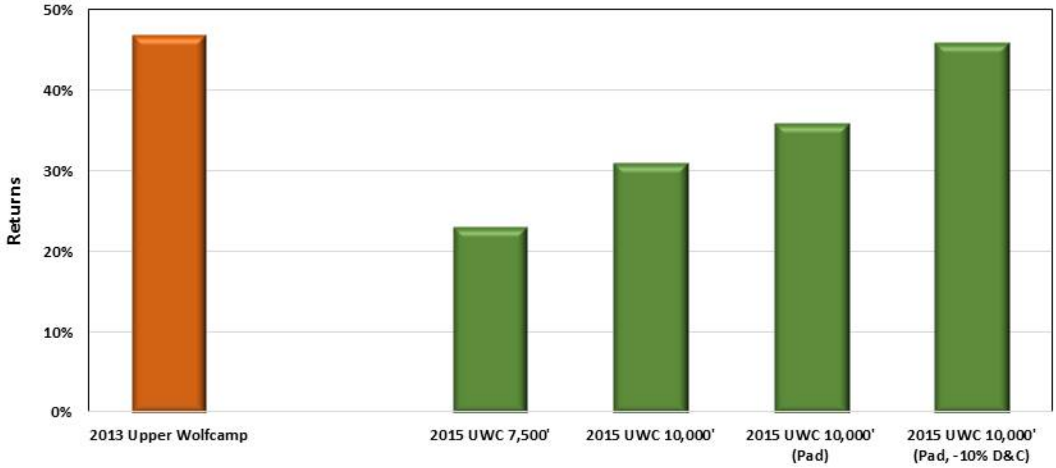
Realizing LOE Annualized Savings

Water: Expanding water management infrastructure
Power: Replacing generators with the grid in new areas
Compression: Well pad compressors to centralized compression
Automation: Bringing SCADA management "in-house"

Lease Maintenance Labor:
Roustabout gang efficiency/management
Per gang service cost reduction
Well Service: Rig cost reduction
Chemicals: Bidding – expect significant cost reduction



Enhancing Well Returns[1,2]



Capital efficiency gains from drilling longer laterals, cost savings from multi-well pad drilling and additional service cost savings can generate well economics in this commodity price environment that rival the returns from a higher oil price environment

[1] 2013 returns reflect $90 oil and $3.75 natural gas
[2] 2015 returns reflect $50 oil and $3.00 natural gas

Earth Model Objectives

Standard Wellbore 1

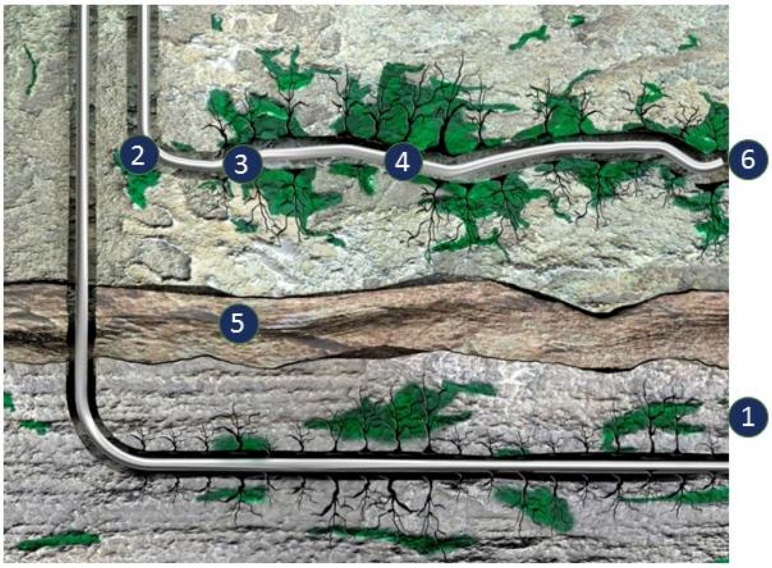
Select Landing Point 2

Geosteering (stay in zone) 3

Frac Design & Spacing 4

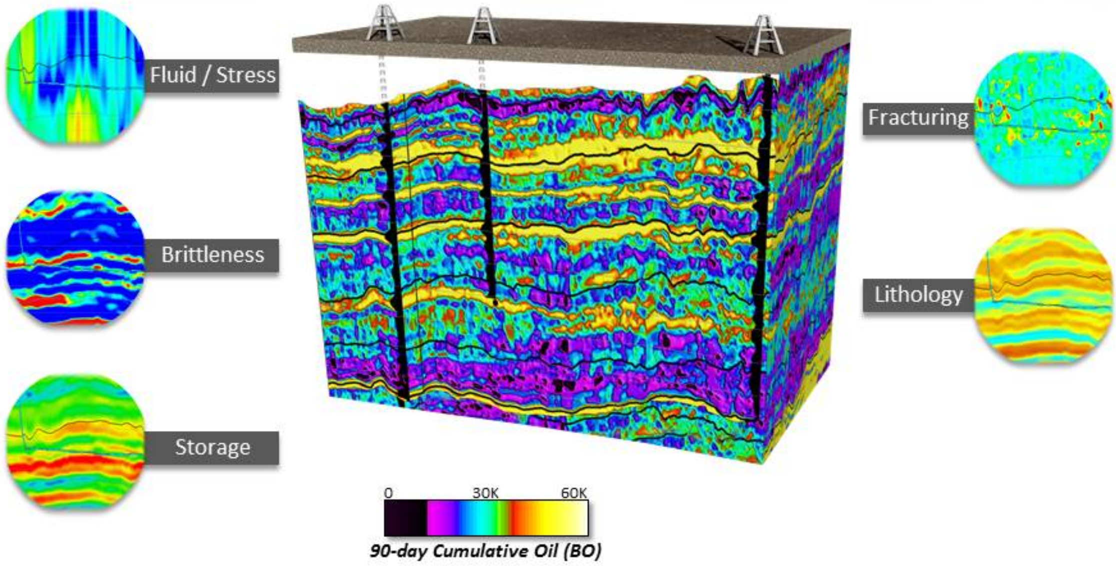
Frac Barrier 5

Lateral Length 6



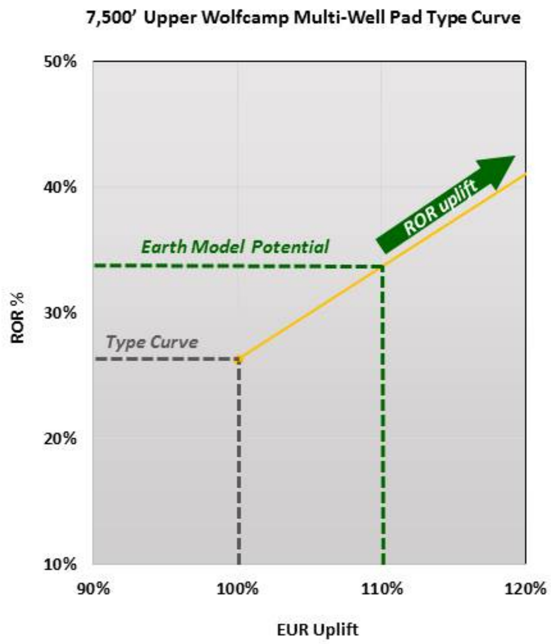
Earth Model potential to optimize development & increase value

3D Production Attribute



Landing, geosteering & staying in-zone fundamentally linked to highest 90-day cumulative oil production

Earth Model Economic "Uplift" Implications

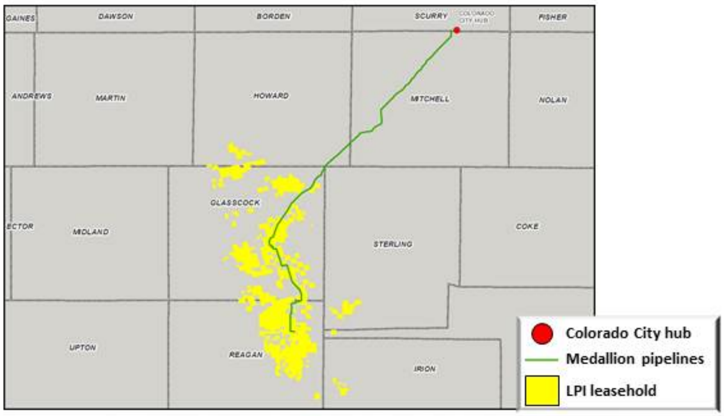


- Anticipate that the Earth Model will be utilized to select the landing point and geosteer for 90% of 2015 horizontal wells
- Landing, geosteering & staying in-zone fundamentally linked to highest 90-day cumulative oil production
- 10% increase in EUR increases ROR by ~25%, from ~26% to ~33%

[1] *Forward strip price deck, as of 4/1/2015*

Colorado City Hub – Enhanced Liquidity

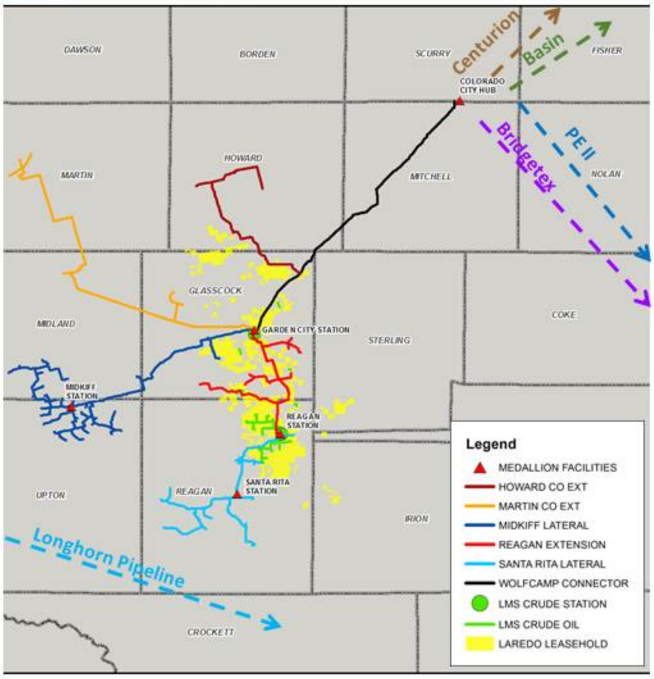
- **Colorado City is an important trading hub for Permian crude oil**
  - **Over 1.7 million BOPD capacity**
  - **Avoids the congestion between Midland and Colorado City**
  - **Provides access to both the Midwest and US Gulf Coast refinery markets**
- **In 2013 partnered with Medallion to build 88-mile crude oil pipeline to Colorado City**
  - **LMS is a 49% partner in the Medallion pipeline system**
  - **LMS is also a firm shipper for 30,000 BOPD* on the pipeline**



*10,000 BOPD in 2015, ramping up to 30,000 BOPD by 2017.

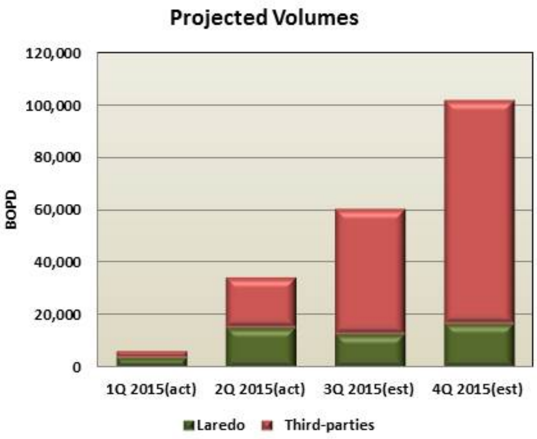
Medallion Crude Oil System Overview

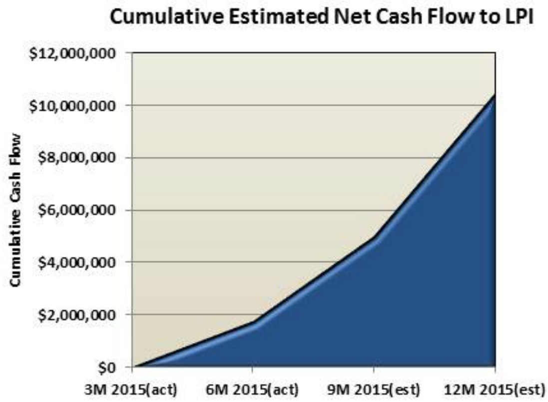
- **Wolfcamp Connector:**
  - ~60 miles of 12"
  - Capacity: ~140,000 BOPD
  - Active October 2014
- **Reagan Extension:**
  - ~53 miles of 4" – 10"
  - Capacity: up to ~90,000 BOPD
  - Active October 2014
- **Midkiff Lateral:**
  - ~95 miles of 4" – 12"
  - Capacity: up to ~150,000 BOPD
  - In-service March 2015
- **Santa Rita Lateral:**
  - ~28 miles of 4" – 10"
  - Capacity: up to ~90,000 BOPD
  - In-service March 2015
- **Howard and Martin County Extensions under construction**



Medallion pipeline system now >400 miles with >290,000 net acres dedicated to system and >1.1 million acres either under AMI or supporting firm commitments on the pipeline

Medallion 2015 Forecast



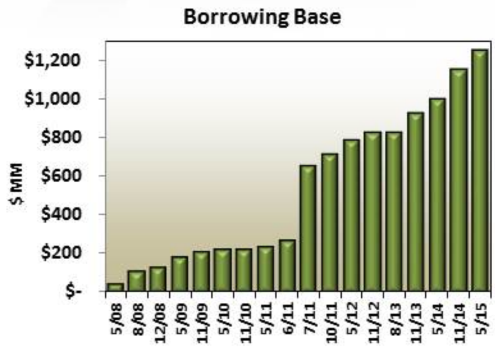


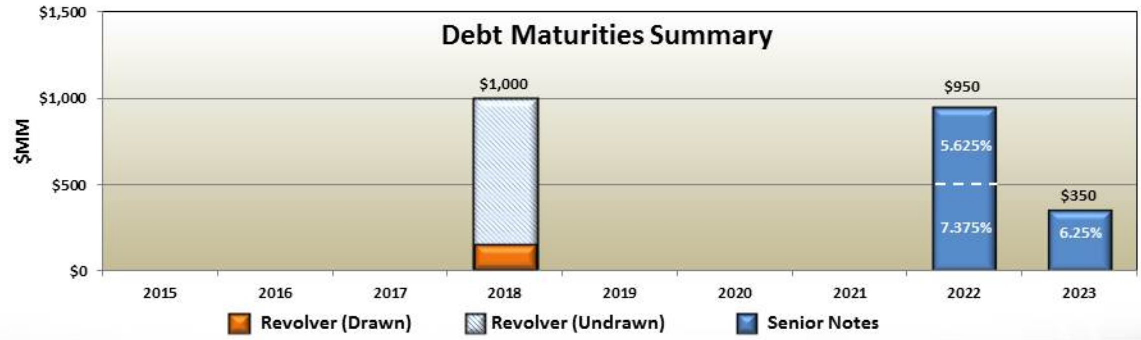
Third-party volume growth driven by continued expansions of the pipeline system and the optionality provided by the redelivery options on the system

Total estimate 2015 LMS net cash flow from the Medallion pipeline of >$10 MM

Financial Flexibility to Enhance Value to Stakeholders

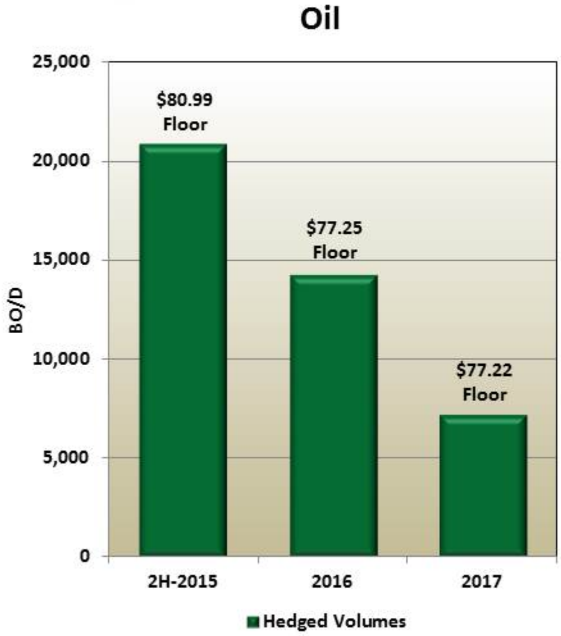
- Decreased total debt ~$675 MM[1]
- Reduced annual interest payment ~$40 MM
- Extended first maturity to seven years
- Reduced weighted-average cost of long-term notes to 6.5%: ⬇110 bps
- Increased liquidity to ~$933 MM[2]

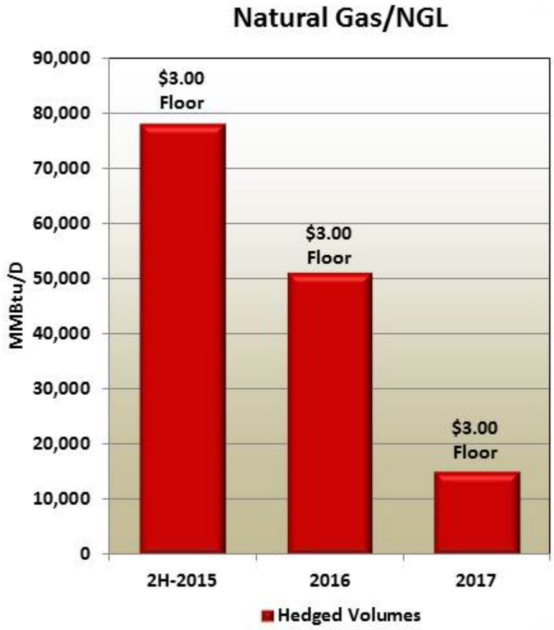




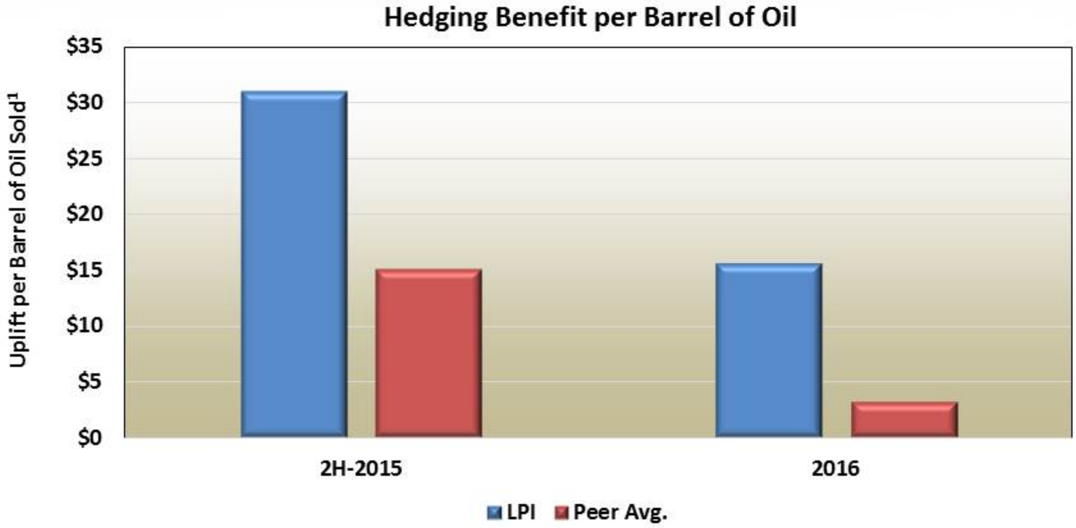
[1] Since 1/1/15
[2] As of 6/30/15

Cash Flow Underpinned With Hedges





Peer Leading Hedging Program



Laredo's hedging program produced approximately $110 million of cash flow in the first six months of 2015

[1] Assumes oil price of $50 per barrel in 2015 and $53 per barrel in 2016
[2] Peer average includes AREX, FANG, PE, PXD and RSPP

2015 Guidance

	3Q-2015	4Q-2015	FY-2015
Production (MMBOE)	3.9 – 4.1	3.7 – 3.9	16.1 – 16.5
Crude oil % of production	~46%	~46%	~47%
Natural gas liquids % of production	~26%	~26%	~25%
Natural gas % of production	~28%	~28%	~28%
Price Realizations (pre-hedge):			
Crude oil (% of WTI)	~88%	~88%	~87%
Natural gas liquids (% of WTI)	~22%	~22%	~22%
Natural Gas (% of Henry Hub)	~70%	~70%	~70%
Operating Costs & Expenses:			
Lease operating expenses ($/BOE)	$6.25 - $7.25	$6.50 - $7.50	$6.50 - $7.50
Midstream expenses ($/BOE)	$0.40 - $0.50	$0.40 - $0.50	$0.40 - $0.50
Production and ad valorem taxes (% of oil and gas revenue)	7.75%	7.75%	7.75%
General and administrative expenses ($/BOE)	$5.75 - $6.75	$5.75 - $6.75	$5.50 - $6.50
Depletion, depreciation and amortization ($/BOE)	$15.50 - $16.50	$15.50 - $16.50	$16.00 - $17.00

Appendix

Building an Extensive Technical Database

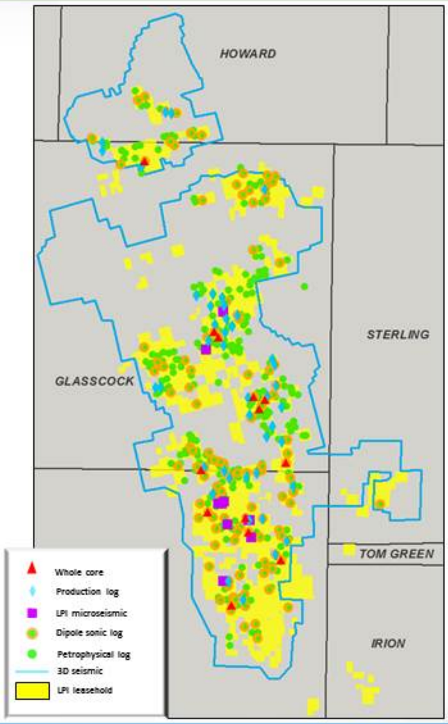
- Technical database consisting of whole cores, sidewall cores, single-zone tests, open-hole logs, 3D seismic and production logs

- Provides the building blocks for identification of resource potential and horizontal locations

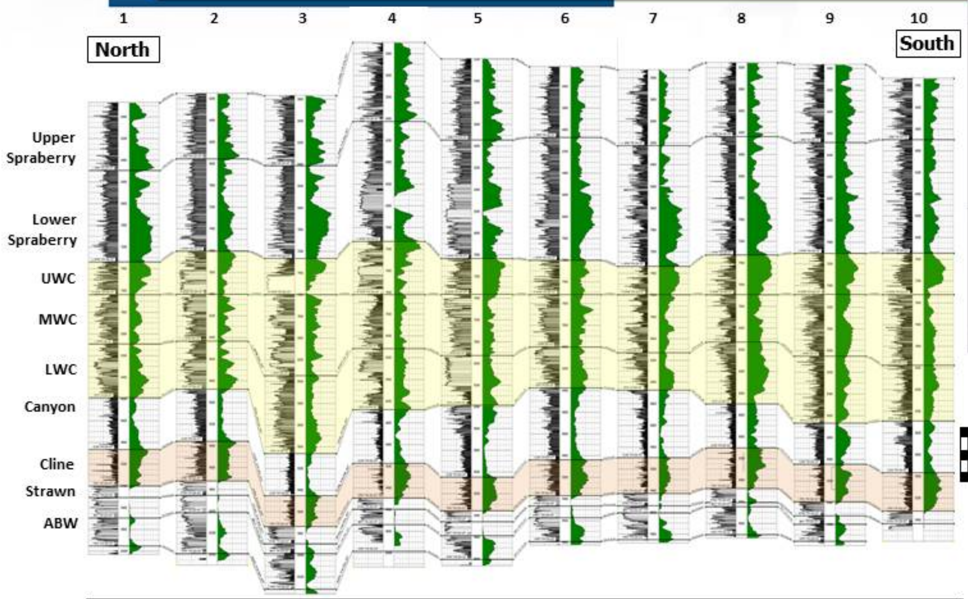
- Majority of technical database attributes are proprietary to Laredo's acreage

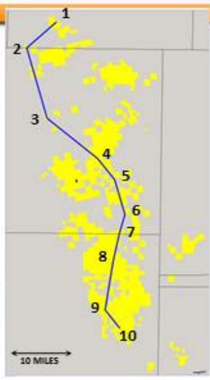
- Timing of data acquisition is integral to data quality

Comprehensive technical database integrated with 3D seismic enables Laredo to successfully identify where to locate and position wells across multiple horizons to maximize value



Regional Cross-Section





Flattened on the Middle Wolfcamp

STOOIP TOTALS	292 MMBO	254 MMBO	305 MMBO	302 MMBO	320 MMBO	322 MMBO	272 MMBO	352 MMBO	354 MMBO	279 MMBO

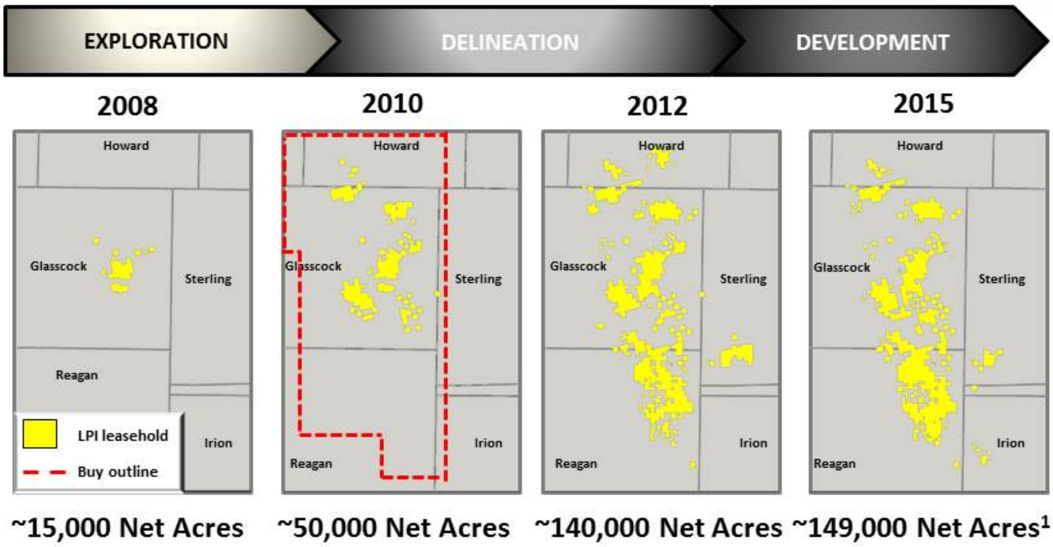
Contiguous thick stratigraphic section from Spraberry through ABW interval indicated by geologic cross-section

ABW – Atoka, Barnett & Woodford

*STOOIP CURVES CALCULATED WITH 50' HEIGHT

$$\text{MMSTOOIP} = \frac{7758 * Phie * (1-Sw) * h * 640ac}{Bo} \Big/ 1{,}000{,}000$$

Land Position Chronology



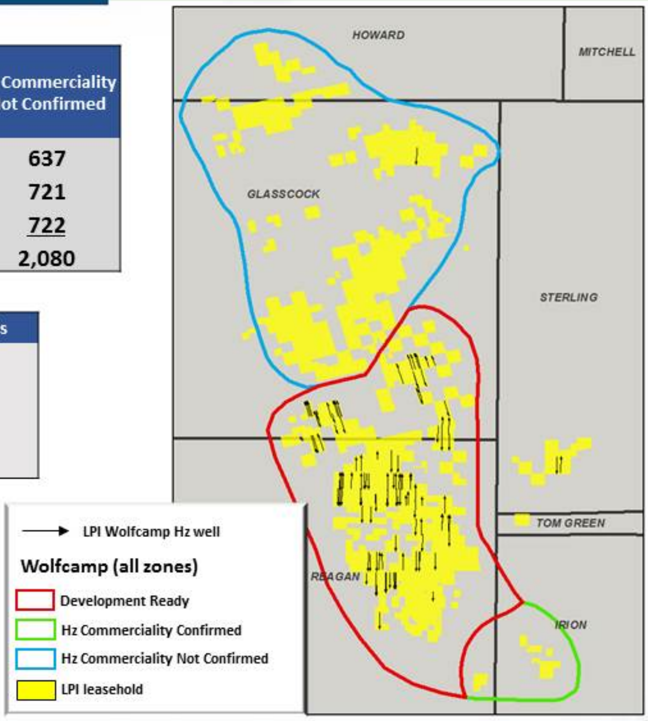
Primary objective has always been to build contiguous acreage positions in the best part of the basin

[1] As of 3/31/15

Wolfcamp Inventory[1]

Formation/Zone	Development Ready	Hz Commerciality Confirmed	Hz Commerciality Not Confirmed
Upper Wolfcamp	828	36	637
Middle Wolfcamp	807	36	721
Lower Wolfcamp	813	36	722
Total	2,448	108	2,080

Formation/Zone	LPI Operated Hz Wells
Upper Wolfcamp	81
Middle Wolfcamp	33
Lower Wolfcamp	23
Total	137

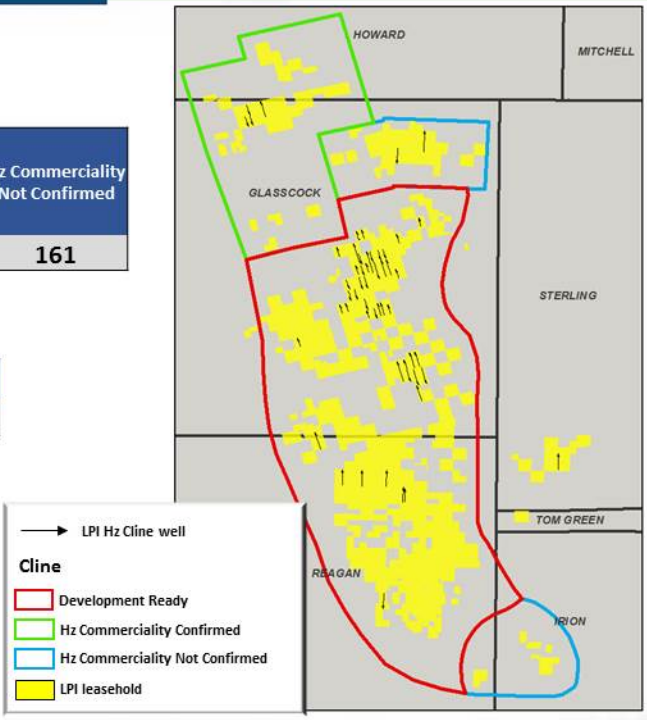


[1] As of 4/13/15

Cline Inventory[1]

Formation/Zone	Development Ready	Hz Commerciality Confirmed	Hz Commerciality Not Confirmed
Cline	1,223	182	161

Formation/Zone	LPI Operated Hz Wells
Cline	52

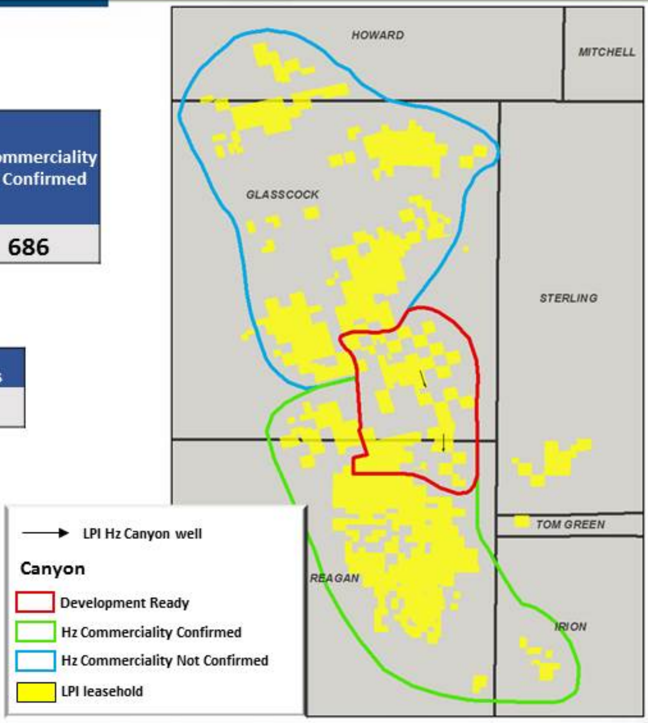


[1] As of 4/13/15

Canyon Inventory[1]

Formation/Zone	Development Ready	Hz Commerciality Confirmed	Hz Commerciality Not Confirmed
Canyon	311	593	686

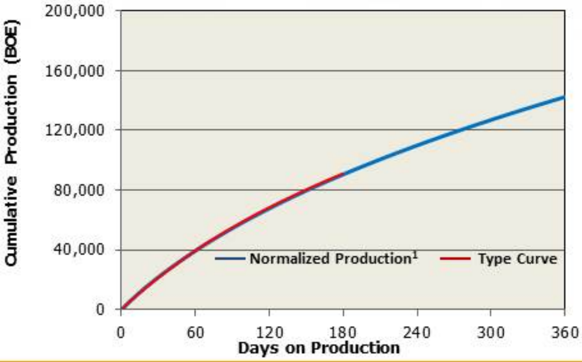
Formation/Zone	LPI Operated Hz wells
Canyon	2

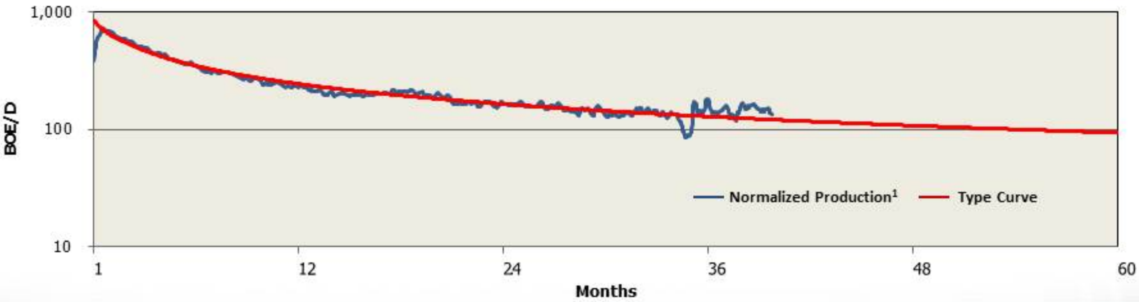


[1] As of 4/13/15

Upper Wolfcamp 7,500' Type Curve

- EUR: 850 MBOE (45% oil)
- 180-day cumulative: 91 MBOE (60% oil)
- 68 UWC wells operated by LPI included in 7,500' type curve normalized production
- PUDs booked: 153 locations
- Total Development Ready: 828 locations[2]

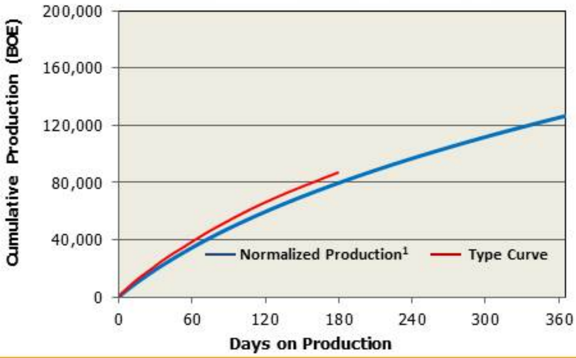


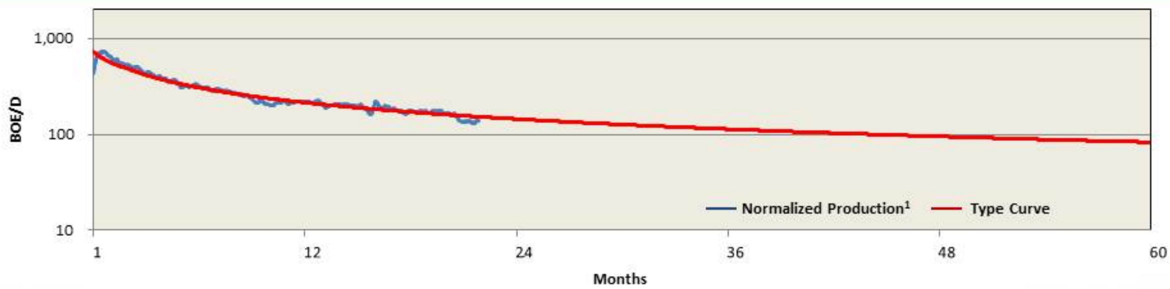


[1] Data includes horizontal wells with lateral lengths >6,000' and 24 stages. As of 6/30/15.
[2] Total Development Ready locations includes PUDs

Middle Wolfcamp 7,500' Type Curve

- EUR: 750 MBOE (50% oil)
- 180-day cumulative: 80 MBOE (61% oil)
- 27 MWC wells operated by LPI included in 7,500' type curve normalized production
- PUDs booked: 34 locations
- Total Development Ready: 807 locations[2]

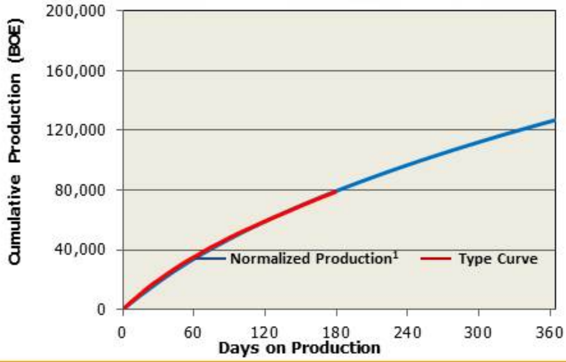


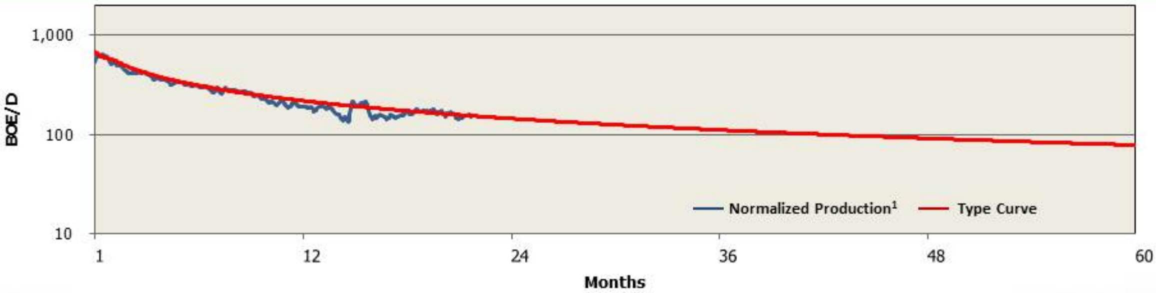


[1] Data includes horizontal wells with lateral lengths >6,000' and 24 stages. As of 6/30/15.
[2] Total Development Ready locations includes PUDs

Lower Wolfcamp 7,500' Type Curve

- EUR: 700 MBOE (45% oil)
- 180-day cumulative: 80 MBOE (55% oil)
- 26 LWC wells operated by LPI included in 7,500' type curve normalized production
- PUDs booked: 45 locations
- Total Development Ready: 813 locations[2]

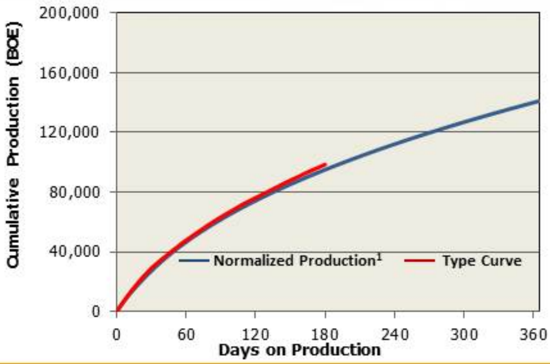


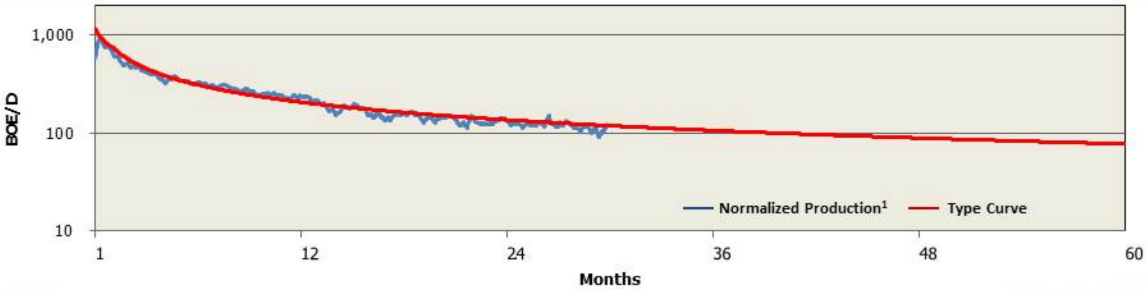


[1] Data includes horizontal wells with lateral lengths >6,000' and 24 stages. As of 6/30/15.
[2] Total Development Ready locations includes PUDs

Cline 7,500' Type Curve

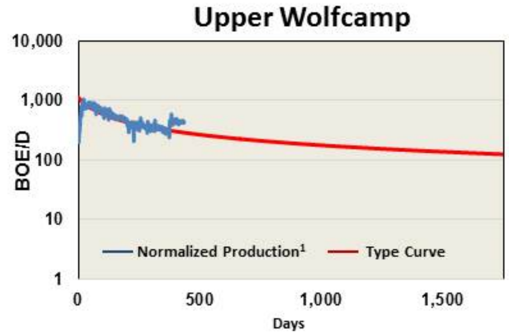
- EUR: 725 MBOE (50% oil)
- 180-day cumulative: 96 MBOE (55% oil)
- 16 Cline wells operated by LPI included in 7,500' type curve normalized production
- PUDs booked: 24 locations
- Total Development Ready: 1,223 locations[2]

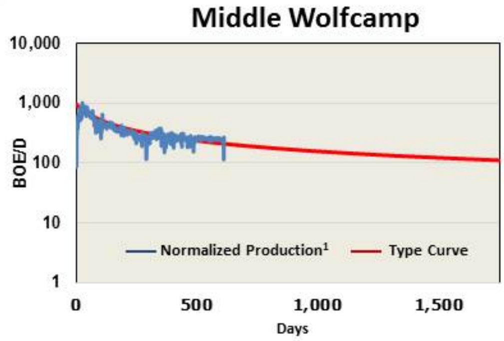


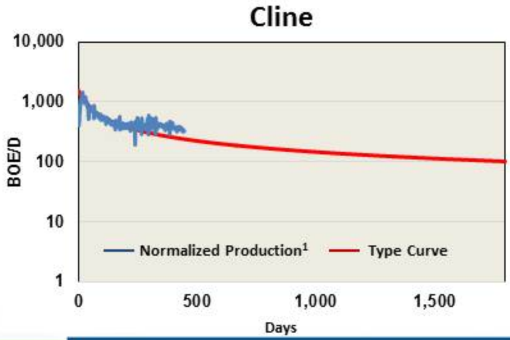


[1] Data includes horizontal wells with lateral lengths > 6,000' and 24 stages. As of 6/30/15.
[2] Total Development Ready locations includes PUDs

10,000' Lateral Type Curves







	Upper Wolfcamp	Middle Wolfcamp	Cline
Lateral Length	~10,000'	~10,000'	~10,000'
EUR (MBOE)	1,110	1,000	1,000
Well Count	9	5	5
Frac Stages	33	32	33

Oil Hedges

Open Positions As of June 30, 2015 [1]	2H-2015	2016	2017	Total
OIL [2]				
Puts:				
Hedged volume (Bbls)	228,000	-	-	228,000
Weighted average price ($/Bbl)	$75.00	$ -	$ -	$75.00
Swaps:				
Hedged volume (Bbls)	336,000	1,573,800	-	1,909,800
Weighted average price ($/Bbl)	$96.56	$84.82	$ -	$86.89
Collars:				
Hedged volume (Bbls)	3,283,760	3,654,000	2,628,000	9,565,760
Weighted average floor price ($/Bbl)	$79.81	$73.99	$77.22	$76.88
Weighted average ceiling price ($/Bbl)	$95.41	$89.63	$97.22	$93.70
Total volume with a floor (Bbls)	**3,847,760**	**5,227,800**	**2,628,000**	**11,703,560**
Weighted average floor price ($/Bbl)	**$80.99**	**$77.25**	**$77.22**	**$78.47**
NYMEX WTI to Midland Basis Swaps:				
Hedged volume (Bbls)	1,840,000	-	-	1,840,000
Weighted average price ($/Bbl)	$ 1.95	$ -	$ -	$1.95

[1] Updated to reflect hedges placed through 8/5/15
[2] Oil derivatives are settled based on the month's average daily NYMEX price of WTI Light Sweet Crude Oil

Natural Gas Hedges

Open Positions As of June 30, 2015 [1]	2H-2015	2016	2017	Total
NATURAL GAS [2]				
Collars:				
Hedged volume (MMBtu)	14,384,000	18,666,000	5,475,000	38,525,000
Weighted average floor price ($/MMBtu)	$3.00	$ 3.00	$3.00	$3.00
Weighted average ceiling price ($/MMBtu)	$5.96	$ 5.60	$4.00	$5.51
Total volume with a floor (MMBtu)	**14,384,000**	**18,666,000**	**5,475,000**	**38,525,000**
Weighted average floor price ($/MMBtu)	**$3.00**	**$3.00**	**$3.00**	**$3.00**

[1] Updated to reflect hedges placed through 8/5/15
[2] Natural gas derivatives are settled based on Inside FERC index price for West Texas Waha for the calculation period.

Two-Stream to Three-Stream Conversions

			1Q-14	2Q-14	3Q-14	4Q-14	FY-14
Production	**Production (2-Stream)**						
	BOE/D		**27,041**	**28,653**	**32,970**	**39,722**	**32,134**
		% oil	58%	58%	59%	60%	59%
	Production (3-Stream)						
	BOE/D		**32,358**	**33,829**	**38,798**	**46,379**	**37,882**
		% oil	49%	49%	50%	51%	50%
Realized Pricing	**2-Stream Prices**						
	Gas ($/Mcf)		$7.04	$6.08	$5.80	$4.46	$5.72
	Oil ($/Bbl)		$91.78	$94.47	$87.65	$65.05	$82.83
	3-Stream Prices						
	Gas ($/Mcf)		$4.00	$3.73	$3.25	$3.00	$3.45
	NGL ($/Bbl)		$32.88	$28.79	$29.21	$19.65	$27.00
	Oil ($/Bbl)		$91.78	$94.47	$87.65	$65.05	$82.83
Unit Cost Metrics	**2-Stream Unit Cost Metrics**						
	Lease Operating ($/BOE)		$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream ($/BOE)		$0.35	$0.59	$0.40	$0.50	$0.46
	G&A ($/BOE)		$11.36	$11.34	$8.93	$5.95	$9.04
	DD&A ($/BOE)		$20.38	$20.35	$21.08	$21.85	$21.01
	3-Stream Unit Cost Metrics						
	Lease Operating ($/BOE)		$7.48	$6.55	$7.05	$6.88	$6.98
	Midstream ($/BOE)		$0.29	$0.50	$0.34	$0.43	$0.39
	G&A ($/BOE)		$9.50	$9.60	$7.59	$5.10	$7.67
	DD&A ($/BOE)		$17.03	$17.23	$17.91	$18.72	$17.83