UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2018

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 001-35380

Laredo Petroleum, Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**45-3007926** (I.R.S. Employer Identification No.)
15 W. Sixth Street, Suite 900 **Tulsa, Oklahoma** (Address of principal executive offices)	**74119** (Zip code)

(918) 513-4570

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐
Emerging growth company ☐	

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. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Number of shares of registrant's common stock outstanding as of July 30, 2018: 235,151,105

LAREDO PETROLEUM, INC.
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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this Quarterly Report on Form 10-Q (this "Quarterly Report") are 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 (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil and natural gas reserves, drilling program capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "will," "foresee," "plan," "goal," "should," "intend," "pursue," "target," "continue," "suggest" or the negative thereof or other variations thereof or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Among the factors that significantly impact our business and could impact our business in the future are:

- the volatility of, and substantial decline in, oil, natural gas liquids ("NGL") and natural gas prices, including in our area of operation in the Permian Basin;
- our ability to discover, estimate, develop and replace oil, NGL and natural gas reserves;
- changes in domestic and global production, supply and demand for oil, NGL and natural gas;
- the ongoing instability and uncertainty in the United States and international financial and consumer markets that could adversely affect the liquidity available to us and our customers and the demand for commodities, including oil, NGL and natural gas;
- capital requirements for our operations and projects;
- the availability and costs of drilling and production equipment, supplies, labor and oil and natural gas processing and other services;
- the availability and costs of sufficient pipeline and transportation facilities and gathering and processing capacity in the Permian Basin, including the impact on steel costs and supplies following the Administration's imposed 25% global tariffs on certain imported steel mill products;
- our ability to maintain the borrowing capacity under our Fifth Amended and Restated Senior Secured Credit Facility (as amended, the "Senior Secured Credit Facility") or access other means of obtaining capital and liquidity, especially during periods of sustained low commodity prices;
- restrictions contained in our debt agreements, including our Senior Secured Credit Facility and the indentures governing our senior unsecured notes, as well as debt that could be incurred in the future;
- our ability to recruit and retain the qualified personnel necessary to operate our business;
- our ability to generate sufficient cash to service our indebtedness, fund our capital requirements and generate future profits;
- the impact of share repurchases or our suspension or discontinuation of the share repurchase program at any time;
- the potential impact on production of oil, NGL and natural gas from our wells due to tighter spacing of our wells;
- our ability to hedge and regulations that affect our ability to hedge;
- revisions to our reserve estimates as a result of changes in commodity prices and other uncertainties;
- impacts to our financial statements as a result of impairment write-downs;
- the potentially insufficient refining capacity in the United States Gulf Coast to refine all of the light sweet crude oil being produced in the United States, which could result in widening price discounts to world crude prices and potential shut-in of production due to lack of sufficient markets;
- risks related to the geographic concentration of our assets;
- changes in the regulatory environment and changes in United States or international legal, political, administrative or economic conditions, including regulations that prohibit or restrict our ability to apply hydraulic fracturing to our oil and natural gas wells and to access and dispose of water used in these operations;

- legislation or regulations that prohibit or restrict our ability to drill new allocation wells;
- our ability to execute our strategies;
- competition in the oil and natural gas industry;
- the adverse outcome and impact of litigation, legal proceedings, investigations and insurance or other claims, including the adverse outcome and impact of pending or protracted litigation;
- drilling and operating risks, including risks related to hydraulic fracturing activities;
- our ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses, assets and properties;
- our ability to comply with federal, state and local regulatory requirements; and
- the impact of the new tax laws enacted on December 22, 2017.

These forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements. Forward-looking statements should, therefore, be considered in light of various factors, including those set forth under "Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Quarterly Report, under "Part I, Item 1A. Risk Factors" and "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the fiscal year ended December 31, 2017 (the "2017 Annual Report"), and those set forth from time to time in our other filings with the Securities and Exchange Commission (the "SEC"). These documents are available through our website or through the SEC's Electronic Data Gathering and Analysis Retrieval system at http://www.sec.gov. In light of such risks and uncertainties, we caution you not to place undue reliance on these forward-looking statements. These forward-looking statements speak only as of the date of this Quarterly Report, or if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities law.

Part I

Item 1. Consolidated Financial Statements (Unaudited)

Laredo Petroleum, Inc.
Consolidated balance sheets
(in thousands, except share data)
(Unaudited)

	June 30, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 36,604	$ 112,159
Accounts receivable, net	101,321	100,645
Derivatives	8,059	6,892
Other current assets	23,710	15,686
Total current assets	169,694	235,382
Property and equipment:		
Oil and natural gas properties, full cost method:		
Evaluated properties	6,432,913	6,070,940
Unevaluated properties not being depleted	156,815	175,865
Less accumulated depletion and impairment	(4,746,413)	(4,657,466)
Oil and natural gas properties, net	1,843,315	1,589,339
Midstream service assets, net	134,827	138,325
Other fixed assets, net	42,384	40,721
Property and equipment, net	2,020,526	1,768,385
Derivatives	3,074	3,413
Other noncurrent assets, net	15,993	16,109
Total assets	$ 2,209,287	$ 2,023,289
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 74,252	$ 58,341
Accrued capital expenditures	73,843	82,721
Undistributed revenue and royalties	45,998	37,852
Derivatives	44,119	22,950
Other current liabilities	45,208	75,555
Total current liabilities	283,420	277,419
Long-term debt, net	902,745	791,855
Derivatives	5,876	384
Asset retirement obligations	54,674	53,962
Other noncurrent liabilities	3,405	134,090
Total liabilities	1,250,120	1,257,710
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued as of June 30, 2018 and December 31, 2017	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized and 235,193,588 and 242,521,143 issued and outstanding as of June 30, 2018 and December 31, 2017, respectively	2,352	2,425
Additional paid-in capital	2,364,833	2,432,262
Accumulated deficit	(1,408,018)	(1,669,108)
Total stockholders' equity	959,167	765,579
Total liabilities and stockholders' equity	$ 2,209,287	$ 2,023,289

The accompanying notes are an integral part of these unaudited consolidated financial statements.

Laredo Petroleum, Inc.
Consolidated statements of operations
(in thousands, except per share data)
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2018	**2017**	**2018**	**2017**
Revenues:				
Oil sales	$ 159,051	$ 104,214	$ 309,965	$ 203,681
NGL sales	36,805	19,801	65,165	40,629
Natural gas sales	12,705	17,822	30,865	36,263
Midstream service revenues	1,976	2,703	4,335	5,702
Sales of purchased oil	140,509	42,461	200,412	89,732
Total revenues	351,046	187,001	610,742	376,007
Costs and expenses:				
Lease operating expenses	22,642	20,104	44,593	37,096
Production and ad valorem taxes	12,405	8,472	24,217	17,253
Transportation and marketing expenses	1,534	—	1,534	—
Midstream service expenses	403	896	1,096	1,812
Costs of purchased oil	140,578	44,020	201,242	94,276
General and administrative	26,834	22,008	51,559	47,605
Depletion, depreciation and amortization	50,762	38,003	96,315	72,115
Other operating expenses	1,121	1,437	2,227	2,463
Total costs and expenses	256,279	134,940	422,783	272,620
Operating income	94,767	52,061	187,959	103,387
Non-operating income (expense):				
Gain (loss) on derivatives, net	(45,976)	28,897	(36,966)	65,568
Income from equity method investee (see Note 3.c)	—	2,471	—	5,539
Interest expense	(14,424)	(23,173)	(27,942)	(45,893)
Interest and other income	443	49	896	194
Gain (loss) on disposal of assets, net	(1,358)	805	(3,975)	591
Non-operating income (expense), net	(61,315)	9,049	(67,987)	25,999
Income before income taxes	33,452	61,110	119,972	129,386
Income tax:				
Deferred	—	—	—	—
Total income tax	—	—	—	—
Net income	$ 33,452	$ 61,110	$ 119,972	$ 129,386
Net income per common share:				
Basic	$ 0.14	$ 0.26	$ 0.51	$ 0.54
Diluted	$ 0.14	$ 0.25	$ 0.51	$ 0.53
Weighted-average common shares outstanding:				
Basic	230,933	239,231	234,561	238,870
Diluted	231,706	244,417	235,501	244,385

The accompanying notes are an integral part of these unaudited consolidated financial statements.

Laredo Petroleum, Inc.
Consolidated statement of stockholders' equity
(in thousands)
(Unaudited)

	Common Stock		Additional paid-in capital	Treasury Stock (at cost)		Accumulated deficit	Total
	Shares	Amount		Shares	Amount		
Balance, December 31, 2017	242,521	$ 2,425	$ 2,432,262	—	$ —	$ (1,669,108)	$ 765,579
Adjustment to the beginning balance of accumulated deficit upon adoption of ASC 606 (see Note 4.a)	—	—	—	—	—	141,118	141,118
Restricted stock awards	3,193	32	(32)	—	—	—	—
Restricted stock forfeitures	(126)	(1)	1	—	—	—	—
Share repurchases	—	—	—	9,879	(87,218)	—	(87,218)
Vested stock exchanged for tax withholding	—	—	—	515	(4,397)	—	(4,397)
Retirement of treasury stock	(10,394)	(104)	(91,511)	(10,394)	91,615	—	—
Stock-based compensation	—	—	24,113	—	—	—	24,113
Net income	—	—	—	—	—	119,972	119,972
Balance, June 30, 2018	235,194	$ 2,352	$ 2,364,833	—	$ —	$ (1,408,018)	$ 959,167

The accompanying notes are an integral part of this unaudited consolidated financial statement.

Laredo Petroleum, Inc.
Consolidated statements of cash flows
(in thousands)
(Unaudited)

	Six months ended June 30,	
	2018	**2017**
Cash flows from operating activities:		
Net income	$ 119,972	$ 129,386
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation and amortization	96,315	72,115
Non-cash stock-based compensation, net	20,015	17,911
Mark-to-market on derivatives:		
(Gain) loss on derivatives, net	36,966	(65,568)
Settlements (paid) received for matured derivatives, net	(2,055)	21,156
Settlements received for early terminations of derivatives, net	—	4,234
Change in net present value of derivative deferred premiums	396	111
Premiums paid for derivatives	(9,475)	(12,094)
Amortization of debt issuance costs	1,638	2,094
Income from equity method investee (see Note 3.c)	—	(5,539)
Other, net	6,910	1,414
(Increase) decrease in accounts receivable	(2,331)	14,760
Increase in other current assets	(10,974)	(3,545)
Decrease in other noncurrent assets	1,835	29
Increase (decrease) in accounts payable and accrued liabilities	15,911	(13,718)
Increase in undistributed revenues and royalties	8,146	5,328
Decrease in other current liabilities	(20,124)	(11,008)
Decrease in other noncurrent liabilities	(544)	(165)
Net cash provided by operating activities	262,601	156,901
Cash flows from investing activities:		
Acquisitions of oil and natural gas properties	(16,340)	—
Capital expenditures:		
Oil and natural gas properties	(341,534)	(232,219)
Midstream service assets	(5,205)	(6,117)
Other fixed assets	(4,965)	(2,683)
Proceeds from disposition of equity method investee, net of selling costs (see Note 3.c)	1,655	—
Proceeds from dispositions of capital assets, net of selling costs	12,317	63,441
Net cash used in investing activities	(354,072)	(177,578)
Cash flows from financing activities:		
Borrowings on Senior Secured Credit Facility	110,000	90,000
Payments on Senior Secured Credit Facility	—	(55,000)
Share repurchases	(87,218)	—
Vested stock exchanged for tax withholding	(4,397)	(7,597)
Proceeds from exercise of stock options	—	358
Payments for debt issuance costs	(2,469)	(4,732)
Net cash provided by financing activities	15,916	23,029
Net (decrease) increase in cash and cash equivalents	(75,555)	2,352
Cash and cash equivalents, beginning of period	112,159	32,672
Cash and cash equivalents, end of period	$ 36,604	$ 35,024

The accompanying notes are an integral part of these unaudited consolidated financial statements.

Note 1—Organization and basis of presentation

a. Organization

Laredo Petroleum, Inc. ("Laredo"), together with its wholly-owned subsidiaries, Laredo Midstream Services, LLC ("LMS") and Garden City Minerals, LLC ("GCM"), is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, and midstream and marketing services, primarily in the Permian Basin of West Texas. LMS and GCM (together, the "Guarantors") guarantee all of Laredo's debt instruments. In these notes, the "Company" refers to Laredo, LMS and GCM collectively, unless the context indicates otherwise. All amounts, dollars and percentages presented in these unaudited consolidated financial statements and the related notes are rounded and, therefore, approximate.

b. Basis of presentation

The accompanying unaudited consolidated financial statements were derived from the historical accounting records of the Company and reflect the historical financial position, results of operations and cash flows for the periods described herein. The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All material intercompany transactions and account balances have been eliminated in the consolidation of accounts.

The accompanying unaudited consolidated financial statements have not been audited by the Company's independent registered public accounting firm, except that the consolidated balance sheet as of December 31, 2017 is derived from audited consolidated financial statements. In the opinion of management, the accompanying unaudited consolidated financial statements reflect all necessary adjustments to present fairly the Company's financial position as of June 30, 2018, results of operations for the three and six months ended June 30, 2018 and 2017 and cash flows for the six months ended June 30, 2018 and 2017.

Certain disclosures have been condensed or omitted from these unaudited consolidated financial statements. Accordingly, these unaudited consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in the 2017 Annual Report.

Significant accounting policies

See Note 2 "Basis of presentation and significant accounting policies" in the 2017 Annual Report for discussion of significant accounting policies.

Use of estimates in the preparation of interim unaudited consolidated financial statements

The preparation of the accompanying unaudited consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ.

For further information regarding the estimates and assumptions, see Note 2.b "Use of estimates in the preparation of consolidated financial statements" in the 2017 Annual Report. Furthermore, see Note 7.c for a discussion of estimates pertaining to the Company's 2018 performance share awards.

Reclassifications

Certain amounts in the accompanying unaudited consolidated financial statements have been reclassified to conform to the 2018 presentation. These reclassifications had no impact on previously reported total assets, total liabilities, net income, stockholders' equity or total operating, investing or financing cash flows.

Note 2—Recently issued or adopted accounting pronouncements

The Company considers the applicability and impact of all accounting standard updates ("ASU") issued by the Financial Accounting Standards Board ("FASB") to the FASB Accounting Standards Codification ("ASC"). The discussion of the ASUs listed below were determined to be meaningful to the Company's unaudited consolidated financial statements and/or footnotes during the six months ended June 30, 2018.

a. Revenue recognition

On January 1, 2018, the Company adopted ASC 606, *Revenue from Contracts with Customers* ("ASC 606"), using the modified retrospective approach of adoption. ASC 606 supersedes previous revenue recognition requirements in ASC 605, *Revenue Recognition* ("ASC 605"), and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. In addition, the new standard requires significantly expanded disclosures related to the nature, timing, amount and uncertainty of revenue and cash flows arising from contracts with customers. See Note 4 for further discussion of the ASC 606 adoption impact on the Company's unaudited consolidated financial statements and the Company's revenue recognition policies.

b. Leases

In February 2016, the FASB issued new guidance in ASC 842, *Leases* ("ASC 842"), which will supersede the current guidance in ASC 840, *Leases* ("ASC 840"). The core principle of the new guidance is that a lessee should recognize in the statement of financial position a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term for leases currently classified as operating leases. For leases with a term of 12 months or less, a lessee is permitted to make an accounting policy election, by class of underlying asset, not to recognize lease assets and lease liabilities. In January 2018, the FASB issued new guidance in ASC 842 to provide an optional transition practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under ASC 840.

The amendments in these ASUs are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted. The Company is evaluating the potential impact of adopting this guidance, and the primary effect will be to record assets and obligations for contracts currently recognized as operating leases with a term greater than 12 months and to evaluate operating leases with a term less than or equal to 12 months for accounting policy election. The Company has formed a team, including third-party consultants, to implement the standard and has identified the software that will be used to track and account for lease activity. The Company does not intend to adopt the standard early.

c. Business combinations

In January 2017, the FASB issued new guidance in ASC 805, *Business Combinations*, to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The amendments in this ASU provide a screen to determine when a set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. If the screen is not met, the amendments in this ASU require that to be considered a business, a set must include, at a minimum, an input and a substantive process that, together, significantly contribute to the ability to create an output.

The primary effect of adoption of this ASU is that, depending on the facts and circumstances of each transaction, more transactions could be accounted for as acquisitions of assets. The Company adopted this ASU on January 1, 2018 on a prospective basis, and the adoption did not have an effect on its unaudited consolidated financial statements. See Note 3.a for discussion of the Company's 2018 acquisitions of evaluated and unevaluated oil and natural gas properties, which were accounted for as asset acquisitions under this ASU.

Note 3—Acquisitions and divestitures

a. 2018 acquisitions of evaluated and unevaluated oil and natural gas properties

During the six months ended June 30, 2018, through multiple transactions, the Company acquired 895 net acres of additional leasehold interests and working interests in 47 producing horizontal and vertical wells in Glasscock county in Texas for an aggregate purchase price of $16.4 million, subject to customary post-closing adjustments. These acquisitions were accounted for as asset acquisitions.

b. 2018 divestitures of evaluated and unevaluated oil and natural gas properties and midstream assets

During the six months ended June 30, 2018, through multiple transactions, the Company completed the sale of 3,070 net acres and working interests in 24 producing vertical and horizontal wells and associated midstream service assets in Glasscock and Howard counties in Texas to third-party buyers for an aggregate sales price of $12.1 million, net of post-closing adjustments. Of this amount, $11.6 million, net of post-closing adjustments, was recorded as adjustments to oil and natural gas properties pursuant to the rules governing full cost accounting. A loss of $1.0 million from the sale of the associated midstream service assets was included in the line item "Gain (loss) on disposal of assets, net" in the unaudited consolidated statements of operations. Effective at the closings, the operations and cash flows of these properties and midstream service assets were eliminated from the ongoing operations of the Company, and the Company has no continuing involvement in the properties. These divestitures did not represent a strategic shift and will not have a major effect on the Company's future operations or financial results.

c. 2017 Medallion sale

Medallion Gathering & Processing, LLC, a Texas limited liability company formed on October 12, 2012, which, together with its wholly-owned subsidiaries (collectively, "Medallion"), was established for the purpose of developing midstream solutions and providing midstream infrastructure to bring oil to market from the Midland Basin. Prior to the Medallion Sale (defined below), LMS held 49% of Medallion's ownership units. LMS and the third-party 51% interest-holder agreed that the voting rights of Medallion, the profit and loss sharing and the additional capital contribution requirements would be equal to the ownership unit percentage held. Additionally, Medallion required a super-majority vote of 75% for many key operating and business decisions. The Company determined that Medallion was a variable interest entity ("VIE"). However, LMS was not considered to be the primary beneficiary of the VIE because LMS did not have the power to direct the activities that most significantly affected Medallion's economic performance. As such, prior to the Medallion Sale, Medallion was accounted for under the equity method of accounting. The Company's proportionate share of Medallion's net income is reflected in the unaudited consolidated statements of operations on the "Income from equity method investee" line item.

On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC, which is owned and controlled by an affiliate of the third-party interest-holder, The Energy & Minerals Group, 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 were $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 proceeds were used to pay in-full borrowings on the Senior Secured Credit Facility, to redeem the May 2022 Notes (as defined below) and for working capital purposes. 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. The Medallion Sale did not represent a strategic shift and will not have a major effect on the Company's future operations or financial results.

LMS has a Transportation Services Agreement (the "TA") with a wholly-owned subsidiary of Medallion under which LMS receives firm transportation of the Company's crude oil production from Reagan and Glasscock counties in Texas to Colorado City, Texas that continues to be in effect after the Medallion Sale. Historically, the Company's crude oil purchasers have fulfilled the commitment by transporting crude oil, purchased from the Company, under the TA, as agent. As a result of the Company's continuing involvement with Medallion by guaranteeing cash flows under the TA, the Company recorded a deferred gain in the amount of its maximum exposure to loss related to such guarantees that would have been amortized over the TA's firm commitment transportation term through 2024 had the Company not adopted new revenue recognition guidance on January 1, 2018. The deferred gain is included in the unaudited consolidated balance sheets in each of the "Other current liabilities" and "Other noncurrent liabilities" line items as of December 31, 2017. See Note 4.a for discussion of the impact to the deferred gain upon the adoption of ASC 606.

d. 2017 divestiture of evaluated and unevaluated oil and natural gas properties

In January 2017, the Company completed the sale of 2,900 net acres and working interests in 16 producing vertical wells in the Midland Basin to a third-party buyer for a purchase price of $59.7 million. After transaction costs reflecting an economic effective date of October 1, 2016, the proceeds were $59.5 million, net of working capital and post-closing adjustments. A significant portion of these proceeds was used to pay down borrowings on the Senior Secured Credit Facility. The purchase price was recorded as an adjustment to oil and natural gas properties pursuant to the rules governing full cost accounting. Effective at closing, the operations and cash flows of these properties were eliminated from the ongoing operations of the Company, and the Company has no continuing involvement in the properties. This divestiture did not represent a strategic shift and will not have a major effect on the Company's future operations or financial results.

e. Exchange of unevaluated oil and natural gas properties

From time to time, the Company exchanges undeveloped acreage with third parties. The exchanges are recorded at fair value and the difference is accounted for as an adjustment of capitalized costs with no gain or loss recognized pursuant to the rules governing full cost accounting, unless such adjustment would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas.

Note 4—Revenue recognition

a. Impact of ASC 606 adoption

Upon adoption of ASC 606 on January 1, 2018, for the three and six months ended June 30, 2018, the Company reclassified certain deficiency payments and other contractual penalties due to customers, historically included in the "Other operating expenses" line item in the unaudited consolidated statements of operations, and netted them with the revenue stream from which they derive as these payments to customers do not relate to the provision of a distinct good or service to the customer. In addition, there was an impact upon adoption related to the treatment of the gain on the Medallion Sale.

The impact of the adoption of ASC 606 on the results of operations for the periods presented is as follows:

	Three months ended June 30, 2018			Six months ended June 30, 2018		
(in thousands)	As computed under ASC 605	As reported under ASC 606	Increase/(decrease)	As computed under ASC 605	As reported under ASC 606	Increase/(decrease)
Revenues:						
Oil sales	$ 161,192	$ 159,051	$ (2,141)	$ 312,250	$ 309,965	$ (2,285)
NGL sales	$ 36,805	$ 36,805	$ —	$ 65,165	$ 65,165	$ —
Natural gas sales	$ 12,705	$ 12,705	$ —	$ 30,865	$ 30,865	$ —
Costs and expenses:						
Other operating expenses	$ 3,262	$ 1,121	$ (2,141)	$ 4,512	$ 2,227	$ (2,285)
Net income	$ 33,452	$ 33,452	$ —	$ 119,972	$ 119,972	$ —

At December 31, 2017, the Medallion Sale was accounted for under the real estate guidance in ASC 360-20, *Property, Plant, and Equipment* ("ASC 360-20"), and the Company's maximum exposure to loss associated with future commitments under the TA was $141.1 million that was not recorded in the Company's unaudited consolidated balance sheets. Under ASC 360-20, as a result of the Company's continuing involvement with Medallion by guaranteeing cash flows under the TA, the Company recorded a deferred gain in the amount of its maximum exposure to loss related to such guarantees. This deferred gain would have been amortized over the TA's firm commitment transportation term through 2024 had the Company not adopted ASC 606 on January 1, 2018. See Note 3.c for further discussion of the Medallion Sale and the TA.

Upon the adoption of ASC 606, the guidance in ASC 360-20 was superseded by ASC 860, *Transfers and Servicing* ("ASC 860"). The Medallion Sale is within the scope of ASC 860 and qualifies for sale accounting and recognition of the previously deferred gain because as of the date of the Medallion Sale (i) the Company transferred and legally isolated its full interests in Medallion to GIP, (ii) GIP received the right to pledge or exchange Medallion ownership interests at its full discretion and (iii) the Company did not have effective control over Medallion. Therefore, the deferred gain of $141.1 million was recognized as an adjustment to the beginning balance of accumulated deficit, presented in the unaudited consolidated statements of stockholders' equity, in accordance with the modified retrospective approach of adoption.

b. Revenue recognition

Oil, NGL and natural gas revenues are generally recognized at the point in time that control of the product is transferred to the customer. Midstream service revenues are generated through fees for products and services that need to be delivered by midstream infrastructure, including oil and liquids-rich natural gas gathering services as well as rig fuel, gas lift and water delivery, recycling and takeaway (collectively, "Midstream Services") and are recognized over time as the customer benefits from these services when provided. A more detailed summary of the underlying contracts that give rise to the Company's revenue and method of recognition is included below.

Oil sales and sales of purchased oil

Under its oil sales contracts, the Company sells produced or purchased oil at the delivery point specified in the contract and collects an agreed-upon index price, net of pricing differentials. The delivery point may be at the wellhead, the inlet of the purchaser's pipeline or nominated pipeline or the Company's truck unloading facility. At the delivery point, the purchaser typically takes custody, title and risk of loss of the product and, therefore, control as defined under ASC 606 typically passes at the delivery point. The Company recognizes revenue at the net price received when control transfers to the purchaser.

From time to time, the Company engages in transactions in which it sells oil at the lease and subsequently repurchases the same volume of oil from that customer at a downstream delivery point under a separate agreement ("Repurchase Agreement") for use in the sale to the final customer. The commercial reasoning for such transactions may vary. Where a Repurchase Agreement exists, the Company must evaluate whether the customer obtains control of the oil at the lease and therefore whether it is appropriate to recognize revenue for the lease sale. Where the Company has an obligation or a right to repurchase the oil, the customer does not obtain control of the oil because it is limited in its ability to direct the use of, and obtain substantially all of the remaining benefits from the oil even though it may have physical possession of the oil. If the Company repurchases the oil for less than the original selling price, such a transaction will be classified as a lease. If the Company repurchases the oil for equal to or more than the original selling price, then the transaction represents a financing arrangement unless there is only a short passage of time between the sale and repurchase, in which case any excess amount paid represents an expense associated with the sale of oil to the final customer. The Company recognizes such repurchase expense and any transportation expenses incurred for the delivery of the oil to the final customer in the "Transportation and marketing expense" line item in the accompanying unaudited consolidated statements of operations.

Under certain of its customer contracts, the Company is subject to deficiency payments and other contractual penalties if it fails to deliver contractual minimum volumes to its customers. Such amounts are recorded as a reduction to the transaction price as these amounts do not represent payments to the customer for distinct goods or services and instead relate specifically to the failure to perform under the specific customer contract. Such amounts are recorded as a reduction to the transaction price when payment is determined as probable, typically when such a deficiency occurs.

NGL and natural gas sales

Under its natural gas processing contracts, the Company delivers produced natural gas to a midstream processing entity at the wellhead or the inlet of the processing entity's system. The processing entity processes the natural gas, sells the resulting NGL and residue gas to third parties and pays the Company for the NGL and residue gas with deductions that may include gathering, compression, processing and transportation fees. In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. For existing contracts, the Company has concluded that it is the agent in the ultimate sale to the third party and the midstream processing entity is the principal and that we have transferred control of unprocessed natural gas to the midstream processing entity; therefore, the Company recognizes revenue based on the net amount of the proceeds received from the midstream processing entity who represents the Company's customer. If for future contracts the Company was to conclude that it was the principal with the ultimate third party being the customer, the Company would recognize revenue for those contracts on a gross basis, with gathering, compression, processing, and transportation fees presented as an expense.

Midstream Services

Revenue from oil throughput agreements is recognized based on a rate per barrel for volumes transported. Under the Company's oil throughput agreements, a volumetric deduction is taken from customer oil as a pipeline loss allowance. While these amounts represent non-cash consideration under ASC 606, such deductions are immaterial. Revenue from natural gas throughput agreements is recognized based on a rate per MMbtu for volumes transported. Revenue from water delivery, recycling and takeaway is recognized based on the volumes of water for which the services are provided at the applicable contractual rate.

Imbalances

The Company recognizes revenue for all oil, NGL and natural gas sold to purchasers regardless of whether the sales are proportionate to the Company's ownership interest in the property. Production imbalances are recognized as a liability to the extent an imbalance on a specific property exceeds the Company's share of remaining proved oil, NGL and natural gas reserves. The Company is also subject to natural gas pipeline imbalances, which are recorded as accounts receivable or payable at values consistent with contractual arrangements with the owner of the pipeline. The Company did not have any producer or pipeline imbalance positions as of June 30, 2018 or December 31, 2017.

Significant judgments

The Company engages in various types of transactions in which unaffiliated midstream entities process the Company's liquids-rich natural gas and, in some scenarios, subsequently market resulting NGL and residue gas to third-party customers on the Company's behalf. These types of transactions require judgment to determine whether the Company is the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net. For existing contracts, the Company has determined that it serves as the agent in the sale of products under certain natural gas processing and marketing agreements with unaffiliated midstream entities in accordance with the control model in ASC 606. As a result, the Company presents revenue on a net basis for amounts expected to be received from third-party customers through the marketing process, with expenses and deductions incurred subsequent to control of the product(s) transferring to the unaffiliated midstream entity being netted against revenue.

Transaction price allocated to remaining performance obligations

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC 606-10-50-14 that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year and for its Midstream Services, the Company has utilized the practical expedient in ASC 606-10-50-14A that states that it is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's product sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied. Under the Midstream Services contracts each unit of service represents a separate performance obligation and therefore performance obligations in respect of future services are wholly unsatisfied.

Contract balances

Under the Company's customer contracts, invoicing occurs once the Company's performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's contracts do not give rise to contract assets or liabilities under ASC 606.

Prior period performance obligations

For sales of oil, NGL, natural gas and purchased oil, the Company records revenue in the month production is delivered to the purchaser. However, settlement statements and payment may not be received for 30 to 90 days after the date production is delivered and, as a result, the Company is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between estimates and the actual amounts received for product sales once payment is received from the purchaser. Such differences have historically not been significant. The Company uses knowledge of its properties, its properties' historical performance, spot market prices and other factors as the basis for these estimates. For the three and six months ended June 30, 2018, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

Note 5—Property and equipment

The following table presents the Company's property and equipment as of the dates presented:

(in thousands)	June 30, 2018	December 31, 2017
Evaluated oil and natural gas properties	$ 6,432,913	$ 6,070,940
Less accumulated depletion and impairment	(4,746,413)	(4,657,466)
Evaluated oil and natural gas properties, net	1,686,500	1,413,474
Unevaluated oil and natural gas properties not being depleted	156,815	175,865
Midstream service assets	171,875	171,427
Less accumulated depreciation and impairment	(37,048)	(33,102)
Midstream service assets, net	134,827	138,325
Depreciable other fixed assets	49,304	48,957
Less accumulated depreciation and amortization	(25,179)	(23,150)
Depreciable other fixed assets, net	24,125	25,807
Land	18,259	14,914
Total property and equipment, net	$ 2,020,526	$ 1,768,385

For the three months ended June 30, 2018 and 2017, depletion expense for the Company's evaluated oil and natural gas properties was $7.68 per barrel of oil equivalent ("BOE") sold and $6.44 per BOE sold, respectively. For the six months ended June 30, 2018 and 2017, depletion expense for the Company's evaluated oil and natural gas properties was $7.52 per BOE sold and $6.44 per BOE sold, respectively.

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain employee-related costs incurred for the purpose of exploring for or developing oil and natural gas properties, are capitalized and depleted on a composite unit-of-production method based on proved oil, NGL and natural gas reserves. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Costs, including employee-related costs, associated with production and general corporate activities, are expensed in the period incurred. Sales of oil and natural gas properties, whether or not being depleted currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas.

The following table presents capitalized employee-related costs for the periods presented:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2018	2017	2018	2017
Capitalized employee-related costs	$ 6,735	$ 5,763	$ 13,264	$ 10,973

The Company excludes the costs directly associated with the acquisition and evaluation of unevaluated properties from the depletion calculation until it is determined whether or not proved reserves can be assigned to the properties. The Company capitalizes a portion of its interest costs to its unevaluated properties. Capitalized interest becomes a part of the cost of the unevaluated properties and is subject to depletion when proved reserves can be assigned to the associated properties. All items classified as unevaluated properties are assessed on a quarterly basis for possible impairment. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of evaluated reserves and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion.

The following table presents costs incurred in the acquisition, exploration and development of oil and natural gas properties, with asset retirement obligations included in evaluated property acquisition costs and development costs, for the periods presented:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Property acquisition costs (see Note 3.a):				
Evaluated	$ 13,847	$ —	$ 13,847	$ —
Unevaluated	2,790	—	2,790	—
Exploration costs	5,108	5,658	11,245	21,201
Development costs	178,796	125,738	327,834	236,896
Total costs incurred	$ 200,541	$ 131,396	$ 355,716	$ 258,097

Note 6—Debt

a. March 2023 Notes

On March 18, 2015, the Company completed an offering of $350.0 million in aggregate principal amount of 6 1/4% senior unsecured notes due 2023 (the "March 2023 Notes"). The March 2023 Notes will mature on March 15, 2023 and bear an interest rate of 6 1/4% per annum, payable semi-annually, in cash in arrears on March 15 and September 15 of each year, commencing September 15, 2015. The March 2023 Notes are fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain automatic customary releases, including the sale, disposition or transfer of all of the capital stock or of all or substantially all of the assets of a subsidiary guarantor to one or more persons that are not the Company or a restricted subsidiary, exercise of legal defeasance or covenant defeasance options or satisfaction and discharge of the applicable indenture, designation of a subsidiary guarantor as a non-guarantor restricted subsidiary or as an unrestricted subsidiary in accordance with the applicable indenture, release from guarantee under the Senior Secured Credit Facility, or liquidation or dissolution (collectively, the "Releases"). The Company may redeem, at its option, all or part of the March 2023 Notes at any time after March 15, 2018, at a price of 104.688% of face value with call premiums declining annually to 100% of face value on March 15, 2021 and thereafter plus accrued and unpaid interest to, but not including, the date of redemption.

b. January 2022 Notes

On January 23, 2014, the Company completed an offering of $450.0 million in aggregate principal amount of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes"). The January 2022 Notes will mature on January 15, 2022 and bear an interest rate of 5 5/8% per annum, payable semi-annually, in cash in arrears on January 15 and July 15 of each year, commencing July 15, 2014. The January 2022 Notes are fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain Releases. The Company may redeem, at its option, all or part of the January 2022 Notes at any time after January 15, 2018, at a price of 102.813% of face value with call premiums declining annually to 100% of face value on January 15, 2020 and thereafter plus accrued and unpaid interest to, but not including, the date of redemption.

c. May 2022 Notes

On April 27, 2012, the Company completed an offering of $500.0 million in aggregate principal amount of 7 3/8% senior unsecured notes due 2022 (the "May 2022 Notes"). The May 2022 Notes were due to mature on May 1, 2022 and bore an interest rate of 7 3/8% per annum, payable semi-annually, in cash in arrears on May 1 and November 1 of each year, commencing November 1, 2012. The May 2022 Notes were fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain Releases.

On November 29, 2017 (the "May 2022 Notes Redemption Date"), utilizing a portion of the proceeds from the Medallion Sale, the entire $500.0 million outstanding principal amount of the May 2022 Notes was redeemed at a redemption price of 103.688% of the principal amount of the May 2022 Notes, plus accrued and unpaid interest up to, but not including, the May 2022 Notes Redemption Date. The Company recognized a loss on extinguishment of $23.8 million related to the difference between the redemption price and the net carrying amount of the extinguished May 2022 Notes.

d. Senior Secured Credit Facility

The Senior Secured Credit Facility matures on April 19, 2023, provided that if either the January 2022 Notes or March 2023 Notes have not been refinanced on or prior to the date (as applicable, the "Early Maturity Date") that is 90 days before their respective stated maturity dates, the Senior Secured Credit Facility will mature on such Early Maturity Date. As of June 30, 2018, the Senior Secured Credit Facility had a maximum credit amount of $2.0 billion, a borrowing base of $1.3 billion and an aggregate elected commitment of $1.2 billion, with $110.0 million outstanding and was subject to an interest rate of 3.32%. The Senior Secured Credit Facility contains both financial and non-financial covenants, all of which the Company was in compliance with as of June 30, 2018. Laredo is required to pay a commitment fee on the unused portion of the financial institutions' commitment of 0.375% to 0.5%, based on the ratio of outstanding revolving credit to the aggregate elected commitment under the Senior Secured Credit Facility. Additionally, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $80.0 million. No letters of credit were outstanding as of June 30, 2018 or December 31, 2017. See Note 17.b for discussion of additional borrowings and payments on the Senior Secured Credit Facility subsequent to June 30, 2018.

e. Long-term debt, net

The following table summarizes the net presentation of the Company's long-term debt and debt issuance costs on the unaudited consolidated balance sheets as of the dates presented:

	June 30, 2018			December 31, 2017		
(in thousands)	Long-term debt	Debt issuance costs, net	Long-term debt, net	Long-term debt	Debt issuance costs, net	Long-term debt, net
January 2022 Notes	$ 450,000	$ (3,499)	$ 446,501	$ 450,000	$ (3,987)	$ 446,013
March 2023 Notes	350,000	(3,756)	346,244	350,000	(4,158)	345,842
Senior Secured Credit Facility(1)	110,000	—	110,000	—	—	—
Total	$ 910,000	$ (7,255)	$ 902,745	$ 800,000	$ (8,145)	$ 791,855

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(1) Debt issuance costs, net related to our Senior Secured Credit Facility of $7.8 million and $6.0 million as of June 30, 2018 and December 31, 2017, respectively, are reported in "Other assets, net" on the unaudited consolidated balance sheets.

Note 7—Stockholders' equity and stock-based compensation

a. Share repurchase program

In February 2018, the Company's board of directors authorized a $200 million share repurchase program commencing in February 2018. The repurchase program expires in February 2020. Share repurchases under the share repurchase program may be made through a variety of methods, which may include open market purchases, privately negotiated transactions and block trades. The timing and actual number of shares repurchased, if any, will depend upon several 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. During the three months ended June 30, 2018, the Company repurchased 3,150,651 shares of common stock at a weighted-average price of $9.12 per common share for a total of $28.7 million under this program. During the six months ended June 30, 2018, the Company repurchased 9,878,552 shares of common stock at a weighted-average price of $8.83 per common share for a total of $87.2 million under this program. All shares were retired upon repurchase.

b. Treasury stock

Treasury stock is recorded at cost, which includes incremental direct transaction costs, and is retired upon acquisition as a result from share repurchases under the share repurchase program or from the withholding of shares of stock to satisfy employee tax withholding obligations that arise upon the lapse of restrictions on their stock awards at the employees' election.

c. Stock-based compensation

The Company's Long-Term Incentive Plan (the "LTIP") provides for the granting of incentive awards in the form of restricted stock awards, stock option awards, performance share awards, performance unit awards and other awards. The LTIP provides for the issuance of up to 24,350,000 shares of Laredo's common stock.

The Company recognizes the fair value of stock-based compensation awards expected to vest over the requisite service period as a charge against earnings, net of amounts capitalized. The Company's stock-based compensation awards are accounted for as equity instruments and are included in the "General and administrative" line item in the unaudited consolidated statements of operations. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration or development of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included as an addition to "Oil and natural gas properties" on the unaudited consolidated balance sheets.

Restricted stock awards

All service vesting restricted stock awards are treated as issued and outstanding in the accompanying unaudited consolidated financial statements. Per the award agreement terms, if an employee terminates employment prior to the restriction lapse date for reasons other than death or disability, the awarded shares are forfeited and canceled and are no longer considered issued and outstanding. If the employee's termination of employment is by reason of death or disability, all of the holder's restricted stock will automatically vest. Restricted stock awards granted to officers and employees vest in a variety of vesting schedules including (i) 33%, 33% and 34% per year beginning on the first anniversary of the grant date and (ii) fully on the first anniversary of the grant date. Beginning August 2017, stock awards granted to non-employee directors vest immediately on the grant date. Restricted stock awards granted to non-employee directors prior to August 2017 vest on the first anniversary of the grant date.

The following table reflects the restricted stock award activity for the six months ended June 30, 2018:

(in thousands, except for weighted-average grant-date fair value)	Restricted stock awards	Weighted-average grant-date fair value (per award)
Outstanding as of December 31, 2017	3,169	$ 12.81
Granted	3,193	$ 8.43
Forfeited	(126)	$ 10.55
Vested[1]	(1,791)	$ 12.34
Outstanding as of June 30, 2018	4,445	$ 9.91

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(1) The total intrinsic value of vested restricted stock awards for the six months ended June 30, 2018 was $15.6 million.

The Company utilizes the closing stock price on the grant date to determine the fair value of service vesting restricted stock awards. As of June 30, 2018, unrecognized stock-based compensation related to the restricted stock awards expected to vest was $33.0 million. Such cost is expected to be recognized over a weighted-average period of 2.00 years.

Stock option awards

Stock option awards granted under the LTIP vest and become exercisable in four equal installments on each of the four anniversaries of the grant date. As of June 30, 2018, the 2,646,996 outstanding stock option awards have a weighted-average exercise price of $12.70 and a weighted-average remaining contractual term of 6.56 years. There were no grants, exercises, forfeitures or cancellations of stock option awards during the six months ended June 30, 2018.

The Company utilizes the Black-Scholes option pricing model to determine the fair value of stock option awards and recognizes the associated expense on a straight-line basis over the four-year requisite service period of the awards. Determining the fair value of equity-based awards requires judgment, including estimating the expected term that stock option awards will be outstanding prior to exercise and the associated expected volatility. As of June 30, 2018, unrecognized stock-based compensation related to stock option awards expected to vest was $6.0 million. Such cost is expected to be recognized over a weighted-average period of 1.87 years.

Performance share awards

Performance share awards, which the Company has determined are equity awards, are subject to a combination of market, performance and service vesting criteria. For awards with market criteria or portions of awards with market criteria, which include the RTSR Performance Percentage (as defined below), the ATSR Appreciation (as defined below) and the Company's total shareholder return ("TSR"), a Monte Carlo simulation prepared by an independent third party is utilized to determine the grant-date fair value and the associated expense is recognized on a straight-line basis over the three-year requisite service period of the awards. For portions of awards with performance criteria, which is the ROACE Percentage (as defined below), the grant-date fair value is equal to the Company's stock price on the grant date, and for each reporting period, the associated expense fluctuates and is trued-up based on an estimated probability of how many shares will be earned at the end of the three-year performance period. Any shares earned under performance share awards are expected to be issued in the first quarter following the completion of the requisite service period based on the achievement of certain market and performance criteria.

The following table reflects the performance share award activity for the six months ended June 30, 2018:

(in thousands, except for weighted-average grant-date fair value)	Performance share awards		Weighted-average grant-date fair value (per award)
Outstanding as of December 31, 2017	2,745	$	17.77
Granted[(1)]	1,389	$	9.22
Forfeited	(28)	$	15.71
Vested[(2)]	(454)	$	16.23
Outstanding as of June 30, 2018	3,652	$	14.55

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(1) The amount of stock potentially payable at the end of the performance period for the performance share awards granted on February 16, 2018 will be determined based on three criteria: (i) relative three-year total shareholder return comparing the Company's shareholder return to the shareholder return of the peer group specified in the award agreement ("RTSR Performance Percentage"), (ii) absolute three-year total shareholder return ("ATSR Appreciation") and (iii) three-year return on average capital employed ("ROACE Percentage"). The RTSR Performance Percentage, ATSR Appreciation and ROACE Percentage will be used to identify the "RTSR Factor," the "ATSR Factor" and the "ROACE Factor," respectively, which are used to compute the "Performance Multiple" and ultimately to determine the final number of shares associated with each performance share unit granted at the maturity date (with all partial shares rounded, as appropriate). In computing the Performance Multiple, the RTSR Factor is given a 25% weight, the ATSR Factor a 25% weight and the ROACE Factor a 50% weight. The $9.22 per unit grant-date fair value consists of a (i) $10.08 per unit grant-date fair value, determined utilizing a Monte Carlo simulation, for the combined (.25) RTSR Factor and (.25) ATSR Factor and (ii) $8.36 per unit grant-date fair value for the (.50) ROACE Factor determined based on the closing price of the Company's common stock on the New York Stock Exchange on February 16, 2018. These awards have a performance period of January 1, 2018 to December 31, 2020.

(2) The performance share awards granted on February 27, 2015 had a performance period of January 1, 2015 to December 31, 2017 and, as their performance criteria were not satisfied, resulted in a TSR modifier of 0% based on the Company finishing in the 36th percentile of its peer group for relative TSR. As such, the units were not converted into the Company's common stock during the first quarter of 2018.

As of June 30, 2018, unrecognized stock-based compensation related to the performance share awards expected to vest was $23.7 million. Such cost is expected to be recognized over a weighted-average period of 1.84 years.

The assumptions used to estimate the combined fair value for the (.25) RTSR Factor and the (.25) ATSR Factor for the market criteria portion of the performance share awards granted on the date presented are as follows:

		February 16, 2018
Risk-free interest rate[(1)]		2.34%
Dividend yield		—%
Expected volatility[(2)]		65.49%
Laredo stock closing price on grant date	$	8.36
Combined fair value per performance share award for the (.25) RTSR Factor and the (.25) ATSR Factor[(3)]	$	10.08

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(1) The risk-free interest rate was derived using a term-matched zero-coupon yield derived from the U.S. Treasury constant maturities yield curve on the grant date.

(2) The Company utilized its own historical volatility in order to develop the expected volatility.

(3) The market criteria portion of the performance share award represents 50% of each of the amount of stock potentially payable, if any, and the grant-date fair value of the award.

Stock-based compensation expense

The following has been recorded to stock-based compensation expense for the periods presented:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Restricted stock award compensation	$ 7,286	$ 5,267	$ 13,331	$ 11,434
Stock option award compensation	971	1,144	2,040	2,441
Performance share award compensation	4,415	4,068	8,742	7,808
Total stock-based compensation, gross	12,672	10,479	24,113	21,683
Less amounts capitalized in oil and natural gas properties	(1,996)	(1,792)	(4,098)	(3,772)
Total stock-based compensation, net	$ 10,676	$ 8,687	$ 20,015	$ 17,911

Note 8—Derivatives

Due to the inherent volatility in oil, NGL and natural gas prices, the Company engages in derivative transactions, such as puts, swaps, collars, basis swaps and, in the past, call spreads to hedge price risk associated with a significant portion of the Company's anticipated production. By removing a portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices.

Each put transaction has an established floor price. The Company pays its counterparty a premium, which can be paid at inception or deferred until settlement, to enter into the put transaction. When the settlement price is below the floor price, the counterparty pays the Company an amount equal to the difference between the settlement price and the floor price multiplied by the hedged contract volume. When the settlement price is at or above the floor price in an individual month in the contract period, the put option expires with no settlement for that particular month, except with regard to the deferred premium, if any.

Each swap transaction has an established fixed price. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

Each collar transaction has an established price floor and ceiling. Depending on the terms, the Company may pay its counterparty a premium, which can be paid at inception or deferred until settlement. When the settlement price is below the price floor established by these collars, the counterparty pays the Company an amount equal to the difference between the settlement price and the price floor multiplied by the hedged contract volume. When the settlement price is above the price ceiling established by these collars, the Company pays its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the hedged contract volume. When the settlement price is between the price floor and price ceiling established by these collars in an individual month in the contract period, the collar expires with no settlement paid by either the Company or the counterparty for that particular month, except with regard to the deferred premium, if any.

Each basis swap transaction has an established fixed basis differential corresponding to two floating index prices. Depending on the difference of the two floating index prices in relationship to the fixed basis differential, the Company either receives an amount from its counterparty, or pays an amount to its counterparty, equal to the difference multiplied by the hedged contract volume.

Each call spread transaction has an established short call price and long call price. Depending on the terms, the counterparty may pay a premium to the Company to enter into the transaction. When the settlement price is above the short call price up to the long call price, the Company pays its counterparty an amount equal to the difference between the settlement price and the short call price multiplied by the hedged contract volume. When the settlement price is above the long call price, the Company pays the counterparty an amount equal to the difference between the long call price and the short call price multiplied by the hedged contract volume. When the settlement price is at or below the short call price in an individual month in the contract period, the call option expires with no settlement paid by either the Company or the counterparty for that particular month, except with regard to the deferred premium, if any.

Other than the oil basis swaps, the Company's oil derivatives are settled based on the month's average daily NYMEX index price for the first nearby month of the West Texas Intermediate Light Sweet Crude Oil Futures Contract. The oil basis swaps are settled based on either (i) the differential between the Argus Americas Crude West Texas Intermediate ("WTI") index prices for WTI Midland-weighted average for the trade month and WTI Cushing-WTI formula basis for the trade month as compared to the basis swaps' fixed differential price or (ii) the differential between the Argus Americas Crude WTI Houston-weighted average price for the trade month and the WTI Midland-weighted average price for the trade month as compared to the basis swaps' fixed differential price. The Company's NGL derivatives are settled based on the month's average daily OPIS index price for Mont Belvieu Purity Ethane, TET and Non-TET Propane, Non-TET Normal Butane, Non-TET Isobutane and Non-TET Natural Gasoline. Other than the natural gas basis swaps, the Company's natural gas derivatives are settled based on the Inside FERC index price for West Texas WAHA for the calculation period. The natural gas basis swaps are settled based on the differential between the Inside FERC index price for West Texas WAHA for the calculation period and the NYMEX Henry Hub index price for the calculation period as compared to the basis swaps' fixed differential price.

During the three and six months ended June 30, 2017, the Company completed a hedge restructuring by early terminating a swap that resulted in a termination amount to the Company of $4.2 million that was settled in full by applying the proceeds to pay the premium on one new collar entered into during the restructuring. The following details the derivative that was terminated:

	Aggregate volumes (Bbl)	Floor price ($/Bbl)	Ceiling price ($/Bbl)	Contract period
Oil swap	1,095,000	$ 52.12	$ 52.12	January 2018 - December 2018

The following table summarizes open positions as of June 30, 2018, and represents, as of such date, derivatives in place through December 2020 on annual production volumes:

	Remaining year 2018	Year 2019	Year 2020
Oil:			
Puts:			
Hedged volume (Bbl)	2,735,550	5,949,500	366,000
Weighted-average floor price ($/Bbl)	$ 51.93	$ 48.31	$ 45.00
Swaps:			
Hedged volume (Bbl)	—	657,000	695,400
Weighted-average price ($/Bbl)	$ —	$ 53.45	$ 52.18
Collars:			
Hedged volume (Bbl)	2,060,800	—	—
Weighted-average floor price ($/Bbl)	$ 41.43	$ —	$ —
Weighted-average ceiling price ($/Bbl)	$ 60.00	$ —	$ —
Totals:			
Total volume hedged with floor price (Bbl)	4,796,350	6,606,500	1,061,400
Weighted-average floor price ($/Bbl)	$ 47.42	$ 48.82	$ 49.70
Total volume hedged with ceiling price (Bbl)	2,060,800	657,000	695,400
Weighted-average ceiling price ($/Bbl)	$ 60.00	$ 53.45	$ 52.18
Basis Swaps:			
WTI Midland to WTI Cushing:			
Hedged volume (Bbl)	1,840,000	—	—
Weighted-average price ($/Bbl)	$ (0.56)	$ —	$ —
WTI Houston to WTI Midland:			
Hedged volume (Bbl)	1,840,000	1,810,000	—
Weighted-average price ($/Bbl)	$ 7.30	$ 7.30	$ —
NGL:			
Swaps - Purity Ethane:			
Hedged volume (Bbl)	312,800	—	—
Weighted-average price ($/Bbl)	$ 11.66	$ —	$ —
Swaps - Non-TET Propane:			
Hedged volume (Bbl)	257,600	—	—
Weighted-average price ($/Bbl)	$ 33.92	$ —	$ —
Swaps - Non-TET Normal Butane:			
Hedged volume (Bbl)	92,000	—	—
Weighted-average price ($/Bbl)	$ 38.22	$ —	$ —
Swaps - Non-TET Isobutane:			
Hedged volume (Bbl)	36,800	—	—
Weighted-average price ($/Bbl)	$ 38.33	$ —	$ —
Swaps - Non-TET Natural Gasoline:			
Hedged volume (Bbl)	92,000	—	—
Weighted-average price ($/Bbl)	$ 57.02	$ —	$ —
Total NGL volume hedged (Bbl)	791,200	—	—
TABLE CONTINUES ON NEXT PAGE			

	Remaining year 2018	Year 2019	Year 2020
Natural gas:			
Puts:			
Hedged volume (MMBtu)	4,110,000	—	—
Weighted-average floor price ($/MMBtu)	$ 2.50	$ —	$ —
Collars:			
Hedged volume (MMBtu)	7,856,800	—	—
Weighted-average floor price ($/MMBtu)	$ 2.50	$ —	$ —
Weighted-average ceiling price ($/MMBtu)	$ 3.35	$ —	$ —
Totals:			
Total volume hedged with floor price (MMBtu)	11,966,800	—	—
Weighted-average floor price ($/MMBtu)	$ 2.50	$ —	$ —
Total volume hedged with ceiling price (MMBtu)	7,856,800	—	—
Weighted-average ceiling price ($/MMBtu)	$ 3.35	$ —	$ —
Basis Swaps:			
Hedged volume (MMBtu)	4,600,000	20,075,000	25,254,000
Weighted-average price ($/MMBtu)	$ (0.62)	$ (1.05)	$ (0.76)

See Note 17.a for discussion of additional hedges entered into subsequent to June 30, 2018.

At each period end, the Company nets the fair value of derivatives by counterparty where the right of offset exists and reports this net basis on the "Derivatives" line items on the unaudited consolidated balance sheets as assets and/or liabilities. See Note 9.a for a summary of the fair value of derivatives on a gross basis. The Company's derivatives were not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized in the unaudited consolidated statements of operations in the "Gain (loss) on derivatives, net" line item. Gains and losses on derivatives are included in cash flows from operating activities.

Note 9—Fair value measurements

The Company accounts for its oil, NGL and natural gas derivatives at fair value. The fair value of derivatives is determined utilizing pricing models for similar instruments. The models use a variety of techniques to arrive at fair value, including quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward curves generated from a compilation of data gathered from third parties.

The Company has categorized its assets and liabilities measured at fair value, based on the priority of inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities recorded at fair value on the unaudited consolidated balance sheets are categorized based on inputs to the valuation techniques as follows:

Level 1— Assets and liabilities recorded at fair value for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2— Assets and liabilities recorded at fair value for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the assets or liabilities. Substantially all of these inputs are observable in the marketplace throughout the full term of the price risk management instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.

Level 3— Assets and liabilities recorded at fair value for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. Unobservable inputs are not corroborated by market data. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. The Company conducts a review of fair value hierarchy classifications on an annual basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities. Transfers between fair value hierarchy levels are recognized and reported in the period in which the transfer occurred. No transfers between fair value hierarchy levels occurred during the six months ended June 30, 2018 or 2017.

a. Fair value measurement on a recurring basis

The following tables summarize the Company's derivatives' fair value hierarchy by commodity and current and noncurrent assets and liabilities on a gross basis and the net presentation on the unaudited consolidated balance sheets measured at fair value on a recurring basis as of the dates presented:

(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the unaudited consolidated balance sheets
As of June 30, 2018:						
Assets:						
Current:						
Oil derivatives	$ —	$ 25,431	$ —	$ 25,431	$ (20,029)	$ 5,402
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	17,759	—	17,759	(11,163)	6,596
Oil derivative deferred premiums	—	—	—	—	(2,703)	(2,703)
Natural gas derivative deferred premiums	—	—	—	—	(1,236)	(1,236)
Noncurrent:						
Oil derivatives	$ —	$ 6,674	$ —	$ 6,674	$ (6,217)	$ 457
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	6,087	—	6,087	(3,470)	2,617
Oil derivative deferred premiums	—	—	—	—	—	—
Natural gas derivative deferred premiums	—	—	—	—	—	—
Liabilities:						
Current:						
Oil derivatives	$ —	$ (57,068)	$ —	$ (57,068)	$ 20,029	$ (37,039)
NGL derivatives	—	(3,697)	—	(3,697)	—	(3,697)
Natural gas derivatives	—	187	—	187	11,163	11,350
Oil derivative deferred premiums	—	—	(16,982)	(16,982)	2,703	(14,279)
Natural gas derivative deferred premiums	—	—	(1,690)	(1,690)	1,236	(454)
Noncurrent:						
Oil derivatives	$ —	$ (8,903)	$ —	$ (8,903)	$ 6,217	$ (2,686)
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	(306)	—	(306)	3,470	3,164
Oil derivative deferred premiums	—	—	(6,354)	(6,354)	—	(6,354)
Natural gas derivative deferred premiums	—	—	—	—	—	—
Net derivative position	$ —	$ (13,836)	$ (25,026)	$ (38,862)	$ —	$ (38,862)

(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the unaudited consolidated balance sheets
As of December 31, 2017:						
Assets:						
Current:						
Oil derivatives	$ —	$ 7,427	$ —	$ 7,427	$ (3,721)	$ 3,706
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	10,546	—	10,546	(4,817)	5,729
Oil derivative deferred premiums	—	—	—	—	(87)	(87)
Natural gas derivative deferred premiums	—	—	—	—	(2,456)	(2,456)
Noncurrent:						
Oil derivatives	$ —	$ 11,613	$ —	$ 11,613	$ (6,087)	$ 5,526
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	934	—	934	(934)	—
Oil derivative deferred premiums	—	—	—	—	(2,113)	(2,113)
Natural gas derivative deferred premiums	—	—	—	—	—	—
Liabilities:						
Current:						
Oil derivatives	$ —	$ (12,477)	$ —	$ (12,477)	$ 3,721	$ (8,756)
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	—	—	—	4,817	4,817
Oil derivative deferred premiums	—	—	(18,202)	(18,202)	87	(18,115)
Natural gas derivative deferred premiums	—	—	(3,352)	(3,352)	2,456	(896)
Noncurrent:						
Oil derivatives	$ —	$ (2,389)	$ —	$ (2,389)	$ 6,087	$ 3,698
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	—	—	—	934	934
Oil derivative deferred premiums	—	—	(7,129)	(7,129)	2,113	(5,016)
Natural gas derivative deferred premiums	—	—	—	—	—	—
Net derivative position	$ —	$ 15,654	$ (28,683)	$ (13,029)	$ —	$ (13,029)

These items are included in the "Derivatives" line items on the unaudited consolidated balance sheets as assets and/or liabilities. Significant Level 2 assumptions associated with the calculation of discounted cash flows used in the mark-to-market analysis of derivatives include each derivative contract's corresponding commodity index price(s), appropriate risk-adjusted discount rates and other relevant data. The Company determines the fair value of its derivatives by utilizing pricing models for substantially similar instruments. Inputs to the pricing models include forward price curves generated from a compilation of data gathered from third parties.

The Company's deferred premiums associated with its derivative contracts are categorized as Level 3, as the Company utilizes a net present value calculation to determine the valuation. They are considered to be measured on a recurring basis as the derivative contracts they derive from are measured on a recurring basis. As derivative contracts containing deferred premiums are entered into, the Company discounts the associated deferred premium to its net present value at the contract trade date, using the Senior Secured Credit Facility rate at the trade date (historical input rates range from 1.69% to 3.56%), and then records the change in net present value to interest expense over the period from trade until the final settlement date at the end of the contract. After this initial valuation, the net present value of each deferred premium is not adjusted; therefore, significant increases (decreases) in the Senior Secured Credit Facility rate would result in a significantly lower (higher) fair value measurement for each new contract entered into that contained a deferred premium; however, the valuation for the deferred premiums already recorded would remain unaffected. While the Company believes the sources utilized to arrive at the fair value estimates are reliable, different sources or methods could have yielded different fair value estimates; therefore, on a quarterly basis, the valuation is compared to counterparty valuations and a third-party valuation of the deferred premiums for reasonableness.

The following table presents payments required for derivative deferred premiums as of June 30, 2018 for the periods presented:

(in thousands)	June 30, 2018
Remaining 2018	$ 10,860
2019	13,511
2020	1,110
Total	$ 25,481

A summary of the changes in net assets and liabilities classified as Level 3 measurements for the periods presented are as follows:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2018	2017	2018	2017
Balance of Level 3 at beginning of period	$ (30,292)	$ (13,025)	$ (28,683)	$ (8,998)
Change in net present value of derivative deferred premiums	(185)	(70)	(396)	(111)
Total purchases and settlements of derivative deferred premiums:				
Purchases	—	(905)	(5,422)	(6,998)
Settlements	5,451	1,446	9,475	3,553
Balance of Level 3 at end of period	$ (25,026)	$ (12,554)	$ (25,026)	$ (12,554)

b. Fair value measurement on a nonrecurring basis

See Note 10.b "Fair value measurement on a nonrecurring basis" and Note 4.c "2016 acquisitions of evaluated and unevaluated oil and natural gas properties" in the 2017 Annual Report for the Company's accounting policies and assumptions in estimating the fair values of assets acquired and liabilities assumed for acquisitions of evaluated and unevaluated oil and natural gas properties. See Note 3.a for additional discussion of the Company's acquisitions of evaluated and unevaluated oil and natural gas properties for the six months ended June 30, 2018.

c. Items not accounted for at fair value

The carrying amounts reported in the unaudited consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, accrued capital expenditures, undistributed revenue and royalties and other accrued assets and liabilities approximate their fair values.

The Company has not elected to account for its debt instruments at fair value. The following table presents the carrying amounts and fair values of the Company's debt as of the dates presented:

	June 30, 2018		December 31, 2017	
(in thousands)	Long-term debt	Fair value	Long-term debt	Fair value
January 2022 Notes	$ 450,000	$ 444,938	$ 450,000	$ 454,500
March 2023 Notes	350,000	352,188	350,000	364,105
Senior Secured Credit Facility	110,000	110,028	—	—
Total	$ 910,000	$ 907,154	$ 800,000	$ 818,605

The fair values of the debt outstanding on the January 2022 Notes and the March 2023 Notes were determined using the June 30, 2018 and December 31, 2017 quoted market price (Level 1) for each respective instrument. The fair value of the outstanding debt on the Senior Secured Credit Facility as of June 30, 2018 was estimated utilizing a pricing model for similar instruments (Level 2).

Note 10—Net income per common share

Basic net income per common share is computed by dividing net income by the weighted-average number of common shares outstanding for the period. Diluted net income per common share reflects the potential dilution of non-vested restricted stock awards, outstanding stock option awards and non-vested performance share awards. The dilutive effects of these awards were calculated utilizing the treasury stock method. See Note 7.c for additional discussion on these awards.

The following table reflects the calculation of basic and diluted weighted-average common shares outstanding and net income per common share for the periods presented:

	Three months ended June 30,		Six months ended June 30,	
(in thousands, except for per share data)	**2018**	**2017**	**2018**	**2017**
Net income (numerator):				
Net income—basic and diluted	$ 33,452	$ 61,110	$ 119,972	$ 129,386
Weighted-average common shares outstanding (denominator):				
Basic(1)	230,933	239,231	234,561	238,870
Non-vested restricted stock awards(2)	683	419	885	896
Outstanding stock option awards(3)	90	101	55	131
Non-vested performance share awards(4)	—	4,666	—	4,488
Diluted	231,706	244,417	235,501	244,385
Net income per common share:				
Basic	$ 0.14	$ 0.26	$ 0.51	$ 0.54
Diluted	$ 0.14	$ 0.25	$ 0.51	$ 0.53

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(1) Weighted-average common shares outstanding used in the computation of basic and diluted net income per common share was computed taking into account share repurchases that occurred during the three and six months ended June 30, 2018. See Note 7.a for additional discussion of the Company's share repurchase program.

(2) The effect of a significant portion of the non-vested restricted stock awards was excluded from the calculation of diluted net income per common share for the three and six months ended June 30, 2018. The inclusion of these non-vested restricted stock awards would be anti-dilutive due to the sum of the assumed proceeds exceeding the average stock price during the period.

(3) The effect of the outstanding stock option awards, with the exception of those granted in 2016, was excluded from the calculation of diluted net income per common share for the three and six months ended June 30, 2018. The inclusion of these stock option awards would be anti-dilutive as their exercise prices were greater than the average stock price during the period.

(4) The effect of the non-vested performance share awards was excluded from the calculation of diluted net income per common share for the three and six months ended June 30, 2018 as the awards were below the respective agreements' payout thresholds. The effect of the non-vested performance share awards granted in 2018 was calculated utilizing the following criteria defined in Note 7.c: (i) the RTSR Performance Percentage, (ii) the ATSR Appreciation and (iii) the ROACE Percentage from the beginning of the performance period to June 30, 2018 for each of the criteria to identify the RTSR Factor, the ATSR Factor and the ROACE Factor, respectively, which were used to compute the Performance Multiple to determine the number of shares for the dilutive effect. The effects of the non-vested performance share awards granted in 2016 and 2017 were calculated utilizing the Company's TSR from the beginning of each performance share awards' respective performance period to June 30, 2018 in comparison to the TSR of the peers specified in each respective performance share awards' agreement.

Note 11—Commitments and contingencies

a. Litigation

From time to time, the Company is subject to various legal proceedings arising in the ordinary course of business, including proceedings for which the Company may not have insurance coverage. While many of these matters involve inherent uncertainty, except with regard to the specific litigation noted below, as of the date hereof, the Company does not currently believe that any such legal proceedings will have a material adverse effect on the Company's business, financial position, results of operations or liquidity.

On May 3, 2017, Shell Trading (US) Company ("Shell") filed an Original Petition and Request for Disclosure in the District Court of Harris County, Texas, alleging that the crude oil purchase agreement entered into between Shell and Laredo effective October 1, 2016 through June 30, 2020 does not accurately reflect the compensation to be paid to Shell under certain circumstances due to a drafting mistake. Shell seeks reformation of one clause of the crude oil purchase agreement on the grounds of alleged mutual mistake or, in the alternative, unilateral mistake, an award of the amounts Shell alleges it should have been or should be paid under the crude oil purchase agreement, court costs and attorneys' fees. The Company does not believe there was a drafting mistake made in the crude oil purchase agreement, which covered the sale to Shell of 19,000 barrels of crude oil per day of the Company's gross production as well as the purchase by the Company of like-quantity crude oil from Shell. On December 11, 2017, Shell filed its First Amended Petition, in which it asserted nine causes of action, including multiple new claims for breach of contract and fraud.

Effective May 1, 2018, Shell terminated the crude oil purchase agreement and ceased purchasing the Company's crude oil and selling crude oil to the Company under the terms of such agreement. As a result, the Company filed its Second Amended Answer and Original Counterclaim against Shell on June 15, 2018, in which the Company denies all allegations by Shell and seeks damages in excess of $150.0 million resulting from Shell's breach and wrongful termination of the crude oil purchase agreement. Shell filed a Second Amended Petition on June 1, 2018, in which it asserted a new cause of action against the Company for alleged repudiation of Shell's proposed reformed version of the crude oil purchase agreement, a version never signed or agreed to by the Company.

Through April 30, 2018, the date on which Shell wrongfully terminated the crude oil purchase agreement, the Company had accounted for the costs and crude oil price realization as reflected in the terms of the crude oil purchase agreement. The accompanying unaudited consolidated balance sheets do not include any amounts for damage claims or attorneys' fees sought by Shell. As of June 30, 2018, the Company had estimated an aggregate amount of $37.4 million that is the subject of Shell's claims, which is generally based on the contractual amount in dispute under the pricing election that is the subject of Shell's claims applied to the barrels of crude oil purchased and sold through the date on which Shell wrongfully terminated the crude oil purchase agreement. As a result of such termination, the Company's estimate of this unrecorded amount is not anticipated to materially increase in the future. This estimate does not include damages sought by Shell pursuant to its latest repudiation claim asserted in its Second Amended Petition or amounts sought by Shell for recovery of attorneys' fees incurred for the prosecution of its claims.

The Company is unable to determine a probability of the outcome of this litigation at this time. The Company believes Shell's claims are meritless and the termination by Shell is improper and a breach of the crude oil purchase agreement. The Company therefore intends to vigorously defend itself against Shell's claims and pursue its rights under the terminated crude oil purchase agreement to seek all appropriate damages from Shell.

b. Drilling contracts

The Company has committed to several drilling contracts with third parties to facilitate the Company's drilling plans. Certain of these contracts are for a term of multiple months and contain early termination clauses that require the Company to potentially pay penalties to the third party should the Company cease drilling efforts. These penalties would negatively impact the Company's financial statements upon early contract termination. There were no penalties incurred for early contract termination for either of the six months ended June 30, 2018 or 2017. The future commitment of $28.1 million as of June 30, 2018 is not recorded in the accompanying unaudited consolidated balance sheets. Management does not currently anticipate the early termination of these contracts in 2018.

c. Firm sale and transportation commitments

The Company has committed to deliver for sale or transportation fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, the Company is subject to deficiency payments. These commitments are normal and customary for the Company's business. In certain instances, the Company has used spot market purchases to meet its commitments in certain locations or due to favorable pricing. Management anticipates continuing this practice in the future. The Company incurred deficiency payments and other contractual penalties of $2.2 million and $0.5 million during the three months ended June 30, 2018 and 2017, respectively, and $2.3 million and $0.6 million during the six months ended June 30, 2018 and 2017, respectively. For the three and six months ended June 30, 2018, these deficiency payments and other contractual penalties are netted with the respective revenue stream in the unaudited consolidated statements of operations. For the three and six months ended June 30, 2017, these deficiency payments and other penalties are included in the "Other operating expenses" line item in the unaudited consolidated statements of operations. See Note 4.a for additional information regarding the presentation of deficiency payments and other contractual penalties. Future commitments of $409.1 million as of June 30, 2018 are not recorded in the accompanying unaudited consolidated balance sheets. For information regarding the TA related to Medallion, see Note 3.c.

d. Purchase commitment

During the three months ended June 30, 2018, the Company entered into a purchase and supply agreement, for a term of one year, whereby it has committed to buy a certain volume of in-basin sand for a fixed price. As of June 30, 2018, under the terms of this agreement, the Company is required to purchase a certain percentage of the volume commitment or it will incur a shortfall payment of $8.0 million at the end of the contract period.

e. Federal and state regulations

Oil and natural gas exploration, production and related operations are subject to extensive federal and state laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases the cost of doing business and affects profitability. The Company believes that it is in compliance with currently applicable federal and state regulations related to oil and natural gas exploration and production, and that compliance with the current regulations will not have a material adverse impact on the financial position or results of operations of the Company. These rules and regulations are frequently amended or reinterpreted; therefore, the Company is unable to predict the future cost or impact of complying with these regulations.

f. Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, among other things, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed in the period incurred. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Management believes no materially significant liabilities of this nature existed as of June 30, 2018 or December 31, 2017.

Note 12—Supplemental cash flow information

The following table presents supplemental cash flow information:

	Six months ended June 30,	
(in thousands)	**2018**	**2017**
Non-cash investing activities:		
(Decrease) increase in accrued capital expenditures	$ (8,878)	$ 22,855
Capitalized stock-based compensation	$ 4,098	$ 3,772
Capitalized asset retirement costs	$ 577	$ 325
Other supplemental cash flow information:		
Capitalized interest	$ 498	$ 490

Note 13—Asset retirement obligations

See Note 2.m "Asset retirement obligations" in the 2017 Annual Report for discussion on asset retirement obligations.

The following reconciles the Company's asset retirement obligation liability associated with tangible long-lived assets:

	Six months ended June 30,	
(in thousands)	**2018**	**2017**
Liability at beginning of period	$ 55,506	$ 52,207
Liabilities added due to acquisitions, drilling, midstream service asset construction and other	577	320
Accretion expense	2,227	1,871
Liabilities settled due to plugging and abandonment or sale	(1,815)	(1,234)
Revision of estimates	—	5
Liability at end of period	$ 56,495	$ 53,169

Note 14—Income taxes

The Company is subject to federal and state income taxes and the Texas franchise tax. The Company had federal net operating loss carry-forwards totaling $1.7 billion and state of Oklahoma net operating loss carry-forwards totaling $40.3 million as of June 30, 2018, which begin expiring in 2026 and 2032, respectively. Due to the passing of Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"), $23.0 million of the federal net operating loss carry-forward will not expire but may be limited in future periods. As of June 30, 2018, the Company believes it is more likely than not that a portion of the net operating loss carry-forwards are not fully realizable. The Company continues to consider new evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance is needed. Such consideration includes projected future cash flows from its oil, NGL and natural gas reserves (including the timing of those cash flows), the reversal of deferred tax liabilities recorded as of June 30, 2018, the Company's ability to capitalize intangible drilling costs, rather than expensing these costs in order to prevent an operating loss carry-forward from expiring unused and future projections of Oklahoma sourced income. As of June 30, 2018, a full valuation allowance of $315.1 million has been recorded against the Company's net deferred tax assets.

Note 15—Related party

The Company has a compression arrangement with an affiliate of Archrock Partners, Inc. ("Archrock"). One of Laredo's directors is on the board of directors of Archrock.

As of of June 30, 2018 and December 31, 2017, no amounts and a de minimis amount, respectively, were included in accounts payable from Archrock in the unaudited consolidated balance sheets.

The following table presents the lease operating expenses related to Archrock included in the unaudited consolidated statements of operations:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Lease operating expenses	$ 16	$ 232	$ 129	$ 656

Note 16—Subsidiary guarantors

The Guarantors have fully and unconditionally guaranteed the January 2022 Notes, the March 2023 Notes and the Senior Secured Credit Facility (and had guaranteed the May 2022 Notes until the May 2022 Notes Redemption Date), subject to the Releases. In accordance with practices accepted by the SEC, Laredo has prepared condensed consolidating financial statements to quantify the balance sheets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. The following unaudited condensed consolidating (i) balance sheets as of June 30, 2018 and December 31, 2017, (ii) statements of operations for the three and six months ended June 30, 2018 and 2017 and (iii) statements of cash flows for the six months ended June 30, 2018 and 2017 present financial information for Laredo on a stand-alone basis (carrying any investment in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis (carrying any investment in subsidiaries under the equity method), and the consolidation and elimination entries necessary to arrive at the information for the Company on a condensed consolidated basis. Income taxes for LMS and for GCM are recorded on Laredo's balance sheets, statements of operations and statements of cash flows as they are disregarded entities for income tax purposes. Laredo and the Guarantors are not restricted from making intercompany distributions to each other.

Condensed consolidating balance sheet
June 30, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$ 84,212	$ 17,109	$ —	$ 101,321
Other current assets	66,601	1,772	—	68,373
Oil and natural gas properties, net	1,854,379	9,175	(20,239)	1,843,315
Midstream service assets, net	—	134,827	—	134,827
Other fixed assets, net	42,154	230	—	42,384
Investment in subsidiaries	128,875	—	(128,875)	—
Other noncurrent assets, net	14,511	4,556	—	19,067
Total assets	$ 2,190,732	$ 167,669	$ (149,114)	$ 2,209,287
Accounts payable and accrued liabilities	$ 51,541	$ 22,711	$ —	$ 74,252
Other current liabilities	196,199	12,969	—	209,168
Long-term debt, net	902,745	—	—	902,745
Other noncurrent liabilities	60,841	3,114	—	63,955
Stockholders' equity	979,406	128,875	(149,114)	959,167
Total liabilities and stockholders' equity	$ 2,190,732	$ 167,669	$ (149,114)	$ 2,209,287

Condensed consolidating balance sheet
December 31, 2017

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$ 79,413	$ 21,232	$ —	$ 100,645
Other current assets	132,219	2,518	—	134,737
Oil and natural gas properties, net	1,596,834	9,220	(16,715)	1,589,339
Midstream service assets, net	—	138,325	—	138,325
Other fixed assets, net	40,344	377	—	40,721
Investment in subsidiaries	(7,566)	—	7,566	—
Other noncurrent assets, net	15,526	3,996	—	19,522
Total assets	$ 1,856,770	$ 175,668	$ (9,149)	$ 2,023,289
Accounts payable and accrued liabilities	$ 34,550	$ 23,791	$ —	$ 58,341
Other current liabilities	193,104	25,974	—	219,078
Long-term debt, net	791,855	—	—	791,855
Other noncurrent liabilities	54,967	133,469	—	188,436
Stockholders' equity	782,294	(7,566)	(9,149)	765,579
Total liabilities and stockholders' equity	$ 1,856,770	$ 175,668	$ (9,149)	$ 2,023,289

Condensed consolidating statement of operations
For the three months ended June 30, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 208,624	$ 163,021	$ (20,599)	$ 351,046
Total costs and expenses	115,602	158,433	(17,756)	256,279
Operating income	93,022	4,588	(2,843)	94,767
Interest expense	(14,424)	—	—	(14,424)
Other non-operating expense	(42,303)	(1,025)	(3,563)	(46,891)
Income before income taxes	36,295	3,563	(6,406)	33,452
Income tax	—	—	—	—
Net income	$ 36,295	$ 3,563	$ (6,406)	$ 33,452

Condensed consolidating statement of operations
For the three months ended June 30, 2017

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 142,224	$ 61,454	$ (16,677)	$ 187,001
Total costs and expenses	91,140	58,299	(14,499)	134,940
Operating income	51,084	3,155	(2,178)	52,061
Interest expense	(23,173)	—	—	(23,173)
Other non-operating income	35,377	2,414	(5,569)	32,222
Income before income taxes	63,288	5,569	(7,747)	61,110
Income tax	—	—	—	—
Net income	$ 63,288	$ 5,569	$ (7,747)	$ 61,110

Condensed consolidating statement of operations
For the six months ended June 30, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 406,449	$ 239,321	$ (35,028)	$ 610,742
Total costs and expenses	221,290	232,997	(31,504)	422,783
Operating income	185,159	6,324	(3,524)	187,959
Interest expense	(27,942)	—	—	(27,942)
Other non-operating expense	(33,721)	(1,281)	(5,043)	(40,045)
Income before income taxes	123,496	5,043	(8,567)	119,972
Income tax	—	—	—	—
Net income	$ 123,496	$ 5,043	$ (8,567)	$ 119,972

Condensed consolidating statement of operations
For the six months ended June 30, 2017

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 281,367	$ 127,240	$ (32,600)	$ 376,007
Total costs and expenses	179,169	121,065	(27,614)	272,620
Operating income	102,198	6,175	(4,986)	103,387
Interest expense	(45,893)	—	—	(45,893)
Other non-operating income	78,067	5,332	(11,507)	71,892
Income before income taxes	134,372	11,507	(16,493)	129,386
Income tax	—	—	—	—
Net income	$ 134,372	$ 11,507	$ (16,493)	$ 129,386

Condensed consolidating statement of cash flows
For the six months ended June 30, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash provided by operating activities	$ 254,991	$ 12,653	$ (5,043)	$ 262,601
Change in investment between affiliates	4,680	(9,723)	5,043	—
Capital expenditures and other	(351,142)	(2,930)	—	(354,072)
Net cash provided by financing activities	15,916	—	—	15,916
Net decrease in cash and cash equivalents	(75,555)	—	—	(75,555)
Cash and cash equivalents, beginning of period	112,158	1	—	112,159
Cash and cash equivalents, end of period	$ 36,603	$ 1	$ —	$ 36,604

Condensed consolidating statement of cash flows
For the six months ended June 30, 2017

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash provided by operating activities	$ 159,048	$ 9,360	$ (11,507)	$ 156,901
Change in investment between affiliates	(8,264)	(3,243)	11,507	—
Capital expenditures and other	(171,461)	(6,117)	—	(177,578)
Net cash provided by financing activities	23,029	—	—	23,029
Net increase in cash and cash equivalents	2,352	—	—	2,352
Cash and cash equivalents, beginning of period	32,671	1	—	32,672
Cash and cash equivalents, end of period	$ 35,023	$ 1	$ —	$ 35,024

Note 17—Subsequent events

a. New derivative contracts

The following table presents new oil derivatives that were entered into subsequent to June 30, 2018:

	Aggregate volumes (Bbl)	Floor price ($/Bbl)	Ceiling price ($/Bbl)	Contract period
Put[(1)]	2,080,500	$ 45.00	$ —	January 2019 - December 2019
Collar	732,000	$ 45.00	$ 76.15	January 2020 - December 2020
Collar	402,600	$ 45.00	$ 76.10	January 2020 - December 2020
Collar	912,500	$ 45.00	$ 71.00	January 2021 - December 2021

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(1) There are $2.2 million in deferred premiums associated with these contracts.

See Note 8 for information regarding the Company's derivative settlement index for oil.

b. Senior Secured Credit Facility

On July 11, 2018 and July 18, 2018, the Company borrowed $30.0 million and $15.0 million, respectively, on the Senior Secured Credit Facility. On July 30, 2018, the Company repaid $20.0 million on the Senior Secured Credit Facility. As a result, the outstanding balance under the Senior Secured Credit Facility was $135.0 million as of July 31, 2018.

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our unaudited consolidated financial statements and condensed notes thereto included elsewhere in this Quarterly Report as well as our audited consolidated financial statements and notes thereto included in our 2017 Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. Please see "Cautionary Statement Regarding Forward-Looking Statements." Except for purposes of the unaudited consolidated financial statements and condensed notes thereto included elsewhere in this Quarterly Report, references in this Quarterly Report to "Laredo," "we," "us," "our" or similar terms refer to Laredo, LMS and GCM collectively, unless the context otherwise indicates or requires. All amounts, dollars and percentages presented in this Quarterly Report are rounded and therefore approximate.

Executive overview

We are an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, and midstream and marketing services, primarily in the Permian Basin of West Texas. Since our inception, we have grown primarily through our drilling program coupled with select strategic acquisitions and joint ventures.

Our financial and operating performance for the three months ended June 30, 2018 included the following:

- Oil, NGL and natural gas sales of $208.6 million, compared to $141.8 million for the three months ended June 30, 2017;
- Average daily sales volumes of 67,206 BOE/D, compared to 58,632 BOE/D for the three months ended June 30, 2017;
- Net income of $33.5 million, compared to $61.1 million for the three months ended June 30, 2017; and
- Adjusted EBITDA (a non-GAAP financial measure) of $152.5 million, compared to $114.3 million for the three months ended June 30, 2017. See page 41 for a discussion and reconciliation of Adjusted EBITDA.

Our financial and operating performance for the six months ended June 30, 2018 included the following:

- Oil, NGL and natural gas sales of $406.0 million, compared to $280.6 million for the six months ended June 30, 2017;
- Average daily sales volumes of 65,270 BOE/D, compared to 55,536 BOE/D for the six months ended June 30, 2017;
- Net income of $120.0 million, compared to $129.4 million for the six months ended June 30, 2017; and
- Adjusted EBITDA (a non-GAAP financial measure) of $295.9 million, compared to $221.7 million for the six months ended June 30, 2017. See page 41 for a discussion and reconciliation of Adjusted EBITDA.

Pricing and reserves

Our results of operations are heavily influenced by oil, NGL and natural gas prices. Oil, NGL and natural gas price fluctuations are caused by changes in global and regional supply and demand, market uncertainty, economic conditions, transportation constraints and a variety of additional factors. Historically, commodity prices have experienced significant fluctuations, and additional changes in commodity prices may affect the economic viability of, and our ability to fund, our drilling projects, as well as the economic valuation and economic recovery of oil, NGL and natural gas reserves.

During the three months ended June 30, 2018, the Midland market crude oil price experienced an increased discount to WTI-Cushing prices primarily due to limited pipeline capacity constraining transportation of crude oil out of the Permian Basin to major marketing hubs including, but not limited to, Cushing, Oklahoma and the United States Gulf Coast. As of June 30, 2018, this discount for prompt month delivery was $12 per Bbl of oil. This pipeline constraint is expected to affect the Midland market oil price until additional transportation capacity becomes operational or until basin-wide crude oil production decreases from its current historical levels. We have focused on achieving the ability to sell oil in multiple markets and protecting the Company's oil value from basin differentials by securing transportation capacity.

We have entered into a number of derivative contracts that have enabled us to offset a portion of the changes in our cash flow caused by price fluctuations for our sales of oil, NGL and natural gas, as discussed in "Item 3. Quantitative and Qualitative Disclosures About Market Risk."

The unweighted arithmetic average first-day-of-the-month prices for each month within the 12-month period prior to the end of the reporting period before pricing differentials, adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received when control passes to the purchaser/customer (the "Realized Prices"), utilized to value our reserves as of June 30, 2018 and June 30, 2017, were $55.36 per Bbl for oil, $19.15 per Bbl for NGL and $1.80 per Mcf for natural gas, and $43.64 per Bbl for oil, $15.16 per Bbl for NGL and $2.15 per Mcf for natural gas, respectively. The Realized Prices used to estimate proved reserves do not include derivative transactions. See "—Costs and expenses-*Transportation and marketing expenses*" for costs incurred prior to control passing to the final customer. The unamortized cost of our evaluated oil and natural gas properties did not exceed the full cost ceiling amount as of June 30, 2018 or June 30, 2017. See Note 5 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for discussion of our full cost method of accounting.

Core area of operations

The oil and liquids-rich Permian Basin is characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. As of June 30, 2018, we had assembled 122,044 net acres in the Permian Basin.

Sources of our revenue

Our revenues are derived from the sale of produced oil, NGL and natural gas, the sale of purchased oil and providing midstream services to third parties, all within the continental United States and do not include the effects of derivatives. Our oil, NGL and natural gas revenues may vary significantly from period to period as a result of changes in volumes of production, pricing differentials and/or changes in commodity prices. Our sales of purchased oil revenue may vary due to changes in oil prices, pricing differentials and the amount of volumes purchased. Our midstream service revenues may vary due to oil throughput fees and the level of services provided to third parties for (i) oil and natural gas gathering and transportation systems and related facilities, (ii) gas lift, rig fuel and centralized compression infrastructure and (iii) water storage, recycling and transportation infrastructure. The following table presents our sources of revenue as a percentage of total revenues:

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Oil sales	45%	56%	51%	54%
NGL sales	10%	11%	10%	11%
Natural gas sales	4%	9%	5%	10%
Midstream service revenues	1%	1%	1%	1%
Sales of purchased oil	40%	23%	33%	24%
Total	100%	100%	100%	100%

Results of operations consolidated

For the three and six months ended June 30, 2018 as compared to the three and six months ended June 30, 2017

Oil, NGL and natural gas sales volumes, revenues and prices

The following table presents information regarding produced oil, NGL and natural gas sales volumes, revenues and average sales prices:

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Sales volumes:				
Oil (MBbl)	2,514	2,482	4,953	4,602
NGL (MBbl)	1,778	1,433	3,341	2,696
Natural gas (MMcf)	10,947	8,524	21,120	16,524
Oil equivalents (MBOE)(1)(2)	6,116	5,336	11,814	10,052
Average daily sales volumes (BOE/D)(2)	67,206	58,632	65,270	55,536
% Oil(2)	41%	47%	42%	46%
Sales revenues (in thousands):				
Oil	$ 159,051	$ 104,214	$ 309,965	$ 203,681
NGL	36,805	19,801	65,165	40,629
Natural gas	12,705	17,822	30,865	36,263
Total oil, NGL and natural gas sales revenues	$ 208,561	$ 141,837	$ 405,995	$ 280,573
Average sales Realized Prices(2):				
Oil, without derivatives ($/Bbl)(3)	$ 63.26	$ 42.00	$ 62.58	$ 44.26
NGL, without derivatives ($/Bbl)(3)	$ 20.71	$ 13.82	$ 19.51	$ 15.07
Natural gas, without derivatives ($/Mcf)(3)	$ 1.16	$ 2.09	$ 1.46	$ 2.19
Average price, without derivatives ($/BOE)(3)	$ 34.10	$ 26.58	$ 34.37	$ 27.91
Oil, with derivatives ($/Bbl)(4)	$ 58.71	$ 46.95	$ 58.62	$ 48.22
NGL, with derivatives ($/Bbl)(4)	$ 20.07	$ 13.61	$ 19.15	$ 14.75
Natural gas, with derivatives ($/Mcf)(4)	$ 1.72	$ 2.12	$ 1.78	$ 2.21
Average price, with derivatives ($/BOE)(4)	$ 33.04	$ 28.88	$ 33.18	$ 29.66

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(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 received when control passes to the purchaser/customer adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. See "—Costs and expenses- *Transportation and marketing expenses*" for costs incurred prior to control passing to the final customer.

(4) Price reflects the after-effects of our derivative transactions on our average Realized Prices. Our calculation of such after-effects includes current period settlements of matured derivatives in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments that settled in the period.

The following table presents settlements (paid) received for matured derivatives and premiums paid previously or upon settlement attributable to derivatives that matured during the periods utilized in our calculation of the average sales Realized Prices with derivatives presented above:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Settlements (paid) received for matured derivatives:				
Oil	$ (5,608)	$ 12,969	$ (9,344)	$ 20,217
NGL	(1,147)	(296)	(1,194)	(864)
Natural gas	6,936	1,032	8,483	1,803
Total	$ 181	$ 13,705	$ (2,055)	$ 21,156
Premiums paid previously or upon settlement attributable to derivatives that matured during the respective period:				
Oil	$ (5,838)	$ (679)	$ (10,241)	$ (2,021)
Natural gas	(845)	(767)	(1,686)	(1,532)
Total	$ (6,683)	$ (1,446)	$ (11,927)	$ (3,553)

Changes in average sales Realized Prices without derivatives and sales volumes caused the following changes to our oil, NGL and natural gas revenues between the three months ended June 30, 2018 and 2017:

(in thousands)	**Oil**	**NGL**	**Natural gas**	**Total net effect of change**
2017 Revenues	$ 104,214	$ 19,801	$ 17,822	$ 141,837
Effect of changes in average sales Realized Prices	53,469	12,254	(10,182)	55,541
Effect of changes in sales volumes	1,368	4,750	5,065	11,183
2018 Revenues	$ 159,051	$ 36,805	$ 12,705	$ 208,561

Changes in average sales Realized Prices and sales volumes caused the following changes to our oil, NGL and natural gas revenues between the six months ended June 30, 2018 and 2017:

(in thousands)	**Oil**	**NGL**	**Natural gas**	**Total net effect of change**
2017 Revenues	$ 203,681	$ 40,629	$ 36,263	$ 280,573
Effect of changes in average sales Realized Prices	90,718	14,828	(15,484)	90,062
Effect of changes in sales volumes	15,566	9,708	10,086	35,360
2018 Revenues	$ 309,965	$ 65,165	$ 30,865	$ 405,995

Oil sales revenue. Our oil sales revenue is a function of oil production volumes sold and average oil sales Realized Prices received for those volumes. The increase in oil sales revenue of $54.8 million, or 53%, for the three months ended June 30, 2018 as compared to the same period in 2017 is due to a 51% increase in average oil sales Realized Prices with a moderate increase in oil sales volumes.

The increase in oil sales revenue of $106.3 million, or 52%, for the six months ended June 30, 2018 as compared to the same period in 2017 is due to a 41% increase in average oil sales Realized Prices realized and an 8% increase in oil sales volumes.

NGL sales revenue. Our NGL sales revenue is a function of NGL production volumes sold and average NGL sales Realized Prices received for those volumes. The increase in NGL sales revenue of $17.0 million, or 86%, for the three months ended June 30, 2018 as compared to the same period in 2017 is due to a 50% increase in average NGL sales Realized Prices realized and a 24% increase in NGL sales volumes.

The increase in NGL sales revenue of $24.5 million, or 60%, for the six months ended June 30, 2018 as compared to the same period in 2017 is due to a 29% increase in average NGL sales Realized Prices received and a 24% increase in NGL sales volumes.

Natural gas sales revenue. Our natural gas sales revenue is a function of natural gas production volumes sold and average natural gas sales Realized Prices received for those volumes. The decrease in natural gas sales revenue of $5.1 million, or 29%, for the three months ended June 30, 2018 as compared to the same period in 2017 is due to a 44% decrease in natural gas sales Realized Prices received, partially offset by a 28% increase in natural gas sales volumes.

The decrease in natural gas revenue of $5.4 million, or 15%, for the six months ended June 30, 2018 as compared to the same period in 2017 is due to a 33% decrease in natural gas sales Realized Prices received, partially offset by a 28% increase in natural gas sales volumes.

The following table presents midstream service and sales of purchased oil revenues:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2018	2017	2018	2017
Midstream service revenues	$ 1,976	$ 2,703	$ 4,335	$ 5,702
Sales of purchased oil	$ 140,509	$ 42,461	$ 200,412	$ 89,732

Midstream service revenues. Our midstream service revenues decreased by $0.7 million, or 27%, and by $1.4 million, or 24%, for the three and six months ended June 30, 2018, respectively, as compared to the same periods in 2017. These revenues are a function of the services provided through our (i) oil and natural gas gathering and transportation systems and related facilities, (ii) gas lift, rig fuel and centralized compression infrastructure and (iii) water storage, recycling and transportation infrastructure.

Sales of purchased oil. Sales of purchased oil increased by $98.0 million, or 231%, and by $110.7 million, or 123%, for the three and six months ended June 30, 2018, respectively, as compared to the same periods in 2017. These revenues are a function of the volume and price of purchased oil sold to customers and are fully offset by the increased cost of purchased oil. During the three months ended June 30, 2018, our volume of purchased oil sold to customers increased by 131%, as compared to the same period in 2017. This second-quarter 2018 increase in the volume of purchased oil sold is expected to decline to levels typical of previous periods in the third quarter of 2018.

Costs and expenses

The following table presents information regarding costs and expenses and average costs per BOE sold:

	Three months ended June 30,		Six months ended June 30,	
(in thousands except for per BOE sold data)	2018	2017	2018	2017
Costs and expenses:				
Lease operating expenses	$ 22,642	$ 20,104	$ 44,593	$ 37,096
Production and ad valorem taxes	12,405	8,472	24,217	17,253
Transportation and marketing expenses	1,534	—	1,534	—
Midstream service expenses	403	896	1,096	1,812
Costs of purchased oil	140,578	44,020	201,242	94,276
General and administrative:				
Cash	16,158	13,321	31,544	29,694
Non-cash stock-based compensation, net	10,676	8,687	20,015	17,911
Depletion, depreciation and amortization	50,762	38,003	96,315	72,115
Other operating expenses	1,121	1,437	2,227	2,463
Total costs and expenses	$ 256,279	$ 134,940	$ 422,783	$ 272,620
Average costs per BOE sold(1):				
Lease operating expenses	$ 3.70	$ 3.77	$ 3.78	$ 3.69
Production and ad valorem taxes	2.03	1.59	2.05	1.72
Transportation and marketing expenses	0.25	—	0.13	—
Midstream service expenses	0.07	0.17	0.09	0.18
General and administrative:				
Cash	2.64	2.50	2.67	2.95
Non-cash stock-based compensation, net	1.75	1.63	1.69	1.78
Depletion, depreciation and amortization	8.30	7.12	8.15	7.17
Total costs and expenses	$ 18.74	$ 16.78	$ 18.56	$ 17.49

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(1) Average costs per BOE sold are based on actual amounts and are not calculated using the rounded numbers presented in the table above.

Lease operating expenses. Lease operating expenses, which include workover expenses, increased by $2.5 million, or 13%, and by $7.5 million, or 20%, for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017. On a per BOE sold basis, lease operating expenses remained relatively flat for the three and six months ended June 30, 2018 compared to the same periods in 2017. We continue to focus on economic efficiencies associated with the usage and procurement of products and services related to lease operating expenses.

Production and ad valorem taxes. Production and ad valorem taxes increased by $3.9 million, or 46%, and by $7.0 million, or 40%, for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017. The increases are mainly due to increases in production taxes, which are based on and fluctuate in proportion to our oil, NGL and natural gas sales revenue. Ad valorem taxes are based on and fluctuate in proportion to the taxable value assessed by the various counties where our oil and natural gas properties are located.

Transportation and marketing expenses. Transportation and marketing expenses were $1.5 million for each of the three and six months ended June 30, 2018. There were no comparable amounts recorded during the same periods in 2017. Transportation and marketing expenses are the costs incurred to transport a portion of our production to the favorable Gulf Coast market.

Midstream service expenses. Midstream service expenses decreased by $0.5 million, or 55%, and by $0.7 million, or 40%, for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017. Midstream service expenses primarily represent costs incurred to operate and maintain our (i) oil and natural gas gathering and transportation systems and related facilities, (ii) centralized oil storage tanks, (iii) natural gas lift, rig fuel and centralized compression infrastructure and (iv) water storage, recycling and transportation facilities.

Costs of purchased oil. Costs of purchased oil increased by $96.6 million, or 219%, and by $107.0 million, or 113%, for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017. These costs include the cost of obtaining oil from third parties and, in some cases, transporting such oil utilized in our marketing activities. Our costs of purchased oil may vary due to changes in oil prices, pricing differentials and the amount of volumes purchased. During the three months ended June 30, 2018, our volume of purchased oil increased by 132%, as compared to the same period in 2017. This second-quarter 2018 increase in the volume of purchased oil is expected to decline to levels typical of previous periods in the third quarter of 2018.

General and administrative ("G&A"). G&A increased by $4.8 million, or 22%, and by $4.0 million, or 8%, for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017 mainly due to increases in employee-related costs and professional fees. Non-cash stock-based compensation, net increased by $2.0 million, or 23%, and by $2.1 million, or 12%, for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017. A significant portion of this increase is due to the immediate vesting of stock awards granted to our non-employee directors in May 2018 compared to a one-year cliff-vest in May 2017.

See Note 7.c to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for information regarding our stock-based compensation.

Depletion, depreciation and amortization ("DD&A"). The following table presents the components of our DD&A expense:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Depletion of evaluated oil and natural gas properties	$ 46,985	$ 34,338	$ 88,802	$ 64,752
Depreciation of midstream service assets	2,460	2,177	4,865	4,328
Depreciation and amortization of other fixed assets	1,317	1,488	2,648	3,035
Total DD&A	$ 50,762	$ 38,003	$ 96,315	$ 72,115

DD&A increased by $12.8 million, or 34%, and by $24.2 million, or 34%, for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017. The increases are mainly due to increases in the depletion base and production volumes sold.

Non-operating income (expense). The following table presents the components of non-operating income (expense):

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Gain (loss) on derivatives, net	$ (45,976)	$ 28,897	$ (36,966)	$ 65,568
Income from equity method investee (see Note 3.c)	—	2,471	—	5,539
Interest expense	(14,424)	(23,173)	(27,942)	(45,893)
Interest and other income	443	49	896	194
Gain (loss) on disposal of assets, net	(1,358)	805	(3,975)	591
Non-operating income (expense), net	$ (61,315)	$ 9,049	$ (67,987)	$ 25,999

Gain (loss) on derivatives, net. The following table presents the changes in the components of gain (loss) on derivatives, net:

(in thousands)	**Three months ended June 30, 2018 compared to 2017**	**Six months ended June 30, 2018 compared to 2017**
Decrease in fair value of derivatives outstanding	$ (57,115)	$ (75,089)
Decrease in settlements received for matured derivatives, net	(13,524)	(23,211)
Decrease in settlements received for early terminations of derivatives, net	(4,234)	(4,234)
Total decrease in gain on derivatives, net	$ (74,873)	$ (102,534)

The change in fair value of derivatives outstanding is the result of new, early-terminated and expiring contracts and the changing relationship between our outstanding contract prices and the future market prices in the forward curves, which we use to calculate the fair value of our derivatives. In general, if no new contracts are entered into or terminated, we experience gains during periods of decreasing market prices and losses during periods of increasing market prices. Settlements received or paid for matured derivatives are based on the settlement prices of our matured derivatives compared to the prices specified in the derivative contracts.

During the three and six months ended June 30, 2017, we completed a hedge restructuring by early terminating a swap that resulted in a termination amount to us of $4.2 million that was settled in full by applying the proceeds to pay the premium on one new collar entered into during the restructuring.

See Notes 8, 9.a and 17.a to our unaudited consolidated financial statements included elsewhere in this Quarterly Report and "Item 3. Quantitative and Qualitative Disclosures About Market Risk" for additional information regarding our derivatives.

Income from equity method investee. Prior to the Medallion Sale on October 30, 2017, we owned 49% of the ownership interests of Medallion. As such, we previously accounted for this investment under the equity method of accounting with our proportionate share of Medallion's net income reflected in the unaudited consolidated statements of operations as "Income from equity method investee." For further discussion of the Medallion Sale, see Note 3.c to our unaudited consolidated financial statements included elsewhere in this Quarterly Report.

Interest expense. Interest expense decreased by $8.7 million, or 38%, and by $18.0 million, or 39%, for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017, mainly due to the early redemption of the May 2022 Notes on November 29, 2017.

Gain (loss) on disposal of assets, net. Gain on disposal of assets, net, decreased by $2.2 million and by $4.6 million for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017. From time to time, we dispose of materials and supplies inventory, midstream service assets and other fixed assets. The associated gain or loss recorded during the period fluctuates depending upon the volume of the assets disposed, their associated net book value and, in the case of a disposal by sale, the sale price.

Income tax. Since September 30, 2015, we have recorded a full valuation allowance against our net deferred tax assets. As such, our effective tax rate was 0% for each of the three and six months ended June 30, 2018 and 2017. For further discussion of our valuation allowance, see Note 14 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report.

Liquidity and capital resources

Historically, our primary sources of liquidity have been cash flows from operations, proceeds from equity offerings, proceeds from senior unsecured note offerings, borrowings under our Senior Secured Credit Facility and proceeds from the Medallion Sale and other asset sales. We believe cash flows from operations and availability under our Senior Secured Credit Facility provide sufficient liquidity to manage our cash needs and contractual obligations and to fund our expected capital expenditures. Our primary operational uses of capital have been for the acquisition, exploration and development of oil and natural gas properties, infrastructure development and investments in Medallion until its sale on October 30, 2017.

A significant portion of our capital expenditures can be adjusted and managed by us. We continually monitor the capital markets and our capital structure and consider which financing alternatives, including equity and debt capital resources, joint ventures and asset sales, are available to meet our future planned or accelerated capital expenditures. We may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency. Such financing alternatives, including capital market transactions and debt and equity repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. See Notes 3, 6.c and 7.a to our unaudited consolidated financial statements and "Part II. Item 2. Purchases of Equity Securities" included elsewhere in this Quarterly Report for additional discussion of our acquisitions and divestitures of oil and natural gas properties and midstream assets, the Medallion Sale, the redemption of our May 2022 Notes and our $200.0 million share repurchase program, from time to time, authorized by our board of directors in February 2018. We also continuously look for other opportunities to maximize shareholder value.

We use derivatives to reduce exposure to fluctuations in the prices of oil, NGL and natural gas. By removing a significant portion of the price volatility associated with future production, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices. Our derivative positions will help us stabilize a portion of our expected cash flows from operations in the event of future declines in the prices of oil, NGL and natural gas. See "Part I. Item 3. Quantitative and Qualitative Disclosures About Market Risk" below. See Notes 8 and 17.a to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for information regarding our derivative settlement indices and our open hedge positions as of June 30, 2018 and derivatives entered into subsequent to June 30, 2018, respectively.

We continually seek to maintain a financial profile that provides operational flexibility. As of June 30, 2018, we had cash and cash equivalents of $36.6 million and undrawn capacity under the Senior Secured Credit Facility of $1.09 billion, resulting in total liquidity of $1.13 billion. As of July 31, 2018, we had cash and cash equivalents of $34.0 million and undrawn capacity under the Senior Secured Credit Facility of $1.07 billion, resulting in total liquidity of $1.10 billion. We believe that our operating cash flow and the aforementioned liquidity sources provide us with the financial resources to manage our business needs, to implement our planned capital expenditure budget and, at our discretion, to fund our share repurchase program.

Cash flows

The following table presents our cash flows:

	Six months ended June 30,	
(in thousands)	**2018**	**2017**
Net cash provided by operating activities	$ 262,601	$ 156,901
Net cash used in investing activities	(354,072)	(177,578)
Net cash provided by financing activities	15,916	23,029
Net (decrease) increase in cash and cash equivalents	$ (75,555)	$ 2,352

Cash flows provided by operating activities

Net cash provided by operating activities increased by $105.7 million, or 67%, for the six months ended June 30, 2018 compared to the same period in 2017 mainly due to increased revenues due to the increase in average realized sales prices for oil and NGL and increased sales volumes of all production with additional details included at "—Results of operations consolidated"; however, other notable cash changes included a decrease of $24.8 million in settlements received for matured derivatives and early terminations of derivatives, net of premiums paid.

Our operating cash flows are sensitive to a number of variables, the most significant of which are the volatility of oil, NGL and natural gas prices, mitigated to the extent of our derivatives' exposure, and sales volume levels. Regional and worldwide economic activity, weather, infrastructure, transportation capacity to reach markets, costs of operations, legislation and regulations and other variable factors significantly impact the prices of these commodities. These factors are not within our control and are difficult to predict. For additional information on risks related to our business, see "Part I. Item 1A. Risk Factors" in our 2017 Annual Report.

Cash flows used in investing activities

Net cash used in investing activities increased by $176.5 million, or 99%, for the six months ended June 30, 2018 compared to the same period in 2017 and is mainly attributable to (i) an increase in capital expenditures on oil and natural gas properties, (ii) a decrease in proceeds from dispositions of capital assets and (iii) second-quarter 2018 acquisitions of oil and natural gas properties. See Note 3 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional discussion of our acquisitions and divestitures of oil and natural gas properties and midstream assets.

The following table presents the components of our cash flows from investing activities:

	Six months ended June 30,	
(in thousands)	**2018**	**2017**
Acquisitions of oil and natural gas properties	$ (16,340)	$ —
Capital expenditures:		
Oil and natural gas properties	(341,534)	(232,219)
Midstream service assets	(5,205)	(6,117)
Other fixed assets	(4,965)	(2,683)
Proceeds from disposition of equity method investee, net of selling costs (see Note 3.c)	1,655	—
Proceeds from dispositions of capital assets, net of selling costs	12,317	63,441
Net cash used in investing activities	$ (354,072)	$ (177,578)

Capital expenditure budget

Due to the increase in operational efficiencies and expected completions, we are increasing the drilling and completion portion of our capital budget to $545.0 million, an increase of $45.0 million from the previously announced level. Other capital expenditures are expected to remain unchanged at $85.0 million, bringing our total annual budgeted capital expenditures, excluding non-budgeted acquisitions, to $630.0 million. We are monitoring the impact of the steel import tariffs recently imposed by the Administration; however, we currently do not believe there will be an impact to us in 2018. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

The amount, timing and allocation of capital expenditures are largely discretionary and within management's control. If oil, NGL and natural gas prices decline below our acceptable levels, or costs increase above our acceptable levels, we may choose to defer a portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. Subject to financing alternatives, we may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We consistently monitor and may adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing and joint venture opportunities, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs and supplies, changes in service costs, contractual obligations, internally generated cash flow and other factors both within and outside our control.

Cash flows provided by financing activities

Net cash provided by financing activities decreased by $7.1 million, or 31%, for the six months ended June 30, 2018, compared to the same period in 2017 and is mainly attributable to share repurchases under our share repurchase program that commenced in February 2018. The decrease was partially offset by an absence of payments on our Senior Secured Credit Facility and increased borrowings on our Senior Secured Credit Facility. Through June 30, 2018, we have repurchased 9,878,552 shares of common stock at a weighted-average price of $8.83 per common share for a total of $87.2 million under this program and, upon repurchase, the shares were retired. As of June 30, 2018, we had authorization remaining to repurchase, from time to time, until February 2020, approximately $112.8 million in common stock, if any.

The following table presents the components of our cash flows from financing activities:

(in thousands)	Six months ended June 30, 2018	2017
Borrowings on Senior Secured Credit Facility	$ 110,000	$ 90,000
Payments on Senior Secured Credit Facility	—	(55,000)
Share repurchases	(87,218)	—
Vested stock exchanged for tax withholding	(4,397)	(7,597)
Proceeds from exercise of stock options	—	358
Payments for debt issuance costs	(2,469)	(4,732)
Net cash provided by financing activities	$ 15,916	$ 23,029

Debt

As of June 30, 2018, we were a party only to our Senior Secured Credit Facility and the indentures governing our senior unsecured notes.

Senior Secured Credit Facility. As of June 30, 2018, our Senior Secured Credit Facility had a maximum credit amount of $2.0 billion, a borrowing base of $1.3 billion and an aggregate elected commitment of $1.2 billion, with $110.0 million outstanding. See Note 17.b to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for subsequent borrowings and repayments on our Senior Secured Credit Facility.

The borrowing base under our Senior Secured Credit Facility is subject to a semi-annual redetermination based on the lenders' evaluation of our oil, NGL and natural gas reserves. The lenders have the right to call for an interim redetermination of the borrowing base once between any two redetermination dates and in other specified circumstances. The Senior Secured Credit Facility matures on April 19, 2023, provided that if either the January 2022 Notes or March 2023 Notes have not been refinanced on or prior to the applicable Early Maturity Date, the Senior Secured Credit Facility will mature on such Early Maturity Date. See Note 6.d to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for further discussion of our Senior Secured Credit Facility.

Principal amounts borrowed under our Senior Secured Credit Facility are payable on the final maturity date with such borrowings bearing interest that is payable, at our election, either on the last day of each fiscal quarter at an "Adjusted Base Rate" as defined in our Senior Secured Credit Facility, or at the end of one-, two-, three-, six- or, to the extent available, 12-month interest periods (and in the case of six- and 12-month interest periods, every three months prior to the end of such interest period) at a "LIBOR Rate" as defined in our Senior Secured Credit Facility, in each case, plus an applicable margin, which ranges from 0.25% to 1.25% for "Adjusted Base Rate Loans" as defined in our Senior Secured Credit Facility, and from 1.25% to 2.25% for "Eurodollar Loans" as defined in our Senior Secured Credit Facility, based on the ratio of the outstanding revolving credit on our Senior Secured Credit Facility to the borrowing base. We are also required to pay a commitment fee, which ranges from 0.375% to 0.50%, based on the ratio of the outstanding revolving credit on our Senior Secured Credit Facility to the aggregate elected commitment.

Our Senior Secured Credit Facility is secured by a first-priority lien on certain of our assets, including oil and natural gas properties constituting at least 85% of the present value of our proved reserves owned now or in the future. Our Senior Secured Credit Facility contains both financial and non-financial covenants. We were in compliance with these covenants as of June 30, 2018 and December 31, 2017.

Senior unsecured notes. The following table presents principal amounts and applicable interest rates for our outstanding senior unsecured notes as of June 30, 2018:

(in millions, except for interest rates)	Principal	Interest rate
January 2022 Notes	$ 450.0	5.625%
March 2023 Notes	350.0	6.250%
Total senior unsecured notes	$ 800.0	

See Notes 6.a and 6.b to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for further discussion of the March 2023 Notes and January 2022 Notes, respectively.

Obligations and commitments

As of June 30, 2018, our contractual obligations included our January 2022 Notes, March 2023 Notes, Senior Secured Credit Facility, drilling contract commitments, firm sale and transportation commitments, sand purchase and supply agreement, derivative deferred premiums, asset retirement obligations and office and equipment operating leases. From December 31, 2017 to June 30, 2018, the material changes in our contractual obligations included (i) an increase of $110.0 million in outstanding borrowings on our Senior Secured Credit Facility, (ii) an increase of $52.1 million for firm sale and transportation commitments due to the timing of when contracts were entered into, completed and terminated, (iii) an increase of $24.6 million for drilling contract commitments due to the timing of when contracts were entered into and completed (on contracts other than those on a well-by-well basis), (iv) a decrease of $23.6 million on our interest obligations for our senior unsecured notes as semi-annual interest payments were made in January and March 2018, (v) an increase of $8.0 million due to a new in-basin sand purchase and supply agreement entered into during the second quarter of 2018 and (vi) a decrease of $3.9 million in derivative deferred premiums mainly due to premiums paid for derivatives partially offset by new deferred premiums entered into.

During the three months ended June 30, 2018, we entered into a purchase and supply agreement for a term of one year, whereby we have committed to buy a certain volume of in-basin sand for a fixed price. As of June 30, 2018, under the terms of this agreement, we are required to purchase a certain percentage of the volume commitment or we will incur a shortfall payment of $8.0 million at the end of the contract period.

See Notes 6, 8, 9, 11, 13 and 17.b to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional discussion of our contractual obligations.

Non-GAAP financial measure

The non-GAAP financial measure of Adjusted EBITDA, as defined by us, may not be comparable to similarly titled measures used by other companies. Therefore, this non-GAAP measure 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 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 EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for depletion, depreciation and amortization, non-cash stock-based compensation, net, accretion expense, mark-to-market on derivatives, premiums paid for derivatives, interest expense, gains or losses on disposal of assets, income or loss from equity method investee, proportionate Adjusted EBITDA of equity method investee and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, 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 (GAAP) to Adjusted EBITDA (non-GAAP):

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Net income	$ 33,452	$ 61,110	$ 119,972	$ 129,386
Plus:				
Depletion, depreciation and amortization	50,762	38,003	96,315	72,115
Non-cash stock-based compensation, net	10,676	8,687	20,015	17,911
Accretion expense	1,121	943	2,227	1,871
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	45,976	(28,897)	36,966	(65,568)
Settlements (paid) received for matured derivatives, net	181	13,705	(2,055)	21,156
Settlements received for early terminations of derivatives, net	—	4,234	—	4,234
Premiums paid for derivatives	(5,451)	(9,987)	(9,475)	(12,094)
Interest expense	14,424	23,173	27,942	45,893
(Gain) loss on disposal of assets, net	1,358	(805)	3,975	(591)
Income from equity method investee	—	(2,471)	—	(5,539)
Proportionate Adjusted EBITDA of equity method investee[1]	—	6,601	—	12,966
Adjusted EBITDA	$ 152,499	$ 114,296	$ 295,882	$ 221,740

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

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Income from equity method investee	$ —	$ 2,471	$ —	$ 5,539
Adjusted for proportionate share of depreciation and amortization	—	4,130	—	7,427
Proportionate Adjusted EBITDA of equity method investee	$ —	$ 6,601	$ —	$ 12,966

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our unaudited consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our unaudited consolidated financial statements. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our unaudited consolidated financial statements.

There have been no material changes in our critical accounting policies and procedures during the six months ended June 30, 2018. For our other critical accounting policies and procedures, please see our disclosure of critical accounting policies in "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2017 Annual Report. Furthermore, see Notes 4 and 7.c to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional discussion of the impact of the adoption of ASC 606 and estimates pertaining to our 2018 performance share awards.

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Recent accounting pronouncements

See Note 2 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for information regarding recent accounting pronouncements.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements other than drilling contracts, firm sale and transportation commitments, a sand purchase and supply agreement and office and equipment operating leases which are described in "—Obligations and commitments." See Note 11 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional information.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk," in our case, refers to the risk of loss arising from adverse changes in oil, NGL and natural gas prices and in interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of how we view and manage our ongoing market risk exposures. All of our market risk-sensitive derivative instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity price exposure

Due to the inherent volatility in oil, NGL and natural gas prices, we engage in derivative transactions, such as puts, swaps, collars, basis swaps and, in the past, call spreads to hedge price risk associated with a significant portion of our anticipated production. By removing a portion of the price volatility associated with future production, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices.

During the three months ended June 30, 2018, the Midland market crude oil price experienced an increased discount to WTI-Cushing prices primarily due to limited pipeline capacity constraining transportation of crude oil out of the Permian Basin to major marketing hubs including, but not limited to, Cushing, Oklahoma and the United States Gulf Coast. As of June 30, 2018, this discount for prompt month delivery was $12 per Bbl of oil. This pipeline constraint is expected to affect the Midland market oil price until additional transportation capacity becomes operational or until basin-wide crude oil production decreases from its current historical levels. We have focused on achieving the ability to sell oil in multiple markets and protecting the Company's oil value from basin differentials by securing transportation capacity.

The fair values of our open derivative contracts are largely determined by forward price curves of the relevant indices. As of June 30, 2018, a 10% change in the forward curves associated with our derivatives would have changed our unaudited consolidated balance sheet's net derivative position to the following amounts:

(in thousands)	10% Increase	10% Decrease
Net liability derivative position	$ 43,767	$ 33,246

As of June 30, 2018 and December 31, 2017, the net derivative positions were liabilities of $38.9 million and $13.0 million, respectively. See Notes 8 and 9.a to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional disclosures regarding our derivatives.

Interest rate risk

Our Senior Secured Credit Facility bears interest at a floating rate and our January 2022 Notes and March 2023 Notes bear interest at fixed rates. The maturity years, outstanding balances and interest rates on our long-term debt as of June 30, 2018 were as follows:

	Maturity year	
(in millions except for interest rates)	2022	2023(1)
Senior Secured Credit Facility	$ —	$ 110.0
Floating interest rate	—%	3.324%
January 2022 Notes	$ 450.0	$ —
Fixed interest rate	5.625%	—%
March 2023 Notes	$ —	$ 350.0
Fixed interest rate	—%	6.250%

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(1) The Senior Secured Credit Facility matures on April 19, 2023, provided that if either the January 2022 Notes or March 2023 Notes have not been refinanced on or prior to the applicable Early Maturity Date, the Senior Secured Credit Facility will mature on such Early Maturity Date.

Counterparty and customer credit risk

See Item 7A. "Quantitative and Qualitative Disclosures about Market Risk" in the 2017 Annual Report, Note 11 to our unaudited consolidated financial statements and "Part II, Item 1. Legal Proceedings" located elsewhere in this Quarterly Report for further discussion on our counterparty and customer credit risk.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of Laredo's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act), was performed under the supervision and with the participation of Laredo's management, including our principal executive officer and principal financial officer. Based on that evaluation, these officers concluded that Laredo's disclosure controls and procedures were effective as of June 30, 2018. Our disclosure controls and other procedures are designed to provide reasonable assurance that the information required to be disclosed in the reports we file and submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to Laredo's management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Evaluation of changes in internal control over financial reporting

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II

Item 1. Legal Proceedings

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we may not have insurance coverage. While many of these matters involve inherent uncertainty, except with regard to the specific litigation noted below, as of the date hereof, we do not currently believe that any such legal proceedings will have a material adverse effect on our business, financial position, results of operations or liquidity.

On May 3, 2017, Shell filed an Original Petition and Request for Disclosure in the District Court of Harris County, Texas, alleging that the crude oil purchase agreement entered into between Shell and Laredo effective October 1, 2016 through June 30, 2020 does not accurately reflect the compensation to be paid to Shell under certain circumstances due to a drafting mistake. Shell seeks reformation of one clause of the crude oil purchase agreement on the grounds of alleged mutual mistake or, in the alternative, unilateral mistake, an award of the amounts Shell alleges it should have been or should be paid under the crude oil purchase agreement, court costs and attorneys' fees. We do not believe there was a drafting mistake made in the crude oil purchase agreement, which covered the sale to Shell of 19,000 barrels of crude oil per day of our gross production, as well as the purchase by us of like-quantity crude oil from Shell. On December 11, 2017, Shell filed its First Amended Petition, in which it asserted nine causes of action, including multiple new claims for breach of contract and fraud.

Effective May 1, 2018, Shell terminated the crude oil purchase agreement and ceased purchasing our crude oil and selling crude oil to us under the terms of such agreement. As a result, we filed our Second Amended Answer and Original Counterclaim against Shell on June 15, 2018, in which we deny all allegations by Shell and seek damages in excess of $150.0 million resulting from Shell's breach and wrongful termination of the crude oil purchase agreement. Shell filed a Second Amended Petition on June 1, 2018, in which it asserted a new cause of action against us for alleged repudiation of Shell's proposed reformed version of the crude oil purchase agreement, a version never signed or agreed to by us.

Through April 30, 2018, the date on which Shell wrongfully terminated the crude oil purchase agreement, we had accounted for the costs and crude oil price realization as reflected in the terms of the crude oil purchase agreement. The accompanying unaudited consolidated balance sheets located elsewhere in this Quarterly Report do not include any amounts for damage claims or attorneys' fees sought by Shell. As of June 30, 2018, we had estimated an aggregate amount of $37.4 million that is the subject of Shell's claims, which is generally based on the contractual amount in dispute under the pricing election that is the subject of Shell's claims applied to the barrels of crude oil purchased and sold through the date on which Shell wrongfully terminated the crude oil purchase agreement. As a result of such termination, our estimate of this unrecorded amount is not anticipated to materially increase in the future. This estimate does not include damages sought by Shell pursuant to its latest repudiation claim asserted in its Second Amended Petition or amounts sought by Shell for recovery of attorneys' fees incurred for the prosecution of its claims.

We are unable to determine a probability of the outcome of this litigation at this time. We believe Shell's claims are meritless and the termination by Shell is improper and a breach of the crude oil purchase agreement. We therefore intend to vigorously defend ourselves against Shell's claims and pursue our rights under the terminated crude oil purchase agreement to seek all appropriate damages from Shell.

Item 1A. Risk Factors

In addition to the other information set forth in this Quarterly Report, you should carefully consider the risks discussed in our 2017 Annual Report. Other than the risk factor set forth below, there have been no material changes in our risk factors from those described in the 2017 Annual Report. The risks described in the 2017 Annual Report are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

Insufficient transportation capacity in the Permian Basin, and the challenges to alleviating such transportation constraints, could cause significant fluctuations in our realized oil prices and our results of operations.

In our area of operation, the Permian Basin has been characterized by periods when oil production has surpassed local transportation capacity, resulting in substantial discounts to the price received for crude oil prices quoted for WTI oil. During the three months ended June 30, 2018, the Midland market crude oil price has experienced a substantial discount to WTI-Cushing prices, primarily due to limited pipeline capacity constraining transportation of crude oil out of the Permian Basin to major marketing hubs including, but not limited to Cushing, Oklahoma and the United States Gulf Coast. As of June 30, 2018, the price differential relative to WTI was $12 per barrel. The expansion and construction of pipeline facilities are affected by the availability and costs of necessary equipment, supplies, labor and other services, as well as the length of time to complete such projects. In addition, these projects can be affected by changes in international trade relationships, including the imposition of trade restrictions or tariffs relating to crude oil and natural gas and any materials or products used to expand or construct pipeline facilities, such as certain imported steel mill products that are currently subject to a 25% global tariff on certain imported steel mill products. All of these factors could negatively impact our realized oil prices, as well as actual results of our operations.

Item 2. Purchases of Equity Securities

The following table summarizes purchases of common stock by Laredo:

Period	Total number of shares purchased[(1)]	Weighted-average price paid per share	Total number of shares purchased as part of publicly announced plans[(2)]	Maximum value that may yet be purchased under the program as of the respective period-end date [(2)]
April 1, 2018 - April 30, 2018	3,152,591	$ 9.12	3,150,651	$ 112,782,213
May 1, 2018 - May 31, 2018	702	$ 10.93	—	$ 112,782,213
June 1, 2018 - June 30, 2018	2,040	$ 9.48	—	$ 112,782,213
Total	3,155,333		3,150,651	

(1) Included in these amounts are 4,682 shares withheld by us to satisfy employee tax withholding obligations that arose upon the lapse of restrictions on restricted stock awards.

(2) In February 2018, our board of directors authorized a $200 million share repurchase program commencing in February 2018. The repurchase program expires in February 2020. Repurchases of shares under this program totaled 3,150,651 at a cost of $28.7 million during the three months ended June 30, 2018. Share repurchases, if any, under the share repurchase program may be made through a variety of methods, which may include open market purchases, privately negotiated transactions and block trades.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit Number	Description
2.1	Membership Interest Purchase and Sale Agreement, dated as of October 1, 2017, by and among Medallion Midland Acquisition, LLC, Medallion Gathering & Processing, LLC, Laredo Midstream Services, LLC, and Medallion Midstream Holdings, LLC (incorporated by reference to Exhibit 2.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on October 30, 2017).
3.1	Amended and Restated Certificate of Incorporation of Laredo Petroleum Holdings, Inc. (incorporated by reference to Exhibit 3.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
3.2	Certificate of Ownership and Merger, dated as of December 30, 2013 (incorporated by reference to Exhibit 3.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 6, 2014).
3.3	Second Amended and Restated Bylaws of Laredo Petroleum, Inc. (incorporated by reference to Exhibit 3.3 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 17, 2016).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 of Laredo's Registration Statement on Form S-1/A (File No. 333-176439) filed on November 14, 2011).
10.1	Third Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 19, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on April 23, 2018).
31.1*	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

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* Filed herewith.
** Furnished herewith.
\# Management contract or compensatory plan or arrangement.

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 thereunto duly authorized.

LAREDO PETROLEUM, INC.

Date: August 2, 2018	By:	/s/ Randy A. Foutch
		Randy A. Foutch
		Chairman and Chief Executive Officer
		(principal executive officer)
Date: August 2, 2018	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President and Chief Financial Officer
		(principal financial officer)
Date: August 2, 2018	By:	/s/ Michael T. Beyer
		Michael T. Beyer
		Vice President - Controller and Chief Accounting Officer
		(principal accounting officer)

EXHIBIT 31.1

CERTIFICATION

I, Randy A. Foutch, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Laredo Petroleum, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting(as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 2, 2018

/s/ Randy A. Foutch

Randy A. Foutch

Chairman and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Richard C. Buterbaugh, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Laredo Petroleum, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting(as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 2, 2018

/s/ Richard C. Buterbaugh

Richard C. Buterbaugh

Executive Vice President and Chief Financial Officer

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, Randy A. Foutch, Chairman and Chief Executive Officer of Laredo Petroleum, Inc. (the "Company"), and Richard C. Buterbaugh, Executive Vice President and Chief Financial Officer of the Company, certify that, to their knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the period ending June 30, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

August 2, 2018

/s/ Randy A. Foutch

Randy A. Foutch
Chairman and Chief Executive Officer

August 2, 2018

/s/ Richard C. Buterbaugh

Richard C. Buterbaugh
Executive Vice President and Chief Financial Officer