UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2018
or
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

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)
Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common Stock, $0.01 par value per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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 ☒	Non-accelerated filer ☐	Smaller reporting company ☐
Accelerated filer ☐		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 ☒

Aggregate market value of the voting and non-voting common equity held by non-affiliates was approximately $1.5 billion on June 30, 2018, based on $9.62 per share, the last reported sales price of the common stock on the New York Stock Exchange on such date.

Number of shares of registrant's common stock outstanding as of February 11, 2019: 233,924,462

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2019 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2018, are incorporated by reference into Part III of this report for the year ended December 31, 2018.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following terms are used throughout this Annual Report on Form 10-K (this "Annual Report"):

"*2D*"—Method for collecting, processing and interpreting seismic data in two dimensions.

"*3D*"—Method for collecting, processing and interpreting seismic data in three dimensions.

"*AFE*"—Authorization for expenditure.

"*Allocation well*"—A horizontal well drilled by an oil and gas producer under two or more leaseholds that are not pooled, under a permit issued by the Texas Railroad Commission.

"*Basin*"—A large natural depression on the earth's surface in which sediments, generally brought by water, accumulate.

"*Bbl*" or "*barrel*"—One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate, natural gas liquids or water.

"*Bcf*"—One billion cubic feet of natural gas.

"*Benchmark Prices*"—The unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials, as required by SEC guidelines.

"*BOE*"—One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

"*BOE/D*"—BOE per day.

"*Btu*"—British thermal unit, the quantity of heat required to raise the temperature of a one pound mass of water by one degree Fahrenheit.

"*Completion*"—The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"*Developed acreage*"—The number of acres that are allocated or assignable to productive wells or wells capable of production.

"*Development well*"—A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

"*Dry hole*"—A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"*Earth Model*"—A proprietary integrated workflow process combining geoscience, production, operations and engineering data utilizing multivariate analytics.

"*Exploratory well*"—A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

"*Field*"—An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"*Formation*"—A layer of rock which has distinct characteristics that differ from nearby rock.

"*Fracturing*" or "*Frac*"—The propagation of fractures in a rock layer by a pressurized fluid. This technique is used to release petroleum and natural gas for extraction.

"*GAAP*"—Generally accepted accounting principles in the United States.

"*Gross acres*" or "*gross wells*"—The total acres or wells, as the case may be, in which a working interest is owned.

"*HBP*"—Acreage that is held by production.

"*Horizon*"—A term used to denote a surface in or of rock, or a distinctive layer of rock that might be represented by a reflection in seismic data.

"*Horizontal drilling*"—A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"*HRGM*"—High-resolution geocellular models.

"*Initial Production*"—The measurement of production from an oil or gas well when first brought on stream. Often stated in terms of production during the first thirty days.

"*Liquids*"—Describes oil, water, condensate and natural gas liquids.

"*MBbl*"—One thousand barrels of crude oil, condensate or natural gas liquids.

"*MBOE*"—One thousand BOE.

"*MMBOE*"—One million BOE.

"*Mcf*"—One thousand cubic feet of natural gas.

"*MMBtu*"—One million British thermal units.

"*MMcf*"—One million cubic feet of natural gas.

"*Natural gas liquids*" or "*NGL*"—Components of natural gas that are separated from the gas state in the form of liquids, which include propane, butanes and ethane, among others.

"*Net acres*"—The percentage of gross acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"*NYMEX*"—The New York Mercantile Exchange.

"*Production corridor*"—Infrastructure put in place over an extended area, usually several miles, containing multiple pipelines to facilitate the transfer of oil, natural gas and/or water. A specific production corridor may also contain water recycling facilities, artificial gas lift and fuel gas distribution lines.

"*Productive well*"—A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"*Proved developed non-producing reserves*" or "*PDNP*"—Developed non-producing reserves.

"*Proved developed reserves*" or "*PDP*"—Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"*Proved reserves*"—The estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

"*Proved undeveloped reserves*" or "*PUD*"—Proved reserves that are expected to be recovered within five years from new wells on undrilled locations and for which a specific capital commitment has been made or from existing wells where a relatively major expenditure is required for recompletion.

"*Realized Prices*"—Prices which reflect adjustments to the Benchmark Prices for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

"*Recompletion*"—The process of re-entering an existing wellbore that is either producing or not producing and completing in new reservoirs in an attempt to establish or increase existing production.

"*Reservoir*"—A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"*Resource play*"—An expansive contiguous geographical area, potentially supporting numerous drilling locations, with prospective crude oil and/or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and multi-stage fracturing technologies.

"*Spacing*"—The distance between wells producing from the same reservoir.

"*Standardized measure*"—Discounted future net cash flows estimated by applying Realized Prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"*Three stream*"—Production or reserve volumes of oil, natural gas liquids and natural gas, where the natural gas liquids have been removed from the natural gas stream and the economic value of the natural gas liquids is separated from the wellhead natural gas price.

"*Undeveloped acreage*"—Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

"*Wellhead natural gas*"—Natural gas produced at or near the well.

"*Wolfberry*"—A general industry term that applies to the vertical stratigraphic interval that can include the shallow Spraberry formation to the deeper Woodford formation throughout the Permian Basin.

"*Working interest*" or "*WI*"—The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas liquids, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this Annual Report are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), 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, NGL 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;
- 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;
- revisions to our reserve estimates as a result of changes in commodity prices, decline curves and other uncertainties;
- 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;
- the potential impact on production of oil, NGL and natural gas from our wells resulting from tighter spacing of our wells;
- capital requirements for our operations and projects;
- impacts to our financial statements as a result of impairment write-downs;
- the availability and costs of drilling and production equipment, labor and oil and natural gas processing and other services;
- the availability of sufficient pipeline and transportation facilities and gathering and processing capacity;
- our ability to maintain the borrowing capacity under our Senior Secured Credit Facility (as defined below) or access other means of obtaining capital and liquidity, especially during periods of sustained low commodity prices;
- 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 generate sufficient cash to service our indebtedness, fund our capital requirements and generate future profits;
- restrictions contained in our debt agreements, including our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes (as defined below), 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;
- the potentially insufficient refining capacity in the U.S. 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;
- our ability to hedge and regulations that affect our ability to hedge;
- changes in the regulatory environment and changes in U.S. or international legal, tax, 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;
- drilling and operating risks, including risks related to hydraulic fracturing activities; and
- our ability to comply with federal, state and local regulatory requirements.

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 in this Annual Report under "Item 1A. Risk Factors," in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report. 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 Annual 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

Laredo Petroleum, Inc. is a Delaware corporation formed in 2011 for the purpose of merging with Laredo Petroleum, LLC (a Delaware limited liability company formed in 2007) to consummate an initial public offering of common stock in December 2011 ("IPO"). Laredo Petroleum, Inc. was the survivor of such merger and currently has two wholly-owned subsidiaries, Laredo Midstream Services, LLC, a Delaware limited liability company ("LMS"), and Garden City Minerals, LLC, a Delaware limited liability company ("GCM").

Unless the context otherwise requires, references in this Annual Report to "Laredo," the "Company," "we," "our," "us," or similar terms refer to Laredo Petroleum, Inc. and its subsidiaries at the applicable time, including former subsidiaries and predecessor companies, as applicable.

Except where the context indicates otherwise, amounts, numbers, dollars and percentages presented in this Annual Report are rounded and therefore approximate.

Item 1. *Business*

Overview

Laredo 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. 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 December 31, 2018, we had assembled 120,617 net acres in the Permian Basin and had total proved reserves, presented on a three-stream basis, of 238,167 MBOE. Our wholly-owned subsidiary, LMS buys, sells, gathers and transports oil, natural gas and water primarily for the account of Laredo.

We have identified one operating segment: exploration and production. Our midstream and marketing functions are integral to our exploration and production activities. We have a single company-wide management team that administers all properties as a whole rather than discrete operating segments and we allocate capital resources on a project-by-project basis across our asset base without regard to individual areas.

2018 operation highlights

- Produced a Company record average of 68,168 BOE per day in full-year 2018, resulting in production growth of 17% from full-year 2017
- Grew the value of our proved reserves by 19% from year-end 2017
- Reduced unit cash general and administrative ("G&A") expense by 16% in full-year 2018
- Recognized $31.9 million of net cash benefits from LMS field infrastructure investments through reduced capital and operating costs and increased revenue

Our core assets

The Permian Basin is comprised of several distinct geological provinces, including the Midland Basin to the east, the Delaware Basin to the west and the Central Platform in the middle. Our primary development and production fairway is located on the east side of the Midland Basin, 35 miles east of Midland, Texas. Our acreage is largely contiguous in the neighboring Texas counties of Howard, Glasscock, Reagan, Sterling and Irion. We refer to this acreage block in this Annual Report as our "Permian-Garden City" area. As of December 31, 2018, we held 120,617 net acres in the Permian Basin, all of which were held in 248 sections in the Permian-Garden City area, with an average working interest of 97% in all Laredo-operated currently producing wells.

We believe our acreage in the Permian-Garden City area is a resource play for multiple producing formations that make up a significant portion of the entire stratigraphic section. We are currently focusing the majority of our development activities on two horizontal drilling targets (Upper and Middle Wolfcamp formations) that have multiple landing points within each target. In addition, we have also established the existence of additional producing formations, including the Lower Wolfcamp, Cline, Spraberry and Canyon. From our inception in 2006 through December 31, 2018, we have drilled and completed (i.e., the particular well is flowing) 314 horizontal wells in the Upper and Middle Wolfcamp and 967 vertical wells in the Wolfberry interval. Of these 314 horizontal wells, 189 were horizontal Upper Wolfcamp wells and 125 were horizontal Middle Wolfcamp wells. We have also drilled and completed 33 horizontal Lower Wolfcamp wells and 64 horizontal Cline wells. We anticipate focusing our 2019 drilling program on the Upper and Middle Wolfcamp formations due to their lower development cost and superior production expectations.

Beginning in mid-2012, we started focusing our horizontal activity on drilling longer laterals. Since that time our average lateral length has grown to 10,000 feet and longer in areas where our contiguous acreage position allows. In 2019, we plan to widen the spacing between our wells and focus on achieving cash flow neutrality.

Because oil, NGL and natural gas prices and related margins continue to remain volatile, our board of directors approved a capital expenditures budget of approximately $365 million, based on annual benchmark averages of a $53.60 per barrel WTI NYMEX strip price and a $2.90 per MMBtu Henry Hub NYMEX strip price, for calendar year 2019, excluding non-budgeted acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. Our goal is to achieve cash flow neutrality, and therefore, our capital spending in 2019 will ultimately be influenced by commodity price changes, as well as any changes in service costs and drilling and completions efficiencies. Of this budget, approximately $300 million is allocated to drilling and completion activities and approximately $65 million is allocated to production facilities, land and other capitalized costs. Substantially all of the planned capital budget is anticipated to be invested in the Permian-Garden City area, primarily in the Upper and Middle Wolfcamp formations.

Our near-term strategy is to continue to concentrate our drilling activities on multi-well packages around our previously established production corridors that have the infrastructure in place to provide us the flexibility to most efficiently and economically drill wells at an attractive rate of return. In the later part of the second quarter of 2019, we plan to widen the spacing between our wells as we seek to increase capital efficiency. In addition, in response to the continued volatile commodity price environment and our stated goal of achieving cash flow neutrality, we anticipate decreasing the number of drilling rigs and/or completions crews that we use. We continue to use our existing data (and acquire new data) to optimize completion designs and well spacing within the development plan in order to enhance inventory and net asset value. We will also continue to pursue cost saving measures, but given the volatile commodity price environment, we are unsure what, if any, changes there will be to service costs.

On December 31, 2018, we had a total of three drilling rigs drilling horizontal wells. Our current drilling schedule anticipates that we will utilize three horizontal rigs during the first part of 2019 and decrease our drilling rig count thereafter. We do not anticipate utilizing any vertical rigs throughout 2019. If we decrease our drilling rig count and/or completion crews, it will have a negative impact on our production, especially oil production, and reserves, as well as potentially result in contract termination penalties. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Obligations and commitments" and Note 14.c to our consolidated financial statements included elsewhere in this Annual Report for additional information.

In addition to the impact of commodity prices, the timing of drilling our potential locations is also influenced by several factors, including capital requirements and availability, the Texas Railroad Commission ("RRC") well-spacing requirements and the positive results from our ongoing development drilling program.

We expect our Permian-Garden City acreage to continue to be the primary driver for the growth of our reserves, production and cash flow for the foreseeable future.

Since our inception, we have established and realized our reserves, production and cash flow primarily through our drilling program, coupled with select strategic acquisitions. Our net proved reserves were estimated at 238,167 MBOE on a three-stream basis as of December 31, 2018, of which 91% are classified as proved developed reserves and 26% are attributed to oil reserves. We report our production volumes on a three-stream basis, which separately reports NGL from crude oil and natural gas. As part of our on-going reserves estimation process, for our year-end 2018 reserves estimation, we incorporated additional production data to reflect (i) the higher gas content and steeper oil declines on our historical wells and (ii) the negative effects on oil production from tighter spacing on our recent wells. This additional production history has led to more specific forecasts, including specific b-factors, for both developed and undeveloped locations as we take into account additional production data. There is inherent uncertainty in the reserves estimation process and therefore we will continue to monitor the future production of these wells as well as other available data. In this Annual Report, the information presented with respect to our estimated proved reserves has been prepared by Ryder Scott Company, L.P. ("Ryder Scott"), our independent reserve engineers, in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to the periods presented.

The following table summarizes our total estimated net proved reserves presented on a three-stream basis, net acreage and producing wells as of December 31, 2018, and average daily production presented on a three-stream basis for the year ended December 31, 2018. Based on estimates in the report prepared by Ryder Scott, we operated wells that represent 99.7% of the economic value of our proved developed oil, NGL and natural gas reserves as of December 31, 2018.

	As of December 31, 2018						Year ended December 31, 2018 average daily production (BOE/D)
	Estimated net proved reserves[1]				Producing wells		
	MBOE	% of total reserves	% Oil	Net acreage	Gross	Net	
Permian Basin	238,167	100%	26%	120,617	1,246	1,155	68,168
Other properties	—	—%	—%	170	—	—	—
Total	238,167	100%	26%	120,787	1,246	1,155	68,168

(1) See "—Our operations—Estimated proved reserves" for discussion of the prices utilized to estimate our reserves.

Our net average daily production for the year ended December 31, 2018 was 68,168 BOE/D, 41% of which was oil, 29% of which was NGL and 30% of which was natural gas.

During 2015, commodity prices for crude oil, NGL and natural gas experienced sharp declines, and this downward trend accelerated further into 2016, with crude oil prices reaching their lowest level in February 2016 since 2003. In the second half of 2016 and through 2017, commodity prices increased and stabilized at relatively higher prices but at significantly lower levels than the first half of 2014. In 2018, commodity prices continued to remain volatile with significantly lower prices in the last quarter of the year. Our capital expenditures budget for 2019 is approximately $365 million, based on annual benchmark averages of a $53.60 per barrel WTI NYMEX strip price and a $2.90 per MMBtu Henry Hub NYMEX strip price, excluding non-budgeted acquisitions. Our goal is to achieve cash flow neutrality, and therefore, our capital spending in 2019 will ultimately be influenced by commodity price changes, as well as any changes in service costs and drilling and completions efficiencies.

Beginning in 2016, we deliberately and significantly reduced the portion of our reserves that had historically been categorized as "proved undeveloped" or "PUD." We adjusted our five-year SEC PUD bookings methodology because we believe it enables us to develop our acreage in the most efficient manner possible and determine which potential locations will be most profitable. We believe that we can optimize value for our shareholders by maintaining greater flexibility in choosing the specific drilling locations that will most efficiently develop our properties, particularly as technology changes and we continue to further understand the geology of our acreage.

As our activities to date have indicated, the majority of our acreage represents a resource play. In the near-term, our goal is to drill those locations that we anticipate have the greatest potential to enhance shareholder value. We have determined that the most efficient way to accomplish this is to maintain the flexibility to choose those locations based upon insight gained as we drill and collect data across our acreage, regardless of SEC reserves-booking status. We converted all 26 PUD locations we booked at December 31, 2017 into proved producing locations in 2018. Reducing our future PUD commitments provides us the most flexibility to maximize our rate of return at prevailing conditions and minimize the requirement to drill wells previously assigned, under very different circumstances, as specific PUD locations. Accordingly, for 2019, we have continued to limit our booked PUD locations to those locations that we have a high degree of certainty that we will develop and have made a specific capital commitment to drill within the first six months of 2019. This strategy maintains our flexibility to add new PUD locations and convert other locations to proved developed reserves as we deem appropriate and opportunistic. See "—Proved undeveloped reserves" for additional information on our PUD reserves.

Capitalizing on our large contiguous acreage blocks, we have built crude oil, natural gas and/or water systems in five production corridors on our Permian-Garden City acreage. These production corridors are designed to provide a combination of services which may include high-pressure centralized natural gas lift systems, crude oil and natural gas gathering and water delivery and takeaway capacity, with certain corridors also capable of accessing recycling facilities. We have built and maintain 60 miles of crude oil gathering pipelines to connect Laredo-operated wells in our Permian-Garden City acreage, providing a safer and more economic transportation alternative than trucking. We have also installed and maintain 159 miles of natural gas gathering pipelines across our Permian-Garden City acreage, providing us with takeaway optionality that enables us to maintain lower operating pressures and more consistent well performance. Our crude oil and natural gas gathering assets provided transportation for 55% of our production in 2018. Combined, our three water recycling facilities provide a recycling capacity of more than 54,000 Bbls of water per day, and a storage capacity of more than 3.6 million Bbls. Having these production corridors and associated facilities and infrastructure already in place is expected to enhance the value of our 2019 drilling program.

Our midstream and marketing activities continue to focus on achieving increased efficiencies and cost reductions for (i) the transportation and marketing of our oil and natural gas (through the utilization of our oil and natural gas gathering systems to provide access to multiple markets and reduce the potential for production shut-ins caused by downstream capacity issues) and (ii) the handling of fresh, recycled and produced water (through the use of our water recycling facilities).

We market the majority of production from properties we operate for both our account and the account of the other working interest owners in our operated properties. We sell substantially all of our production under contracts ranging from one month to several years, all at fluctuating market prices. We normally sell production to a relatively limited number of customers, as is customary in the exploration, development and production business; however, we believe that our customer diversification affords us optionality in our sales destination. We have committed a portion of our Permian crude oil production under firm transportation agreements, including with 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 in the Midland Basin. This commitment will enhance our ability to move our crude oil out of the Permian Basin and give us access to potentially more favorable U.S. Gulf Coast pricing. See Note 4.c to our consolidated financial statements included elsewhere in this Annual Report for a further discussion of our firm transportation agreement with Medallion.

On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC ("MMH"), which was owned and controlled by an affiliate of The Energy & Minerals Group ("EMG"), completed the sale of 100% of the ownership interests in Medallion to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion, subject to customary post-closing adjustments (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 our Senior Secured Credit Facility, to redeem our 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.

As of December 31, 2018, we were committed to deliver for sale or transportation the following fixed quantities of production under certain contractual arrangements that specify the delivery of a fixed and determinable quantity:

	Total	2019	2020	2021	2022 and after
Crude oil (MBbl):					
Sales commitments	730	730	—	—	—
Transportation commitments:					
Field	68,224	13,414	10,980	10,950	32,880
To U.S. Gulf Coast	98,910	7,475	13,730	16,425	61,280
Natural gas (MMcf):					
Sales commitments	69,109	10,339	9,578	5,620	43,572
Total commitments (MBOE)(1)	179,382	23,342	26,306	28,312	101,422

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

We have firm field transportation agreements that enable us or the purchasers of our oil production to move oil from our production area to major market hubs, including Colorado City, Texas, Midland, Texas and Crane, Texas. One of these agreements is with Medallion and it remains in place and unchanged following the Medallion Sale. Effective as of June 1, 2017, we signed a Dedication and Connection Agreement with Medallion whereby we dedicated to Medallion for transportation the oil from a significant portion of our acreage, subject to certain exceptions. We also have a firm transportation agreement to move oil from Colorado City, Texas to the U.S. Gulf Coast. In 2018, we signed an agreement with Gray Oak Pipeline, LLC to initially transport 25,000 barrels of oil per day going to 35,000 barrels of oil per day of our production from Crane, Texas to the U.S. Gulf Coast. Our shipments under this contract will begin when the pipeline commences operations which is anticipated in the second half of 2019.

Our production has been substantially equivalent to or greater than our delivery commitments during the three most recent years, and we expect such production to meet our 2019 commitments. We are subject to firm transportation payments on excess pipeline capacity and other contractual penalties. In certain instances, we have used spot market purchases to meet commitments in certain locations or due to favorable pricing. We anticipate continuing this practice in the future. We incurred firm transportation payments on excess pipeline capacity and other contractual penalties of $4.7 million, $1.1 million and $2.2 million during the years ended December 31, 2018, 2017 and 2016, respectively. Also, if our production is not sufficient to satisfy our delivery commitments, we can and may use spot market purchases to fulfill the commitments.

In the current market environment, we believe that we could sell our production to numerous companies, so that the loss of any one of our major purchasers would not have a material adverse effect on our financial condition and results of operations solely by reason of such loss. For information regarding each of our customers that accounted for the purchase of 10% or more of our oil, NGL and natural gas revenues during the last three calendar years, see Note 13 to our consolidated financial statements included elsewhere in this Annual Report. See "Item 1A. Risk Factors—Risks related to our business—The inability of our significant customers to meet their obligations to us may materially adversely affect our financial results."

We have built an extensive proprietary technical database on our properties, including (but not limited to) 1,133 square miles of 3D seismic, 70 wells with microseismic, 7,073 feet of whole core in 18 wells, 958 sidewall cores in 24 wells, over 1,300 open and cased-hole logging suites with over 130 dipole sonic logs, 23 single-zone tests and 40 production logs. Our strategic interest in utilizing this database is directed at characterizing subsurface reservoir properties to gain insight into principles that potentially govern resource recovery, which can be subsequently leveraged during development planning, with the goal of maximizing the value of our entire asset base. Our reservoir characterization process encompasses four fundamental areas: (i) high-resolution geocellular modeling, (ii) well spacing and completions optimization, (iii) reservoir engineering studies and (iv) predictive analytics.

HRGM's integrate the above-described data with enhanced interpretations conducted in 2018 to provide 3D reservoir and mechanical property models across the majority of Laredo's acreage. HRGM's provide a sufficiently high resolution and accurate depiction of subsurface development potential to continue executing the "drill to plan" technical workflow, implemented in 2017. Drill to plan targets geological landing points in the perceived highest quality reservoir. This minimizes target changes during operations, increasing the accuracy of well positioning, while reducing time and costs associated with target changes and enhancing operational efficiencies. All of the 2019 planned wells are anticipated to utilize drill to plan.

HRGM's provide the foundation for hydraulic fracture modeling, where hydraulic fracture and proppant transport models have been utilized to explicitly describe fracture networks. These fracture networks have then been used in conjunction with reservoir simulators to match specific packages of wells with unique landing points and completion designs. These models are then used to assess possible differences in fracture geometry and well productivity due to a multitude of variables, which include, but are not limited to, the landing point, well path, proppant loading, fluid loading, proppant concentration, pump rate and perforation design. Additionally, these models can be used for simulation of multi-well packages to assess potential interactions during the completion operation and total recovery factor of the resource in place.

Microseismic analysis continues to advance knowledge across various well spacing combinations and individual completion design field trials, improving our understanding of fracture geometry, cluster efficiency and proppant distribution associated with both well spacing and individual completion design. We consider our database and workflows advantageous in yielding important insights into subsurface behavior and consequently improved development decision making**.**

Predictive analytical modeling includes non-linear multivariate regression and machine learning algorithms facilitating the detection and assessment of the impact of individual parameters on fundamental value drivers. Proprietary software and workflows quantify the effects of individual parameters within completion designs, well spacing and rock properties on production. This knowledge can be leveraged to generate optimized, capital-efficient development plans.

We consider the above technical workflows to be potentially significant tools in optimizing multi-well developments. We anticipate that all of our horizontal wells to be drilled in 2019 will utilize at least some aspects of the above workflows. If our preliminary applications of these workflows are replicated in forward-looking well planning, we anticipate this will positively impact our ability to select optimal multi-well development plans.

Corporate history and structure

Laredo Petroleum, Inc. is a Delaware corporation formed in 2011 for the purpose of merging with Laredo Petroleum, LLC (a Delaware limited liability company formed in 2007) to consummate an IPO in December 2011. Laredo Petroleum, Inc. was the survivor of such merger and currently has two wholly-owned subsidiaries, LMS and GCM. As of December 31, 2018, affiliates of Warburg Pincus LLC ("Warburg Pincus"), our founding member, owned 21.9% of our common stock.

Debt

Laredo Petroleum, Inc. is the borrower under our Fifth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility"), as well as the issuer of our $350.0 million in aggregate principal amount of 6 1/4% senior unsecured notes due 2023 (the "March 2023 Notes") and our $450.0 million in aggregate principal amount of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes"). We refer to the March 2023 Notes and the January 2022 Notes collectively as the "Senior Unsecured Notes." Our subsidiaries, LMS and GCM, are guarantors of the obligations under our Senior Secured Credit Facility and Senior Unsecured Notes. The maturity date of our Senior Secured Credit Facility is 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.

On November 29, 2017 (the "May 2022 Notes Redemption Date"), following the Medallion Sale, we redeemed the entire $500.0 million outstanding principal amount of 7 3/8% senior unsecured notes due 2022 (the "May 2022 Notes") 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.

Our business strategy

Our goal is to enhance shareholder value by executing the following strategy:

Maximize our capital efficiency by seeking to drill high rate of return wells through wider well spacing, reduced overhead and operational improvements

- In 2019, we will seek to reduce overhead costs while increasing operational efficiency and in the later part of the second quarter of 2019, we will widen the spacing between our wells in order to target high rate of return well results.
- In order to increase our operational flexibility, in the past three years, we deliberately reduced our PUD bookings within our reserves. While this decision impacts our total booked reserves in the short term, we believe that it enhances our ability to drill our most efficient wells by providing us with crucial flexibility in tailoring our drilling plans in a manner that is more cost-efficient. We converted all 26 PUD locations we booked at December 31, 2017 into proved producing locations in 2018.

Deploy our capital in a strategic manner while considering value-enhancing acquisitions, divestitures, mergers, redemptions, repurchases, delevering and similar transactions

- We will be highly selective in the projects that we consider and we will continue to monitor the market for strategic opportunities that we believe could be accretive and enhance shareholder value. These opportunities may take the form of acquisitions, divestitures, mergers, redemptions, repurchases, delevering or other similar transactions, any of which could result in the utilization of our Senior Secured Credit Facility and accessing the capital markets.

Proactively manage risk to limit downside

- We actively attempt to limit our business and operating risks by focusing on safety, flexibility in our financial profile, operational efficiencies, hedging, controlling costs and developing oil and natural gas takeaway capacity with multiple delivery points.

Seek accretive acquisitions

- As we continue to develop our existing Permian-Garden City acreage position, we believe that the acquisition of additional acreage may be beneficial as consolidation and increased scale may lead to increased operational and corporate efficiencies.

Continue to hedge our production to protect cash flows, diminish the effects of commodity price fluctuations and maintain upside exposure

- During 2018, our hedging program provided us with cash flow certainty. In the future, we will continue to seek hedging opportunities on a multi-year basis to further protect our cash flows from commodity price fluctuations while maintaining upside exposure if commodity prices increase.

Increase the use of our previously built infrastructure and evaluate opportunities for strategic expansion

- We believe that our infrastructure provides us with optionality and efficiencies in developing and transporting production from our Permian-Garden City acreage position, as well as providing water transportation and recycling services for a significant portion of our planned drilling activities. Because of the value we ascribe to this infrastructure, we will continue to look for strategic expansion opportunities while maintaining our core strategy of providing marketing optionality for our oil, NGL and natural gas production.

Our competitive strengths

We have a number of competitive strengths that we believe will assist in the successful execution of our business strategy:

Contiguous acreage position with high working interests and extensive interests in leases held by production containing multiple formations, resulting in a substantial drilling inventory

- We have 120,617 net acres in the Permian-Garden City area that are largely contiguous with a high average working interest percentage (average working interest of 97% in all Laredo-operated producing wells), are 88% held by production and have identified up to seven targets to date from which we can produce, resulting in a long-term drilling inventory. Our contiguous acreage position also enables us to drill long laterals (10,000 feet or greater) in many locations, which may provide an even greater rate of return as we continue to refine our spacing, drilling and completions techniques.

Drilling and lease operating efficiencies afforded by our acreage position and production corridors that enable low-cost operations

- By making upfront investments in production infrastructure on our contiguous acreage position, we are now able to drill and operate in a more efficient and low-cost manner. We believe that this infrastructure will enable us to continue to be a low-cost operator while at the same time drilling facilitates productive new wells.

Significant cash flow from existing operations

- Our Permian-Garden City acreage currently has approximately 1,155 net producing wells. That current base provides us with a significant amount of cash flow and such wells require little additional capital to maintain. In addition, we have few on-going drilling requirements to keep our Permian-Garden City acreage from lease expirations which further strengthens our flexibility to use cash flow from operations in a manner we see as most efficient.

Significant operational control

- We operated wells that represent 99.7% of the economic value of our proved developed oil, NGL and natural gas reserves as of December 31, 2018, based on our reserve report prepared by Ryder Scott. We believe that maintaining operating control permits us to better pursue our strategy of enhancing returns through operational and cost efficiencies and maximizing cost-efficient ultimate hydrocarbon recoveries through reservoir analysis and evaluation and continuous improvement of drilling, completions and stimulation techniques. We expect to maintain operating control over nearly all of our potential drilling locations.

Our production corridors and water recycle facilities enable us to more efficiently develop our acreage and utilize/dispose of water that facilitates development and reduces our capital and operating expenses

- We believe that our previously built production corridors increase field level operating efficiencies in oil and natural gas gathering and takeaway capacity, water supply and operations. We have demonstrated that our production corridors provide us with identified areas within which we can achieve material cost savings and efficiencies through the use of our previously built infrastructure, including water recycling. In addition, drilling wells within these corridors increases our production consistency through increased knowledge thus enabling us to better plan our development program.
- The use and disposal of water is one of the most challenging aspects of horizontal drilling in the Permian Basin and our production corridors provide us with a reliable and consistent means to ensure that we have the water we need to complete our wells while also providing low-cost takeaway capacity for flowback and produced water.

Extensive infrastructure in place

- We own and operate more than 238 miles of pipeline in our crude oil and natural gas gathering, fuel gas and gas lift systems in the Permian Basin as of December 31, 2018. These systems and pipelines provide greater operational efficiency, capital and cost savings and potentially better pricing for our production and enable us to coordinate our activities to connect our wells to market upon completion with minimal pipeline delays.

Strong corporate governance and institutional investor support

- Our board of directors is well qualified and represents a meaningful resource to our management team. Our board of directors, which is comprised of representatives of Warburg Pincus, other independent directors and our Chief Executive Officer, has extensive oil and natural gas industry and general business expertise. We actively engage our board of directors, on a regular basis, for their expertise on strategic, financial, governance and risk management activities. In addition, Warburg Pincus has many years of relevant experience in financing and supporting exploration and production companies and management teams. Warburg Pincus has been the lead investor in many such companies, including two previous companies operated by certain members of our management team.

Our extensive Permian technical database

- We have made a substantial upfront investment in technical data in order to accurately assess reservoir and production characteristics of our largely contiguous acreage. Our extensive proprietary technical data set, in combination with industry-leading technologies and in-house workflows, enables a comprehensive characterization and visualization of the total subsurface resource potential. This, in turn, facilitates a development planning workflow that seeks to maximize resource recovery and achieve an attractive return on capital employed with respect to each discrete development package of wells.

Other properties

In addition to our Permian-Garden City acreage, as of December 31, 2018, we held 170 net acres in the Palo Duro Basin. Essentially all of this acreage will expire in 2019, absent drilling or renegotiation of the applicable leases. We anticipate little or no activity on these properties in 2019.

Our operations

Estimated proved reserves

Our reserves are reported in three streams: crude oil, NGL and natural gas. In this Annual Report, the information with respect to our estimated proved reserves presented below has been prepared by Ryder Scott, in accordance with applicable SEC rules and regulations.

SEC guidelines require companies to use the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials ("Benchmark Prices"). The Benchmark Prices are then adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead ("Realized Prices"). The Realized Prices are utilized to calculate estimated reserves and the associated discounted future cash flows. The following table presents the Benchmark Prices and Realized Prices as of the dates presented:

	As of December 31,	
	2018	2017
Benchmark Prices:		
Oil ($/Bbl)	$ 62.04	$ 47.79
NGL ($/Bbl)[(1)]	$ 31.46	$ 26.13
Natural gas ($/MMBtu)	$ 1.76	$ 2.63
Realized Prices:		
Oil ($/Bbl)	$ 59.29	$ 46.34
NGL ($/Bbl)	$ 21.42	$ 18.45
Natural gas ($/Mcf)	$ 1.38	$ 2.06

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(1) Based on the Company's average composite NGL Bbl.

Our net proved reserves were estimated at 238,167 MBOE on a three-stream basis as of December 31, 2018, of which 91% were classified as proved developed reserves and 26% are attributable to oil reserves. The following table presents summary data for our operating area as of December 31, 2018.

	As of December 31, 2018	
	Proved reserves	% of total
Area:	(MBOE)	
Permian Basin	238,167	100%
Other properties	—	—%
Total	238,167	100%

Our estimated proved reserves as of December 31, 2018 assume our ability to fund the capital costs necessary for their development and are affected by pricing assumptions. See "Item 1A. Risk Factors—Risks related to our business—Estimating reserves and future net revenues involves uncertainties. Negative revisions to reserve estimates, decreases in oil, NGL and natural gas prices or increases in service costs, may lead to decreased earnings and increased losses or impairment of oil and natural gas properties."

The following table sets forth additional information regarding our estimated proved reserves as of December 31, 2018 and 2017. Ryder Scott estimated 100% of our proved reserves as of December 31, 2018 and 2017. The reserve estimates as of December 31, 2018 and 2017 were prepared in accordance with the applicable SEC rules regarding oil, NGL and natural gas reserves reporting.

	As of December 31,	
	2018	2017
Proved developed producing:		
Oil (MBbl)	55,893	68,877
NGL (MBbl)	79,241	60,441
Natural gas (MMcf)	491,828	371,946
Total proved developed producing (MBOE)	217,105	191,309
Proved undeveloped:		
Oil (MBbl)	6,001	10,536
NGL (MBbl)	7,406	6,930
Natural gas (MMcf)	45,928	42,646
Total proved undeveloped (MBOE)	21,062	24,574
Estimated proved reserves:		
Oil (MBbl)	61,894	79,413
NGL (MBbl)	86,647	67,371
Natural gas (MMcf)	537,756	414,592
Total estimated proved reserves (MBOE)	238,167	215,883
Percent developed	91%	89%

Technology used to establish proved reserves

Under SEC rules, proved reserves are those quantities of oil, NGL and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible within five years from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil, NGL and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, our internal reserve engineers and Ryder Scott, our independent reserve engineers, employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, open-hole logs, core analyses, geologic maps, available downhole and production data and seismic data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves, including individual b-factors, material balance calculations or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated primarily by performance from analogous wells in the surrounding area and the use of geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation, well spacing and completion using similar techniques.

During 2015, commodity prices for crude oil, NGL and natural gas experienced sharp declines, and this downward trend accelerated further into 2016, with crude oil prices reaching their lowest level in February 2016 since 2003. In the second half of 2016 and through 2017, commodity prices increased and stabilized at relatively higher prices but at significantly lower levels than the first half of 2014. In 2018, commodity prices continued to remain volatile with significantly lower prices in the last quarter of the year. Our capital expenditures budget for 2019 is approximately $365 million, based on annual benchmark averages of a $53.60 per barrel WTI NYMEX strip price and a $2.90 per MMBtu Henry Hub NYMEX strip price, excluding non-budgeted acquisitions. Our goal is to achieve cash flow neutrality, and therefore, our capital spending in 2019 will ultimately be influenced by commodity price changes, as well as any changes in service costs and drilling and completions efficiencies.

Beginning in 2016, we purposely significantly reduced the portion of our reserves that have historically been categorized as "proved undeveloped" or "PUD." We adjusted our five-year SEC PUD bookings methodology because we believe it enables us to develop our acreage in the most efficient manner possible and determine which potential locations best enhance our overall value. We believe that we can optimize value for our shareholders by maintaining greater flexibility in choosing the specific drilling locations that will most efficiently develop our properties, particularly as technology changes and we continue to further understand the geology of our acreage.

As our activities to date have indicated, the majority of our acreage represents a resource play. In the near term, our goal is to drill those locations that we anticipate have the potential to provide the greatest shareholder value. We have determined that the most efficient way to accomplish this is to maintain the flexibility to choose those locations based upon our continuing insight as we drill and collect data across our acreage, regardless of SEC reserves booking status. We converted all 26 PUD locations booked at December 31, 2017 into proved producing locations in 2018. Reducing our future PUD commitments provides us the most flexibility to maximize our rate of return at prevailing conditions and minimize the requirement to drill wells previously assigned, under very different circumstances, as specific PUD locations. Accordingly, for 2019, we have continued to limit our booked PUD locations to those we have a high degree of certainty to believe that we will develop and have made a specific capital commitment to drill within the first six months of 2019. This strategy maintains our flexibility to add new PUD locations and convert other locations to proved developed reserves as our plans deem appropriate and opportunistic.

Qualifications of technical persons and internal controls over reserves estimation process

In accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE Reserves Auditing Standards") and guidelines established by the SEC, Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserve information as of December 31, 2018 and 2017 included in this Annual Report. The technical persons responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the SPE Reserves Auditing Standards.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to Ryder Scott in their reserves estimation process. Our technical team meets regularly with representatives of Ryder Scott to review properties and discuss methods and assumptions used in Ryder Scott's preparation of the year-end reserve estimates. The Ryder Scott reserve report is reviewed with representatives of Ryder Scott and our internal technical staff before dissemination of the information.

Our Vice President of Reservoir Engineering is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has more than 19 years of practical experience, with 10 years of this experience being in the estimation and evaluation of reserves. He has a Bachelors of Science in Chemical Engineering from Rice University, a Masters of Business Administration from the Kellogg School of Management and a Masters of Engineering Management from Northwestern University. Our Vice President of Reservoir Engineering reports to our Senior Vice President - Midstream, Marketing & Subsurface. Reserve estimates are reviewed and approved by our senior engineering staff, other members of senior management and our technical staff, our audit committee and our Chief Executive Officer.

Proved undeveloped reserves

Our proved undeveloped reserves decreased from 24,574 MBOE as of December 31, 2017 to 21,062 MBOE as of December 31, 2018. We estimate that we incurred $215.1 million of costs to convert 24,574 MBOE of proved undeveloped reserves from 26 locations into proved developed reserves in 2018. New proved undeveloped reserves of 18,452 MBOE were added during the year from 18 new horizontal Wolfcamp locations. Positive revisions to proved undeveloped reserves of 2,610 MBOE were due to adding two undeveloped locations that were removed from reserves in a previous year. A final investment decision has been made on these 20 locations and they are scheduled to be drilled and completed in 2019.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2018 reserve report are $159.0 million. Based on this report and our PUD booking methodology, the capital estimated to be spent in 2019 to develop the proved undeveloped reserves is $155.0 million and $0 for each of 2020, 2021, 2022 and 2023. Based on our anticipated cash flows and capital expenditures, as well as the availability of capital markets transactions, all of the proved undeveloped locations are expected to be drilled within the first six months of 2019. Reserve calculations at any end-of-year period are representative of our development plans at that time. Changes in circumstance, including commodity pricing, oilfield service costs, technology, acreage position and availability and other economic and regulatory factors may lead to changes in development plans.

Sales volumes, revenues and price history

The following table presents information regarding our oil, NGL and natural gas sales volumes, revenues, average sales Realized Prices, and average costs and expenses per BOE sold for the periods presented. Our reserves and production are reported in three streams: crude oil, NGL and natural gas. For additional information on price calculations, see the information in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	For the years ended December 31,		
(unaudited)	**2018**	**2017**	**2016**
Sales volumes:			
Oil (MBbl)	10,175	9,475	8,442
NGL (MBbl)	7,259	5,800	4,784
Natural gas (MMcf)	44,680	35,972	29,535
Oil equivalents (MBOE)(1)(2)	24,881	21,270	18,149
Average daily sales volumes (BOE/D)(2)	68,168	58,273	49,586
Sales revenues (in thousands):			
Oil	$ 605,197	$ 445,012	$ 318,466
NGL	$ 149,843	$ 101,438	$ 56,982
Natural gas	$ 53,490	$ 75,057	$ 51,037
Average sales Realized Prices(2):			
Oil, without derivatives ($/Bbl)(3)	$ 59.48	$ 46.97	$ 37.73
NGL, without derivatives ($/Bbl)(3)	$ 20.64	$ 17.49	$ 11.91
Natural gas, without derivatives ($/Mcf)(3)	$ 1.20	$ 2.09	$ 1.73
Average price, without derivatives ($/BOE)(3)	$ 32.50	$ 29.22	$ 23.50
Oil, with derivatives ($/Bbl)(4)	$ 55.49	$ 50.45	$ 58.07
NGL, with derivatives ($/Bbl)(4)	$ 20.03	$ 16.91	$ 11.91
Natural gas, with derivatives ($/Mcf)(4)	$ 1.77	$ 2.15	$ 2.20
Average price, with derivatives ($/BOE)(4)	$ 31.72	$ 30.71	$ 33.73
Average costs and expenses per BOE sold(2):			
Lease operating expenses	$ 3.67	$ 3.53	$ 4.15
Production and ad valorem taxes	$ 1.99	$ 1.78	$ 1.58
Transportation and marketing expenses	$ 0.47	$ —	$ —
Midstream service expenses	$ 0.12	$ 0.19	$ 0.22
General and administrative:			
Cash	$ 2.40	$ 2.85	$ 3.45
Non-cash stock-based compensation, net	$ 1.46	$ 1.68	$ 1.61
Depletion, depreciation and amortization	$ 8.55	$ 7.45	$ 8.17

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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.

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

Productive wells

The following table sets forth certain information regarding productive wells in our core operating area as of December 31, 2018. All but three of our wells are classified as oil wells, all of which also produce liquids-rich natural gas and condensate. Wells are classified as oil or natural gas wells according to the predominant production stream. We also own royalty and overriding royalty interests in a small number of wells in which we do not own a working interest.

	Total producing wells				
	Gross			Net	
	Vertical	Horizontal	Total	Total	Average WI %
Permian Basin:					
Operated Permian-Garden City	766	412	1,178	1,141	97%
Non-operated Permian-Garden City	61	7	68	14	21%
Other properties	—	—	—	—	—%
Total	827	419	1,246	1,155	93%

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2018 for our core operating area and other properties, including acreage HBP. A majority of our developed acreage is subject to liens securing our Senior Secured Credit Facility.

	Developed acres		Undeveloped acres		Total acres		%
	Gross	Net	Gross	Net	Gross	Net	HBP
Permian Basin	119,433	105,998	16,082	14,619	135,515	120,617	88%
Other properties	—	—	520	170	520	170	—%
Total	119,433	105,998	16,602	14,789	136,035	120,787	88%

Undeveloped acreage expirations

The following table sets forth the gross and net undeveloped acreage in our core operating area and other properties as of December 31, 2018 that will expire over the next four years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	2019		2020		2021		2022	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin	161	180	5,652	4,576	566	159	—	46
Other properties	520	170	—	—	—	—	—	—
Total	681	350	5,652	4,576	566	159	—	46

Of the total undeveloped acreage identified as expiring over the next four years, 690 net acres have associated PUD reserves as of December 31, 2018. All of those PUD reserves are scheduled to be drilled and completed in the first half of 2019.

At December 31, 2017, 0 net acres of potentially expiring leasehold were identified as attributable to PUD reserves.

Drilling activity

The following table summarizes our drilling activity for the years ended December 31, 2018, 2017 and 2016. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	74	71.2	62	60.7	45	44.5
Dry	—	—	—	—	—	—
Total development wells	74	71.2	62	60.7	45	44.5
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	1	0.5
Total exploratory wells	—	—	—	—	1	0.5

Title to properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations under oil and gas leases or net profit interests.

Oil and natural gas leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil, NGL and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 12.5% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 87.5%. As of December 31, 2018, 88% of our Permian-Garden City acreage was HBP.

Seasonality

Demand for oil and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and natural gas industry is intensely competitive, and we compete with a wide range of companies in our industry, including those that have greater resources than we do and those that are smaller with fewer ongoing obligations. Many of the larger companies not only explore for and produce oil and natural gas, but also conduct refining operations and market petroleum and other products on a regional, national or worldwide basis. Many of the smaller companies have a lower cost structure and more liquidity. These companies may be able to pay more for productive properties and exploratory locations or evaluate, bid for and purchase a greater number of properties and locations than our financial or human resources permit and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration and production activities during periods of low market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because of the inherent advantages of some of our competitors, those companies may have an advantage in bidding for exploratory and producing properties.

Hydraulic fracturing

We use hydraulic fracturing as a means to maximize the productivity of almost every well that we drill and complete. Hydraulic fracturing is a necessary part of the completion process for our producing properties in Texas because our properties are dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. We are currently conducting hydraulic fracturing activity in the completion of our wells in the Permian Basin. While hydraulic fracturing is not required to maintain any of our leasehold acreage that is currently held by production from existing wells, it will be required in the future to develop the proved non-producing and proved undeveloped reserves associated with this acreage. Nearly all of our proved undeveloped reserves associated with future drilling, recompletion and refracture stimulation projects require hydraulic fracturing.

We have and continue to follow standard industry practices and applicable legal requirements. State and federal regulators impose requirements on our operations designed to ensure protection of human health and the environment. These protective measures include setting surface casing at a depth sufficient to protect fresh water formations and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This well design is intended to eliminate a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval.

Injection rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations would be shut down immediately if an abrupt change occurred to the injection pressure or annular pressure.

Certain state regulations require disclosure of the components in the solutions used in hydraulic fracturing operations. Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand. The remainder of the constituents in the fracturing fluid are managed and used in accordance with applicable requirements. In accordance with Texas regulations, we report the constituents of the hydraulic fracturing fluids utilized in our well completions on FracFocus (www.fracfocus.org). Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it by recycling or by discharging into the approved disposal wells. We currently do not discharge water to the surface. Based upon results of testing the performance of recycled flowback/produced water in our fracing operations, we have constructed and currently operate three water recycle facilities on our production corridors providing a recycling capacity of more than 54,000 Bbls of water per day, and a storage capacity of more than 3.6 million Bbls.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read "-Regulation of environmental and occupational health and safety matters-Hydraulic fracturing." For related risks to our stockholders, please read "Item 1A. Risk Factors—Risks related to our business—Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and water disposal wells could prohibit projects or result in materially increased costs and additional operating restrictions or delays because of the significance of hydraulic fracturing and water disposal wells in our business."

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, the production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The State of Texas has regulations governing environmental and conservation matters, including provisions for the pooling of oil and natural gas properties, the permitting of allocation wells, the establishment of maximum allowable rates of production from oil and natural gas wells (including the proration of production to the market demand for oil, NGL and natural gas), the regulation of well spacing, the handling and disposing or discharge of waste materials and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil, NGL and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, Texas imposes a production or severance tax with respect to the production and sale of oil, NGL and natural gas within its jurisdiction. Texas further regulates drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

The regulatory burden on the industry increases the cost of doing business and affects profitability. Additional proposals and proceedings that affect the natural gas industry are regularly considered by the current administration, Congress, the states, the Environmental Protection Agency ("EPA"), Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered, and such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impacts of compliance.

Regulation of environmental and occupational health and safety matters

Our operations are subject to numerous stringent federal, state and local statutes and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures, the noncompliance with which carries substantial administrative, civil and criminal penalties and may result in injunctive obligations to remediate noncompliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling, completion and production process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier, seismically active areas and other protected areas, require some form of remedial action to prevent or mitigate pollution from current or former operations such as plugging abandoned wells or closing earthen pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

Certain of these laws and regulations impose strict liability (i.e., no showing of "fault" is required) that, in some circumstances, may be joint and several. Public interest in the protection of the environment has tended to increase over time. The trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. Changes in environmental laws and regulations occur frequently, and to the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and clean-up requirements, our business and prospects, as well as the oil and natural gas industry in general, could be materially adversely affected.

Hazardous substance and waste handling

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes, and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, referred to as CERCLA or the Superfund law, and comparable state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons deemed "responsible parties." These persons include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release or disposal of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. Despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties. Finally, it is not uncommon for neighboring landowners and other third parties to file common law based claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

The Oil Pollution Act of 1990 (the "OPA") is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on "responsible parties" for all containment and clean-up costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility. The OPA establishes a liability limit for onshore facilities, but these liability limits may not apply if: a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or a party fails to report a spill or to cooperate fully in a clean-up. We are also subject to analogous state statutes that impose liabilities with respect to oil spills.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. Although RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is also possible that these wastes, which could include wastes currently generated during our operations, will be designated as "hazardous wastes" in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration and production wastes as "hazardous wastes." Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We believe that we are in substantial compliance with the requirements of CERCLA, RCRA, OPA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water and other waste discharges and spills

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, the Safe Drinking Water Act ("SDWA"), the OPA and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps"). On June 29, 2015, the EPA and the Corps jointly promulgated final rules redefining the scope of waters protected under the Clean Water Act. The rules are subject to ongoing litigation and have been stayed in more than half the States, including Texas. Also, on December 11, 2018, the EPA and the Corps released a proposed rule that would replace the 2015 rule, and significantly reduce the waters subject to federal regulation under the Clean Water Act. The proposal is currently subject to public review and comment, after which additional legal challenges are anticipated. As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the Clean Water Act. To the extent the rules expand the range of properties subject to the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. The State of Texas also maintains groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs.

These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and the underground injection of fluids and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with their terms.

Hydraulic fracturing

Hydraulic fracturing is a practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The SDWA regulates the underground injection of substances through the Underground Injection Control Program (the "UIC"). However, hydraulic fracturing is generally exempt from regulation under the UIC, and thus the process is typically regulated by state oil and gas commissions. Nevertheless, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC. On February 12, 2014, the EPA published a revised UIC Program permitting guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document describes how Class II regulations may be tailored to address the purported unique risks of diesel fuel injection during the hydraulic fracturing process. Although the EPA is not the permitting authority for UIC Class II programs in Texas, where we maintain acreage, the EPA is encouraging state programs to review and consider use of this permit guidance. Furthermore, legislation has been proposed in recent sessions of Congress to repeal the hydraulic fracturing exemption from the SDWA, provide for federal regulation of hydraulic fracturing and require public disclosure of the chemicals used in the fracturing process.

In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities. We cannot predict the impact that these actions may have on our business at this time, but further regulation of hydraulic fracturing activities could have a material impact on our business, financial condition and results of operation.

Also, on March 26, 2015, the Bureau of Land Management (the "BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. On March 28, 2017, President Trump signed an executive order directing the BLM to review the rule, and, if appropriate, to initiate a rulemaking to rescind or revise it. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule; however, a coalition of environmentalists, tribal advocates and the State of California filed lawsuits challenging the rule rescission. At this time, it is uncertain when, or if, the hydraulic fracturing rule will be implemented, and what impact it would have on our operations.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, impose additional requirements on hydraulic fracturing activities or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, pursuant to legislation adopted by the State of Texas in June 2011, beginning February 1, 2012, companies were required to disclose to the RRC and the public the chemical components used in the hydraulic fracturing process, as well as the volume of water used. Also, in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The new rules took effect in January 2014. Additionally, on October 28, 2014, the RRC adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments, which became effective on November 17, 2014, also clarify the RRC's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The RRC has used this authority to deny permits for waste disposal wells. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water, and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. These developments, as well as new laws or regulations, could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation governing hydraulic fracturing is enacted into law.

Air emissions

The federal Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Also, on May 12, 2016, the EPA issued a final rule regarding the criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects.

In August 2012, the EPA published final rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP"). The rules include NSPS for completions of hydraulically fractured gas wells and establish specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in volatile organic compounds ("VOC") emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests for reconsideration. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and VOC emissions for certain new, modified and reconstructed equipment, processes and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. Also, on October 15, 2018, the EPA published a proposed rule to significantly reduce regulatory burdens imposed by the 2016 regulations, including, for example, reducing the monitoring frequency for fugitive emissions and revising the requirements for pneumatic pumps at well sites.

In addition, on November 15, 2016, the BLM finalized a waste prevention rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The rule requires operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule also clarifies when operators owe the government royalties for flared gas. On March 28, 2017, President Trump signed an executive order directing the BLM to review the above rule and, if appropriate, to initiate a rulemaking to rescind or revise it. On April 4, 2018, a federal district court stayed certain provisions of the rule pending the BLM's reconsideration and, on September 28, 2018, the BLM finalized revisions to the waste prevention rule to reduce "unnecessary compliance burdens." The States of California and New Mexico have challenged the scaled-back rule. At this time, it is uncertain when, and to what extent, the waste prevention rule will be implemented, and what impact it will have on our operations.

These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions.

We have incurred additional capital expenditures to insure compliance with these new regulations as they come into effect. We may also be required to incur additional capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission related issues, which may have a material adverse effect on our operations. Obtaining permits also has the potential to delay the development of oil and natural gas projects. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Regulation of "greenhouse gas" emissions

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases ("GHGs"). The EPA has finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry, and Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce GHG emissions primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs. Also, some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

At the international level, in December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement went into effect on November 4, 2016. The Paris Agreement establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil, NGL and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA") and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an environmental assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. Any exploration and production activities, as well as proposed exploration and development plans, on federal lands would require governmental permits that are subject to the requirements of NEPA. This environmental impact assessment process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Endangered Species Act

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species or its habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act, though, in December 2017, the U.S. Fish and Wildlife Service ("USFWS") provided guidance limiting the reach of the Act. The USFWS may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. If we were to have a portion of our leases designated as critical or suitable habitat, it could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas, which could adversely impact the value of our leases.

Summary

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters during the years ended December 31, 2018, 2017 or 2016.

Regulation of oil and gas pipelines

Our oil and gas pipelines are subject to construction, installation, operation and safety regulation by the U.S. Department of Transportation ("DOT") and various other federal, state and local agencies. Congress has enacted several pipeline safety acts over the years. Currently, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") under DOT administers pipeline safety requirements for natural gas and hazardous liquid pipelines. These regulations, among other things, address pipeline integrity management and pipeline operator qualification rules. In June 2016, Congress approved new pipeline safety legislation, the "Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016" (the "PIPES Act"), which provides the PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquids pipeline facilities. Significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the current pipeline control system capabilities.

Recently, the PHMSA has proposed additional regulations for gas pipeline safety. For example, in March 2016, the PHMSA proposed a rule that would expand integrity management requirements beyond "High Consequence Areas" to apply to gas pipelines in newly defined "Moderate Consequence Areas." The public comment period closed on July 7, 2016. Also, on January 10, 2017, the PHMSA approved final rules expanding its safety regulations for hazardous liquid pipelines by, among other things, expanding the required use of leak detection systems, requiring more frequent testing for corrosion and other flaws and requiring companies to inspect pipelines in areas affected by extreme weather or natural disasters. The final rule was withdrawn by the PHMSA in January 2017, and it is unclear whether and to what extent the PHMSA will move forward with its regulatory reforms.

Disclosures required pursuant to Section 13(r) of the Securities Exchange Act of 1934

Pursuant to Section 13(r) of the Exchange Act, we are required to include certain disclosures in our periodic reports if we or any of our "affiliates" (as defined in Rule 12b-2 under the Exchange Act) knowingly engaged in certain specified activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by United States' economic sanctions during the period covered by the report. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable law. Neither we nor any of our controlled affiliates or subsidiaries knowingly engaged in any of the specified activities relating to Iran or otherwise engaged in any activities associated with Iran during the reporting period. However, because the SEC defines the term "affiliate" broadly, it includes any entity controlled by us as well as any person or entity that controlled us or is under common control with us.

The description of the activities below has been provided to us by Warburg Pincus, affiliates of which: (i) beneficially own more than 10% of our outstanding common stock and are members of our board of directors and (ii) beneficially own more than 10% of the outstanding common stock of and are members of the board of directors of Endurance International Group Holdings, Inc. (together with its subsidiaries, "EIGI"). EIGI may therefore be deemed to be under "common control" with us; however, this statement is not meant to be an admission that common control exists.

The disclosure below relates solely to activities conducted by EIGI. The disclosure does not relate to any activities conducted by Laredo or by Warburg Pincus and does not involve our or Warburg Pincus' management. Neither Laredo nor

Warburg Pincus had any involvement in or control over the disclosed activities of EIGI, and neither Laredo nor Warburg Pincus has independently verified or participated in the preparation of the disclosure. Neither Laredo nor Warburg Pincus is representing as to the accuracy or completeness of the disclosure nor do we or Warburg Pincus undertake any obligation to correct or update it.

Laredo understands that EIGI intends to disclose in its next annual or quarterly SEC report that:

"On July 25, 2018, the Office of Foreign Assets Control ("OFAC") designated Electronics Katrangi Trading ("Katrangi") as a Specially Designated National ("SDN") pursuant to the Weapons of Mass Destruction Proliferators Sanctions Regulations, 31 C.F.R. Part 544. On July 30, 2018, during a regular compliance scan of EIGI's user base, EIGI identified the domain SGP-FRANCE.COM (the "Domain Name") which was listed as a website associated with Katrangi, on one of EIGI's platforms. The Domain Name was managed using one of EIGI's platforms by one of its reseller customers. Accordingly, there was no direct financial transaction between EIGI and the registered owner of the Domain Name and EIGI did not generate any revenue in connection with the Domain Name since Katrangi was added to the SDN list on July 25, 2018. Upon discovering the Domain Name on its platform, EIGI promptly suspended the Domain Name and removed it from its platform. EIGI reported the Domain Name to OFAC on August 7, 2018.

On November 6, 2018, EIGI terminated an end customer account (the "End Customer Account") that EIGI believed to be associated with Arian Bank, which was identified by OFAC as an SDN on November 5, 2018, pursuant to 31 C.F.R. Part 594. EIGI initially acquired the End Customer Account on January 23, 2014 as part of EIGI's acquisition of P.D.R Solutions FZC. EIGI reported the End Customer Account to OFAC as potentially the property of an SDN subject to blocking pursuant to Executive Order 13224. As of February 1, 2019, EIGI had not received any correspondence from OFAC regarding this matter."

Employees

As of December 31, 2018, we had 340 full-time employees. We also employed a total of 20 contract personnel who assist our full-time employees with respect to specific tasks and perform various field and other services. Our future success will depend partially on our ability to identify, attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Our offices

Our executive offices are located at 15 W. Sixth Street, Suite 900, Tulsa, Oklahoma 74119, and the phone number at this address is (918) 513-4570. We also lease corporate offices in Midland and Dallas, Texas.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC, which are available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov. Our common stock is listed and traded on the New York Stock Exchange under the symbol "LPI."

We also make available on our website (http://www.laredopetro.com) all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers, Corporate Governance Guidelines and the charters of our audit committee, compensation committee and nominating and corporate governance committee are also available on our website and in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our executive office. Information contained on our website is not incorporated by reference into this Annual Report. We intend to disclose on our website any amendments or waivers to our Code of Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K.

Item 1A. *Risk Factors*

Our business involves a high degree of risk. If any of the following risks, or any risks described elsewhere in this Annual Report, were actually to occur, our business, financial condition or results of operations could be materially adversely affected and the trading price of our shares could decline resulting in the loss of part or all of your investment. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial may also adversely affect us.

Risks related to our business

Oil, NGL and natural gas prices are volatile. The continuing and extended volatility in oil, NGL and natural gas prices has adversely affected, and may continue to adversely affect, our business, financial condition and results of operations and may in the future affect our ability to meet our capital expenditure obligations and financial commitments as well as negatively impact our stock price further.

The prices we receive for our oil, NGL and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil, NGL and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the market for oil, NGL and natural gas has been volatile, and this volatility exhibited a negative trend beginning in the second half of 2014. While prices have increased from recent lows, they are still significantly below previous highs and the market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic and financial conditions impacting the global supply and demand for oil, NGL and natural gas;
- actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil, NGL and natural gas production and price controls;
- the level of global oil, NGL and natural gas exploration, production and supplies, in particular due to supply growth from the United States;
- foreign and domestic supply capabilities for oil, NGL and natural gas;
- the price and quantity of U.S. imports and exports of oil, natural gas, including liquefied natural gas, and NGL;
- the pricing disparity between oil and natural gas and the negative effect it may have on our cash flow from operations;
- political conditions in or affecting other oil, NGL and natural gas-producing countries;
- the extent to which U.S. shale producers act as "swing producers" adding or subtracting to the world supply of oil, NGL and natural gas;
- future regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells;
- current and future regulations regarding well spacing;
- prevailing prices on local oil, NGL and natural gas price indexes in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Lower oil, NGL and natural gas prices have reduced, and may in the future continue to reduce, our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil, NGL and natural gas reserves as existing reserves are depleted. A further decrease in oil, NGL and natural gas prices could render uneconomic a large portion of our exploration, development and exploitation projects. This has already resulted in us having to make significant downward adjustments to our estimated proved reserves, and we may need to make further downward adjustments in the future. Furthermore, under our Senior Secured Credit Facility, scheduled borrowing base redeterminations occur by May 1 and November 1 of each year, and the lenders have the right to call for an interim redetermination of the borrowing base one time between any two scheduled redetermination dates and in other specified circumstances. A reduced borrowing base could trigger repayment obligations under our Senior Secured Credit Facility. Also, lower oil, NGL and natural gas prices would likely cause a decline in our stock price.

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 and/or natural gas production has surpassed local transportation capacity, resulting in substantial discounts to the price received for crude oil prices quoted for WTI oil and Henry Hub natural gas. During a significant portion of 2018, Midland market crude oil prices experienced an increased discount to WTI Cushing and WTI Houston prices and the West Texas WAHA market natural gas prices experienced an increased discount to Henry Hub NYMEX prices. The discounts are primarily due to limited pipeline capacity constraining transportation of crude oil and natural gas out of the Permian Basin to major market hubs including, but not limited to, Cushing, Oklahoma and the United States Gulf Coast. Recently, each of these three basin differentials have narrowed; however, they remain volatile. These pipeline constraints may continue to affect Midland market crude oil prices and West Texas WAHA market natural gas prices until further transportation capacity becomes operational or until basin-wide crude oil and natural gas production decreases from its current levels. We will continue to pursue avenues to attempt to protect our oil and natural gas value from basin differentials by securing crude oil transportation capacity, which enables us to sell oil in multiple markets, and entering into basis-swap derivatives, which provides pricing protection. 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.

There is no guarantee that we will be successful in optimizing our spacing, drilling and completions techniques in order to maximize our rate of return, cash flow from operations and shareholder value.

As we accumulate and process geological and production data, we attempt to create a development plan, including well spacing and completion design, that maximizes our rate of return, cash flow from operations and shareholder value. However, due to many factors, including some beyond our control, there is no guarantee that we will be able to find the optimal plan or one that provides continuous improvement. If we are unable to design and implement an effective spacing, drilling and completions strategy, it may have a material adverse effect on our production results, financial performance, stock price and net asset value.

We may be unable to quickly adapt to changes in market/investor priorities.

Historically, one of the key drivers in the unconventional resource industry has been growth in production and reserves. With the continued downturn and volatility in oil and natural gas prices, and the possibility that interest rates will rise in the near term, increasing the cost of borrowing, the market and investor emphasis has elevated capital efficiency and free cash flow from earnings as potentially the key drivers for energy companies, especially those primarily focused in the shale play arena. Shifts in focus such as these sometimes require changes in planning and resource management, which cannot necessarily occur instantaneously. Any delay in responding to such changes in market sentiment or perception can result in the investment community in general having a negative sentiment regarding our business plan, potential profitability and our ability to operate in a manner deemed "efficient," which can have a negative impact on the price of our common stock.

Our business requires significant capital expenditures and we may be unable to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, development, marketing, transportation and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of 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 dispositions. We do not have commitments from anyone to contribute capital to us. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of oil, NGL and natural gas and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on terms favorable to us or at all. The failure to obtain additional capital could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our oil, NGL and natural gas production or reserves and, in some areas, a loss of properties.

We may incur significant additional amounts of debt.

As of February 13, 2019, we had total long-term indebtedness of $1.04 billion. We may be able to incur substantial additional indebtedness, including secured indebtedness, in the future. The restrictions on the incurrence of additional indebtedness contained in the indentures governing our Senior Unsecured Notes and in our Senior Secured Credit Facility are subject to a number of significant qualifications and exceptions, and under certain circumstances, the amount of indebtedness that could be incurred in compliance with these restrictions could be substantial. If new debt is added to our existing debt levels, the related risks that we face would increase and may make it more difficult to satisfy our existing financial obligations. In addition, the restrictions on the incurrence of additional indebtedness contained in the indentures governing the Senior Unsecured Notes apply only to debt that constitutes indebtedness under the indentures.

Estimating reserves and future net revenues involves uncertainties. Negative revisions to reserve estimates, decreases in oil, NGL and natural gas prices or increases in service costs, may lead to decreased earnings and increased losses or impairment of oil and natural gas properties.

The reserves data included in this Annual Report represent estimates. Reserves estimation is a subjective process of evaluating underground accumulations of oil, NGL and natural gas that cannot be measured in an exact manner. Reserves that are "proved reserves" are those estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions and that relate to specific locations for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain will commence within a five-year period.

The estimation process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including more rapid production declines than previously expected and many other factors beyond the control of the operator. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. Production declines may be rapid and irregular when compared to a well's initial production or initial estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct.

For the year ended December 31, 2018, our positive revision of 2,173 MBOE of previously estimated quantities consisted of (i) 11,364 MBOE of negative revisions from performance driven mainly by steeper oil decline curves and tighter well spacing, and a decrease in the Realized Price for natural gas, (ii) 7,045 MBOE of positive revisions from increases in the Realized Prices for oil and NGL and other changes to proved developed producing wells and (iii) 6,492 MBOE of positive revisions due to proved undeveloped locations that were removed from the development plan in prior years. However, in both 2014 and 2015, the Company had negative revisions of estimated quantities, primarily due to a sharp decline in commodity prices. It is possible that the Company will have negative revisions of its reserves in the future.

Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depletion on the affected properties, which decrease earnings or result in losses through higher depletion expense. These revisions, as well as revisions in the assumptions of future cash flows of these reserves, may also trigger impairment losses on certain properties, which would result in a non-cash charge to earnings. See Note 18.d to our consolidated financial statements included elsewhere in this Annual Report.

Unless we replace our oil, NGL and natural gas production, our reserves and production will continue to decline, which would adversely affect our future cash flows and results of operations.

Producing oil, NGL and natural gas reservoirs are generally characterized by rapidly declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration, development and exploitation activities and/or continually acquire properties containing proved reserves, our proved reserves will continue to decline as those reserves are produced. Our future oil, NGL and natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

As a result of the volatility in prices for oil, NGL and natural gas, we have taken and may be required to take further write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we have been required to, and may be required to further, write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings.

Our unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling as of March 31, 2016 and as a result, we recorded a non-cash full cost ceiling impairment of $161.1 million for the year ended December 31, 2016, but did not record any similar impairments for the years ended December 31, 2018 or 2017. If prices remain at or below the current low levels, subject to numerous factors and inherent limitations, and all other factors remain constant, it is possible we would incur a non-cash full cost impairment in 2019, which would have an adverse effect on our results of operations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations-Recent developments" and Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce our cash flow and/or liquidity available for drilling and place us at a competitive disadvantage. For example, as of February 13, 2019 we had an aggregate elected commitment of $1.2 billion with $240.0 million outstanding on our Senior Secured Credit Facility, subject to compliance with financial covenants. The impact of a 1.0% increase in interest rates on an assumed borrowing of the full aggregate elected commitment of $1.2 billion would result in increased annual interest expense of $12.0 million and a decrease in our income before income taxes. Disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in our cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

We receive debt credit ratings from Standard & Poor’s Ratings Group, Inc. ("S&P") and Moody’s Investors Service, Inc. ("Moody's"), which are subject to regular reviews. S&P and Moody’s consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels and asset and reserves mix.

A downgrade in our credit ratings could negatively impact our cost of capital and our ability to effectively execute aspects of our strategy. Further, a downgrade in our credit ratings could affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

We require a significant amount of cash to service our indebtedness. Our ability to generate cash depends on many factors beyond our control.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures depends on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. We cannot assure you that we will generate sufficient cash flow from operations or that future funding will be available to us under our Senior Secured Credit Facility, equity offerings or other actions in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness at or before maturity. We cannot assure you that we will be able to refinance any of our indebtedness on commercially reasonable terms or at all.

The marketability of our production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues reduced.

The marketability of our oil, NGL and natural gas production depends on a variety of factors, including the availability, proximity, capacity and quality constraints of transportation, compression, natural gas processing, fractionation and storage facilities owned by us or third parties. We do not control many of the trucks and other third-party facilities necessary for the transportation to market of the products originating at our leases. Our failure to provide or obtain such services on acceptable terms could materially harm our business. In recent years there has been a capacity constraint to move oil, natural gas and NGL out of the Permian Basin. If this constraint continues or gets worse in the future, it could have a negative impact on the price that we get for our oil, natural gas and NGL.

Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil, NGL and natural gas and thereby cause a significant interruption in our operations. The oil pipelines that transport our oil to market have quality specifications, including a Reid

Vapor Pressure ("RVP") specification and oxygen content. While our tank batteries and equipment are designed to deliver oil that meets all pipeline specifications, including RVP, there is a risk that our oil production at any of our tank batteries could have an RVP that exceeds the pipeline specifications. The pipelines have the right under their tariffs to request that oil that does not meet their quality specifications, including RVP, be shut in until such oil is brought within quality specifications. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or specifications or encounter production-related difficulties, we may be required to shut in or curtail production. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil, NGL and natural gas produced from our fields, could materially and adversely affect our financial condition and results of operations.

Any significant reduction in our borrowing base under our Senior Secured Credit Facility as a result of a periodic borrowing base redetermination or otherwise will negatively impact our liquidity and, consequently, our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our Senior Secured Credit Facility or any other obligation if required as a result of a borrowing base redetermination.

Availability under our Senior Secured Credit Facility is currently subject to a borrowing base of $1.3 billion. The borrowing base is subject to scheduled semiannual (May 1 and November 1) and other elective borrowing base redeterminations based upon, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the Senior Secured Credit Facility. The lenders under our Senior Secured Credit Facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Senior Secured Credit Facility. Reductions in estimates of our oil, NGL and natural gas reserves will result in a reduction in our borrowing base (if prices are kept constant). Reductions in our borrowing base could also arise from other factors, including but not limited to:

- lower commodity prices or production;
- increased leverage ratios;
- inability to drill or unfavorable drilling results;
- changes in oil, NGL and natural gas reserves engineering;
- increased operating and/or capital costs;
- the lenders' inability to agree to an adequate borrowing base; or
- adverse changes in the lenders' practices (including required regulatory changes) regarding estimation of reserves.

As of February 13, 2019, we had $945.3 million in available capacity under our Senior Secured Credit Facility. We anticipate borrowing under our Senior Secured Credit Facility in the future. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise will negatively impact our liquidity and our ability to fund our operations and, as a result, would have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our Senior Secured Credit Facility were to exceed the borrowing base as a result of any such redetermination, we could be required to repay the excess. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Competition in the oil and natural gas industry is intense, making it difficult for us to acquire properties, market oil, NGL and natural gas and secure trained personnel.

Our ability to acquire additional locations and to find and develop reserves in the future may depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil, NGL and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil, NGL and natural gas industry, especially in our focus areas. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil, NGL and natural gas properties and exploratory locations and to evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

We may be subject to risks in connection with acquisitions and disposition of assets.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, NGL and natural gas prices and their applicable differentials;
- timing of development;
- capital and operating costs; and
- potential environmental and other liabilities.

The successful disposition of assets requires an assessment of several factors, including historical operations, potential environmental and other liabilities and impact on our business. The accuracy of these assessments is inherently uncertain. Our assessment will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller or buyer may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire or sell assets on an "as is" basis. Even in those circumstances in which we have contractual indemnification rights for pre-closing liabilities, it remains possible that the seller or buyer will not be able to fulfill its contractual obligations. Problems with assets we acquire or dispose of could have a material adverse effect on our business, financial condition and results of operations.

A decrease in our production of oil, NGL and natural gas could negatively impact our ability to meet our contractual obligations to deliver oil, NGL and natural gas and our ability to retain our leases.

A portion of our oil, NGL and gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss or unavailability of pipeline or gathering system access and capacity, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions, including low oil, NGL and gas prices. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow. Furthermore, if we were required to shut in wells, we might also be obligated to pay shut-in royalties to certain mineral interest owners to maintain our leases.

In addition, we have entered into agreements with third party shippers, including Medallion, and purchasers that require us to deliver minimum amounts of oil and natural gas. Pursuant to these agreements, we must deliver specific amounts, either from our own production or from oil we acquire, over the next twelve years. If we are unable to fulfill all of our contractual delivery obligations from our own production, we may be required to pay penalties or damages pursuant to these agreements or we may have to purchase oil from third parties to fulfill our delivery obligations. This could adversely impact our cash flows, profit margins and net income.

Currently, we receive a level of cash flow stability as a result of our hedging activity. To the extent we are unable to obtain future hedges at beneficial prices or our derivative activities are not effective, our cash flows and financial condition may be adversely impacted.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil, NGL and natural gas, we enter into derivative instrument contracts for a portion of our oil, NGL and natural gas production, including puts, swaps, collars, basis swaps and, in the past, call spreads. In accordance with applicable accounting principles, we are required to record our derivatives at fair market value, and they are included in our consolidated balance sheet as assets or liabilities and in our consolidated statements of operations as gain (loss) on derivatives. Gain (loss) on derivatives are included in our cash flows from operating activities. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair market value of our derivative instruments, including a decrease in earnings if the price of commodities increases above the price of hedges that we have in place. As our current hedges expire, there is a significant uncertainty that we will be able to put new hedges in place that satisfy our hedge philosophy.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

In addition, recent government regulation may adversely impact our ability to hedge these risks.

For additional information regarding our hedging activities, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Notes 9 and 10 to our consolidated financial statements included elsewhere in this Annual Report.

The potential drilling locations that we have tentatively internally identified for our future wells will be drilled, if at all, over many years. This makes them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Although our management team has established certain potential drilling locations as a part of our long-range planning related to future drilling activities on our existing acreage, our ability to drill and develop these locations depends on a number of uncertainties, including oil, NGL and natural gas prices, the availability and cost of capital, drilling and production costs, our ability to leverage our data and development experience to drill wells in multi-well packages with tighter spacing, including the impact on longer laterals, the availability of drilling services and equipment, lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential drilling locations we have currently identified will ever be drilled or if we will be able to produce oil, NGL or natural gas from these or any other potential drilling locations. As such, it is likely that our actual drilling activities, especially in the long term, could materially differ from those presently anticipated.

Our use of 2D and 3D seismic, analytics and other data is subject to interpretation and may not accurately identify the presence of oil, NGL and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2D and 3D seismic data, analytics and other data that provide either visualization techniques and/or statistical analyses are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures or the amount of hydrocarbons. We employ 3D seismic technology on certain of our projects. The implementation and practical use of 3D seismic technology is relatively unproven, which can lessen its effectiveness, at least in the near term, and increase our costs. In addition, the use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and exploration expenses as a result of such expenditures, which may result in a reduction in our returns. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

We often gather 3D seismic data over large areas. Our interpretation of seismic data delineates those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, we will have made substantial expenditures to acquire and analyze 3D data without having an opportunity to attempt to benefit from those expenditures.

The inability of our significant customers to meet their obligations to us may materially adversely affect our financial results.

In addition to credit risk related to receivables from the fair values of open derivative contracts of $50.9 million, our principal exposure to credit risk is through (i) the sale of our oil, NGL and natural gas production ($45.0 million in receivables as of December 31, 2018), which we market to energy marketing companies, refineries and affiliates, (ii) the sale of purchased oil and other products ($10.2 million in receivables as of December 31, 2018) and (iii) net joint operations receivables ($16.8 million as of December 31, 2018). Joint interest receivables arise from billing entities who own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We are generally unable to control which co-owners participate in our wells. We are also subject to credit risk due to the concentration of our oil, NGL and natural gas sales receivables and our sales of purchased oil receivables with several significant customers. The four largest purchasers of our oil, NGL and natural gas production accounted for 29.5%, 24.2%, 16.2% and 16.0% of our total oil, NGL and natural gas sales for the year ended December 31, 2018. We had two customers that accounted for 63.9% and 36.1% of our total sales of purchased oil for the year ended December 31, 2018. See Note 13 to our consolidated financial statements included elsewhere in this Annual Report for additional information. The inability or failure of our significant customers or joint working interest owners to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial results. Current economic circumstances may further increase these risks. See "Item 3. Legal Proceedings" for a discussion of Shell's breach and wrongful termination of the crude oil purchase agreement entered into between Shell and Laredo effective October 1, 2016 through June 30, 2020.

The unavailability or high cost of additional oilfield services, including personnel, drilling rigs, equipment and supplies, as well as fees for the cancellation of such services, could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for and availability of qualified and experienced personnel to drill and complete wells and conduct field operations (including, but not limited to, frac crews), geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, NGL and natural gas prices, causing periodic shortages. From time to time, there have also been shortages of drilling and workover rigs, pipe, sand, water and equipment as demand for rigs, crews, supplies and equipment has increased along with the number of wells being drilled. We have committed in the past, and we may in the future commit, to drilling contracts with various third parties that contain penalties for early terminations. These penalties could negatively impact our financial statements upon contract termination. Rig shortages, shortages in completions equipment and crews as well as related fees could result in delays or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

If we are unable to drill new allocation wells, it could have a material adverse impact on our future production results.

In the State of Texas, allocation wells allow an oil and gas producer to drill a horizontal well under two or more leaseholds that are not pooled. We are active in drilling and producing allocation wells. If there are regulatory changes with regard to allocation wells, the RRC denies or significantly delays the permitting of allocation wells or if legislation is enacted that negatively impacts the current process under which allocation wells are permitted, it could have an adverse impact on our ability to drill long horizontal lateral wells on some of our leases, which in turn could have a material adverse impact on our anticipated future production, rates of return and other projected capital efficiencies.

Our oil, NGL and natural gas is sold to a limited number of geographic markets so an oversupply in any of those areas could have a material negative effect on the price we receive.

Our oil, NGL and natural gas is sold to a limited number of geographic markets that each have a fixed amount of storage and processing capacity. As a result, if such markets become oversupplied with oil, NGL and/or natural gas, it could have a material negative effect on the price we receive for our products and therefore an adverse effect on our financial condition. There is a risk that refining capacity in the U.S. Gulf Coast may be insufficient to refine all of the light sweet crude oil being produced in the United States. If light sweet crude oil production remains at current levels or continues to increase, demand for our light crude oil production could result in widening price discounts to the world oil prices and potential shut-in of production due to a lack of sufficient markets despite the lift on prior restrictions on the exporting of oil and natural gas.

Our business could be negatively impacted by disruption of electronic systems, security threats, including cyber-security threats, and other disruptions.

We are heavily dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure or we were subject to cyberspace breaches or attacks, possible consequences include our loss of communication links, inability to find, produce, process and sell oil, NGL and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. In particular, cyber-security attacks are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows.

The loss of senior management or technical personnel and the failure to attract, train and retain qualified personnel could adversely affect our operations.

We have historically depended on our senior management for the general supervision of the Company. As senior management has aged, we have attempted to hire, train and retain younger management personnel, including technical personnel, with the view toward business growth and succession planning. Effective succession planning, which we have recently become more focused on, is important to our long-term success. Failure to ensure effective transfer of knowledge and smooth transitions involving senior management and technical personnel could hinder our strategic planning and execution and could have a material adverse impact on our operations. We do not maintain any key-man or similar insurance for any officer or other employee.

We may not always foresee new operational/technical issues as new technology enables greater operational capabilities.

The unconventional oil and natural gas industry has seen a large increase in new technologies to enhance all aspects of operations. This boon has arguably accelerated as a result of the extended downturn in commodity prices, forcing companies to find new ways to efficiently produce oil and natural gas. While such technologies can and often ultimately enhance operations, production and profitability, the utilization of such technologies, especially in their early phases, may result in unforeseen consequences and operational issues, resulting in negative consequences. As an example, new technologies have resulted in the ability to drill longer horizontal laterals than previously envisioned; however, in certain instances such longer laterals may initially take a longer than projected time to begin flow-back of production, thereby causing us to fail to meet short-term projections, with a resulting negative impact on our stock price.

Our operations are substantially dependent on the availability, use and disposal of water. New legislation and regulatory initiatives or restrictions relating to water disposal wells could have a material adverse effect on our future business, financial condition, operating results and prospects.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. Texas has previously experienced, and may experience again, low inflows of water. As a result of these conditions, some local water districts may begin restricting the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, NGL and natural gas, which could have an adverse effect on our results of operations, cash flows and financial condition.

Additionally, our operational and production procedures produce large volumes of water that we must properly dispose. The Clean Water Act, the Safe Drinking Water Act, the Oil Pollution Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the U.S. Environmental Protection Agency (the "EPA") or the state. Furthermore, the State of Texas maintains groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil, NGL and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs. The RRC adopted new regulations effective in November 2014 that require additional supporting documentation, including records from the U.S. Geological Survey regarding previous seismic events in the area, as part of applications for new disposal wells. The new regulations also clarify the RRC's ability to modify, suspend or terminate a disposal well permit if scientific data indicates it is likely to contribute to seismic activity. The RRC has used this authority to deny permits for waste disposal sites.

Moreover, the EPA is examining regulatory requirements for "indirect dischargers" of wastewater - i.e., those that send their discharges to private or publicly owned treatment facilities, which treat the wastewater before discharging it to regulated waters. On June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

Because of the necessity to safely dispose of water produced during operational and production activities, these regulations, or others like them, could have a material adverse effect on our future business, financial condition, operating results and prospects. See "Item 1. Business—Regulation of environmental and occupational health and safety matters" for a further description of the laws and regulations that affect us.

We have incurred losses from operations for various periods since our inception and may do so in the future.

We incurred net losses from our inception to December 31, 2006 of $1.8 million and for each of the years ended

December 31, 2007, 2008, 2009, 2015 and 2016 of $6.1 million, $192.0 million, $184.5 million, $2.2 billion and $260.7 million, respectively. Our development of and participation in an increasingly larger number of locations has required and will continue to require substantial capital expenditures. The uncertainty and factors described throughout this section may impede our ability to economically find, develop, exploit and acquire oil, NGL and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical accounting policies and estimates."

Our debt agreements contain restrictions that limit our flexibility in operating our business.

Our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes each contain, and any future indebtedness we incur may contain, various covenants that limit our ability to engage in specified types of transactions. These covenants limit our ability to, among other things:

- incur additional indebtedness;
- pay dividends on, repurchase or make distributions in respect of our capital stock or make other restricted payments;
- make certain investments;
- sell certain assets;
- create liens;
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets; and
- enter into certain transactions with our affiliates.

As a result of these covenants and a covenant in our Senior Secured Credit Facility that limits our ability to hedge, we are limited in the manner in which we may conduct our business and we may be unable to engage in favorable business activities or finance future operations or our capital needs. In addition, the covenants in our Senior Secured Credit Facility require us to maintain a minimum current ratio and maximum leverage ratio and also limit our capital expenditures. A breach of any of these covenants could result in a default under one or more of these agreements, including as a result of cross-default provisions and, in the case of our Senior Secured Credit Facility, permit the lenders to cease making loans to us. Upon the occurrence of an event of default under our Senior Secured Credit Facility, the lenders could elect to declare all amounts outstanding under our Senior Secured Credit Facility to be immediately due and payable and terminate all commitments to extend further credit. Such actions by those lenders could cause cross defaults under our other indebtedness, including the Senior Unsecured Notes. If we were unable to repay those amounts, the lenders under our Senior Secured Credit Facility could proceed against the collateral granted to them to secure that indebtedness. We pledged a significant portion of our assets as collateral under our Senior Secured Credit Facility. If the lenders under our Senior Secured Credit Facility accelerate the repayment of the borrowings thereunder, the proceeds from the sale or foreclosure upon such assets will first be used to repay debt under our Senior Secured Credit Facility, and we may not have sufficient assets to repay our unsecured indebtedness thereafter. Our 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 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.

Our producing properties are in a concentrated geographic area, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Permian Basin. At December 31, 2018, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional transportation constraints, supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing capacity constraints, market limitations, water shortages, interruption of the processing or transportation of oil or natural gas, as well as impacts from extreme weather or other natural disasters impacting the Permian Basin.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We could be impacted by the outcome of pending litigation as well as unexpected litigation or proceedings. Certain litigation claims may not be covered under our insurance policies, or our insurance carriers may seek to deny coverage. Because we cannot accurately predict the outcome of any action, it is possible that, as a result of pending and/or unexpected litigation, we will be subject to adverse judgments or settlements that could significantly reduce our earnings or result in losses. See "Item 3. Legal Proceedings" for a description of our pending litigation.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil, NGL and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil, NGL and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- disagreements regarding the royalty due to our royalty owners
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil, NGL and natural gas related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage and associated clean-up responsibilities;
- regulatory investigations, penalties or other sanctions;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The impact of litigation as well as the occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and water disposal wells could prohibit projects or result in materially increased costs and additional operating restrictions or delays because of the significance of hydraulic fracturing and water disposal wells in our business.

Hydraulic fracturing is a practice that is used to stimulate production of oil and/or natural gas from tight formations. The process, which involves the injection of water, proppants and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as "Class II" Underground Injection Control wells under the Safe Drinking Water Act. The EPA has also published air emission standards for certain equipment, processes and activities across the oil and natural gas sector. In addition, the BLM published rules governing hydraulic fracturing on federal and Indian lands, but it subsequently rescinded or revised those rules and litigation is ongoing. See "Item 1. Business—Regulation of environmental and occupational health and safety matters—Hydraulic fracturing" for a further description of federal and state regulations addressing hydraulic fracturing.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, impose additional requirements on hydraulic fracturing activities or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, pursuant to legislation adopted by the State of Texas in June 2011, the chemical components used in the hydraulic fracturing process, as well as the volume of water used, must be disclosed to the RRC and the public beginning February 1, 2012. Furthermore, on May 23, 2013, the RRC issued the "well integrity rule," which updates the RRC's Rule 13 requirements for drilling, putting pipe down and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit to the RRC cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The "well integrity rule" took effect in January 2014. Additionally, in 2014 the RRC adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments, which became effective in November 2014, also clarify the RRC's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The RRC has used this authority to deny permits for waste disposal wells. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted or laws or regulations are adopted to restrict water disposal wells, such laws could make it more difficult or costly for us to drill and produce from conventional or tight formations as well as make it easier for third parties opposing the oil, NGL and natural gas industry to initiate legal proceedings. In addition, if these matters are regulated at the federal level, fracturing and disposal activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also result in permitting delays and potential other increases in costs. These developments, as well as new laws or regulations, could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation or regulations governing hydraulic fracturing or water disposal wells are enacted into law.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing-related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. See "Item 1. Business—Regulation of environmental and occupational health and safety matters—Hydraulic fracturing" for a further description of local regulations addressing seismic activity.

We dispose of large volumes of produced water gathered from our drilling and production operations by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to use hydraulic fracturing or dispose of produced water gathered from our drilling and production activities by owned disposal wells could have a material adverse effect on our business, financial condition and results of operations.

We are subject to other complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

In addition to the specific laws and regulations discussed elsewhere herein, our oil, NGL and natural gas exploration, production and gathering operations are subject to numerous other complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations.

See "Item 1. Business—Regulation of the oil and natural gas industry" and other risk factors described in this "Item 1A. Risk Factors" for a further description of the laws and regulations that affect us.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938 (the "NGA") exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("FERC"). We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish whether a pipeline performs a gathering function and, therefore, is exempt from the FERC's jurisdiction under the NGA. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is a fact-based determination. The classification of facilities as unregulated gathering is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress, which could cause our revenues to decline and operating expenses to increase and may materially adversely affect our business, financial condition or results of operations. In addition, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, which could have a material adverse effect on our business, financial condition or results of operations.

The adoption of climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil, NGL and natural gas we produce.

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases. The EPA has finalized a series of greenhouse gas monitoring, reporting and emission control rules for the oil and natural gas industry, and Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of greenhouse gases primarily through the development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs.

In December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement went into effect on November 4, 2016. The Paris Agreement establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil, NGL and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that GHG emissions from oil, NGL and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While we are currently not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development, marketing, transportation and production activities. These laws and regulations may require us to obtain a variety of permits or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, production and transporting product pipelines or other operations; regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier, seismically active areas and other protected areas; require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, the issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, accidental spills or releases from our operations could expose us to significant liabilities under environmental laws. Moreover, public interest in the protection of the environment has tended to increase over time. The trend of more expansive and stringent environmental legislation and regulations applied to the oil, NGL and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental actions are taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

See "Item 1. Business—Regulation of environmental and occupational health and safety matters" for a further description of the laws and regulations that affect us.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission (the "CFTC"), the SEC, and federal regulators of financial institutions (the "Prudential Regulators") adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities.

Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC, the SEC and the Prudential Regulators have issued many rules to implement the Dodd-Frank Act, including a rule, which we refer to as the "Mandatory Clearing Rule," requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, which we do not presently have), a rule, which we refer to as the "End User Exception," establishing an "end user" exception to the Mandatory Clearing Rule, a rule, which we refer to as the "Margin Rule," setting forth collateral requirements in connection with swaps that are not cleared and also an exception to the Margin Rule for end users that are not financial end users, which exception we refer to as the "Non-Financial End User Exception," and a rule, subsequently vacated by the United States District Court for the District of Columbia and remanded to the CFTC for further proceedings, imposing position limits. The CFTC proposed a new version of this rule, with respect to which the comment period closed but the rule was not adopted, and another new version of this rule, which we refer to as the "Re-Proposed Position Limit Rule," with respect to which the comment period has closed but a final rule has not been issued. The Re-Proposed Position Limit Rule provides an exemption from the position limits for swaps that constitute "bona fide hedging positions" within the definition of such term under the Re-Proposed Position Limit Rule, subject to the party claiming the exemption complying with the applicable filing, recordkeeping and reporting requirements of the Re-Proposed Position Limit Rule.

We qualify for the End User Exception and will utilize it if the Mandatory Clearing Rule is expanded to cover swaps in which we participate, we qualify for the Non-Financial End User Exception and will not be required to post margin in connection with uncleared swaps under the Margin Rule, and our existing and anticipated hedging positions constitute "bona fide hedging positions" under the Re-Proposed Position Limit Rule and we intend to undertake the filing, recordkeeping and reporting necessary to utilize the bona fide hedging position exemption under the Re-Proposed Position Limit Rule if and when it becomes effective, so we do not expect to be directly affected by any of such rules. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End User Exception and will be required to post margin in connection with their hedging activities with other swap dealers, major swap participants, financial end users and other persons that do not qualify for the Non-Financial End User Exception. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations (including laws and regulations giving the European Union financial authorities the power to write down amounts we may be owed on hedging agreements with counterparties subject to such laws and regulations and/or require that we accept equity interests in such counterparties in lieu of cash in satisfaction of such amounts), which we refer to collectively as "Foreign Regulations," which may apply to our transactions with counterparties subject to such Foreign Regulations, which we refer to as "Foreign Counterparties." The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Re-Proposed Position Limit Rule is effected, such proposed rule could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. The Foreign Regulations could have similar effects. We have stopped entering into new hedging transactions with Foreign Counterparties and do not currently intend to resume hedging with Foreign Counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations and Foreign Regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

A significant reduction by Warburg Pincus of its ownership interest in us could adversely affect us.

Warburg Pincus is our largest stockholder and two members of our board of directors are affiliates of Warburg Pincus. As of December 31, 2018, Warburg Pincus owned 21.9% of our outstanding common stock. We believe that Warburg Pincus' substantial ownership interest in us provides them with an economic incentive to assist us to be successful. However, Warburg Pincus is not obligated to maintain its ownership interest in us and may elect at any time to change its ownership position in our stock. If Warburg Pincus sells all or a substantial portion of its ownership interest in us, Warburg Pincus may have less incentive to assist in our success and its affiliates that are members of our board of directors may resign. Such actions could adversely affect our ability to successfully implement our business strategies, which could adversely affect our cash flows or results of operations.

Tax laws and regulations may change over time, and the comprehensive tax reform bill could adversely affect our business and financial condition.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act") that significantly reformed the Internal Revenue Code of 1986, as amended (the "Code"). The Tax Act, among other things, (i) reduces the U.S. corporate income tax rate, (ii) repeals the corporate alternative minimum tax, (iii) eliminates the deduction for certain domestic production activities, (iv) imposes new limitations on the utilization of net operating losses, and (v) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and gas companies. The Tax Act is complex and far-reaching and we cannot predict with certainty the resulting impact its enactment has on us. The ultimate impact of the Tax Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued and any such changes in interpretations or assumptions could adversely affect our business and financial condition. See Note 12 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

In addition, from time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including (i) the elimination of the immediate deduction for intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties and (iii) an extension of the amortization period for certain geological and geophysical expenditures. While these specific changes are not included in the Tax Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could adversely affect our business and financial condition.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income. In addition, our ability to use net operating loss carryforwards to reduce future tax payments may be limited if our taxable income does not reach sufficient levels.

As of December 31, 2018, we had federal net operating loss ("NOL") carry-forwards totaling $1.9 billion. If we were to experience an "ownership change," as determined under Section 382 of the Code, our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOL we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Code) at any time during a rolling three-year period. In addition, as a result of the Tax Act, NOL arising before January 1, 2018, and NOL arising on or after January 1, 2018, are subject to different rules. NOL arising before January 1, 2018, can generally be carried forward to offset future taxable income for a period of 20 years. Any NOL arising on or after January 1, 2018, while subject to additional limitations, can generally be carried forward indefinitely. Our ability to use our NOL during this period will be dependent on our ability to generate taxable income, and the NOL could expire before we generate sufficient taxable income. As of December 31, 2018, based on evidence available to us, including projected future cash flows from our oil, NGL and natural gas reserves and the timing of those cash flows, we believe a portion of our NOL is not fully realizable. As a result, as of December 31, 2018, a valuation allowance has been recorded against our NOL tax assets. See Note 12 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil, NGL and natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect threatened or endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

Risks relating to our common stock

The concentration of our capital stock ownership among our largest stockholder will limit other stockholders' ability to influence corporate matters.

As of December 31, 2018, Warburg Pincus owned 21.9% of our outstanding common stock. Consequently, Warburg Pincus has significant influence over all matters that require approval by our stockholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership limits the ability of other stockholders to influence corporate matters.

Furthermore, conflicts of interest could arise in the future between us, on the one hand, and Warburg Pincus and its affiliates, including its portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities. Warburg Pincus LLC is a private equity firm that has invested in, among other things, companies in the energy industry. As a result, Warburg Pincus' existing and future portfolio companies which it controls may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.

We have also renounced our interest in certain business opportunities. Our amended and restated certificate of incorporation provides that, to the fullest extent permitted by applicable law, we renounce any interest or expectancy in any business opportunity, transaction or other matter in which Warburg Pincus or any private fund that it manages or advises, any of their respective officers, directors, partners and employees, and any portfolio company in which such persons or entities have an equity interest (other than us and our subsidiaries) (each, a "specified party") participates or desires or seeks to participate and that involves any aspect of the energy business or industry, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such specified party shall be liable to us for breach of any fiduciary or other duty, as a director or officer or controlling stockholder or otherwise, by reason of the fact that such specified party pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us. Notwithstanding the foregoing, we do not renounce any interest or expectancy in any business opportunity, transaction or other matter that is offered in writing solely to (i) one of our directors or officers who is not also a specified party or (ii) a specified party who is one of our directors, officers or employees and is offered such business opportunity solely in his or her capacity as our director, officer or employee. By renouncing our interest and expectancy in any business opportunity that from time to time may be presented to Warburg Pincus and its affiliates, our business and prospects could be adversely affected if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

Our amended and restated certificate of incorporation, amended and restated bylaws, and Delaware state law contain provisions that may have the effect of delaying or preventing a change in control and may adversely affect the market price of our capital stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without any further vote or action by the stockholders. The rights of the holders of our common stock will be subject to the rights of the holders of any preferred stock that may be issued in the future. The issuance of preferred stock could delay, deter or prevent a change in control and could adversely affect the voting power or economic value of our shares.

In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- limitations on the ability of our stockholders to call special meetings;
- a separate vote of 75% of the voting power of the outstanding shares of capital stock in order for stockholders to amend the bylaws in certain circumstances;
- our board of directors is divided into three classes with each class serving staggered three-year terms;
- stockholders do not have the right to take any action by written consent; and
- advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who owns 15% of our stock cannot acquire us for a period of three years from the date such stockholder became an interested stockholder, unless various conditions are met, such as the approval of the transaction by our board of directors. Warburg Pincus, however, is not subject to this restriction. Provisions such as these are also not favored by various institutional investor services, which may periodically "grade" us on various factors, including stockholder rights and corporate governance policies. Certain institutional investors may have internal policies that prohibit investments in companies receiving a certain grade level from such services, and if we fail to meet such criteria, it could limit the number or type of certain investors which might otherwise be attracted to an investment in the Company, potentially negatively impacting the public float and/or market price of our common stock.

The availability of shares for sale in the future could reduce the market price of our common stock.

Our board of directors has the authority, without action or vote of our stockholders, to issue our authorized but unissued shares of common stock. In the future, we may issue securities to raise cash for acquisitions, to pay down debt, to fund capital expenditures or general corporate expenses, in connection with the exercise of stock options or to satisfy our obligations under our incentive plans. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our Company, reduce our earnings per share and have an adverse impact on the price of our common stock.

We cannot guarantee that our previously announced share repurchase program will be fully consummated or that it will enhance long-term stockholder value. Share repurchases could also increase the volatility of the trading price of our common stock and could diminish our cash reserves.

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. As of December 31, 2018, we had repurchased 11,048,742 shares of common stock at a weighted-average price of $8.78 per common share for a total of $97.1 million under this program. 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. Although our board of directors has authorized this share repurchase program, the program does not obligate us to repurchase any specific dollar amount or to acquire any specific number of shares. The timing and actual number of shares repurchased, if any, will depend upon several factors, including market conditions, business conditions, the trading price of our common stock and the nature of other investment opportunities available to us. The share repurchase program may be limited, suspended or discontinued at any time without prior notice. The share repurchase program could affect the trading price of our common stock and increase volatility, and any announcement of a termination of this program may result in a decrease in the trading price of our common stock. In addition, the share repurchase program could diminish our cash reserves.

Because we have no plans to pay and are currently restricted from paying dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 2. ***Properties***

The information required by Item 2. is contained in "Item 1. Business".

Item 3. ***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 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. 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 last day before Shell's wrongful termination of 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 consolidated balance sheets located elsewhere in this Annual Report do not include any amounts for damage claims or attorneys' fees sought by Shell. As of December 31, 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 4. ***Mine Safety Disclosures***

Not applicable.

Part II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Market for Registrant's Common Equity. Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "LPI." On February 13, 2019, the last sale price of our common stock, as reported on the NYSE, was $3.79 per share.

Holders. As of February 11, 2019, there were 38 holders of record of our common stock.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our Senior Secured Credit Facility and the indentures governing our Senior Unsecured Notes restrict the payment of cash dividends on our common stock. See "Item 1A. Risk Factors—Risks related to our business—Our debt agreements contain restrictions that limit our flexibility in operating our business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Cash flows—Debt." We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Purchases of Equity Securities.

The following table summarized 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)
October 1, 2018 - October 31, 2018	960	$ 7.62	—	$ 102,945,283
November 1, 2018 - November 30, 2018	—	$ —	—	$ 102,945,283
December 1, 2018 - December 31, 2018	—	$ —	—	$ 102,945,283
Total	960			

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(1) Represents shares that were 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. 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 our common stock and the nature of other investment opportunities available to us.

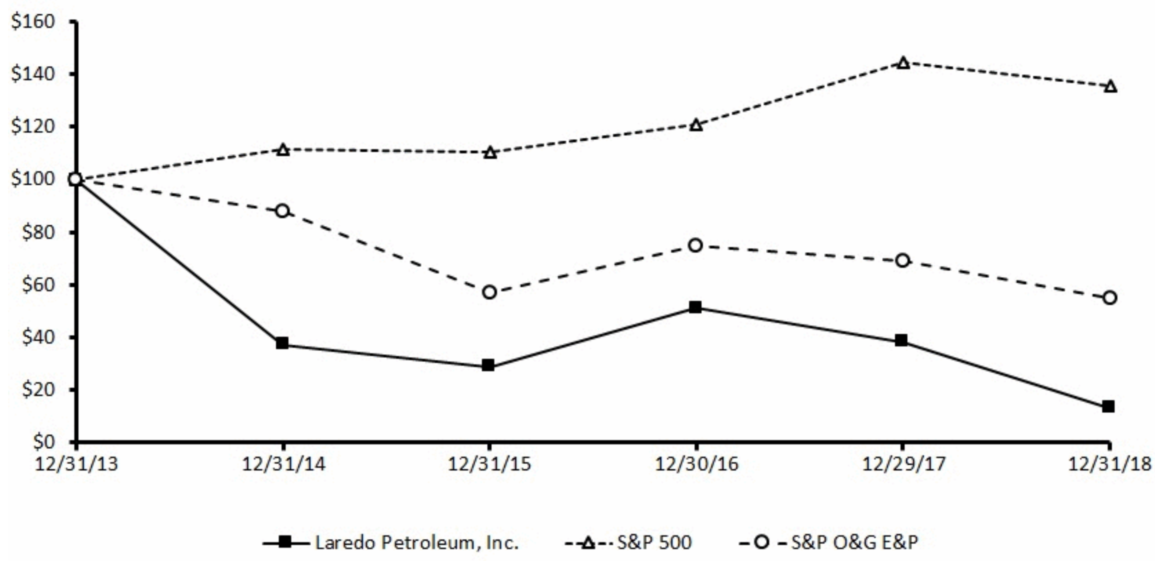
Unregistered Sales of Equity Securities and Use of Proceeds. None.

Stock Performance Graph. The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or Exchange Act, except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

The performance graph below compares the cumulative five-year total returns to our common stockholders relative to the cumulative total returns on the Standard and Poor's 500 Index (the "S&P 500") and the Standard and Poor's Oil & Gas Exploration & Production Select Industry Index (the "S&P O&G E&P"). The comparison was prepared based upon the following assumptions:

1. $100 was invested in our common stock, the S&P 500 and the S&P O&G E&P from December 31, 2013 to December 31, 2018; and

2. Dividends, if any, are reinvested.



Item 6. ***Selected Historical Financial Data***

The selected historical consolidated financial data presented below is not intended to replace our consolidated financial statements. This data should be read along with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included elsewhere in this Annual Report. We believe that the assumptions underlying the preparation of our financial statements are reasonable. The financial information included in this Annual Report may not be indicative of our future results of operations, financial position or cash flows.

Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the years ended December 31, 2018, 2017 and 2016 and the balance sheet data as of December 31, 2018 and 2017 are derived from our consolidated financial statements and the notes thereto included elsewhere in this Annual Report. The historical financial data for the years ended December 31, 2015 and 2014 and the balance sheet data as of December 31, 2016, 2015 and 2014 are derived from our consolidated financial statements not included in this Annual Report.

	For the years ended December 31,				
(in thousands, except per share data)	**2018**	**2017**	**2016**	**2015**	**2014**
Statement of operations data:					
Total revenues	$ 1,105,775	$ 822,162	$ 597,378	$ 606,640	$ 793,885
Total costs and expenses(1)	757,283	572,490	685,340	3,078,154	567,499
Operating income (loss)	348,492	249,672	(87,962)	(2,471,514)	226,386
Non-operating income (expense), net	(19,648)	301,102	(172,777)	84,633	203,473
Income (loss) before income taxes	328,844	550,774	(260,739)	(2,386,881)	429,859
Total income tax (expense) benefit	(4,249)	(1,800)	—	176,945	(164,286)
Net income (loss)	$ 324,595	$ 548,974	$ (260,739)	$ (2,209,936)	$ 265,573
Net income (loss) per common share:					
Basic	$ 1.40	$ 2.30	$ (1.16)	$ (11.10)	$ 1.88
Diluted	$ 1.39	$ 2.29	$ (1.16)	$ (11.10)	$ 1.85

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(1) Includes full cost ceiling impairment expense of $161.1 million and $2.4 billion for the years ended December 31, 2016 and 2015, respectively.

	As of December 31,				
(in thousands)	**2018**	**2017**	**2016**	**2015**	**2014(1)**
Balance sheet data:					
Cash and cash equivalents	$ 45,151	$ 112,159	$ 32,672	$ 31,154	$ 29,321
Property and equipment, net	$ 2,199,635	$ 1,768,385	$ 1,366,867	$ 1,200,255	$ 3,354,082
Total assets	$ 2,420,305	$ 2,023,289	$ 1,782,346	$ 1,813,287	$ 3,910,701
Total current liabilities	$ 200,465	$ 277,419	$ 187,945	$ 216,815	$ 353,834
Long-term debt, net	$ 983,636	$ 791,855	$ 1,353,909	$ 1,416,226	$ 1,779,447
Total stockholders' equity	$ 1,174,230	$ 765,579	$ 180,573	$ 131,447	$ 1,563,201

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(1) Amounts have been reclassified to conform to presentation changes made in 2015.

	For the years ended December 31,				
(in thousands)	**2018**	**2017**	**2016**	**2015**	**2014**
Other financial data:					
Net cash provided by operating activities	$ 537,804	$ 384,914	$ 356,295	$ 315,947	$ 498,277
Net cash (used in) provided by investing activities	$ (690,956)	$ 295,050	$ (564,402)	$ (667,507)	$ (1,406,961)
Net cash provided by (used in) financing activities	$ 86,144	$ (600,477)	$ 209,625	$ 353,393	$ 739,852

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 income taxes, depletion, depreciation and amortization, bad debt expense, impairment expense, non-cash stock-based compensation, net, accretion expense, mark-to-market on derivatives, premiums paid for derivatives, interest expense, write-off of debt issuance costs, gains or losses on disposal of assets, income or loss from equity method investee, proportionate Adjusted EBITDA of our equity method investee and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

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

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

For the year ended December 31, 2016, we changed the methodology for calculating Adjusted EBITDA by including adjustments for both accretion expense and our proportionate share of our equity method investee's Adjusted EBITDA. Accordingly, the prior periods' Adjusted EBITDA has been modified for comparability.

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

	For the years ended December 31,				
(in thousands, unaudited)	**2018**	**2017**	**2016**	**2015**	**2014**
Net income (loss)	$ 324,595	$ 548,974	$ (260,739)	$ (2,209,936)	$ 265,573
Plus:					
Income tax expense (benefit)	4,249	1,800	—	(176,945)	164,286
Depletion, depreciation and amortization	212,677	158,389	148,339	277,724	246,474
Bad debt expense	—	—	—	255	342
Impairment expense	—	—	162,027	2,374,888	3,904
Non-cash stock-based compensation, net	36,396	35,734	29,229	24,509	23,079
Accretion expense	4,472	3,791	3,483	2,423	1,787
Restructuring expenses	—	—	—	6,042	—
Mark-to-market on derivatives:					
(Gain) loss on derivatives, net	(42,984)	(350)	87,425	(214,291)	(327,920)
Settlements received for matured derivatives, net	6,090	37,583	195,281	255,281	28,241
Settlements received for early terminations of derivatives, net	—	4,234	80,000	—	76,660
Premiums paid for derivatives	(20,335)	(25,853)	(89,669)	(5,167)	(7,419)
Interest expense	57,904	89,377	93,298	103,219	121,173
Write-off of debt issuance costs	—	—	842	—	124
Gain on sale of investment in equity method investee	—	(405,906)	—	—	—
Loss on disposal of assets, net	5,798	1,306	790	2,127	3,252
Loss on early redemption of debt	—	23,761	—	31,537	—
Buyout of minimum volume commitment	—	—	—	3,014	—
(Income) loss from equity method investee	—	(8,485)	(9,403)	(6,799)	192
Proportionate Adjusted EBITDA of equity method investee[(1)]	—	22,081	20,367	9,383	462
Adjusted EBITDA	$ 588,862	$ 486,436	$ 461,270	$ 477,264	$ 600,210

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

	For the years ended December 31,				
(in thousands, unaudited)	**2018**	**2017**	**2016**	**2015**	**2014**
Income (loss) from equity method investee	$ —	$ 8,485	$ 9,403	$ 6,799	$ (192)
Adjusted for proportionate share of:					
Depreciation and amortization	—	13,596	10,964	4,061	654
Buyout of minimum volume commitment	—	—	—	(1,477)	—
Proportionate Adjusted EBITDA of equity method investee	$ —	$ 22,081	$ 20,367	$ 9,383	$ 462

Item 7. ***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 consolidated financial statements and notes thereto included elsewhere in this 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" and "Item 1A. Risk Factors." All amounts, dollars and percentages presented in this Annual 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 year ended December 31, 2018 included the following:

- Oil, NGL and natural gas sales of $808.5 million, compared to $621.5 million for the year ended December 31, 2017;
- Average daily sales volumes of 68,168 BOE/D, compared to 58,273 BOE/D for the year ended December 31, 2017;
- Net income of $324.6 million, compared to $549.0 million for the year ended December 31, 2017;
- Adjusted EBITDA (a non-GAAP financial measure) of $588.9 million, compared to $486.4 million for the year ended December 31, 2017. See "Item 6. Selected Historical Financial Data" for a reconciliation of Adjusted EBITDA; and
- Proved developed and undeveloped reserves of 238,167 MBOE, compared to 215,883 MBOE for the year ended December 31, 2017. See Note 18.d to our consolidated financial statements included elsewhere in this Annual Report for discussion of changes in our estimated reserve quantities of oil, NGL and natural gas.

Recent developments

Potential future low commodity price impact on our quarterly 2019 full cost ceiling impairment tests

Oil, NGL and natural gas prices decreased in the fourth quarter of 2018 and have remained low in January and February 2019. If prices remain at or below the current low levels, subject to numerous factors and inherent limitations, some of which are discussed below, and all other factors remain constant, it is possible we will incur a non-cash full cost ceiling impairment in 2019, which will have an adverse effect on our results of operations.

There are numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties in future periods. In addition to unknown future commodity prices, other uncertainties include (i) changes in drilling and completion costs, (ii) changes in oilfield service costs, (iii) production results, (iv) our ability, in a low price environment, to strategically drill the most economic locations in our multi-stack horizontal targets, (v) income tax impacts, (vi) potential recognition of additional proved undeveloped reserves, (vii) any potential value added to our proved reserves when testing recoverability from drilling unbooked locations, (viii) revising production curves based on additional data and (ix) the inherent significant volatility in the commodity prices for oil, NGL and natural gas recently exemplified by price changes in recent months.

Each of the above factors is evaluated on a quarterly basis and if there is a material change in any factor it is incorporated into our reserves estimation utilized in our quarterly accounting estimates. We use our reserve estimates to evaluate, also on a quarterly basis, the reasonableness of our resource development plans for our reported reserves. Changes in circumstance, including commodity pricing, economic factors and the other uncertainties described above may lead to changes in our development plans.

We have set forth below a calculation of a potential future impairment of our evaluated oil and natural gas properties. Such implied impairment should not be interpreted to be indicative of our development plan or of our actual future results. Each of the uncertainties noted above has been evaluated for material known trends to be potentially included in the estimation of possible first-quarter effects. Based on such review, we determined that the impact of decreased commodity prices is the only significant known variable necessary in calculating the following scenario.

Our hypothetical first-quarter 2019 full cost ceiling calculation has been prepared by substituting (i) $57.26 per Bbl for oil, (ii) $20.67 per Bbl for NGL and (iii) $1.29 per Mcf for natural gas (the "Pro Forma First-Quarter Prices") for the respective Realized Prices as of December 31, 2018. All other inputs and assumptions have been held constant. Accordingly, this estimation strictly isolates the estimated impact of lower commodity prices on the first-quarter 2019 Realized Prices that will be utilized in our full cost ceiling calculation. The Pro Forma First-Quarter Prices use a slightly modified Realized Price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for oil, NGL and natural gas for the 11 months ended February 1, 2019, with the price for February 1, 2019 held constant for the remaining twelfth month of the calculation. Based solely on the substitution of the Pro Forma First-Quarter Prices into our December 31, 2018 reserve estimates, we would not have a first-quarter 2019 impairment. Under the same assumptions as above, but reducing the oil price to $50 per Bbl ("Pro Forma Oil Price"), our full cost ceiling would approximately equal our after-tax net book basis to be recovered, implying a potential impairment of our evaluated oil and natural gas properties if the oil Realized Price applied to our reserves decreased below this Pro Forma Oil Price during 2019. We believe that substituting these prices into our December 31, 2018 reserve estimates may help provide users with an understanding of the potential impact on our quarterly 2019 full cost ceiling tests.

See "Item 1A. Risk Factors—Risks related to our business—As a result of the volatility in prices for oil, NGL and natural gas, we have taken and may be required to take further write-downs of the carrying values of our properties." and Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Core area of operations

The oil and liquids-rich Permian Basin is characterized by multiple target horizons, long-lived reserves, high drilling success rates and high initial production rates. As of December 31, 2018, we had assembled 120,617 net acres in the Permian Basin.

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.

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 fluctuations in price and basis differentials for our sales of oil, NGL and natural gas, as discussed in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

The Realized Prices utilized to value our reserves as of December 31, 2018 and December 31, 2017, were $59.29 per Bbl for oil, $21.42 per Bbl for NGL and $1.38 per Mcf for natural gas, and $46.34 per Bbl for oil, $18.45 per Bbl for NGL and $2.06 per Mcf for natural gas, respectively. The Realized Prices used to estimate proved reserves do not include derivative transactions. The unamortized cost of our evaluated oil and natural gas properties did not exceed the full cost ceiling amount as of December 31, 2018 or December 31, 2017. As more specifically addressed in "Recent developments" above, if prices remain at or below the current low levels, subject to numerous factors and inherent limitations, and all other factors remain constant, it is possible we would incur a non-cash full cost impairment in 2019, which would have an adverse effect on our results of operations. See Notes 2.h and 6.a to our consolidated financial statements included elsewhere in this Annual Report for discussion of our full cost method of accounting.

Horizontal drilling of unconventional wells using enhanced completions techniques, including, but not limited to, hydraulic fracturing, is a relatively new process and, as such, forecasting the long-term production of such wells is inherently uncertain and subject to varying interpretations. As we receive and process geological and production data from these wells over time, we analyze such data to confirm whether previous assumptions regarding original forecasted production and reserves continue to appear accurate or require modification. While all production forecasts have elements of uncertainty over the life of the related wells, we are seeing indications that the oil portion of such reserves may be less and the decline curves steeper than originally anticipated.

Initial production results, production decline rates, well density, completion design and operating method are examples of the numerous uncertainties and variables inherent in the estimation of proved reserves in future periods. The quantity of proved reserves is one of the many variables inherent in the calculation of depletion. Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depletion on the affected properties, which decreases earnings and increases losses through higher depletion expense. We have experienced increased depletion per BOE sold for each of the quarters of 2018.

The table below presents our depletion per BOE sold for the periods presented:

	For the years ended December 31,		
	2018	2017	2016
Depletion per BOE sold	$ 7.90	$ 6.75	$ 7.39

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. See Notes 2.n and 5.b to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our revenue recognition policies.

The following table presents our sources of revenue as a percentage of total revenues:

	For the years ended December 31,		
	2018	2017	2016
Oil sales	55%	54%	53%
NGL sales	13%	13%	10%
Natural gas sales	5%	9%	9%
Midstream service revenues	1%	1%	1%
Sales of purchased oil	26%	23%	27%
Total	100%	100%	100%

Principal components of our cost structure

Lease operating expenses. These are daily costs incurred to bring oil, NGL and natural gas out of the ground and to market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and non-routine workover expenses related to our oil and natural gas properties.

Production and ad valorem taxes. Production taxes are based on and fluctuate in proportion to our oil, NGL and natural gas sales revenues, and are established by federal, state or local taxing authorities. We take full advantage of all credits and exemptions in our various taxing jurisdictions. 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 are the costs incurred to transport a portion of our production to the U.S. Gulf Coast market.

Midstream service expenses. These are 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. These are costs incurred for 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, the amount of volumes purchased and fluctuations in transportation fees.

General and administrative ("G&A"). These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other fees for professional services, legal compliance and compensation expense related to employee and director stock awards, option awards and performance share awards with market criteria, which have been recognized on a straight-line basis over the vesting period associated with the award, and performance share awards with performance criteria, which have been recognized based on an estimated probability of how many shares will be earned at the end of the performance period with expense trued-up at each reporting period. The 2013 performance unit awards' fair value was re-measured at the end of each reporting period until settlement in first-quarter 2016. See Note 8.c to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our stock-based compensation.

Depletion, depreciation and amortization ("DD&A"). Under the full cost method of accounting for our oil and natural gas properties, we capitalize all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for or developing oil and natural gas properties and then systematically expense those costs on a unit-of-production basis based on proved oil, NGL and natural gas reserve quantities. Unevaluated costs and related carrying costs are excluded from the depletion base until the properties associated with these costs are evaluated. The depletion base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. We calculate depreciation on our midstream service assets and other fixed assets utilizing the straight-line method based on estimated useful lives of the assets or, in the case of leasehold improvements, over the shorter of the estimated useful lives of the assets or the terms of the related leases. See Note 6 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the DD&A of our property and equipment.

Impairment expense. Impairment of our oil and natural gas properties is based principally on the estimated future net revenues from our proved oil and natural gas properties discounted at 10%. Our Realized Prices are utilized to calculate the discounted future net revenues in our full cost ceiling calculation. In the event the unamortized cost of our evaluated oil and natural gas properties being depleted exceeds the full cost ceiling as defined by the SEC, the excess is charged to expense in the period such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible. With the continuing volatility in commodity prices, we may incur additional write-downs on our oil and natural gas properties. See Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our full cost ceiling calculation.

Impairment losses are recorded on long-lived assets when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. Materials and supplies inventory used in production activities of oil and natural gas properties and midstream service assets, frac pit water inventory used in developing oil and natural gas properties and line-fill in third-party pipelines are carried at the lower of cost or net realizable value ("NRV") with costs determined using the weighted-average cost method. See Notes 2.i, 6.b and 10.b to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our inventory and long-lived assets.

Other operating expenses. These costs include accretion expense due to the passage of time on our asset retirement obligations for the years ended December 31, 2018, 2017 and 2016 and firm transportation payments on excess pipeline capacity and other contractual penalties for the years ended December 31, 2017 and 2016. See Notes 2.k and 14.d to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our asset retirement obligations and firm transportation payments on excess pipeline capacity and other contractual penalties, respectively.

Non-operating income (expense)

Gain (loss) on derivatives, net. We utilize derivatives to reduce our exposure to fluctuations in commodity prices, commodity transportation costs and differences in commodity prices between where we produce and where we sell our products. This amount represents (i) the recognition of gains and losses associated with our open derivatives as commodity and location differential prices change and contracts expire or new contracts are entered into, and (ii) our gains and losses on the settlement, termination and modification of these derivatives. We classify these gains and losses as operating activities in our consolidated statements of cash flows. See Notes 9 and 10.a to our consolidated financial statements included elsewhere in this Annual Report for additional information on our derivatives.

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Senior Secured Credit Facility and our Senior Unsecured Notes. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to the lenders and bondholders in interest expense, net of amounts capitalized. In addition, we include the amortization of: (i) debt issuance costs (including origination, amendment and professional fees), (ii) deferred premiums associated with our derivative contracts, (iii) commitment fees and (iv) annual agency fees in interest expense. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt and interest expense.

Other income, net. This represents the interest received on our cash and cash equivalents and sublease income as well as other miscellaneous income. See Note 14.a to our consolidated financials statements included elsewhere in this Annual Report for additional information regarding our sublease income.

Income from equity method investee. We owned 49% of the ownership units in Medallion that was sold on October 30, 2017. Prior to the Medallion Sale, we accounted for this investment under the equity method of accounting with our proportionate share of net income reflected in the consolidated statements of operations as "Income from equity method investee" and the carrying amount reflected in the consolidated balance sheets as "Investment in equity method investee." See

Note 4.c to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the Medallion Sale.

Gain on sale of investment in equity method investee. This represents the difference between the net proceeds received from the Medallion Sale and the book value of Medallion as of October 30, 2017. A portion of this gain was deferred in the amount of our maximum exposure to loss associated with future commitments under the Transportation Services Agreement with a wholly-owned subsidiary of Medallion as of December 31, 2017. In accordance with the modified retrospective approach of adoption to ASC 606, this deferred gain was recognized as an adjustment to the beginning balance of accumulated deficit, presented in the consolidated statements of stockholders' equity for the year ended December 31, 2018. See Notes 4.c and 5.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the Medallion Sale.

Loss on early redemption of debt. This represents the loss on extinguishment recognized in the early redemption of our May 2022 Notes in November 2017 and is the difference between the redemption price and the net carrying amount. See Note 7.c to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the redemption of our May 2022 Notes.

Loss on disposal of assets, net. This represents losses recorded from selling or disposing of midstream service assets, other fixed assets or inventory. Sale proceeds are compared with the recorded net book value of the asset and the appropriate gain (loss) is recorded and the cost and related accumulated depreciation and amortization are removed from the accounts.

Write-off of debt issuance costs. Debt issuance costs, which are stated at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the effective interest and straight-line methods. Write-offs of such costs can occur when borrowing terms change and/or debt has been extinguished. See Note 7.e to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt issuance costs.

Income tax benefit (expense). Income taxes in our financial statements are generally presented on a consolidated basis. We are subject to federal and Oklahoma corporate income taxes and the Texas franchise tax. These taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating losses and tax credit carry-forwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax laws or tax rates is recognized in income in the period that includes the enactment date.

On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realization of the deferred tax assets and adjusts the amount of such allowances, if necessary. We consider all available evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance is needed on either the federal or Oklahoma net operating loss carry-forwards. Such consideration includes (i) our earnings history, (ii) our ability to recover net operating loss carry-forwards, (iii) the existence of significant proved oil, NGL and natural gas reserves, (iv) our ability to use tax planning strategies, (v) our current price protection utilizing oil, NGL and natural gas hedges, (vi) our future revenue and operating cost projections and (vii) the current market prices for oil, NGL and natural gas. See Note 12 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our income taxes.

Results of operations

For the year ended December 31, 2018 as compared to the year ended December 31, 2017, and for the year ended December 31, 2017 as compared to the year ended December 31, 2016

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

The following table presents information regarding our oil, NGL and natural gas sales volumes, revenues and average sales Realized Prices:

	For the years ended December 31,		
	2018	2017	2016
Sales volumes:			
Oil (MBbl)	10,175	9,475	8,442
NGL (MBbl)	7,259	5,800	4,784
Natural gas (MMcf)	44,680	35,972	29,535
Oil equivalents (MBOE)(1)(2)	24,881	21,270	18,149
Average daily sales volumes (BOE/D)(2)	68,168	58,273	49,586
% Oil(2)	41%	45%	47%
Sales revenues (in thousands):			
Oil	$ 605,197	$ 445,012	$ 318,466
NGL	149,843	101,438	56,982
Natural gas	53,490	75,057	51,037
Total oil, NGL and natural gas sales revenues	$ 808,530	$ 621,507	$ 426,485
Average sales Realized Prices(2):			
Oil, without derivatives ($/Bbl)(3)	$ 59.48	$ 46.97	$ 37.73
NGL, without derivatives ($/Bbl)(3)	$ 20.64	$ 17.49	$ 11.91
Natural gas, without derivatives ($/Mcf)(3)	$ 1.20	$ 2.09	$ 1.73
Average price, without derivatives ($/BOE)(3)	$ 32.50	$ 29.22	$ 23.50
Oil, with derivatives ($/Bbl)(4)	$ 55.49	$ 50.45	$ 58.07
NGL, with derivatives ($/Bbl)(4)	$ 20.03	$ 16.91	$ 11.91
Natural gas, with derivatives ($/Mcf)(4)	$ 1.77	$ 2.15	$ 2.20
Average price, with derivatives ($/BOE)(4)	$ 31.72	$ 30.71	$ 33.73

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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.

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

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:

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Settlements (paid) received for matured derivatives:			
Oil	$ (18,631)	$ 35,724	$ 181,401
NGL	(4,466)	(3,368)	—
Natural gas	29,187	5,227	13,880
Total	$ 6,090	$ 37,583	$ 195,281
Premiums paid previously or upon settlement attributable to derivatives that matured during the respective period:			
Oil	$ (21,890)	$ (2,738)	$ (9,669)
Natural gas	(3,385)	(3,070)	—
Total	$ (25,275)	$ (5,808)	$ (9,669)

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 years ended December 31, 2018, 2017 and 2016:

(in thousands)	**Oil**	**NGL**	**Natural gas**	**Total net effect of change**
2016 Revenues	$ 318,466	$ 56,982	$ 51,037	$ 426,485
Effect of changes in average sales Realized Prices	87,572	32,363	12,897	132,832
Effect of changes in sales volumes	38,974	12,093	11,123	62,190
2017 Revenues	445,012	101,438	75,057	621,507
Effect of changes in average sales Realized Prices	127,272	22,882	(39,736)	110,418
Effect of changes in sales volumes	32,913	25,523	18,169	76,605
2018 Revenues	$ 605,197	$ 149,843	$ 53,490	$ 808,530

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 $160.2 million, or 36%, for the year ended December 31, 2018 as compared to 2017, is due to a 27% increase in average oil sales Realized Prices and a 7% increase in oil sales volumes. The increase in oil sales revenue of $126.5 million, or 40%, for the year ended December 31, 2017 as compared to 2016, is due to a 24% increase in average oil sales Realized Prices and a 12% 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 $48.4 million, or 48%, for the year ended December 31, 2018 as compared to 2017, is due to a 25% increase in NGL sales volumes and an 18% increase in average NGL sales Realized Prices. The increase in NGL sales revenue of $44.5 million, or 78%, for the year ended December 31, 2017 as compared to 2016, is due to a 47% increase in average NGL sales Realized Prices and a 21% 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 $21.6 million, or 29%, for the year ended December 31, 2018 as compared to 2017, is due to a 43% decrease in average natural gas sales Realized Prices, partially offset by a 24% increase in natural gas sales volumes. The increase in natural gas sales revenue of $24.0 million, or 47%, for the year ended December 31, 2017 as compared to 2016, is due to a 22% increase in natural gas sales volumes and a 21% increase in average natural gas sales Realized Prices.

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

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Midstream service revenues	$ 8,987	$ 10,517	$ 8,342
Sales of purchased oil	$ 288,258	$ 190,138	$ 162,551

Midstream service revenues. Our midstream service revenues decreased by $1.5 million, or 15%, for the year ended December 31, 2018 as compared to 2017, and increased by $2.2 million, or 26%, for the year ended December 31, 2017 as compared to 2016. These revenues fluctuate and will vary due to oil throughput fees and the level of services provided to third parties.

Sales of purchased oil. These revenues are a function of the volume and price of purchased oil sold to customers and are offset by the increased costs of purchased oil. Sales of purchased oil increased by $98.1 million, or 52%, for the year ended December 31, 2018 as compared to 2017, due to an increase in the volume of purchased oil sold during the second quarter of 2018. Sales of purchased oil increased by $27.6 million, or 17%, for the year ended December 31, 2017 as compared to 2016, mainly due to the increase in oil prices. We enter into purchase transactions with third parties and separate sale transactions with purchasers/customers to diversify a portion of the sales of oil to the U.S. Gulf Coast market. These transactions are presented on a gross basis as we act as the principal in the transaction by assuming control of the commodities purchased and the responsibility to deliver the commodities sold. Revenue is recognized when control transfers to the purchaser/customer at the delivery point based on the price received. The transportation costs associated with these transactions are presented as a component of costs of purchased oil. See "—Costs and expenses - *Costs of purchased oil*."

Costs and expenses

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

	For the years ended December 31,		
(in thousands except for per BOE sold data)	**2018**	**2017**	**2016**
Costs and expenses:			
Lease operating expenses	$ 91,289	$ 75,049	$ 75,327
Production and ad valorem taxes	49,457	37,802	28,586
Transportation and marketing expenses	11,704	—	—
Midstream service expenses	2,872	4,099	4,077
Costs of purchased oil	288,674	195,908	169,536
General and administrative:			
Cash	59,742	60,578	62,527
Non-cash stock-based compensation, net	36,396	35,734	29,229
Depletion, depreciation and amortization	212,677	158,389	148,339
Impairment expense	—	—	162,027
Other operating expenses	4,472	4,931	5,692
Total costs and expenses	$ 757,283	$ 572,490	$ 685,340
Average costs and expenses per BOE sold(1):			
Lease operating expenses	$ 3.67	$ 3.53	$ 4.15
Production and ad valorem taxes	1.99	1.78	1.58
Transportation and marketing expenses	0.47	—	—
Midstream service expenses	0.12	0.19	0.22
General and administrative:			
Cash	2.40	2.85	3.45
Non-cash stock-based compensation, net	1.46	1.68	1.61
Depletion, depreciation and amortization	8.55	7.45	8.17
Total costs and expenses	$ 18.66	$ 17.48	$ 19.18

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

See "— Principal components of our cost structure" for further discussion of the costs and expenses noted below.

Lease operating expenses. Lease operating expenses, which include workover expenses, increased by $16.2 million, or 22%, for the year ended December 31, 2018 compared to 2017 and decreased by $0.3 million for the year ended December 31, 2017 compared to 2016. On a per BOE sold basis, lease operating expenses increased 4% for the year ended December 31, 2018 compared to 2017 due to increased recurring and non-routine workover expenses in 2018. On a per BOE sold basis, lease operating expenses decreased 15% for the year ended December 31, 2017 compared to 2016. The year-over-year 2017 decrease compared to 2016 is due to previous investments in field infrastructure, primarily in four of our production corridors, including water recycling facilities and centralized compression, that lowered expenses and reduced well downtime. 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 $11.7 million, or 31%, for the year ended December 31, 2018 compared to 2017. This change is comprised of a $9.0 million, or 28%, increase in production taxes and a $2.7 million increase in ad valorem taxes for the year ended December 31, 2018 compared to 2017. Production and ad valorem taxes increased by $9.2 million, or 32%, for the year ended December 31, 2017 compared to 2016. This change is comprised of an $8.5 million, or 37%, increase in production taxes and a $0.7 million increase in ad valorem taxes for the year ended December 31, 2017 compared to 2016. Production taxes are based on and fluctuate in proportion to our oil, NGL and natural gas sales revenues. 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 $11.7 million for the year ended December 31, 2018. In July 2018, we began selling produced oil in the U.S. Gulf Coast market with transportation expenses incurred for the delivery of the oil to the customer recognized as transportation and marketing expense. We did not have any comparable transactions during the years ended December 31, 2017 and 2016.

Midstream service expenses. Midstream service expenses decreased $1.2 million, or 30%, for the year ended December 31, 2018 compared to 2017 and remained relatively flat for the year ended December 31, 2017 compared to 2016.

Costs of purchased oil. Costs of purchased oil increased $92.8 million, or 47%, for the year ended December 31, 2018 compared to 2017 due to an increase in the volume of purchased oil during the second quarter of 2018. Costs of purchased oil increased $26.4 million, or 16%, for the year ended December 31, 2017 compared to 2016 mainly due increases in oil prices.

General and administrative ("G&A"). Total G&A remained relatively flat for year ended December 31, 2018 compared to 2017 and increased $4.6 million, or 5%, for the year ended December 31, 2017 compared to 2016 mainly due to an increase in stock-based compensation and professional fees, partially offset by a decrease in salaries, benefits and bonuses, net of amounts capitalized. On a per BOE sold basis, G&A decreased 15% for the year ended December 31, 2018 compared to 2017. Stock-based compensation, net remained relatively flat for the year ended December 31, 2018 compared to 2017, and increased $6.5 million, or 22%, for the year ended December 31, 2017 compared to 2016 as the result of a greater number of performance share awards granted to a larger base of management and employees during the year ended December 31, 2017 compared to 2016. See "— Critical accounting policies and estimates" along with Notes 2.p and 8.c to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our stock and performance-based compensation.

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

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Depletion of evaluated oil and natural gas properties	$ 196,458	$ 143,592	$ 134,105
Depreciation of midstream service assets	10,144	8,939	8,331
Depreciation and amortization of other fixed assets	6,075	5,858	5,903
Total DD&A	$ 212,677	$ 158,389	$ 148,339

DD&A increased by $54.3 million, or 34%, for the year ended December 31, 2018 as compared to 2017 mainly due to increases in the depletion base and production volumes sold. Depletion per BOE increased 17% for the year ended December 31, 2018 compared to 2017. For further discussion on our depletion per BOE see "—Pricing and reserves." DD&A increased by $10.1 million, or 7%, for the year ended December 31, 2017 as compared to 2016 mainly due to an increase in production volumes sold for the year ended December 31, 2017 as compared to 2016.

Impairment expense. Our unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling as of March 31, 2016, and, as a result, we recorded a full cost ceiling impairment of $161.1 million for the year ended December 31, 2016. There were no comparable full cost ceiling impairments recorded during the years ended December 31, 2018 or 2017. For further discussion of our full cost ceiling impairment accounting policy, see Notes 2.h and 6.a to our consolidated financial statements included elsewhere in this Annual Report.

During the year ended December 31, 2016, we reduced materials and supplies inventory by $1.0 million in order to reflect the balance at lower of cost or NRV. There were no comparable inventory impairments during the years ended December 31, 2018 and 2017. For further discussion of long-lived assets and inventory impairment accounting policies, see Notes 10.b and 2.i to our consolidated financial statements included elsewhere in this Annual Report.

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

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Gain (loss) on derivatives, net	$ 42,984	$ 350	$ (87,425)
Interest expense	(57,904)	(89,377)	(93,298)
Other income, net	1,070	805	175
Income from equity method investee (see Note 4.c)	—	8,485	9,403
Gain on sale of investment in equity method investee (see Note 4.c)	—	405,906	—
Loss on early redemption of debt	—	(23,761)	—
Loss on disposal of assets, net	(5,798)	(1,306)	(790)
Write-off of debt issuance costs	—	—	(842)
Non-operating income (expense), net	$ (19,648)	$ 301,102	$ (172,777)

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

(in thousands)	**Year ended December 31, 2018 compared to 2017**	**Year ended December 31, 2017 compared to 2016**
Increase in fair value of derivatives outstanding	$ 78,361	$ 321,239
Decrease in settlements received for matured derivatives, net	(31,493)	(157,698)
Decrease in settlements received for early terminations of derivatives, net	(4,234)	(75,766)
Total change in gain (loss) on derivatives, net	$ 42,634	$ 87,775

The increase 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 year ended December 31, 2017, we 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 hedge restructuring. During the year ended December 31, 2016, we completed a hedge restructuring by early terminating the floors of certain derivative contract collars that resulted in a termination amount to the Company of $80.0 million, which was settled in full by applying the proceeds to pay the premiums on two new derivatives entered into during the hedge restructuring. There were no comparable hedge restructuring amounts for the year ended December 31, 2018.

See Notes 2.f, 9 and 10.a to our consolidated financial statements included elsewhere in this Annual Report and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional information regarding our derivatives.

Interest expense. Interest expense decreased by $31.5 million, or 35%, for the year ended December 31, 2018 compared to 2017 and by $3.9 million, or 4%, for the year ended December 31, 2017 compared to 2016 both mainly due to the early redemption of the May 2022 Notes on November 29, 2017.

Income from equity method investee. For further discussion of the Medallion Sale, see Note 4.c to our consolidated financial statements included elsewhere in this Annual Report.

Gain on sale of investment in equity method investee. For further discussion of the Medallion Sale, see Note 4.c to our consolidated financial statements included elsewhere in this Annual Report.

Loss on early redemption of debt. For additional discussion of the redemption of our May 2022 Notes, see Note 7.c to our consolidation financial statements included elsewhere in this Annual Report.

Loss on disposal of assets, net. Loss on disposal of assets, net, increased by $4.5 million for the year ended December 31, 2018 compared to 2017 and increased by $0.5 million for the year ended December 31, 2017 compared to 2016. 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.

Write-off of debt issuance costs. We wrote-off $0.8 million of debt issuance costs during the year ended December 31, 2016 as a result of changes in the borrowing base and aggregate elected commitment of the Senior Secured Credit Facility. We wrote-off $5.3 million of debt issuance costs during the year ended December 31, 2017 as a result of the early redemption of the May 2022 Notes, which are included in the "Loss on early redemption of debt" line item in the consolidated statements of operations. There were no comparable debt issuance costs written off during the year ended December 31, 2018. See Note 7.e for further discussion of our debt issuance costs.

Income tax benefit (expense). The following table presents income tax benefit (expense):

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Current	$ 807	$ (1,800)	$ —
Deferred	(5,056)	—	—
Total income tax expense	$ (4,249)	$ (1,800)	$ —

Income tax expense of $4.2 million for the year ended December 31, 2018 is comprised of deferred Texas franchise tax expense of $5.1 million offset by a current income tax benefit of $0.8 million due to a Texas franchise tax refund which is a result of differences in estimated versus actual taxable income from the gain on the Medallion Sale. Income tax expense of $1.8 million for the year ended December 31, 2017 is comprised of current Texas franchise tax, mainly as a result of the Medallion Sale.

During the years ended December 31, 2018 and 2017, we determined it was more likely than not that our deferred tax assets were not realizable through future net income. We maintain a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized, and as of December 31, 2018 we have recorded a total valuation allowance of $237.3 million against our federal and Oklahoma deferred tax assets. As such, the effective tax rates for our operations were 1% for the year ended December 31, 2018, and 0% for each of the years ended December 31, 2017 and 2016. Our effective tax rate is affected by changes in tax rates, valuation allowances, recurring permanent differences and by discrete items that may occur in any given year, but are not consistent from year to year. For further discussion of our income taxes, see Note 12 to our consolidated financial statements located elsewhere in this Annual 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 dispositions. 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 the following Notes to our consolidated financial statements included elsewhere in this Annual Report for further discussion regarding our investing and financing activities (i) Notes 4.a and 4.e for our acquisitions of evaluated and unevaluated oil and natural gas properties, (ii) Notes 4.b and 4.d for divestitures of oil and natural gas properties and midstream service assets, (iii) Note 4.c for the Medallion Sale, (iv) Note 7 and 7.c for our debt instruments and the redemption of our May 2022 Notes, respectively, (v) Note 8.a and "Part II. Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" above for our $200.0 million share repurchase program authorized by our board of directors and commenced in February 2018 and (vi) Note 8.b for our equity offerings. We also continuously look for other opportunities to maximize shareholder value.

Due to the inherent volatility in oil, NGL and natural gas prices, commodity transportation costs and differences in the prices of oil, NGL and natural gas between where we produce and where we sell such commodities, 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 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. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" below.

See Note 17.b to our consolidated financial statements included elsewhere in this Annual Report for a summary of open derivative positions as of December 31, 2018 for derivatives that were entered into through February 13, 2019.

See Note 9 to our consolidated financial statements included elsewhere in this Annual Report for information regarding our derivative settlement indexes and a summary of open derivative positions as of December 31, 2018 for derivatives that were entered into through December 31, 2018.

We continually seek to maintain a financial profile that provides operational flexibility. As of December 31, 2018, we had cash and cash equivalents of $45.2 million and available capacity under the Senior Secured Credit Facility of $995.3 million, resulting in total liquidity of $1.04 billion. As of February 12, 2019, we had cash and cash equivalents of $30.0 million and available capacity under the Senior Secured Credit Facility of $945.3 million, resulting in total liquidity of $975.3 million. 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. We expect 2019 to be a transitional year as we tailor our operational cadence and corporate cost structure, including G&A expense, to balance capital expenditures and cash flow from operations.

Cash flows

The following table presents our cash flows:

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Net cash provided by operating activities	$ 537,804	$ 384,914	$ 356,295
Net cash (used in) provided by investing activities	(690,956)	295,050	(564,402)
Net cash provided by (used in) financing activities	86,144	(600,477)	209,625
Net (decrease) increase in cash and cash equivalents	$ (67,008)	$ 79,487	$ 1,518

Cash flows from operating activities

Net cash provided by operating activities increased by $152.9 million, or 40%, from 2017 to 2018, mainly due to increased revenues due to the increase in average sales Realized Prices for oil and NGL and increased sales volumes of all production streams, with additional details included at "—Results of operations," partially offset by a decrease in average sales Realized Prices for natural gas and a decrease of $30.2 million in settlements received for matured and early terminations of derivatives, net of premiums paid.

Net cash provided by operating activities increased by $28.6 million, or 8%, from 2016 to 2017, mainly due to the increased revenues due to the increase in average sales Realized Prices for oil, NGL and natural gas; however, other notable cash changes included (i) a decrease of $169.6 million in settlements received for matured and early terminations of derivatives, net of premiums paid, (ii) an increase in working capital cash inflows of $8.1 million and (iii) a cash outflow of $6.4 million related to the settlement of our last tranche of performance unit awards in first-quarter 2016 with no comparable amount incurred in 2017.

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" included elsewhere in this Annual Report.

Cash flows from investing activities

Net cash provided by investing activities decreased by $986.0 million, or 334%, from 2017 to 2018, and is mainly attributable to (i) proceeds we received from the Medallion Sale in 2017, (ii) an increase in capital expenditures on oil and natural gas properties, (iii) a decrease in proceeds from dispositions of capital assets and (iv) our acquisitions of oil and natural gas properties partially offset by (a) our contributions to Medallion prior to its sale and (b) a decrease in capital expenditures on midstream service assets.

Net cash used in investing activities decreased by $859.5 million, or 152%, from 2016 to 2017, and is mainly attributable to (i) proceeds we received from the Medallion Sale in 2017, (ii) proceeds we received from a divestiture of oil and natural gas properties and (iii) decreased contributions to Medallion. These increases in cash flows were partially offset by an increase in capital expenditures due to our increased capital budget.

See the following Notes to our consolidated financial statements included elsewhere in this Annual Report for further discussion regarding our investing activities (i) Notes 4.a and 4.e our acquisitions of evaluated and unevaluated oil and natural gas properties, (ii) Notes 4.b and 4.d our divestitures of evaluated and unevaluated oil and natural gas properties and midstream service assets and (iii) Note 4.c the Medallion Sale.

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

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Deposit received for potential sale of oil and natural gas properties	$ —	$ —	$ 3,000
Deposit utilized for sale of oil and natural gas properties	—	(3,000)	—
Acquisitions of oil and natural gas properties	(17,538)	—	(124,660)
Capital expenditures:			
Oil and natural gas properties	(673,584)	(538,122)	(360,679)
Midstream service assets	(6,784)	(20,887)	(5,240)
Other fixed assets	(7,308)	(4,905)	(7,611)
Investment in equity method investee (see Note 4.c)	—	(31,808)	(69,609)
Proceeds from disposition of equity method investee, net of selling costs (see Note 4.c)	1,655	829,615	—
Proceeds from dispositions of capital assets, net of selling costs	12,603	64,157	397
Net cash (used in) provided by investing activities	$ (690,956)	$ 295,050	$ (564,402)

Capital expenditures budget

Our board of directors approved a capital expenditures budget of approximately $365.0 million, based on annual benchmark averages of a $53.60 per barrel WTI NYMEX strip price and a $2.90 per MMBtu Henry Hub NYMEX strip price, for calendar year 2019, excluding non-budgeted acquisitions. Our goal is to achieve cash flow neutrality, and therefore, our capital spending in 2019 will ultimately be influenced by commodity price changes, as well as any changes in service costs and drilling and completions efficiencies. 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 from financing activities

Net cash used in financing activities decreased by $686.6 million, or 114%, from 2017 to 2018, and is mainly attributable to (i) our early redemption of debt in 2017, (ii) decreased payments on our Senior Secured Credit Facility, and (iii) increased borrowings on our Senior Secured Credit Facility partially offset by share repurchases under our share repurchase program that commenced in February 2018. During the year ended December 31, 2018, we repurchased 11,048,742 shares of common stock at a weighted-average price of $8.78 per common share for a total of $97.1 million under this program. All shares were retired upon repurchase. As of December 31, 2018, we had authorization remaining to repurchase until its expiration in February 2020, $102.9 million of common stock.

For the year ended December 31, 2017, our net cash flows used in financing activities were the result of (i) the early redemption of our May 2022 Notes, (ii) payments on our Senior Secured Credit Facility, partially offset by borrowings, (iii) the purchase of treasury stock to satisfy employees' tax withholding upon vesting of their stock-based compensation awards and (iv) payments for debt issuance costs as a result of entering into the Fifth Amended and Restated Credit Agreement. The aforementioned increase in the purchase of treasury stock is mainly due to the increase of our stock price at the stock awards' vest dates, which is utilized to determine the taxable compensation, compared to our stock price at the stock awards' grant dates, which is utilized to determine the number of shares of restricted stock awards to be granted.

For the year ended December 31, 2016, our net cash flows provided by financing activities were mainly the result of (i) the combined proceeds from our equity offerings in May and July 2016 and (ii) borrowings on our Senior Secured Credit Facility offset by payments.

See the following Notes to our consolidated financial statements included elsewhere in this Annual Report for further discussion regarding our financing activities (i) Note 7 and 7.c for our debt instruments and the redemption of our May 2022 Notes, respectively, (ii) Note 8.a and "Part II. Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" above for our $200.0 million share repurchase program authorized by our board of directors and commenced in February 2018 and (iii) Note 8.b for our equity offerings.

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

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Borrowings on Senior Secured Credit Facility	$ 210,000	$ 190,000	$ 239,682
Payments on Senior Secured Credit Facility	(20,000)	(260,000)	(304,682)
Early redemption of debt	—	(518,480)	—
Proceeds from issuance of common stock, net of offering costs	—	—	276,052
Share repurchases	(97,055)	—	—
Vested stock exchanged for tax withholding	(4,418)	(7,662)	(1,635)
Proceeds from exercise of stock options	86	397	208
Payments for debt issuance costs	(2,469)	(4,732)	—
Net cash provided by (used in) financing activities	$ 86,144	$ (600,477)	$ 209,625

Debt

As of December 31, 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 December 31, 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 $190.0 million outstanding and was subject to an interest rate of 3.75%. As of December 31, 2018, we had one letter of credit outstanding of $14.7 million under the Senior Secured Credit Facility.

The borrowing base is subject to a semi-annual redetermination occurring by May 1 and November 1 of each year 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.

On October 23, 2018, pursuant to the regular semi-annual redetermination, the lenders reaffirmed the borrowing base of $1.3 billion under our Senior Secured Credit Facility. Our aggregate elected commitment of $1.2 billion remains unchanged.

As defined in the Senior Secured Credit Facility, (i) the Adjusted Base Rate advances under the facility bear interest payable quarterly at an Adjusted Base Rate plus applicable margin, which ranges from 0.25% to 1.25%, based on the ratio of outstanding revolving credit to the borrowing base under the Senior Secured Credit Facility; and (ii) the Eurodollar advances under the facility bear interest, at our election, at the end of one-month, two-month, three-month, six-month or, to the extent available, 12-month interest periods (and in the case of six-month and 12-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate plus an applicable margin, which ranges from 1.25% to 2.25%, based on the ratio of outstanding revolving credit to the borrowing base under the Senior Secured Credit Facility. We are required to pay a quarterly 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.

The Senior Secured Credit Facility is secured by a first-priority lien on our assets and stock, including oil and natural gas properties, constituting at least 85% of the present value of our proved reserves. Further, we are subject to various financial and non-financial covenants. We were in compliance with these covenants for all periods presented.

As of December 31, 2018, we were subject to the following financial ratios on a consolidated basis:

- a current ratio at the end of each calendar quarter, of not less than 1.00 to 1.00; as defined by the Senior Secured Credit Facility, the current ratio represents the ratio of current assets to current liabilities, inclusive of available capacity and exclusive of current balances associated with derivative positions; and
- a leverage ratio as of the last day of each calendar quarter of (a) our total debt (excluding reimbursement obligations in respect of undrawn letters of credit, if no loans are outstanding under the Senior Secured Credit Facility) minus a maximum of $50 million of unrestricted and unencumbered cash and cash equivalents, to (b) "Consolidated EBITDAX," as defined in the Senior Secured Credit Facility, for any period of four consecutive calendar quarters ending on the last day of such applicable calendar quarter of not greater than 4.25 to 1.00.

Our Senior Secured Credit Facility contains various non-financial covenants that limit our ability to:

- incur indebtedness;
- pay dividends and repay certain indebtedness;
- grant certain liens;
- merge or consolidate;
- engage in certain asset dispositions;
- use proceeds for any purpose other than to finance the acquisition, exploration and development of mineral interests and for working capital and general corporate purposes;
- make certain investments;
- enter into transactions with affiliates;
- engage in certain transactions that violate the Employment Retirement Income Security Act of 1974 or the Code or enter into certain employee benefit plans and transactions;
- enter into certain swap agreements or hedge transactions;
- incur, become or remain liable under any operating lease that would cause rentals payable to be greater than $20.0 million in a fiscal year;
- acquire all or substantially all of the assets or capital stock of any person, other than assets consisting of oil and natural gas properties and certain other oil and natural gas related acquisitions and investments; and
- repay or redeem our Senior Unsecured Notes, or amend, modify or make any other change to any of the terms in our Senior Unsecured Notes that would change the term, life, principal, rate or recurring fee, add call or pre-payment premiums, or shorten any interest periods.

As of December 31, 2018, we were in compliance with the terms of our Senior Secured Credit Facility. If an event of default exists under our Senior Secured Credit Facility, the lenders will be able to accelerate the maturity of our Senior Secured Credit Facility and exercise other rights and remedies. As of December 31, 2018, each of the following would be an event of default:

- failure to pay any principal of any note or any reimbursement obligation under any letter of credit when due or any interest, fees or other amount within certain grace periods;
- failure to perform or otherwise comply with the covenants in our Senior Secured Credit Facility and other loan documents, subject, in certain instances, to certain grace periods;
- a representation, warranty, certification or statement in our Senior Secured Credit Facility is incorrect in any material respect when deemed made or confirmed;
- failure to make any payment in respect of any other indebtedness in excess of $50.0 million, any event occurs that permits or causes the acceleration of any such indebtedness or any event of default or termination event under a hedge agreement occurs in which the net hedging obligation owed is greater than $50.0 million;
- voluntary or involuntary bankruptcy or insolvency events involving us or our subsidiary and in the case of an involuntary proceeding, such proceeding remains undismissed and unstayed for the applicable grace period;
- one or more adverse judgments in excess of $50.0 million to the extent not covered by acceptable third-party insurers, are rendered and are not satisfied, stayed or paid for the applicable grace period;
- incurring environmental liabilities that exceed $50.0 million to the extent not covered by acceptable third-party insurers;
- the loan agreement or any other loan paper ceases to be in full force and effect, or is declared null and void, or is contested or challenged, or any lien ceases to be a valid, first-priority, perfected lien;
- failure to cure any borrowing base deficiency in accordance with our Senior Secured Credit Facility;
- a change of control, as defined in our Senior Secured Credit Facility; and
- an "event of default" under the indentures governing our Senior Unsecured Notes.

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. See Note 7.d to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our Senior Secured Credit Facility.

Senior Unsecured Notes. The following table presents principal amounts and applicable interest rates for our outstanding Senior Unsecured Notes as of December 31, 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 7.a and 7.b to our consolidated financial statements included elsewhere in this Annual Report for further discussion of the March 2023 Notes and January 2022 Notes, respectively.

Utilizing a significant portion of the proceeds from the Medallion Sale, we redeemed the May 2022 Notes in full on November 29, 2017. See Note 7.c to our consolidated financial statements included elsewhere in this Annual Report for information regarding the early redemption of the May 2022 Notes.

Obligations and commitments

The following table presents significant contractual obligations and commitments as of December 31, 2018:

(in thousands)	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior Unsecured Notes(1)	$ 47,188	$ 94,375	$ 845,468	$ —	$ 987,031
Firm sale and transportation commitments(2)	66,102	115,315	87,642	96,881	365,940
Senior Secured Credit Facility(3)	—	—	190,000	—	190,000
Asset retirement obligations(4)	3,495	13,762	8,262	31,363	56,882
Lease commitments(5)	3,092	6,307	3,918	4,556	17,873
Derivatives(6)	15,502	1,295	—	—	16,797
Drilling contracts(7)	15,179	1,322	—	—	16,501
Sand purchase and supply agreement(8)	3,858	—	—	—	3,858
Total	$ 154,416	$ 232,376	$ 1,135,290	$ 132,800	$ 1,654,882

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(1) Values presented include both our principal and interest obligations.

(2) As of December 31, 2018, we have 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, we are subject to firm transportation payments on excess pipeline capacity and other contractual penalties. See "Part I. Item 1A. Risk Factors" and Note 14.d to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our firm sale and transportation commitments.

(3) This table does not include future loan advances, repayments, commitment fees or other fees on our Senior Secured Credit Facility as we cannot determine with accuracy the timing of such items. Additionally, this table does not include interest expense as it is a floating rate instrument and we cannot determine with accuracy the future interest rates to be charged. As of December 31, 2018, the principal on our Senior Secured Credit Facility is due on April 19, 2023.

(4) Amounts represent our asset retirement obligation liabilities. See Note 2.k to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our asset retirement obligations.

(5) See Note 14.a to our consolidated financial statements included elsewhere in this Annual Report for a description of our lease obligations.

(6) Represents payments due for deferred premiums on our commodity hedging contracts. See Note 10.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our deferred premiums.

(7) As of December 31, 2018, we have committed to several drilling contracts with third parties to facilitate our drilling plans. The value in the table represents the gross amount that we are committed to pay. However, we will record our proportionate share based on our working interest in our consolidated financial statements as incurred. See Note 14.c to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our drilling contracts.

(8) See Note 14.e to our consolidated financial statements included elsewhere in this Annual Report for discussion of our sand purchase and supply agreement.

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our 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 consolidated financial statements. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements.

In management's opinion, the more significant reporting areas impacted by our judgments and estimates are (i) the choice of accounting method for oil and natural gas activities, (ii) volumes of our reserves of oil, NGL and natural gas, (iii) future cash flows from oil and natural gas properties, (iv) depletion, depreciation and amortization, (v) impairments, (vi) asset retirement obligations, (vii) stock-based compensation, (viii) deferred income taxes, (ix) fair value of assets acquired and liabilities assumed in an acquisition, (x) fair values of derivatives and deferred premiums and (xi) contingent liabilities. As fair value is a market-based measurement, it is determined based on the assumptions that would be used by market participants. These estimates and assumptions are based on management's best judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment. Such estimates and assumptions are adjusted when facts and circumstances dictate. Illiquid credit markets and volatile equity and energy markets have combined to increase the uncertainty inherent in such estimates and assumptions. Management believes its estimates and assumptions to be reasonable under the circumstances. As future events and their effects cannot be determined with precision, actual values and results could differ from these estimates. Any changes in estimates resulting from future changes in the economic environment will be reflected in the financial statements in future periods.

There have been no material changes in our critical accounting policies and procedures during the year ended December 31, 2018. See Note 2 to our consolidated financial statements included elsewhere in this Annual Report for discussion on significant accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full cost method. We use the full cost method of accounting for our oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee 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 related employee 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. If we maintain the same level of production year over year, the depletion expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly.

We exclude 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. We capitalize a portion of our interest costs to 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. See Note 2.h and 6.a to our consolidated financial statements included elsewhere in this Annual Report for discussion of our significant accounting policy for oil and natural gas properties and additional discussion of our full cost method of accounting for oil and natural gas properties, respectively.

Oil, NGL and natural gas reserve quantities and standardized measure of future net revenue

On an annual basis, our independent reserve engineers prepare the estimates of oil, NGL and natural gas reserves and associated future net cash flows. The SEC has defined proved reserves as the estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil, NGL and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material. See Notes 18.d and 18.e to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our net proved oil, NGL and natural gas reserves and standardized measure of discounted future net cash flows, respectively.

Impairment of oil and natural gas 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.

We review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. The full cost ceiling is based principally on the estimated future net revenues from proved oil and natural gas properties discounted at 10%. The SEC guidelines require companies to use the Benchmark Prices. The Benchmark Prices are then adjusted, resulting in the Realized Prices. The Realized Prices are utilized to calculate the discounted future net revenues in the full cost ceiling calculation. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include our estimate of operating and development costs, anticipated production of proved reserves and other relevant data. In the event the unamortized cost of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible. See Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our full cost ceiling impairment recorded during the year ended 2016.

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. Under our oil sales contracts, we sell produced or purchased oil at the delivery point specified in the contract and collect 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 our 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. We recognize revenue at the net price received when control transfers to the purchaser.

From time to time, we engage in transactions in which we sell oil at the lease and subsequently repurchase 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, we 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 we have 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 we repurchase the oil for less than the original selling price, such a transaction will be classified as a lease. If we repurchase 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. We recognize such repurchase expense and any transportation expenses incurred for the delivery of the oil to the final customer in the "Transportation and marketing expenses" line item in the accompanying consolidated statements of operations.

Under certain of our customer contracts, we are subject to firm transportation payments on excess pipeline capacity and other contractual penalties if we fail to deliver contractual minimum volumes to our 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.

Under our natural gas processing contracts, we deliver 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 us for the NGL and residue gas with deductions that may include gathering, compression, processing and transportation fees. In these scenarios, we evaluate whether we are the principal or the agent in the transaction. For existing contracts, we have concluded that we are 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, we recognize revenue based on the net amount of the proceeds received from the midstream processing entity who represents our customer. If for future contracts we were to conclude that we were the principal with the ultimate third party being the customer, we would recognize revenue for those contracts on a gross basis, with gathering, compression, processing, and transportation fees presented as an expense.

Midstream service revenues are generated from oil throughput fees and 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 (collectively, "Midstream Services"), and are recognized over time as the customer benefits from these services when provided.

See Note 5.b to our consolidated financial statements included elsewhere in this Annual Report for discussion of our revenue recognition.

Income taxes

As of December 31, 2018 and 2017, we had a net deferred tax liability of $5.1 million and zero, respectively.

As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which we operate. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items such as derivative instruments, depletion, depreciation and amortization, and certain accrued liabilities for tax and financial accounting purposes. These differences and our net operating loss carry-forwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available negative and positive evidence and our estimate of the impact of the Tax Act, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provision in the consolidated statement of operations.

Under accounting guidance for income taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (i) the more positive evidence is necessary and (ii) the more difficult it is to support a conclusion that a valuation allowance is not needed for all or a portion of the deferred tax asset. Among the more significant types of evidence that we consider are:

- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition;
- the ability to recover our net operating loss carry-forward deferred tax assets in future years;
- the existence of significant proved oil, NGL and natural gas reserves;
- our ability to use tax planning strategies, such as electing to capitalize intangible drilling costs as opposed to expensing such costs;
- current price protection utilizing oil and natural gas hedges;
- future revenue and operating cost projections that indicate we will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures; and
- current market prices for oil, NGL and natural gas.

During 2018, in evaluating whether it was more-likely-than-not that our deferred tax asset was recoverable from future net income, we considered all positive and negative evidence available. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. See Note 12 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our income taxes.

Asset retirement obligations ("ARO")

The ARO represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. Asset retirement obligations associated with the retirement of tangible long-lived assets are recognized as a liability in the period in which they are incurred and become determinable. The associated asset retirement costs are part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related long-lived asset is charged to expense through depletion, or for midstream service assets through depreciation. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and accretion expense.

The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, which converts future cash flows into a single discounted amount. Significant inputs to the valuation include: (i) estimated plug and abandonment cost per well based on our experience and estimated remaining life per well, (ii) estimated removal and/or remediation costs for midstream service assets and estimated remaining life of midstream service assets, (iii) future inflation factors and (iv) our average credit-adjusted risk-free rate. Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including, in addition to those noted above, the ultimate settlement of these amounts, the ultimate timing of such settlement and changes in legal, regulatory and environmental matters. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, an adjustment will be made to the asset balance.

We are obligated by contractual and regulatory requirements to remove certain pipeline and gathering assets and perform other remediation of the sites where such pipeline and gathering assets are located upon the retirement of those assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminate. We will record an asset retirement obligation for pipeline and gathering assets in the periods in which settlement dates are reasonably determinable. See Note 2.k to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our asset retirement obligations.

Derivatives

Derivatives are recorded at fair value and are presented on a net basis on the "Derivatives" line items on the consolidated balance sheets as assets and/or liabilities. We present the fair value of derivatives net by counterparty where the right of offset exists. We determine the fair value of its derivatives by utilizing pricing models for substantially similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Our derivatives were not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized in the 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. See Notes 9 and 10.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of derivatives and the fair value measurement of derivatives, respectively.

Compensation awards

Stock-based compensation expense, net, is included in the "General and administrative" line item in our consolidated statements of operations over the awards' vesting periods and is based on the awards' grant date fair value. We utilize the closing stock price on the grant date, less an expected forfeiture rate, to determine the fair values of service vesting restricted stock awards and a Black-Scholes pricing model to determine the fair values of service vesting restricted stock option awards. We utilize a Monte Carlo simulation prepared by an independent third party to determine the fair values, less an expected forfeiture rate, of the performance share awards with market criteria and, in prior periods, the performance unit awards. For performance share awards with performance criteria, the grant-date fair value is equal to our stock price on the grant date, less an expected forfeiture rate, 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 performance period. We capitalize a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration and development of its oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included in the "Evaluated properties" line item on the consolidated balance sheets. See Note 8.c to our consolidated financial statements included elsewhere in this Annual Report for further discussion regarding the restricted stock awards, stock option awards and performance share awards.

Recently issued or adopted accounting pronouncements

For discussion of recently issued or adopted accounting pronouncements, see Note 3 to our consolidated financial statements included elsewhere in this Annual Report.

Inflation

Inflation in the U.S. has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2018, 2017 and 2016. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the U.S. economy and, historically, we have experienced inflationary pressure on the costs of oilfield services and equipment as drilling activity increases in the areas in which we operate.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements other than operating leases, drilling contracts, firm sale and transportation commitments and our sand purchase and supply agreement, which are described in "—Obligations and commitments." See Note 14 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Item 7A. ***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 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, commodity transportation costs and differences in the prices of oil, NGL and natural gas between where we produce and where we sell such commodities, 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 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.

During a significant portion of 2018, Midland market crude oil prices experienced an increased discount to WTI Cushing and WTI Houston prices and the West Texas WAHA market natural gas prices experienced an increased discount to Henry Hub NYMEX prices. The discounts are primarily due to limited pipeline capacity constraining transportation of crude oil and natural gas out of the Permian Basin to major market hubs including, but not limited to, Cushing, Oklahoma and the United States Gulf Coast. Recently, each of these three basin differentials have narrowed; however, they remain volatile. These pipeline constraints may continue to affect Midland market crude oil prices and West Texas WAHA market natural gas prices until further transportation capacity becomes operational or until basin-wide crude oil and natural gas production decreases from its current levels. We will continue to pursue avenues to attempt to protect our oil and natural gas value from basin differentials by securing crude oil transportation capacity, which enables us to sell oil in multiple markets, and entering into basis-swap derivatives, which provides pricing protection.

The fair values of our open derivative positions are largely determined by forward price curves of the relevant price indices. As of December 31, 2018, a 10% change in the forward curves associated with our derivatives would have changed our consolidated balance sheet's net derivative position to the following amounts:

(in thousands)	10% Increase	10% Decrease
Net asset derivative position	$ 25,365	$ 67,887

As of December 31, 2018 and 2017, the net derivative positions were an asset of $43.5 million and a liability of $13.0 million, respectively. See to Notes 2.f, 9, 10.a and 17.b of our consolidated financial statements included elsewhere in this Annual 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 December 31, 2018 were as follows:

	Maturity year	
(in millions except for interest rates)	2022	2023[(1)]
Senior Secured Credit Facility	$ —	$ 190.0
Floating interest rate	—%	3.747%
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 "Part I, Item 3. Legal Proceedings," Notes 13 and 14 to our consolidated financial statements included elsewhere in this Annual Report for additional disclosures regarding credit risk. See Notes 2.e and 5 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the our accounts receivable and revenue recognition, respectively. See Notes 2.f, 9, 10.a and 17.b to our consolidated financial statements included elsewhere in this Annual Report for additional disclosures regarding our derivatives.

Item 8. ***Financial Statements and Supplementary Data***

Our consolidated financial statements and supplementary financial data are included in this Annual Report beginning on page F-1.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2018, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in the 2013 "Internal Control - Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2018.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report, has issued their report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2018. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2018, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Laredo Petroleum, Inc.

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2018, and our report dated February 14, 2019 expressed an unqualified opinion on those financial statements.

Basis for opinion
The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting
A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 14, 2019

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2018 at the reasonable assurance level.

Design and Evaluation of Internal Control Over Financial Reporting. Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, our management has included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report for the year ended December 31, 2018. Grant Thornton LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting. Management's report and the independent registered public accounting firm's attestation report are included in "Item 8. Financial Statements and Supplementary Data" in this Annual Report under the caption entitled "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm," respectively, and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Item 9B. ***Other Information***

Not applicable.

Part III

Item 10. *Directors, Executive Officers and Corporate Governance*

Information regarding our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers and Corporate Governance Guidelines for our principal executive officer and principal financial and accounting officer are described in "Item 1. Business" in this Annual Report. Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 10 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2018.

Item 11. *Executive Compensation*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 11 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2018.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 12 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2018.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 13 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2018.

Item 14. *Principal Accounting Fees and Services*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 14 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2018.

Part IV

Item 15. *Exhibits, Financial Statement Schedules*

(a)(1) Financial Statements

Our consolidated financial statements are included under Part II, Item 8 of this Annual Report. For a listing of these statements and accompanying footnotes, see "Index to Consolidated Financial Statements" on page F-1 of this Annual Report.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

Exhibit Number	Description
2.1	Agreement and Plan of Merger by and between Laredo Petroleum, LLC and Laredo Petroleum Holdings, Inc., dated as of December 19, 2011 (incorporated by reference to Exhibit 2.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
2.2	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 8-A12B/A (File No. 001-35380) filed on January 7, 2014).
4.2	Indenture, dated as of January 23, 2014, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 24, 2014).
4.3	First Supplemental Indenture, dated as of December 3, 2014, among Laredo Petroleum, Inc., Garden City Minerals, LLC, Laredo Midstream Services, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.9 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 26, 2015).
4.4	Indenture, dated as of March 18, 2015, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on March 24, 2015).
4.5	First Supplemental Indenture, dated as of March 18, 2015, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on March 24, 2015).
10.1	Fifth Amended and Restated Credit Agreement, dated as of May 2, 2017, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the other financial institutions signatory thereto (incorporated by reference to Exhibit 10.1 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on May 4, 2017).

Exhibit Number	Description
10.2	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of October 24, 2017, 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 October 30, 2017).
10.3	Second Amendment to Fifth Amended and Restated Credit Agreement, dated as of February 14, 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 10.3 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 15, 2018)
10.4	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).
10.5	Form of Registration Rights Agreement dated December 20, 2011 among Laredo Petroleum Holdings, Inc. and the signatories thereto (incorporated by reference to Exhibit 10.5 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
10.6	Form of Indemnification Agreement between Laredo Petroleum Holdings, Inc. and each of the officers and directors thereof (incorporated by reference to Exhibit 10.6 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
10.7#	Laredo Petroleum, Inc. Omnibus Equity Incentive Plan, as amended and restated as of March 30, 2016 (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 25, 2016).

Exhibit Number	Description
10.8#	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 9, 2012).
10.9#	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.3 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on August 9, 2012).
10.10#	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 25, 2016).
10.11#	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 9, 2012).
10.12#	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.3 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 25, 2016).
10.13#	Form of Performance Compensation Award Agreement (incorporated by reference to Exhibit 10.3 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 9, 2012).
10.14#	Form of 2013 Performance Compensation Award Agreement (incorporated by reference to Exhibit 10.16 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on March 12, 2013).
10.15#	Form of Performance Share Unit Award Agreement (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 23, 2018).
10.16#	Form of Performance Share Unit Award Agreement (incorporated by reference to Exhibit 10.4 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on May 25, 2016).
10.17#	Laredo Petroleum, Inc. Change in Control Executive Severance Plan, as amended June 21, 2015, December 14, 2015 and September 9, 2016 (incorporated by reference to Exhibit 10.18 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 16, 2017).
10.18	Non-Exclusive Aircraft Lease Agreement, dated July 1, 2018 between Lariat Ranch, LLC and Laredo Petroleum, Inc. (incorporated by reference to Exhibit 10.1 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on November 6, 2018).
21.1*	List of Subsidiaries of Laredo Petroleum, Inc.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P.
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.
99.1*	Summary Report of Ryder Scott Company, L.P.
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 Section 13 or 15(d) 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: February 14, 2019	By:	/s/ Randy A. Foutch
		Randy A. Foutch *Chief Executive Officer*

KNOWN ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Randy A. Foutch, Richard C. Buterbaugh, Kenneth E. Dornblaser and Michael T. Beyer, each of whom may act without joinder of the other, as their true and lawful attorneys-in-fact and agents, each with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ Randy A. Foutch Randy A. Foutch	Chairman and Chief Executive Officer (principal executive officer)	2/14/2019
/s/ Richard C. Buterbaugh Richard C. Buterbaugh	Executive Vice President and Chief Financial Officer (principal financial officer)	2/14/2019
/s/ Michael T. Beyer Michael T. Beyer	Vice President - Controller and Chief Accounting Officer (principal accounting officer)	2/14/2019
/s/ Peter R. Kagan Peter R. Kagan	Director	2/14/2019
/s/ James R. Levy James R. Levy	Director	2/14/2019
/s/ Frances Powell Hawes Frances Powell Hawes	Director	2/14/2019
/s/ B.Z. (Bill) Parker B.Z. (Bill) Parker	Director	2/14/2019
/s/ Pamela S. Pierce Pamela S. Pierce	Director	2/14/2019
/s/ Dr. Myles W. Scoggins Dr. Myles W. Scoggins	Director	2/14/2019
/s/ Edmund P. Segner, III Edmund P. Segner, III	Director	2/14/2019
/s/ Donald D. Wolf Donald D. Wolf	Director	2/14/2019

LAREDO PETROLEUM, INC.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Laredo Petroleum, Inc.

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 14, 2019 expressed an unqualified opinion.

Change in accounting principle
As disclosed in Note 5.a to the financial statements, the Company has changed its method of accounting for revenue in the year ended December 31, 2018 due to the adoption of FASB Accounting Standards Codification Topic 606, *Revenue from Contracts with Customers*.

Basis for opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2007.

Tulsa, Oklahoma
February 14, 2019

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

	December 31, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 45,151	$ 112,159
Accounts receivable, net	94,321	100,645
Derivatives	39,835	6,892
Other current assets	13,445	15,686
Total current assets	192,752	235,382
Property and equipment:		
Oil and natural gas properties, full cost method:		
Evaluated properties	6,752,631	6,070,940
Unevaluated properties not being depleted	130,957	175,865
Less accumulated depletion and impairment	(4,854,017)	(4,657,466)
Oil and natural gas properties, net	2,029,571	1,589,339
Midstream service assets, net	130,245	138,325
Other fixed assets, net	39,819	40,721
Property and equipment, net	2,199,635	1,768,385
Derivatives	11,030	3,413
Other noncurrent assets, net	16,888	16,109
Total assets	$ 2,420,305	$ 2,023,289
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 69,504	$ 58,341
Accrued capital expenditures	29,975	82,721
Undistributed revenue and royalties	48,841	37,852
Derivatives	7,359	22,950
Other current liabilities	44,786	75,555
Total current liabilities	200,465	277,419
Long-term debt, net	983,636	791,855
Derivatives	—	384
Asset retirement obligations	53,387	53,962
Other noncurrent liabilities	8,587	134,090
Total liabilities	1,246,075	1,257,710
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued as of December 31, 2018 and 2017	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized and 233,936,358 and 242,521,143 issued and outstanding as of December 31, 2018 and 2017, respectively	2,339	2,425
Additional paid-in capital	2,375,286	2,432,262
Accumulated deficit	(1,203,395)	(1,669,108)
Total stockholders' equity	1,174,230	765,579
Total liabilities and stockholders' equity	$ 2,420,305	$ 2,023,289

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

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

	For the years ended December 31,		
	2018	2017	2016
Revenues:			
Oil sales	$ 605,197	$ 445,012	$ 318,466
NGL sales	149,843	101,438	56,982
Natural gas sales	53,490	75,057	51,037
Midstream service revenues	8,987	10,517	8,342
Sales of purchased oil	288,258	190,138	162,551
Total revenues	1,105,775	822,162	597,378
Costs and expenses:			
Lease operating expenses	91,289	75,049	75,327
Production and ad valorem taxes	49,457	37,802	28,586
Transportation and marketing expenses	11,704	—	—
Midstream service expenses	2,872	4,099	4,077
Costs of purchased oil	288,674	195,908	169,536
General and administrative	96,138	96,312	91,756
Depletion, depreciation and amortization	212,677	158,389	148,339
Impairment expense	—	—	162,027
Other operating expenses	4,472	4,931	5,692
Total costs and expenses	757,283	572,490	685,340
Operating income (loss)	348,492	249,672	(87,962)
Non-operating income (expense):			
Gain (loss) on derivatives, net	42,984	350	(87,425)
Interest expense	(57,904)	(89,377)	(93,298)
Other income, net	1,070	805	175
Income from equity method investee (see Note 4.c)	—	8,485	9,403
Gain on sale of investment in equity method investee (see Note 4.c)	—	405,906	—
Loss on early redemption of debt	—	(23,761)	—
Loss on disposal of assets, net	(5,798)	(1,306)	(790)
Write-off of debt issuance costs	—	—	(842)
Non-operating income (expense), net	(19,648)	301,102	(172,777)
Income (loss) before income taxes	328,844	550,774	(260,739)
Income tax benefit (expense):			
Current	807	(1,800)	—
Deferred	(5,056)	—	—
Total income tax expense	(4,249)	(1,800)	—
Net income (loss)	$ 324,595	$ 548,974	$ (260,739)
Net income (loss) per common share:			
Basic	$ 1.40	$ 2.30	$ (1.16)
Diluted	$ 1.39	$ 2.29	$ (1.16)
Weighted-average common shares outstanding:			
Basic	232,339	239,096	225,512
Diluted	233,172	240,122	225,512

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

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

	Common Stock		Additional paid-in capital	Treasury Stock (at cost)		Accumulated deficit	Total
	Shares	Amount		Shares	Amount		
Balance, December 31, 2015	213,808	$ 2,138	$ 2,086,652	—	$ —	$ (1,957,343)	$ 131,447
Restricted stock awards	2,982	30	(30)	—	—	—	—
Restricted stock forfeitures	(457)	(5)	5	—	—	—	—
Vested stock exchanged for tax withholding	—	—	—	296	(1,635)	—	(1,635)
Retirement of treasury stock	(296)	(3)	(1,632)	(296)	1,635	—	—
Exercise of stock options	17	—	208	—	—	—	208
Equity issuances, net of offering costs	25,875	259	275,793	—	—	—	276,052
Stock-based compensation	—	—	35,240	—	—	—	35,240
Net loss	—	—	—	—	—	(260,739)	(260,739)
Balance, December 31, 2016	241,929	2,419	2,396,236	—	—	(2,218,082)	180,573
Restricted stock awards	1,237	12	(12)	—	—	—	—
Restricted stock forfeitures	(302)	(3)	3	—	—	—	—
Performance share conversion	150	2	(2)	—	—	—	—
Vested stock exchanged for tax withholding	—	—	—	547	(7,662)	—	(7,662)
Retirement of treasury stock	(547)	(5)	(7,657)	(547)	7,662	—	—
Exercise of stock options	54	—	397	—	—	—	397
Stock-based compensation	—	—	43,297	—	—	—	43,297
Net income	—	—	—	—	—	548,974	548,974
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 5.a)	—	—	—	—	—	141,118	141,118
Restricted stock awards	3,328	33	(33)	—	—	—	—
Restricted stock forfeitures	(367)	(4)	4	—	—	—	—
Share repurchases	—	—	—	11,049	(97,055)	—	(97,055)
Vested stock exchanged for tax withholding	—	—	—	518	(4,418)	—	(4,418)
Retirement of treasury stock	(11,567)	(115)	(101,358)	(11,567)	101,473	—	—
Exercise of stock options	21	—	86	—	—	—	86
Stock-based compensation	—	—	44,325	—	—	—	44,325
Net income	—	—	—	—	—	324,595	324,595
Balance, December 31, 2018	233,936	$ 2,339	$ 2,375,286	—	$ —	$ (1,203,395)	$ 1,174,230

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

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

	For the years ended December 31,		
	2018	2017	2016
Cash flows from operating activities:			
Net income (loss)	$ 324,595	$ 548,974	$ (260,739)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred income tax expense	5,056	—	—
Depletion, depreciation and amortization	212,677	158,389	148,339
Impairment expense	—	—	162,027
Gain on sale of investment in equity method investee (see Note 4.c)	—	(405,906)	—
Loss on early redemption of debt	—	23,761	—
Non-cash stock-based compensation, net	36,396	35,734	29,229
Mark-to-market on derivatives:			
(Gain) loss on derivatives, net	(42,984)	(350)	87,425
Settlements received for matured derivatives, net	6,090	37,583	195,281
Settlements received for early terminations of derivatives, net	—	4,234	80,000
Change in net present value of derivative deferred premiums	694	394	232
Premiums paid for derivatives	(20,335)	(25,853)	(89,669)
Amortization of debt issuance costs	3,331	4,086	4,279
Write-off of debt issuance costs	—	—	842
Income from equity method investee (see Note 4.c)	—	(8,485)	(9,403)
Cash settlement of performance unit awards	—	—	(6,394)
Other, net	11,857	6,067	4,596
Decrease (increase) in accounts receivable	4,669	(12,124)	832
Increase in other current assets	(1,865)	(3,461)	(1,373)
Decrease (increase) in other noncurrent assets	124	(4,774)	360
Increase in accounts payable and accrued liabilities	11,163	9,137	5,432
Increase (decrease) in undistributed revenues and royalties	10,989	11,014	(7,735)
(Decrease) increase in other current liabilities	(23,799)	(2,327)	13,153
(Decrease) increase in other noncurrent liabilities	(854)	8,821	(419)
Net cash provided by operating activities	537,804	384,914	356,295
Cash flows from investing activities:			
Deposit received for potential sale of oil and natural gas properties	—	—	3,000
Deposit utilized for sale of oil and natural gas properties	—	(3,000)	—
Acquisitions of oil and natural gas properties	(17,538)	—	(124,660)
Capital expenditures:			
Oil and natural gas properties	(673,584)	(538,122)	(360,679)
Midstream service assets	(6,784)	(20,887)	(5,240)
Other fixed assets	(7,308)	(4,905)	(7,611)
Investment in equity method investee (see Note 4.c)	—	(31,808)	(69,609)
Proceeds from disposition of equity method investee, net of selling costs (see Note 4.c)	1,655	829,615	—
Proceeds from dispositions of capital assets, net of selling costs	12,603	64,157	397
Net cash (used in) provided by investing activities	(690,956)	295,050	(564,402)
Cash flows from financing activities:			
Borrowings on Senior Secured Credit Facility	210,000	190,000	239,682
Payments on Senior Secured Credit Facility	(20,000)	(260,000)	(304,682)
Early redemption of debt	—	(518,480)	—
Proceeds from issuance of common stock, net of offering costs	—	—	276,052
Share repurchases	(97,055)	—	—
Vested stock exchanged for tax withholding	(4,418)	(7,662)	(1,635)
Proceeds from exercise of stock options	86	397	208
Payments for debt issuance costs	(2,469)	(4,732)	—
Net cash provided by (used in) financing activities	86,144	(600,477)	209,625
Net (decrease) increase in cash and cash equivalents	(67,008)	79,487	1,518
Cash and cash equivalents, beginning of period	112,159	32,672	31,154

Cash and cash equivalents, end of period	$ 45,151	$ 112,159	$ 32,672

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

Note 1—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 consolidated financial statements and the related notes are rounded and therefore approximate.

The Company has identified one operating segment: exploration and production. The Company's midstream and marketing functions are integral to its exploration and production activities. The Company has a single company-wide management team that administers all properties as a whole rather than discrete operating segments and it allocates capital resources on a project-by-project basis across its asset base without regard to individual areas.

Note 2—Basis of presentation and significant accounting policies

a. Basis of presentation

The accompanying 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 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 Company uses the equity method of accounting to record its net interests when the Company holds 20% to 50% of the voting rights and/or has the ability to exercise significant influence but does not control the entity. Under the equity method, the Company's proportionate share of the investee's net income is included in the consolidated statements of operations. See Notes 4.c and 5.a for additional discussion of the Company's former equity method investment.

b. Use of estimates in the preparation of consolidated financial statements

The preparation of the accompanying 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.

Significant estimates include, but are not limited to, (i) volumes of the Company's reserves of oil, natural gas liquids ("NGL") and natural gas, (ii) future cash flows from oil and natural gas properties, (iii) depletion, depreciation and amortization, (iv) impairments, (v) asset retirement obligations, (vi) stock-based compensation, (vii) deferred income taxes, (viii) fair value of assets acquired and liabilities assumed in an acquisition, (ix) fair values of derivatives and deferred premiums and (x) contingent liabilities. As fair value is a market-based measurement, it is determined based on the assumptions that would be used by market participants. These estimates and assumptions are based on management's best judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment. Such estimates and assumptions are adjusted when facts and circumstances dictate. Illiquid credit markets and volatile equity and energy markets have combined to increase the uncertainty inherent in such estimates and assumptions. Management believes its estimates and assumptions to be reasonable under the circumstances. As future events and their effects cannot be determined with precision, actual values and results could differ from these estimates. Any changes in estimates resulting from future changes in the economic environment will be reflected in the financial statements in future periods.

c. Reclassifications

Certain amounts in the accompanying 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 (loss), stockholders' equity or total operating, investing or financing cash flows.

d. Cash and cash equivalents

The Company defines cash and cash equivalents to include cash on hand, cash in bank accounts and highly liquid investments with original maturities of three months or less. The Company maintains cash and cash equivalents in bank deposit accounts and money market funds that may not be federally insured. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on such accounts. See Note 13 for discussion regarding the Company's exposure to credit risk.

e. Accounts receivable

The Company sells produced oil, NGL and natural gas and purchased oil to various customers and participates with other parties in the development and operation of oil and natural gas properties.

The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging and existing industry and economic data. The Company reviews its allowance for doubtful accounts quarterly. Past due amounts greater than 90 days and greater than a specified amount are reviewed individually for collectability. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is remote.

Accounts receivable consisted of the following components as of the dates presented:

(in thousands)	December 31, 2018	December 31, 2017
Oil, NGL and natural gas sales	$ 44,958	$ 67,116
Joint operations, net[1]	16,772	8,780
Sales of purchased oil and other products	10,244	19,504
Other	22,347	5,245
Total accounts receivable	$ 94,321	$ 100,645

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(1) Accounts receivable for joint operations are presented net of an allowance for doubtful accounts of $0.1 million as of December 31, 2018 and 2017. As the operator of the majority of its wells, the Company has the ability to realize some or all of these receivables through the netting of revenues.

f. Derivatives

Derivatives are recorded at fair value and are presented on a net basis on the "Derivatives" line items on the consolidated balance sheets as assets and/or liabilities. The Company presents the fair value of derivatives net by counterparty where the right of offset exists. The Company determines the fair value of its derivatives by utilizing pricing models for substantially similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. The Company's derivatives were not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized in the 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. See Notes 9 and 10.a for additional discussion of derivatives and the fair value measurement of derivatives, respectively.

g. Other current liabilities and noncurrent liabilities

Other current liabilities consisted of the following components as of the dates presented:

(in thousands)	December 31, 2018	December 31, 2017
Accrued interest payable	$ 18,281	$ 18,013
Accrued compensation and benefits	13,317	21,287
Deferred gain on sale of equity method investment[1]	—	20,144
Other accrued liabilities	13,188	16,111
Total other current liabilities	$ 44,786	$ 75,555

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(1) See Notes 4.c and 5.a for additional discussion regarding the Company's former equity method investee.

Other noncurrent liabilities consisted of the following components as of the dates presented:

(in thousands)	December 31, 2018	December 31, 2017
Deferred gain on sale of equity method investment(1)	$ —	$ 120,974
Other accrued liabilities	8,587	13,116
Total other noncurrent liabilities	$ 8,587	$ 134,090

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(1) See Notes 4.c and 5.a for additional discussion regarding the Company's former equity method investee.

h. Oil and natural gas properties

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 related employee 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 related employee 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. See Note 6 for additional discussion of the Company's oil and natural gas properties and other property and equipment.

i. Inventory

The Company has the following types of inventory: (i) materials and supplies inventory used in production activities of oil and natural gas properties and midstream service assets, (ii) frac pit water inventory used in developing oil and natural gas properties and (iii) line-fill in third-party pipelines, which is the minimum volume of product in a pipeline system that enables the system to operate, and is generally not available to be withdrawn from the pipeline until the expiration of the transportation contract. All inventory is carried at the lower of cost or net realizable value ("NRV"), with cost determined using the weighted-average cost method, and is included in each of the "Other current assets" and "Other noncurrent assets, net" line items on the consolidated balance sheets. The NRV for materials and supplies inventory and frac pit water inventory is determined utilizing a replacement cost approach (Level 2). The NRV for line-fill in third-party pipelines is determined utilizing a quoted market price adjusted for regional price differentials (Level 2).

For the year ended December 31, 2016, the Company recorded impairment expense of $1.0 million for materials and supplies inventory. No such inventory impairments were recorded for the years ended December 31, 2018 or 2017.

j. Debt issuance costs

Debt issuance fees, which are recorded at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the effective interest and straight-line methods. See Note 7.e for additional discussion of the Company's debt issuance costs.

k. Asset retirement obligations

Asset retirement obligations associated with the retirement of tangible long-lived assets are recognized as a liability in the period in which they are incurred and become determinable. The associated asset retirement costs are part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related long-lived asset is charged to expense through depletion, or for midstream service assets through depreciation. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and accretion expense.

The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, which converts future cash flows into a single discounted amount. Significant inputs to the valuation include: (i) estimated plug and abandonment cost per well based on Company experience and estimated remaining life per well, (ii) estimated removal and/or remediation costs for midstream service assets and estimated remaining life of midstream service assets, (iii) future inflation factors and (iv) the Company's average credit-adjusted risk-free rate. Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including, in addition to those noted above, the ultimate settlement of these amounts, the ultimate timing of such settlement and changes in legal, regulatory and environmental matters. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, an adjustment will be made to the asset balance.

The Company is obligated by contractual and regulatory requirements to remove certain pipeline and gathering assets and perform other remediation of the sites where such pipeline and gathering assets are located upon the retirement of those assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminate. The Company will record an asset retirement obligation for pipeline and gathering assets in the periods in which settlement dates are reasonably determinable.

The following table reconciles the Company's asset retirement obligation liability:

(in thousands)	For the years ended December 31, 2018	2017
Liability at beginning of year	$ 55,506	$ 52,207
Liabilities added due to acquisitions, drilling, midstream service asset construction and other	995	616
Accretion expense	4,472	3,791
Liabilities settled upon plugging and abandonment	(2,848)	(408)
Liabilities removed due to sale of property	(1,243)	(871)
Revision of estimates	—	171
Liability at end of year	$ 56,882	$ 55,506

l. *Fair value measurements*

The carrying amounts reported in the 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 carries its derivatives at fair value. See Note 10.a for details regarding the fair value of the Company's derivatives. See Note 10.c for fair value disclosures related to the Company's debt obligations.

m. *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-based awards at the employees' election.

n. *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 from oil throughput fees and 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 (collectively, "Midstream Services"), and are recognized over time as the customer benefits from these services when provided. See Note 5.b for additional discussion on revenue recognition.

o. *Fees received for the operation of jointly-owned oil and natural gas properties*

The Company receives fees for the operation of jointly-owned oil and natural gas properties and records such reimbursements as a reduction of general and administrative expenses.

The following table presents the fees received for the operation of jointly-owned oil and natural gas properties:

(in thousands)	For the years ended December 31, 2018	2017	2016
Fees received for the operation of jointly-owned oil and natural gas properties	$ 2,507	$ 2,549	$ 2,477

p. *Compensation awards*

Stock-based compensation expense, net, is included in the "General and administrative" line item in the Company's consolidated statements of operations over the awards' vesting periods and is based on the awards' grant date fair value. The Company utilizes the closing stock price on the grant date, less an expected forfeiture rate, to determine the fair values of service vesting restricted stock awards and a Black-Scholes pricing model to determine the fair values of service vesting restricted stock option awards. The Company utilizes a Monte Carlo simulation prepared by an independent third party to determine the fair values, less an expected forfeiture rate, of the performance share awards with market criteria and, in prior periods, the performance unit awards. For performance share awards with performance criteria, the grant-date fair value is equal to the Company's stock price on the grant date, less an expected forfeiture rate, 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 performance period. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration and development of its oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included in the "Evaluated properties" line item on the consolidated balance sheets. See Note 8.c for further discussion regarding the restricted stock awards, stock option awards and performance share awards.

q. Income taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating losses and tax credit carry-forwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income (loss) in the period that includes the enactment date.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more-likely-than-not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company has no unrecognized tax benefits related to uncertain tax positions in the consolidated financial statements at December 31, 2018 or 2017. See Note 12 for additional information regarding the Company's income taxes.

r. Non-cash investing and supplemental cash flow information

The following table presents non-cash investing and supplemental cash flow information:

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Non-cash investing information:			
(Decrease) increase in accrued capital expenditures	$ (52,746)	$ 51,876	$ (31,027)
Change in accrued capital contribution to equity method investee[1]	$ —	$ —	$ (27,583)
Capitalized stock-based compensation	$ 7,929	$ 7,563	$ 6,011
Capitalized asset retirement cost	$ 995	$ 787	$ 3,660
Supplemental cash flow information:			
Cash paid for interest, net of $988, $1,152 and $294 of capitalized interest, respectively[2]	$ 53,981	$ 91,548	$ 89,432
Cash paid for income taxes[3]	$ 735	$ 5,500	$ —

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(1) See Notes 4.c and 5.a for additional discussion of the Company's former equity method investee.

(2) See Note 7.f for additional discussion of the Company's interest expense.

(3) See Note 12 for additional discussion of the Company's income taxes.

Note 3—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 and a final rule issued by the SEC listed below were determined to be meaningful to the Company's consolidated financial statements and/or footnotes during the year ended December 31, 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 5 for further discussion of the ASC 606 adoption impact on the Company's 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.

In July 2018, the FASB issued new guidance in ASC 842 to provide entities with an additional (and optional) transition method to adopt the new leases standard. Under this new transition method, an entity initially applies the new leases standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements in which it adopts the new leases standard will continue to be in accordance with ASC 840. An entity that elects this transition method must provide the required ASC 840 disclosures for all periods that continue to be reported in accordance with 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 was permitted. The primary effect on the Company's consolidated financial statements 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 a team, including third-party consultants, to implement the standard and has implemented the software that will be used to track and account for lease activity. As of December 31, 2018, the Company anticipates that the adoption and implementation of ASC 842 will result in approximately a $25.0 million to $40.0 million increase in assets and liabilities on the consolidated balance sheet in 2019, but will not result in a material impact to the consolidated statement of operations. This estimate may vary based on any additional contracts entered into subsequent to December 31, 2018.

The Company has made certain accounting policy decisions including that it plans to adopt the short-term lease recognition exemption, accounting for certain asset classes at a portfolio level, and establishing a balance sheet recognition capitalization threshold. The transition will utilize the modified retrospective approach to adopting the new standard that will be applied at the beginning of the period adopted (January 1, 2019). The Company will utilize the transition package of expedients to leases that commenced before the effective date. The Company expects for certain lessee asset classes to elect the practical expedient and not separate lease and non-lease components. For these asset classes, the agreements will be accounted for as a single lease component.

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 consolidated financial statements. See Note 4.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.

d. Fair value measurements

In August 2018, the FASB issued new guidance in ASC 820, *Fair Value Measurement*, to modify disclosure requirements. Of the amendments in the ASU, the below items affected the Company's fair value measurement disclosures in Note 10. Removed disclosure requirements that should be applied retrospectively to all periods presented are: (i) the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy, (ii) the policy for timing of transfers between levels and (iii) the valuation processes for Level 3 fair value measurements. A modified disclosure requirement that should be applied prospectively is to clarify that the measurement uncertainty disclosure communicates information about the uncertainty in measurement as of the reporting date. A new disclosure requirement that should be applied prospectively is to disclose the range and weighted-average of significant unobservable inputs used to develop Level 3 fair value measurements. The Company has elected to early adopt this guidance upon the issuance of the ASU and has modified its disclosures accordingly.

e. SEC disclosure update and simplification

In August 2018, the SEC issued Final Rule Release No. 33-10532, *Disclosure Update and Simplification*, which amends various SEC disclosure requirements that they have determined to be redundant, duplicative, overlapping, outdated or superseded. The amendments also extend the annual disclosure requirement of presenting the changes in stockholders' equity to interim periods. An analysis of changes in stockholders' equity will now be required for the current and comparative year-to-date interim periods. The Company has completed its implementation of the final rule.

Note 4—Acquisitions and divestitures

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

During the year ended December 31, 2018, through multiple transactions, the Company acquired 966 net acres of additional leasehold and working interests in 48 producing wells in Glasscock County, Texas for an aggregate purchase price of $17.5 million, net of 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 service assets

During the year ended December 31, 2018, through multiple transactions, the Company completed the sale of 3,070 net acres and working interests in 24 producing wells and associated midstream service assets in Glasscock County and Howard County in Texas to third-party buyers for an aggregate sales price of $12.0 million, net of post-closing adjustments. Of this amount, $11.5 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 "Loss on disposal of assets, net" in the consolidated statements of operations. Effective at the closings, the operations and cash flows of these oil and natural gas 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 in 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 fo r under the equity method of accounting. The Company's proportionate share of Medallion's net income is reflected in the consolidated statements of operations on the "Income from equity method investee" line item.

On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC ("MMH"), which is owned and controlled by an affiliate of the third-party interest-holder, The Energy & Minerals Group ("EMG"), completed the sale of 100% of the ownership interests in Medallion to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion (the "Medallion Sale"). LMS' net cash proceeds for its 49% ownership interest in Medallion in 2017 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 down borrowings on the Senior Secured Credit Facility in full, to redeem the May 2022 Notes (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 does 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 County and Glasscock County 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 consolidated balance sheets in each of the "Other current liabilities" and "Other noncurrent liabilities" line items as of December 31, 2017. See Note 5.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 oil and natural gas 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. 2016 Acquisitions of evaluated and unevaluated oil and natural gas properties

The Company accounts for acquisitions of evaluated and unevaluated oil and natural gas properties under the acquisition method of accounting. Accordingly, the Company conducts assessments of net assets acquired and recognizes amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisitions are expensed as incurred.

The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair value of evaluated and unevaluated oil and natural gas properties. The fair value of these properties are measured using a discounted cash flow model that converts future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) forecasted oil, NGL and natural gas reserve quantities; (ii) future commodity strip prices as of the closing dates adjusted for transportation and regional price differentials; (iii) forecasted ad valorem taxes, production taxes, income taxes, general and administrative expenses, operating expenses and development costs; and (iv) a peer group weighted-average cost of capital rate subject to additional project-specific risk factors. To compensate for the inherent risk of estimating the value of the unevaluated properties, the discounted future net revenues of proved undeveloped and probable reserves are reduced by additional reserve adjustment factors. These assumptions represent Level 3 inputs under the fair value hierarchy, as described in Note 10.a.

During the year ended December 31, 2016, the Company acquired 9,200 net acres of additional leasehold and working interests in 81 producing vertical wells in western Glasscock County and Reagan County which included production of approximately 300 net barrels of oil equivalent ("BOE") per day within the Company's core development area for an aggregate purchase price of $124.7 million subject to customary closing adjustments.

The following table reflects an aggregate of the final estimate of the fair values of the assets and liabilities acquired during the year ended December 31, 2016:

(in thousands)	Fair value of acquisitions
Fair value of net assets:	
Evaluated oil and natural gas properties	$ 4,800
Unevaluated oil and natural gas properties	119,923
Asset retirement cost	1,105
Total assets acquired	125,828
Asset retirement obligations	(1,105)
Net assets acquired	$ 124,723
Fair value of consideration paid for net assets:	
Cash consideration	$ 124,723

f. Exchange of evaluated 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 5—Revenue recognition

a. Impact of ASC 606 adoption

Upon adoption of ASC 606 on January 1, 2018, for the year ended December 31, 2018, the Company reclassified certain firm transportation payments on excess pipeline capacity and other contractual penalties, historically included in the "Other operating expenses" line item in the 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 discussed below.

The impact of the adoption of ASC 606 on the results of operations for the year ended December 31, 2018 is as follows:

(in thousands)	As computed under ASC 605	As reported under ASC 606	Increase/(decrease)
Revenues:			
Oil sales	$ 607,870	$ 605,197	$ (2,673)
NGL sales	$ 150,822	$ 149,843	$ (979)
Natural gas sales	$ 54,511	$ 53,490	$ (1,021)
Costs and expenses:			
Other operating expenses	$ 9,145	$ 4,472	$ (4,673)
Net income	$ 324,595	$ 324,595	$ —

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 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 4.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 consolidated statements of stockholders' equity, in accordance with the modified retrospective approach of adoption. See Note 12 for discussion of the income tax effect of the adoption of ASC 606.

b. Revenue recognition

See Note 2.n for a summary of revenue recognition policies, a more detailed discussion 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 expenses" line item in the accompanying consolidated statements of operations.

Under certain of its customer contracts, the Company is subject to firm transportation payments on excess pipeline capacity 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 the Company has 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 service revenues

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 December 31, 2018 or 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 year ended December 31, 2018, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

Note 6—Property and equipment

a. Oil and natural gas properties

The Company computes the provision for depletion of oil and natural gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the depletion base until the properties associated with these costs are evaluated. The depletion base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values.

Oil and natural gas properties consisted of the following components as of the dates presented:

(in thousands)	December 31, 2018	December 31, 2017
Evaluated properties	$ 6,752,631	$ 6,070,940
Unevaluated properties not being depleted	130,957	175,865
Less accumulated depletion and impairment	(4,854,017)	(4,657,466)
Oil and natural gas properties, net	$ 2,029,571	$ 1,589,339

The following table presents depletion and depletion per BOE sold of the Company's evaluated oil and natural gas properties for the periods presented:

	For the years ended December 31,		
(in thousands except per BOE data)	2018	2017	2016
Depletion of evaluated oil and natural gas properties	$ 196,458	$ 143,592	$ 134,105
Depletion per BOE sold	$ 7.90	$ 6.75	$ 7.39

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. See Note 18 for further information regarding unevaluated property costs. 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 full cost ceiling is based principally on the estimated future net revenues from proved oil and natural gas properties discounted at 10%. The Securities and Exchange Commission ("SEC") guidelines require companies to use the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials ("Benchmark Prices"). The Benchmark Prices are then adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead ("Realized Prices"). The Realized Prices are utilized to calculate the discounted future net revenues in the full cost ceiling calculation. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of operating and development costs, anticipated production of proved reserves and other relevant data.

In the event the unamortized cost of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

The following table presents the Benchmark Prices and Realized Prices as of the dates presented:

	December 31, 2018	December 31, 2017	December 31, 2016
Benchmark Prices:			
Oil ($/Bbl)	$ 62.04	$ 47.79	$ 39.25
NGL ($/Bbl)[(1)]	$ 31.46	$ 26.13	$ 18.24
Natural gas ($/MMBtu)	$ 1.76	$ 2.63	$ 2.33
Realized Prices:			
Oil ($/Bbl)	$ 59.29	$ 46.34	$ 37.44
NGL ($/Bbl)	$ 21.42	$ 18.45	$ 11.72
Natural gas ($/Mcf)	$ 1.38	$ 2.06	$ 1.78

(1) Based on the Company's average composite NGL barrel.

Full cost ceiling impairment expense for the year ended December 31, 2016 was $161.1 million. This amount is included in the "Impairment expense" line item in the consolidated statements of operations. There were no full cost ceiling impairments recorded during the years ended December 31, 2018 or 2017. See Note 2.h for discussion of the Company's significant accounting policy for oil and natural gas properties.

The following table presents capitalized employee-related costs incurred for the purpose of exploring for or developing oil and natural gas properties for the periods presented:

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Capitalized employee-related costs	$ 25,372	$ 25,553	$ 19,222

b. Midstream service assets

Midstream service assets, which consist of oil and natural gas pipeline gathering assets, related equipment, oil delivery stations, water storage and treatment facilities and their related asset retirement cost, are recorded at cost, net of impairment. See Note 2.k for discussion regarding midstream service asset retirement cost. Depreciation of assets is recorded using the straight-line method based on estimated useful lives of 10 to 20 years, as applicable. Expenditures for significant betterments or renewals, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation are removed from the accounts and any gain or loss is recognized in "Loss on disposal of assets, net" in the consolidated statements of operations. Depreciation expense for midstream service assets was $10.1 million, $8.9 million and $8.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Midstream service assets consisted of the following components as of the dates presented:

(in thousands)	**December 31, 2018**	**December 31, 2017**
Midstream service assets	$ 172,308	$ 171,427
Less accumulated depreciation and impairment	(42,063)	(33,102)
Total midstream service assets, net	$ 130,245	$ 138,325

c. Other fixed assets

Other fixed assets are recorded at cost and are subject to depreciation and amortization. Land is recorded at cost and is not subject to depreciation. Depreciation and amortization of other fixed assets is provided using the straight-line method based on estimated useful lives of three to ten years, as applicable. Leasehold improvements are capitalized and amortized over the shorter of the estimated useful lives of the assets or the terms of the related leases. Expenditures for significant betterments or renewals, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation and amortization are removed from the accounts and any gain or loss is recognized in "Loss on disposal of assets, net" in the consolidated statements of operations. Depreciation and amortization expense for other fixed assets was $6.1 million, $5.9 million, and $5.9 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Other fixed assets consisted of the following components as of the dates presented:

(in thousands)	**December 31, 2018**	**December 31, 2017**
Vehicles	$ 10,660	$ 9,661
Computer hardware and software	9,222	11,696
Buildings	7,804	7,618
Leasehold improvements	7,608	7,590
Aircraft	6,402	6,402
Other	3,735	5,990
Depreciable total	45,431	48,957
Less accumulated depreciation and amortization	(23,871)	(23,150)
Depreciable total, net	21,560	25,807
Land	18,259	14,914
Total other fixed assets, net	$ 39,819	$ 40,721

Note 7—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"), and entered into an Indenture (the "Base Indenture"), as supplemented by the Supplemental Indenture (the "Supplemental Indenture" and, together with the Base Indenture, the "Indenture"), among Laredo, LMS and GCM, as guarantors, and Wells Fargo Bank, National Association, as trustee. 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 the Guarantors 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 Indenture, designation of a subsidiary guarantor as a non-guarantor restricted subsidiary or as an unrestricted subsidiary in accordance with the Indenture, release from guarantee under the Senior Secured Credit Facility, or liquidation or dissolution (collectively, the "Releases").

The March 2023 Notes were offered and sold pursuant to a prospectus supplement dated March 4, 2015 and the base prospectus dated March 22, 2013, relating to the Company's effective shelf registration statement on Form S-3 (File No. 333-187479). The Company received net proceeds of $343.6 million from the offering, after deducting the underwriters' discount and the estimated outstanding offering expenses. In April 2015, the Company used the net proceeds of the offering to fund a portion of the Company's redemption of previously issued senior unsecured notes.

The March 2023 Notes became callable by the Company on March 15, 2018. The Company may redeem, at its option, all or part of the March 2023 Notes at any time on or 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"), and entered into an Indenture (the "2014 Indenture") among Laredo, LMS as guarantor and Wells Fargo Bank, National Association, as trustee. 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 the Guarantors and certain of the Company's future restricted subsidiaries, subject to certain Releases.

The January 2022 Notes were issued pursuant to the 2014 Indenture in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"). The January 2022 Notes were offered and sold only to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the United States pursuant to Regulation S under the Securities Act. The Company received net proceeds of $442.2 million from the offering, after deducting the initial purchasers' discount and the estimated outstanding offering expenses. The Company used the net proceeds of the offering for general working capital purposes.

The January 2022 Notes became callable by the Company on January 15, 2017. The Company may redeem, at its option, all or part of the January 2022 Notes at any time on and after January 15, 2019, at a price of 101.406% of face value with call premiums declining to 100% of face value on January 15, 2020 and thereafter plus accrued and unpaid interest to 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 the Guarantors 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 Fifth Amended and Restated Credit Agreement (as amended, 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 December 31, 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 $190.0 million outstanding and was subject to an interest rate of 3.75%. The borrowing base is subject to a semi-annual redetermination occurring by May 1 and November 1 of each year based on the lenders' evaluation of the Company's oil, NGL and natural gas reserves. As defined in the Senior Secured Credit Facility, (i) the Adjusted Base Rate advances under the facility bear interest payable quarterly at an Adjusted Base Rate plus applicable margin, which ranges from 0.25% to 1.25%, based on the ratio of outstanding revolving credit to the borrowing base under the Senior Secured Credit Facility; and (ii) the Eurodollar advances under the facility bear interest, at the Company's election, at the end of one-month, two-month, three-month, six-month or, to the extent available, 12-month interest periods (and in the case of six-month and 12-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate plus an applicable margin, which ranges from 1.25% to 2.25%, based on the ratio of outstanding revolving credit to the borrowing base under the Senior Secured Credit Facility. Laredo is required to pay a quarterly 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.

The Senior Secured Credit Facility is secured by a first-priority lien on Laredo and the Guarantors' assets and stock, including oil and natural gas properties, constituting at least 85% of the present value of the Company's proved reserves. Further, the Company is subject to various financial and non-financial covenants on a consolidated basis, including a current ratio at the end of each calendar quarter, of not less than 1.00 to 1.00. As defined by the Senior Secured Credit Facility, the current ratio represents the ratio of current assets to current liabilities, inclusive of available capacity and exclusive of current balances associated with derivative positions. Additionally, the Company must maintain as of the last day of each calendar quarter a ratio of (a) its total debt (excluding reimbursement obligations in respect of undrawn letters of credit, if no loans are outstanding under the Senior Secured Credit Facility) minus a maximum of $50 million of unrestricted and unencumbered cash and cash equivalents, to (b) "Consolidated EBITDAX," as defined in the Senior Secured Credit Facility, for any period of four consecutive calendar quarters ending on the last day of such applicable calendar quarter of not greater than 4.25 to 1.00. Prior to the Company entering into the Fifth Amended and Restated Credit Agreement as of May 2, 2017, at the end of each calendar quarter, the Company was required to maintain a ratio of (I) its consolidated net income (loss) (a) plus each of the following; (i) any provision for (or less any benefit from) income or franchise taxes; (ii) consolidated net interest expense; (iii) depletion, depreciation and amortization expense; (iv) exploration expenses; and (v) other non-cash charges, and (b) minus other non-cash income ("EBITDAX"), as defined in the Senior Secured Credit Facility, to (II) the sum of consolidated net interest expense plus letter of credit fees of not less than 2.50 to 1.00, in each case for the four quarters then ending. The Company was in compliance with these covenants for all periods presented.

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. As of December 31, 2018, the Company had one letter of credit outstanding of $14.7 million under the Senior Secured Credit Facility. No letters of credit were outstanding as of December 31, 2017.

e. Debt issuance costs

The Company capitalized $2.5 million of debt issuance costs during the year ended December 31, 2018 as a result of entering into the Third Amendment to the Senior Secured Credit Facility. The Company capitalized $4.7 million of debt issuance costs during the year ended December 31, 2017 as a result of entering into the Fifth Amended and Restated Credit Agreement. No debt issuance costs were capitalized during the year ended December 31, 2016.

The Company wrote-off $5.3 million of debt issuance costs during the year ended December 31, 2017 as a result of the early redemption of the May 2022 Notes, which are included in the "Loss on early redemption of debt" line item in the consolidated statements of operations. The Company wrote-off $0.8 million of debt issuance costs during the year ended December 31, 2016 as a result of changes in the borrowing base and aggregate elected commitment of the Senior Secured Credit Facility, which are included in the "Write-off of debt issuance costs" line item in the consolidated statements of operations. No debt issuance costs were written off during the year ended December 31, 2018.

The Company had total debt issuance costs of $13.3 million and $14.2 million, net of accumulated amortization of $24.2 million and $20.8 million, as of December 31, 2018 and 2017, respectively. Debt issuance costs related to the Company's senior unsecured notes are included in the "Long-term debt, net" line item on the consolidated balance sheets. Debt issuance costs related to the Senior Secured Credit Facility are included in the "Other noncurrent assets, net" line item on the consolidated balance sheets. See Note 7.g for additional discussion of debt issuance costs.

The following table presents future amortization expense of debt issuance costs:

(in thousands)	December 31, 2018
2019	$ 3,385
2020	3,385
2021	3,385
2022	2,490
2023	669
Total	$ 13,314

f. Interest expense

The following table presents amounts that have been incurred and charged to interest expense:

	For the years ended December 31,		
(in thousands)	2018	2017	2016
Cash payments for interest	$ 54,969	$ 92,700	$ 89,726
Amortization of debt issuance costs and other adjustments	3,655	3,968	3,922
Change in accrued interest	268	(6,139)	(56)
Interest costs incurred	58,892	90,529	93,592
Less capitalized interest	(988)	(1,152)	(294)
Total interest expense	$ 57,904	$ 89,377	$ 93,298

g. Long-term debt, net

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

	December 31, 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	$ (3,010)	$ 446,990	$ 450,000	$ (3,987)	$ 446,013
March 2023 Notes	350,000	(3,354)	346,646	350,000	(4,158)	345,842
Senior Secured Credit Facility(1)	190,000	—	190,000	—	—	—
Total	$ 990,000	$ (6,364)	$ 983,636	$ 800,000	$ (8,145)	$ 791,855

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(1) Debt issuance costs, net related to our Senior Secured Credit Facility of $7.0 million and $6.0 million as of December 31, 2018 and 2017, respectively, are reported in "Other noncurrent assets, net" on the consolidated balance sheets.

Note 8—Stockholders' equity, stock-based compensation and defined contribution plan

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 share repurchases 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 year ended December 31, 2018, the Company repurchased 11,048,742 shares of common stock at a weighted-average price of $8.78 per common share for a total of $97.1 million under this program. All shares were retired upon repurchase.

b. Equity offerings

On July 19, 2016, the Company completed the sale of 13,000,000 shares of Laredo's common stock (the "July 2016 Equity Offering") for net proceeds of $136.3 million, after underwriting discounts, commissions and offering expenses. On August 9, 2016, the underwriters exercised their option to purchase an additional 1,950,000 shares of Laredo's common stock, which resulted in net proceeds to the Company of $20.5 million, after underwriting discounts, commissions and offering expenses.

On May 16, 2016, the Company completed the sale of 10,925,000 shares of Laredo's common stock (the "May 2016 Equity Offering") for net proceeds of $119.3 million, after underwriting discounts, commissions and offering expenses.

There were no offerings of Laredo's stock during the years ended December 31, 2018 or 2017.

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 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 in the "Evaluated properties" line item on the consolidated balance sheets.

Restricted stock awards

All service vesting restricted stock awards are treated as issued and outstanding in the accompanying 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 that mainly include (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 vested fully on the first anniversary of the grant date.

The following table reflects the restricted stock award activity for the years ended December 31, 2016, 2017 and 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, 2015	2,539	$ 15.26
Granted	2,982	$ 12.28
Forfeited	(457)	$ 13.95
Vested	(1,186)	$ 16.07
Outstanding as of December 31, 2016	3,878	$ 12.88
Granted	1,237	$ 13.87
Forfeited	(302)	$ 12.87
Vested	(1,644)	$ 13.75
Outstanding as of December 31, 2017	3,169	$ 12.81
Granted	3,328	$ 8.34
Forfeited	(367)	$ 10.13
Vested[(1)]	(1,934)	$ 11.92
Outstanding as of December 31, 2018	4,196	$ 9.91

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(1) The total intrinsic value of vested restricted stock awards for the year ended December 31, 2018 was $16.6 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 December 31, 2018, unrecognized stock-based compensation related to the restricted stock awards expected to vest was $20.5 million. Such cost is expected to be recognized over a weighted-average period of 1.79 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. The following table reflects the stock option award activity for the years ended December 31, 2016, 2017 and 2018:

(in thousands, except for weighted-average exercise price and weighted-average remaining contractual term)	Stock option awards		Weighted-average exercise price (per award)	Weighted-average remaining contractual term (years)
Outstanding as of December 31, 2015	1,778	$	17.86	7.91
Granted	1,016	$	4.18	
Exercised	(17)	$	11.93	
Expired or canceled	(109)	$	21.71	
Forfeited	(298)	$	12.49	
Outstanding as of December 31, 2016	2,370	$	12.54	7.71
Granted	391	$	14.12	
Exercised	(54)	$	7.43	
Expired or canceled	(60)	$	20.41	
Outstanding as of December 31, 2017	2,647	$	12.70	7.12
Exercised(1)	(21)	$	4.10	
Expired or canceled	(53)	$	18.92	
Forfeited	(40)	$	9.23	
Outstanding as of December 31, 2018	2,533	$	12.69	5.99
Vested and exercisable as of December 31, 2018(2)	1,697	$	14.75	5.32
Expected to vest as of December 31, 2018(3)	836	$	8.53	7.34

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(1) The total intrinsic value of exercised stock option awards for the year ended December 31, 2018 was $0.1 million.

(2) The vested and exercisable stock option awards as of December 31, 2018 had no aggregate intrinsic value.

(3) The stock option awards expected to vest as of December 31, 2018 had no an aggregate intrinsic value.

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 volatility. As of December 31, 2018, unrecognized stock-based compensation related to stock option awards expected to vest was $3.9 million. Such cost is expected to be recognized over a weighted-average period of 1.51 years.

The assumptions used to estimate the fair value of stock option awards granted as of the dates presented are as follows:

	February 17, 2017	May 25, 2016	April 1, 2016
Risk-free interest rate(1)	2.14%	1.58%	1.44%
Expected option life(2)	6.25 years	6.25 years	6.25 years
Expected volatility(3)	60.84%	61.94%	61.34%
Fair value per stock option award	$ 8.22	$ 9.75	$ 4.44

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(1) U.S. Treasury yields as of the grant date were utilized for the risk-free interest rate assumption, correlating the treasury yield terms to the expected life of the stock option award.

(2) As the Company had limited or no exercise history at the time of valuation relating to terminations and modifications, expected stock option award life assumptions were developed using the simplified method in accordance with GAAP.

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

In accordance with the LTIP and stock option agreement, the stock option awards granted will become exercisable in accordance with the following schedule based upon the number of full years of the optionee's continuous employment or service with the Company, following the date of grant:

Full years of continuous employment	Incremental percentage of option exercisable	Cumulative percentage of option exercisable
Less than one	—%	—%
One	25%	25%
Two	25%	50%
Three	25%	75%
Four	25%	100%

No shares of common stock may be purchased unless the optionee has remained in continuous employment with the Company for one year from the grant date. Unless terminated sooner, the stock option award will expire if and to the extent it is not exercised within 10 years from the grant date. The unvested portion of a stock option award shall expire upon termination of employment, and the vested portion of a stock option award shall remain exercisable for (i) one year following termination of employment by reason of the holder's death or disability, but not later than the expiration of the option period, or (ii) 90 days following termination of employment for any reason other than the holder's death or disability, and other than the holder's termination of employment for cause. Both the unvested and the vested but unexercised portion of a stock option award shall expire upon the termination of the option holder's employment or service by the Company for cause.

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 years ended December 31, 2016, 2017 and 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, 2015	874	$	20.06
Granted	1,801	$	17.71
Forfeited	(350)	$	19.34
Outstanding as of December 31, 2016	2,325	$	18.35
Granted	696	$	18.96
Forfeited	(76)	$	18.12
Vested(1)	(200)	$	28.56
Outstanding as of December 31, 2017	2,745	$	17.77
Granted(2)	1,389	$	9.22
Forfeited	(244)	$	14.93
Vested(3)	(454)	$	16.23
Outstanding as of December 31, 2018	3,436	$	13.74

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(1) These performance share awards had a performance period of January 1, 2014 to December 31, 2016 and, as their vesting and market criteria were satisfied, each award converted into 0.75 shares representing 150,388 shares of common stock issued during the first quarter of 2017.

(2) 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. As of December 31, 2018, the estimated probability of how many shares will be earned at the end of the three-year performance period was estimated to be 50%, resulting in expense of $4.18 per unit for the (.50) ROACE Factor for the year ended December 31, 2018. The grant-date fair value of the market criteria portion of the award is locked in at $10.08 per unit for the combined (.25) RTSR Factor and (.25) ATSR Factor and, as a result, the expense for the total award is $7.13 per unit for the year ended December 31, 2018.

(3) The performance share awards granted on February 27, 2015 had a performance period of January 1, 2015 to December 31, 2017 and, as their market 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.

The performance share awards granted on April 1, 2016 and May 25, 2016 had a performance period of January 1, 2016 to December 31, 2018 and, as their market criteria were not satisfied, resulted in a TSR modifier of 0% based on the Company finishing in the ninth percentile of its peer group for relative TSR. As such, the 1,502,868 units were not converted into the Company's common stock during the first quarter of 2019.

As of December 31, 2018, unrecognized stock-based compensation related to the performance share awards expected to vest was $11.9 million. Such cost is expected to be recognized over a weighted-average period of 1.59 years.

The assumptions used to estimate the fair value of the performance share awards granted as of the dates presented are as follows:

	February 16, 2018[3]	February 17, 2017	May 25, 2016	April 1, 2016
Risk-free interest rate[1]	2.34%	1.44%	1.02%	0.87%
Dividend yield	—%	—%	—%	—%
Expected volatility[2]	65.49%	74.00%	74.73%	71.54%
Closing stock price on grant date	$ 8.36	$ 14.12	$ 12.36	$ 7.71
Fair value per performance share award	$ 10.08	$ 18.96	$ 17.86	$ 9.83

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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) These are 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. 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:

	For the years ended December 31,		
(in thousands)	2018	2017	2016
Restricted stock award compensation	$ 25,271	$ 22,223	$ 21,609
Stock option award compensation	3,862	4,762	4,519
Performance share award compensation	15,192	16,312	9,112
Total stock-based compensation, gross	44,325	43,297	35,240
Less amounts capitalized in evaluated oil and natural gas properties	(7,929)	(7,563)	(6,011)
Total stock-based compensation, net	$ 36,396	$ 35,734	$ 29,229

Performance unit awards

The performance unit awards issued to management in 2013 were subject to a combination of market and service vesting criteria. These awards were accounted for as liability awards as they were settled in cash at the end of the requisite service period based on the achievement of certain performance criteria. A Monte Carlo simulation prepared by an independent third party was utilized to determine the fair values of these awards at the grant date and to re-measure the fair values at the end of each reporting period until settlement in accordance with GAAP. The volatility criteria utilized in the Monte Carlo simulation was based on the volatility of the Company's stock price and the stock price volatilities of a group of peer companies defined in each respective award agreement. The liability and related compensation expense of these awards for each period was recognized by dividing the fair value of the total liability by the requisite service period and recording the pro rata share for the period for which service had already been provided.

The 44,481 settled 2013 performance unit awards had a performance period of January 1, 2013 to December 31, 2015 and, as their performance criteria were satisfied, they were paid at $143.75 per unit during the first quarter of 2016.

d. *Defined contribution plan*

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees at the date of hire. The plan allows eligible employees to make pre-tax and after-tax contributions up to 100% of their annual compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to 6% of an employee's compensation and may make additional discretionary contributions for eligible employees. Employees are 100% vested in the employer contributions upon receipt.

The following table presents the cost recognized for the Company's defined contribution plan for the periods presented:

	For the years ended December 31,		
(in thousands)	2018	2017	2016
Contributions	$ 2,156	$ 1,929	$ 1,789

Note 9—Derivatives

Due to the inherent volatility in oil, NGL and natural gas prices, commodity transportation costs and differences in the prices of oil, NGL and natural gas between where the Company produces and where the Company sells such commodities, 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 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.

The following discussion regarding the Company's transaction types and settlement indexes pertain to the years ended December 31, 2018, 2017 and 2016 as well as the open positions as of December 31, 2018.

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 at or 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 and less than or equal 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 arithmetic average of the daily settlement prices for the 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 the differential between the basis swaps' fixed differential price as compared to the differential between the arithmetic average of each day's index prices for the first nearby month on the pricing dates in each calculation period with the index prices being either (i) the Argus Americas Crude's West Texas Intermediate ("WTI") Midland-weighted average and the Cushing-based NYMEX West Texas Intermediate Light Sweet Crude

Oil Futures Contract, (ii) the Argus Americas Crude's WTI Midland-weighted average and the Cushing-based WTI formula basis or (iii) the Argus Americas Crude's WTI Houston-weighted average and the WTI Midland-weighted average. The Company's NGL derivatives are settled based on the month's arithmetic average of the daily average of the high and low OPIS index prices 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 or the NYMEX index price for Henry Hub for the calculation period. The natural gas basis swaps are settled based on the differential between the basis swaps' fixed differential price as compared to the differential between the Inside FERC index price for West Texas WAHA and the NYMEX index price for Henry Hub for the calculation period.

During the year ended December 31, 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 hedge 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

During the year ended December 31, 2016, the Company completed a hedge restructuring by early terminating the floors of certain derivative contract collars that resulted in a termination amount to the Company of $80.0 million, which was settled in full by applying the proceeds to pay the premiums on two new derivatives entered into during the hedge restructuring.

The following table summarizes open derivative positions as of December 31, 2018 for derivatives that were entered into through December 31, 2018, and represents derivatives in place through December 2021 on annual production volumes:

	Year 2019	Year 2020	Year 2021
Oil:			
Puts:			
Hedged volume (Bbl)	8,030,000	366,000	—
Weighted-average floor price ($/Bbl)	$ 47.45	$ 45.00	$ —
Hedged volume with deferred premium (Bbl)	4,745,000	—	—
Weighted-average deferred premium price ($/Bbl)	$ 3.21	$ —	$ —
Swaps:			
Hedged volume (Bbl)	657,000	695,400	—
Weighted-average price ($/Bbl)	$ 53.45	$ 52.18	$ —
Collars:			
Hedged volume (Bbl)	—	1,134,600	912,500
Weighted-average floor price ($/Bbl)	$ —	$ 45.00	$ 45.00
Weighted-average ceiling price ($/Bbl)	$ —	$ 76.13	$ 71.00
Totals:			
Total volume hedged with floor price (Bbl)	8,687,000	2,196,000	912,500
Weighted-average floor price ($/Bbl)	$ 47.91	$ 47.27	$ 45.00
Total volume hedged with ceiling price (Bbl)	657,000	1,830,000	912,500
Weighted-average ceiling price ($/Bbl)	$ 53.45	$ 67.03	$ 71.00
Basis Swaps:			
WTI Midland to WTI NYMEX:			
Hedged volume (Bbl)	1,840,000	—	—
Weighted-average price ($/Bbl)	$ (2.89)	$ —	$ —
WTI Midland to WTI formula basis:			
Hedged volume (Bbl)	552,000	—	—
Weighted-average price ($/Bbl)	$ (4.37)	$ —	$ —
WTI Houston to WTI Midland:			
Hedged volume (Bbl)	1,810,000	—	—
Weighted-average price ($/Bbl)	$ 7.30	$ —	$ —
NGL:			
Swaps - Purity Ethane:			
Hedged volume (Bbl)	730,000	366,000	365,000
Weighted-average price ($/Bbl)	$ 14.07	$ 13.60	$ 13.02
Swaps - Non-TET Natural Gasoline:			
Hedged volume (Bbl)	182,500	—	—
Weighted-average price ($/Bbl)	$ 46.62	$ —	$ —
Total NGL volume hedged (Bbl)	912,500	366,000	365,000
Natural gas:			
Henry Hub NYMEX Swaps:			
Hedged volume (MMBtu)	21,900,000	—	—
Weighted-average price ($/MMBtu)	$ 3.23	$ —	$ —
Basis Swaps:			
Hedged volume (MMBtu)	39,055,000	32,574,000	16,425,000
Weighted-average price ($/MMBtu)	$ (1.51)	$ (0.76)	$ (0.47)

See Note 2.f for discussion of derivatives significant accounting policies, and see Note 17.b for a summary of open derivative positions as of December 31, 2018 for derivatives that were entered into through February 13, 2019.

Note 10—Fair value measurements

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 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.

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 included in the "Derivatives" line items on the consolidated balance sheets 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 consolidated balance sheets
As of December 31, 2018:						
Assets						
Current:						
Oil derivatives	$ —	$ 44,425	$ —	$ 44,425	$ (7,907)	$ 36,518
NGL derivatives	—	1,974	—	1,974	—	1,974
Natural gas derivatives	—	18,991	—	18,991	(3,267)	15,724
Oil derivative deferred premiums	—	—	—	—	(14,381)	(14,381)
Natural gas derivative deferred premiums	—	—	—	—	—	—
Noncurrent:						
Oil derivatives	$ —	$ 10,626	$ —	$ 10,626	$ —	$ 10,626
NGL derivatives	—	1,024	—	1,024	—	1,024
Natural gas derivatives	—	108	—	108	(728)	(620)
Oil derivative deferred premiums	—	—	—	—	—	—
Natural gas derivative deferred premiums	—	—	—	—	—	—
Liabilities						
Current:						
Oil derivatives	$ —	$ (9,059)	$ —	$ (9,059)	$ 7,907	$ (1,152)
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	(7,290)	—	(7,290)	3,267	(4,023)
Oil derivative deferred premiums	—	—	(16,565)	(16,565)	14,381	(2,184)
Natural gas derivative deferred premiums	—	—	—	—	—	—
Noncurrent:						
Oil derivatives	$ —	$ —	$ —	$ —	$ —	$ —
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	(728)	—	(728)	728	—
Oil derivative deferred premiums	—	—	—	—	—	—
Natural gas derivative deferred premiums	—	—	—	—	—	—
Net derivative asset (liability) positions	$ —	$ 60,071	$ (16,565)	$ 43,506	$ —	$ 43,506

(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the 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 asset (liability) positions	$ —	$ 15,654	$ (28,683)	$ (13,029)	$ —	$ (13,029)

Significant Level 2 inputs associated with the calculation of discounted cash flows used in the fair value mark-to-market analysis of derivatives include each derivative contract's corresponding commodity index price(s), appropriate risk-adjusted discount rates and forward price curve models for substantially similar instruments 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 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. The deferred premiums are included in the "Derivatives" line items on the consolidated balance sheets, and as of December 31, 2018, their input rates range from 2.31% to 3.32% with a net fair value weighted-average rate of 2.76%.

The following table presents payments required for derivative deferred premiums as of December 31, 2018 for the calendar years presented:

(in thousands)	December 31, 2018
2019	$ 15,502
2020	1,295
Total	$ 16,797

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

	For the years ended December 31,		
(in thousands)	2018	2017	2016
Balance of Level 3 at beginning of year	$ (28,683)	$ (8,998)	$ (14,619)
Change in net present value of derivative deferred premiums(1)	(694)	(394)	(232)
Purchases and settlements of derivative deferred premiums:			
Purchases	(7,523)	(25,733)	(7,715)
Settlements(2)	20,335	6,442	13,568
Balance of Level 3 at end of year	$ (16,565)	$ (28,683)	$ (8,998)

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(1) These amounts are included in the "Interest expense" line item in the consolidated statements of operations.

(2) The amount for the year ended December 31, 2016 includes $3.9 million that represents the present value of deferred premiums settled in the Company's hedge restructuring upon their early termination.

See Note 2.f for discussion of derivatives significant accounting policies.

b. Fair value measurement on a nonrecurring basis

See Note 2.i for the Level 2 fair value hierarchy input assumptions used in estimating the NRV of materials and supplies inventory used to account for the impairment of materials and supplies inventory recorded during the year ended December 31, 2016. There were no impairments of materials and supplies inventory recorded during the years ended December 31, 2018 or 2017.

See Note 4.e for the Level 3 fair value hierarchy input assumptions used in estimating the fair values of assets acquired and liabilities assumed for acquisitions of evaluated and unevaluated oil and natural gas properties accounted for as a business combination for the year ended December 31, 2016. There were no acquisitions of evaluated and unevaluated oil and natural gas properties accounted for as business combinations for the years ended December 31, 2018 or 2017.

Impairment losses are recorded on long-lived assets when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. For purposes of fair value measurement, it was determined that the impairment of long-lived assets is classified as Level 3, based on the use of internally developed cash flow models. There were no long-lived asset impairments recorded during the years ended December 31, 2018, 2017 or 2016.

c. Items not accounted for at fair value

The carrying amounts reported in the 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:

	December 31, 2018		December 31, 2017	
(in thousands)	**Long-term debt**	**Fair value(1)**	**Long-term debt**	**Fair value(1)**
January 2022 Notes	$ 450,000	$ 402,885	$ 450,000	$ 454,500
March 2023 Notes	350,000	316,624	350,000	364,105
Senior Secured Credit Facility	190,000	190,054	—	—
Total	$ 990,000	$ 909,563	$ 800,000	$ 818,605

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(1) The fair values of the debt outstanding on the January 2022 Notes and the March 2023 Notes were determined using the as of December 31, 2018 and 2017 Level 1 fair value hierarchy quoted market price for each respective instrument. The fair value of the outstanding debt on the Senior Secured Credit Facility as of December 31, 2018 was estimated utilizing the Level 2 fair value hierarchy pricing model for similar instruments. See Note 10.a for information about the fair value hierarchy levels.

Note 11—Net income (loss) per common share

Basic net income (loss) per common share is computed by dividing net income (loss) by the weighted-average number of common shares outstanding for the period. Diluted net income (loss) 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 8.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 (loss) per common share for the periods presented:

	For the years ended December 31,		
(in thousands, except for per share data)	**2018**	**2017**	**2016**
Net income (loss) (numerator):			
Net income (loss)—basic and diluted	$ 324,595	$ 548,974	$ (260,739)
Weighted-average common shares outstanding (denominator):			
Basic(1)	232,339	239,096	225,512
Non-vested restricted stock awards(2)	813	880	—
Outstanding stock option awards(3)	20	122	—
Non-vested performance share awards(4)	—	24	—
Diluted	233,172	240,122	225,512
Net income (loss) per common share:			
Basic	$ 1.40	$ 2.30	$ (1.16)
Diluted	$ 1.39	$ 2.29	$ (1.16)

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(1) Weighted-average common shares outstanding used in the computation of basic and diluted net income (loss) per common share was computed taking into account share repurchases that occurred during the year ended December 31, 2018 and equity offerings that occurred during the year ended December 31, 2016. See Notes 8.a and 8.b for additional discussion of the Company's share repurchase program and equity offerings, respectively.

(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 year ended December 31, 2018. The inclusion of these non-vested restricted stock awards would be anti-dilutive mainly due to the grant-date fair value per common share for the awards being greater than 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 year ended December 31, 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 year ended December 31, 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 8.c: (i) the RTSR Performance Percentage, (ii) the ATSR Appreciation and (iii) the ROACE Percentage from the beginning of the performance period to December 31, 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 2017 and 2016 were calculated utilizing the Company's TSR from the beginning of each performance share awards' respective performance period to December 31, 2018 in comparison to the TSR of the peers specified in each respective performance share awards' agreement.

Note 12—Income taxes

The Company is subject to federal and state income taxes and the Texas franchise tax. The following table presents the federal and state income taxes included in the income tax expense "Current" and "Deferred" line items in the consolidated statements of operations for the periods presented:

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Current income tax benefit:			
Federal	$ —	$ —	$ —
State	807	(1,800)	—
Deferred income tax expense:			
Federal	—	—	—
State	(5,056)	—	—
Total income tax expense	$ (4,249)	$ (1,800)	$ —

As of December 31, 2018, a Texas deferred tax liability of $5.1 million has been recorded, which is included in the "Other noncurrent liabilities" line item on the consolidated balance sheets, along with the corresponding deferred income tax expense for the year ended December 31, 2018. Additionally, a current tax refund of $0.8 million of Texas franchise tax was received as a result of differences in estimated versus actual taxable income from the gain on the Medallion Sale and is recorded as a current income tax benefit.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"). The Tax Act, among other things, (i) reduces the U.S. corporate income tax rate, (ii) repeals the corporate alternative minimum tax, (iii) imposes new limitations on the utilization of net operating losses and (iv) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense. The Company recognizes the effects of changes in tax laws and rates on deferred tax assets and liabilities and the retroactive effects of changes in tax laws in the period in which the new legislation is enacted. The enactment date in the U.S. is the date the bill becomes law, which is when the President signs the bill.

For the year ended December 31, 2017, current tax expense recorded of $1.8 million is comprised of Texas franchise tax, mainly as a result of the Medallion Sale. Additionally, the Company paid Alternative Minimum Tax ("AMT") related to the Medallion Sale. The payment of AMT creates an AMT credit carryforward. Due to changes in the Tax Act, AMT credit carryforwards do not expire and are now refundable over the next five years, and therefore, as of December 31, 2018, a receivable has been recorded in the amount of $4.8 million, of which $2.4 million is included in the "Accounts receivable, net" line item and $2.4 million is included in the "Other noncurrent assets, net" line item on the consolidated balance sheets.

The following table presents the expected years in which the Company's AMT credit carryforward will be refunded:

(in thousands)	**December 31, 2018**
2019	$ 2,408
2020	1,203
2021	602
2022	602
AMT credit carryforward	$ 4,815

Income tax expense differed from amounts computed by applying the applicable federal income tax rate of 21% for the year ended December 31, 2018 and 35% for the years ended December 31, 2017 and 2016 to pre-tax earnings as a result of the following:

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Income tax (expense) benefit computed by applying the statutory rate	$ (69,057)	$ (192,141)	$ 91,259
Decrease (increase) in deferred tax valuation allowance	74,289	417,518	(86,569)
State income tax and change in valuation allowance	(9,070)	696	(370)
Change in tax rate applicable to net deferred tax assets	—	(226,263)	—
Stock-based compensation tax deficiency	—	(64)	(4,144)
Other items	(411)	(1,546)	(176)
Total income tax expense	$ (4,249)	$ (1,800)	$ —

The effective tax rates for the Company's operations were 1% for the year ended December 31, 2018, and 0% for each of the years ended December 31, 2017 and 2016. The Company's effective tax rate is affected by changes in tax rates, valuation allowances, recurring permanent differences and by discrete items that may occur in any given year, but are not consistent from year to year. The Company's effective tax rate is expected to remain at 1%, due to the full valuation allowance against the Company's federal and Oklahoma net deferred tax assets.

On January 1, 2018, the Company adopted ASC 606 using the modified retrospective approach of adoption with the cumulative effect recognized as an adjustment to the beginning balance of accumulated deficit, presented in the consolidated statements of stockholders' equity. As the effect on income taxes of adoption and transition to ASC 606 are direct effects of the change, the beginning balances of the federal and state deferred tax assets and the offsetting valuation allowances relating to the reclassification of the $141.1 million deferred gain on Medallion Sale were reduced by $30.7 million. See Note 5.a for further discussion of the impact of ASC 606 adoption.

A valuation allowance is established to reduce deferred tax assets if it is determined that it is more likely than not that the related tax benefit will not be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. During the years ended December 31, 2018 and 2017, in evaluating whether it was more likely than not that the Company's net deferred tax assets were realizable through future net income, management considered all available positive and negative evidence, including (i) its earnings history, (ii) its ability to recover net operating loss carry-forwards, (iii) the existence of significant proved oil, NGL and natural gas reserves, (iv) its ability to use tax planning strategies, (v) its current price protection utilizing oil, NGL and natural gas hedges, (vi) its future revenue and operating cost projections and (vii) the current market prices for oil, NGL and natural gas. Based on all the evidence available, during the year ended December 31, 2018 and 2017, management determined it was more likely than not that the net deferred tax assets were not realizable. The Company maintains a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized. As of December 31, 2018, a total valuation allowance of $237.3 million had been recorded against the deferred tax assets.

The following table presents significant components of the Company's net deferred tax liability as of December 31:

(in thousands)	**2018**	**2017**
Net operating loss carryforward	$ 392,276	$ 355,100
Oil and natural gas properties, midstream service assets and other fixed assets	(168,031)	(80,153)
Stock-based compensation	19,845	14,025
Derivatives	(8,188)	3,788
Gain (loss) on sale of assets	(7,693)	40,177
Other	3,997	8,465
Net deferred tax asset before valuation allowance	232,206	341,402
Valuation allowance	(237,262)	(341,402)
Net deferred tax liability	$ (5,056)	$ —

The following presents the Company's federal net operating loss carryforwards and their applicable expiration dates as of the period presented:

(in thousands)	December 31, 2018
2026	$ 2,741
2027	38,651
2028	228,661
2029	101,932
2030	80,963
Thereafter	1,406,873
Total	$ 1,859,821

The Company had federal net operating loss carry-forwards totaling $1.9 billion and state of Oklahoma net operating loss carryforwards totaling $36.2 million as of December 31, 2018, which begin expiring in 2026 and 2032, respectively. Due to the passing of the Tax Act, $122.7 million of the federal net operating loss carry-forward will not expire but may be limited in future periods. As of December 31, 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 December 31, 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.

The Company files a single return. The Company's income tax returns for the years 2015 through 2018 remain open and subject to examination by federal tax authorities and/or the tax authorities in Oklahoma and Texas, which are the jurisdictions where the Company has or had operations. Additionally, the statute of limitations for examination of federal net operating loss carryforwards typically does not begin to run until the year the attribute is utilized in a tax return. See Note 2.q for further discussion of accounting policies regarding income taxes.

Note 13—Credit risk

The Company's oil, NGL and natural gas production sales are made to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. The Company's joint operations accounts receivable are from a number of oil and natural gas companies, partnerships, individuals and others who own interests in the oil and natural gas properties operated by the Company. The Company's sales of purchased oil are generally made to one customer.

The majority of the Company's accounts receivable are unsecured. On occasion the Company requires its customers to post collateral, and the inability of the Company's significant customers to meet their obligations to the Company or their insolvency or liquidation may adversely affect the Company's financial results. Management believes that any credit risk imposed by a concentration in the oil and natural gas industry is offset by the creditworthiness of the Company's customer base and industry partners. The Company routinely assesses the recoverability of all material trade and other receivables to determine collectability. See Notes 2.e and 5 for additional information regarding the Company's accounts receivable and revenue recognition, respectively.

The Company uses derivatives to hedge its exposure to oil, NGL and natural gas price volatility. These transactions expose the Company to potential credit risk from its counterparties. The Company has entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of its derivative counterparties, each of whom is also a lender in the Company's Senior Secured Credit Facility, which is secured by the Company's oil, NGL and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not require collateral from its derivative counterparties. The terms of the ISDA Agreements provide the non-defaulting or non-affected party the right to terminate the agreement upon the occurrence of certain events of default and termination events by a party and also provide for the marking to market of outstanding positions and the offset of the mark to market amounts owed to and by the parties (and in certain cases, the affiliates of the non-defaulting or non-affected party) upon termination; therefore, the credit risk associated with the Company's derivative counterparties is somewhat mitigated. The Company minimizes the credit risk in derivatives by:
(i) limiting its exposure to any single counterparty, (ii) entering into derivatives only with counterparties that meet its minimum credit quality standard or have a guarantee from an affiliate that meets the Company's minimum credit quality standard

and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis. As of December 31, 2018, the Company had receivables of $50.9 million from the fair values of open derivative contracts. See "Part II, Item 7a. Quantitative and Qualitative Disclosures About Market Risk—Commodity price exposure" located elsewhere in this Annual Report and Notes 2.f, 9, 10.a and 17.b for additional information regarding the Company's derivatives.

The Company had four customers that accounted for 29.5%, 24.2%, 16.2% and 16.0% of total oil, NGL and natural gas sales for the year ended December 31, 2018, and three customers that accounted for 33.8%, 23.9%, and 23.3% of total oil, NGL and natural gas sales accounts receivable as of December 31, 2018. The Company had four customers that accounted for (i) 39.3%, 26.1%, 17.4% and 12.6% of total oil, NGL and natural gas sales for the year ended December 31, 2017, and (ii) 34.6%, 27.3%, 15.6% and 15.4% of total oil, NGL and natural gas sales accounts receivable as of December 31, 2017. The Company had three customers that accounted for 48.5%, 23.0% and 17.0% of total oil, NGL and natural gas sales for the year ended December 31, 2016.

The Company had two partners that accounted for 46.7% and 30.9% of total joint operations, net accounts receivable as of December 31, 2018. The Company had one partner that accounted for 21.4% of total joint operations, net accounts receivable as of December 31, 2017.

The Company had two customers that accounted for 63.9% and 36.1% of total sales of purchased oil for the year ended December 31, 2018, and one customer that accounted for 100.0% of total sales of purchased oil and other products accounts receivable as of December 31, 2018. The Company had one customer that accounted for 97.5% of total sales of purchased oil for the year ended December 31, 2017, with the same customer accounting for 99.7% of total sales of purchased oil and other products accounts receivable as of December 31, 2017. The Company had one customer that accounted for 100.0% of total sales of purchased oil for the year ended December 31, 2016.

The Company's cash balances that are insured by the FDIC up to $250,000 per bank did not exceed this amount as of December 31, 2018. The Company had $48.2 million in cash balances on deposit with three banks as of December 31, 2018 that were not insured by the FDIC. Management believes that the risk of loss is mitigated by the banks' reputation and financial position.

See "Part I, Item 3. Legal Proceedings" located elsewhere in this Annual Report and Note 14 for additional discussion regarding credit risk.

Note 14—Commitments and contingencies

a. Lease commitments

The Company leases office space under operating leases expiring on various dates through 2027. The following table presents future minimum rental payments required:

(in thousands)	December 31, 2018
2019	$ 3,092
2020	3,179
2021	3,128
2022	2,560
2023	1,358
Thereafter	4,556
Total future minimum rental payments required	$ 17,873

The Company subleases office space with $5.9 million total future minimum rentals to be received as of December 31, 2018.

The following table presents rent expense:

	For the years ended December 31,		
(in thousands)	2018	2017	2016
Rent expense	$ 2,735	$ 2,696	$ 2,664

Rent income for the year ended December 31, 2018 totaled $0.6 million. Rent income for the year ended December 31, 2017 totaled de minimis amounts. No such amounts were included for the year ended December 31, 2016.

The Company's office space lease agreements contain scheduled escalation in lease payments during the term of the leases. In accordance with GAAP, the Company records rent expense and rent income on a straight-line basis and a deferred lease liability and deferred lease asset, respectively, for the difference between the straight-line amount and the actual amounts of the lease payments and lease receipts. Deferred lease liability, net is included in the "Other current liabilities" and "Other noncurrent liabilities" line items on the consolidated balance sheets. Rent expense and rent income are included in the "General and administrative" line item and "Interest and other income" line item, respectively, in the consolidated statements of operations.

b. 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 the Company 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 last day before Shell's wrongfully termination of 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 consolidated balance sheets do not include any amounts for damage claims or attorneys' fees sought by Shell. As of December 31, 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.

c. 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 the years ended December 31, 2018, 2017 or 2016. Future commitments of $16.5 million as of December 31, 2018 are not recorded in the accompanying consolidated balance sheets. Management does not currently anticipate the early termination of these contracts in 2019.

d. 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 firm transportation payments on excess pipeline capacity and other contractual penalties. 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 firm transportation payments on excess pipeline capacity and other contractual penalties of $4.7 million, $1.1 million and $2.2 million during the years ended December 31, 2018, 2017 and 2016, respectively. In the consolidated statements of operations, these firm transportation payments on excess pipeline capacity and other contractual penalties are netted with their respective revenue stream for the year ended December 31, 2018, and are included in the "Other operating expenses" line item for the years ended December 31, 2017 and 2016. Future commitments of $365.9 million as of December 31, 2018 are not recorded in the accompanying consolidated balance sheets. For information regarding the impact of the adoption of ASC 606 on the TA related to Medallion and the presentation of firm transportation payments on excess pipeline capacity and other contractual penalties, see Notes 4.c and 5 .

e. Sand purchase and supply agreement

During the year ended December 31, 2018, the Company entered into a sand purchase and supply agreement, for a term of one year, whereby it has committed to buy a certain volume of in-basin sand, utilized in the Company's completion activities, for a fixed price. As of December 31, 2018, under the terms of this agreement, the Company is required to purchase a certain percentage of the volume commitment or it would incur a shortfall payment of $3.9 million at the end of the contract period.

f. 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.

g. 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 material significant liabilities of this nature existed as of December 31, 2018 or 2017.

Note 15—Related parties

a. Medallion

Medallion was a related party and an equity method investee until the Medallion Sale in October 2017. See Note 4.c for discussion of the Medallion Sale.

For the year ended December 31, 2017, a de minimis amount related to Medallion was included in the "Loss on disposal of assets, net" line item in the consolidated statements of operations. No such amounts were included for the years ended December 31, 2018 or 2016.

b. Helmerich & Payne, Inc.

The Company has a drilling contract with Helmerich & Payne, Inc. ("H&P"). Laredo's Chairman and Chief Executive Officer is on the board of directors of H&P.

The following table presents accounts payable and accrued liabilities related to H&P included in the consolidated balance sheets:

(in thousands)	December 31, 2018	December 31, 2017
Accounts payable and accrued liabilities	$ 399	$ —

The following table presents the capital expenditures for oil and natural gas properties related to H&P included in the consolidated statements of cash flows:

	For the years ended December 31,		
(in thousands)	2018	2017	2016
Oil and natural gas properties	$ 3,040	$ —	$ —

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 condensed consolidating balance sheets as of December 31, 2018 and 2017 and condensed consolidating statements of operations and condensed consolidating statements of cash flows each for the years ended December 31, 2018, 2017 and 2016 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. During the year ended December 31, 2016, certain assets were transferred from Laredo to LMS and from LMS to Laredo at historical cost. No such transfers occurred during the years ended December 31, 2018 or 2017.

Condensed consolidating balance sheet
December 31, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$ 83,424	$ 10,897	$ —	$ 94,321
Other current assets	97,045	1,386	—	98,431
Oil and natural gas properties, net	2,043,009	9,113	(22,551)	2,029,571
Midstream service assets, net	—	130,245	—	130,245
Other fixed assets, net	39,751	68	—	39,819
Investment in subsidiaries	128,380	—	(128,380)	—
Other noncurrent assets, net	23,783	4,135	—	27,918
Total assets	$ 2,415,392	$ 155,844	$ (150,931)	$ 2,420,305
Accounts payable and accrued liabilities	$ 54,167	$ 15,337	$ —	$ 69,504
Other current liabilities	121,297	9,664	—	130,961
Long-term debt, net	983,636	—	—	983,636
Other noncurrent liabilities	59,511	2,463	—	61,974
Total stockholders' equity	1,196,781	128,380	(150,931)	1,174,230
Total liabilities and stockholders' equity	$ 2,415,392	$ 155,844	$ (150,931)	$ 2,420,305

Laredo Petroleum, Inc.
Notes to the consolidated financial statements

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
Total 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 year ended December 31, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 809,396	$ 365,633	$ (69,254)	$ 1,105,775
Total costs and expenses	466,895	353,806	(63,418)	757,283
Operating income	342,501	11,827	(5,836)	348,492
Interest expense	(57,904)	—	—	(57,904)
Other non-operating income (expense), net	50,083	(1,049)	(10,778)	38,256
Income before income tax	334,680	10,778	(16,614)	328,844
Total income tax expense	(4,249)	—	—	(4,249)
Net income	$ 330,431	$ 10,778	$ (16,614)	$ 324,595

Condensed consolidating statement of operations
For the year ended December 31, 2017

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 623,028	$ 266,455	$ (67,321)	$ 822,162
Total costs and expenses	376,938	254,398	(58,846)	572,490
Operating income	246,090	12,057	(8,475)	249,672
Interest expense	(89,377)	—	—	(89,377)
Gain on sale of investment in equity method investee (see Note 4.c)	—	405,906	—	405,906
Other non-operating income (expense), net	402,536	8,083	(426,046)	(15,427)
Income before income tax	559,249	426,046	(434,521)	550,774
Total income tax expense	(1,800)	—	—	(1,800)
Net income	$ 557,449	$ 426,046	$ (434,521)	$ 548,974

Condensed consolidating statement of operations
For the year ended December 31, 2016

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 427,028	$ 213,866	$ (43,516)	$ 597,378
Total costs and expenses	514,483	208,056	(37,199)	685,340
Operating income (loss)	(87,455)	5,810	(6,317)	(87,962)
Interest expense	(93,298)	—	—	(93,298)
Other non-operating income (expense), net	(73,669)	9,381	(15,191)	(79,479)
Income (loss) before income tax	(254,422)	15,191	(21,508)	(260,739)
Total income tax	—	—	—	—
Net income (loss)	$ (254,422)	$ 15,191	$ (21,508)	$ (260,739)

Condensed consolidating statement of cash flows
For the year ended December 31, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash provided by operating activities	$ 528,281	$ 20,301	$ (10,778)	$ 537,804
Change in investments between affiliates	5,175	(15,953)	10,778	—
Capital expenditures and other	(686,608)	(6,003)	—	(692,611)
Proceeds from disposition of equity method investee, net of selling costs (see Note 4.c)	—	1,655	—	1,655
Net cash provided by financing activities	86,144	—	—	86,144
Net decrease in cash and cash equivalents	(67,008)	—	—	(67,008)
Cash and cash equivalents, beginning of period	112,158	1	—	112,159
Cash and cash equivalents, end of period	$ 45,150	$ 1	$ —	$ 45,151

Condensed consolidating statement of cash flows
For the year ended December 31, 2017

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash provided by operating activities	$ 778,851	$ 32,109	$ (426,046)	$ 384,914
Change in investments between affiliates	383,613	(809,659)	426,046	—
Capital expenditures and other	(482,500)	(52,065)	—	(534,565)
Proceeds from disposition of equity method investee, net of selling costs (see Note 4.c)	—	829,615 —	—	829,615
Net cash used in financing activities	(600,477)	—	—	(600,477)
Net increase in cash and cash equivalents	79,487	—	—	79,487
Cash and cash equivalents, beginning of period	32,671	1	—	32,672
Cash and cash equivalents, end of period	$ 112,158	$ 1	$ —	$ 112,159

Condensed consolidating statement of cash flows
For the year ended December 31, 2016

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash provided by operating activities	$ 355,458	$ 16,028	$ (15,191)	$ 356,295
Change in investments between affiliates	(73,988)	58,797	15,191	—
Capital expenditures and other	(489,577)	(74,825)	—	(564,402)
Net cash provided by financing activities	209,625	—	—	209,625
Net increase in cash and cash equivalents	1,518	—	—	1,518
Cash and cash equivalents, beginning of period	31,153	1	—	31,154
Cash and cash equivalents, end of period	$ 32,671	$ 1	$ —	$ 32,672

Note 17—Subsequent events

a. Senior Secured Credit Facility

On January 14, 2019 and February 12, 2019, the Company borrowed $30.0 million and $20.0 million, respectively, on the Senior Secured Credit Facility. As a result, the outstanding balance under the Senior Secured Credit Facility was $240.0 million as of February 13, 2019.

b. Derivatives

The following table summarizes open derivative positions as of December 31, 2018 for derivatives that were entered into through February 13, 2019, and represents derivatives in place through December 2021 on annual production volumes:

	Year 2019	Year 2020	Year 2021
Oil:			
Puts:			
Hedged volume (Bbl)	8,030,000	366,000	—
Weighted-average floor price ($/Bbl)	$ 47.45	$ 45.00	$ —
Hedged volume with deferred premium (Bbl)	4,745,000	—	—
Weighted-average deferred premium price ($/Bbl)	$ 3.21	$ —	$ —
Swaps:			
Hedged volume (Bbl)	657,000	695,400	—
Weighted-average price ($/Bbl)	$ 53.45	$ 52.18	$ —
Collars:			
Hedged volume (Bbl)	—	1,134,600	912,500
Weighted-average floor price ($/Bbl)	$ —	$ 45.00	$ 45.00
Weighted-average ceiling price ($/Bbl)	$ —	$ 76.13	$ 71.00
Totals:			
Total volume hedged with floor price (Bbl)	8,687,000	2,196,000	912,500
Weighted-average floor price ($/Bbl)	$ 47.91	$ 47.27	$ 45.00
Total volume hedged with ceiling price (Bbl)	657,000	1,830,000	912,500
Weighted-average ceiling price ($/Bbl)	$ 53.45	$ 67.03	$ 71.00
Basis Swaps:			
WTI Midland to WTI NYMEX:			
Hedged volume (Bbl)	1,840,000	—	—
Weighted-average price ($/Bbl)	$ (2.89)	$ —	$ —
WTI Midland to WTI formula basis:			
Hedged volume (Bbl)	552,000	—	—
Weighted-average price ($/Bbl)	$ (4.37)	$ —	$ —
WTI Houston to WTI Midland:			
Hedged volume (Bbl)	1,810,000	—	—
Weighted-average price ($/Bbl)	$ 7.30	$ —	$ —
NGL:			
Swaps - Purity Ethane:			
Hedged volume (Bbl)	2,233,000	366,000	912,500
Weighted-average price ($/Bbl)	$ 14.21	$ 13.60	$ 12.01
Swaps - Non-TET Propane:			
Hedged volume (Bbl)	1,736,800	1,244,400	730,000
TABLE CONTINUES ON NEXT PAGE			

	Year 2019	Year 2020	Year 2021
Weighted-average price ($/Bbl)	$ 27.97	$ 26.58	$ 25.52
Swaps - Non-TET Normal Butane:			
Hedged volume (Bbl)	668,000	439,200	255,500
Weighted-average price ($/Bbl)	$ 30.73	$ 28.69	$ 27.72
Swaps - Non-TET Isobutane:			
Hedged volume (Bbl)	167,000	109,800	67,525
Weighted-average price ($/Bbl)	$ 31.08	$ 29.99	$ 28.79
Swaps - Non-TET Natural Gasoline:			
Hedged volume (Bbl)	583,300	402,600	237,250
Weighted-average price ($/Bbl)	$ 45.83	$ 45.15	$ 44.31
Total NGL volume hedged (Bbl)	5,388,100	2,562,000	2,202,775
Natural gas:			
Henry Hub NYMEX Swaps:			
Hedged volume (MMBtu)	21,900,000	—	—
Weighted-average price ($/MMBtu)	$ 3.23	$ —	$ —
Basis Swaps:			
Hedged volume (MMBtu)	39,055,000	32,574,000	23,360,000

Weighted-average price ($/MMBtu)	$ (1.51)	$ (0.76)	$ (0.47)

See Note 9 for discussion regarding the Company's derivative settlement indexes.

Note 18—Supplemental oil, NGL and natural gas disclosures (unaudited)

a. Costs incurred in oil and natural gas property acquisition, exploration and development activities

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:

	For the years ended December 31,		
(in thousands)	2018	2017	2016
Property acquisition costs:			
Evaluated	$ 15,072	$ —	$ 5,905
Unevaluated	2,790	—	119,923
Exploration costs	23,884	36,257	41,333
Development costs	607,790	560,919	298,942
Total costs incurred	$ 649,536	$ 597,176	$ 466,103

b. Aggregate capitalized oil, NGL and natural gas costs

The following table presents the aggregate capitalized costs related to oil, NGL and natural gas production activities with applicable accumulated depletion and impairment:

(in thousands)	December 31, 2018	December 31, 2017
Gross capitalized costs:		
Evaluated properties	$ 6,752,631	$ 6,070,940
Unevaluated properties not being depleted	130,957	175,865
Total gross capitalized costs	6,883,588	6,246,805
Less accumulated depletion and impairment	(4,854,017)	(4,657,466)
Net capitalized costs	$ 2,029,571	$ 1,589,339

The following table presents a summary of the unevaluated property costs not being depleted as of December 31, 2018, by year in which such costs were incurred:

(in thousands)	2018	2017	2016	2015 and prior	Total
Unevaluated properties not being depleted	$ 38,815	$ 15,076	$ 56,826	$ 20,240	$ 130,957

Unevaluated properties, which are not subject to depletion, are not individually significant and consist of costs for acquiring oil and natural gas leasehold where no evaluated reserves have been identified, including costs of wells being evaluated. The evaluation process associated with these properties has not been completed and therefore, the Company is unable to estimate when these costs will be included in the depletion calculation.

c. *Results of operations of oil, NGL and natural gas producing activities*

The following table presents the results of operations of oil, NGL and natural gas producing activities (excluding corporate overhead and interest costs):

(in thousands)	For the years ended December 31, 2018	2017	2016
Revenues:			
Oil, NGL and natural gas sales	$ 808,530	$ 621,507	$ 426,485
Production costs:			
Lease operating expenses	91,289	75,049	75,327
Production and ad valorem taxes	49,457	37,802	28,586
Transportation and marketing expenses	11,704	—	—
Total production costs	152,450	112,851	103,913
Other costs:			
Depletion	196,458	143,592	134,105
Accretion of asset retirement obligations	4,233	3,567	3,274
Impairment expense	—	—	161,064
Income tax expense[(1)]	4,554	—	—
Total other costs	205,245	147,159	298,443
Results of operations	$ 450,835	$ 361,497	$ 24,129

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(1) During each of the years ended December 31, 2018, 2017 and 2016, the Company recorded valuation allowances against its deferred tax assets related to its oil, NGL and natural gas producing activities. Accordingly, the income tax expense was computed utilizing the Company's effective rate of 1% for the year ended December 31, 2018 and 0% for each of the years ended December 31, 2017 and 2016, which reflects tax deductions and tax credits and allowances relating to the oil, NGL and natural gas producing activities that are reflected in the Company's consolidated income tax expense for the period.

d. *Net proved oil, NGL and natural gas reserves*

Ryder Scott Company, L.P. ("Ryder Scott"), the Company's independent reserve engineers, estimated 100% of the Company's proved reserves as of December 31, 2018, 2017 and 2016. In accordance with SEC regulations, the reserves as of December 31, 2018, 2017 and 2016 were estimated using the Realized Prices, which reflect adjustments to the Benchmark Prices for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. See Note 6.a for additional discussion. The Company's reserves as of December 31, 2018, 2017 and 2016 are reported in three streams: oil, NGL and natural gas. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and natural gas properties. Accordingly, the estimates may change as future information becomes available.

The following tables provide an analysis of the changes in estimated proved reserve quantities of oil, NGL and natural gas for the years ended December 31, 2018, 2017 and 2016, all of which are located within the U.S.

	Year ended December 31, 2018			
	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	79,413	67,371	414,592	215,883
Revisions of previous estimates	(20,921)	11,089	72,028	2,173
Extensions, discoveries and other additions	13,330	15,112	93,762	44,069
Acquisitions of reserves in place	596	457	2,810	1,521
Divestitures of reserves in place	(349)	(123)	(756)	(598)
Production	(10,175)	(7,259)	(44,680)	(24,881)
End of year	61,894	86,647	537,756	238,167
Proved developed reserves:				
Beginning of year	68,877	60,441	371,946	191,309
End of year	55,893	79,241	491,828	217,105
Proved undeveloped reserves:				
Beginning of year	10,536	6,930	42,646	24,574
End of year	6,001	7,406	45,928	21,062

	Year ended December 31, 2017			
	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	63,940	50,350	316,857	167,100
Revisions of previous estimates	9,818	13,158	74,247	35,351
Extensions, discoveries and other additions	15,250	9,711	59,759	34,921
Divestitures of reserves in place	(120)	(48)	(299)	(218)
Production	(9,475)	(5,800)	(35,972)	(21,270)
End of year	79,413	67,371	414,592	215,883
Proved developed reserves:				
Beginning of year	53,156	42,950	270,291	141,155
End of year	68,877	60,441	371,946	191,309
Proved undeveloped reserves:				
Beginning of year	10,784	7,400	46,566	25,945
End of year	10,536	6,930	42,646	24,574

	Year ended December 31, 2016			
	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	52,639	36,067	221,952	125,698
Revisions of previous estimates	8,726	12,021	80,004	34,082
Extensions, discoveries and other additions	10,741	6,930	43,614	24,940
Acquisitions of reserves in place	276	116	822	529
Production	(8,442)	(4,784)	(29,535)	(18,149)
End of year	63,940	50,350	316,857	167,100
Proved developed reserves:				
Beginning of year	40,944	29,349	180,613	100,395
End of year	53,156	42,950	270,291	141,155
Proved undeveloped reserves:				
Beginning of year	11,695	6,718	41,339	25,303
End of year	10,784	7,400	46,566	25,945

For the year ended December 31, 2018, the Company's positive revision of 2,173 MBOE of previously estimated quantities consisted of (i) 11,364 MBOE of negative revisions from performance driven mainly by steeper oil decline curves and tighter well spacing, and a decrease in the Realized Price for natural gas, (ii) 7,045 MBOE of positive revisions from increases in the Realized Prices for oil and NGL and other changes to proved developed producing wells and (iii) 6,492 MBOE of positive revisions due to proved undeveloped locations that were removed from the development plan in prior years, eight of these locations were drilled in 2018 and two are scheduled to be drilled in 2019. Extensions, discoveries and other additions of 44,069 MBOE during the year ended December 31, 2018 consisted of (i) 25,617 MBOE that resulted from new wells drilled during the year and (ii) 18,452 MBOE that resulted from new horizontal proved undeveloped locations added during the year.

For the year ended December 31, 2017, the Company's positive revision of 35,351 MBOE of previously estimated quantities consisted of (i) 16,916 MBOE from positive performance, price increases and other changes to proved developed producing wells and (ii) 18,435 MBOE of revisions due to proved undeveloped locations that were removed from the development plan in prior years, 10 of these locations were drilled in 2017 and eight were scheduled to be drilled in 2018. Extensions, discoveries and other additions of 34,921 MBOE during the year ended December 31, 2017 consisted of (i) 18,985 MBOE that resulted from new wells drilled during the year and (ii) 15,936 MBOE that resulted from new horizontal proved undeveloped locations added during the year.

For the year ended December 31, 2016, the Company's positive revision of 34,082 MBOE of previously estimated quantities is primarily attributable to the combination of positive performance, lower operating costs and other changes to proved developed producing wells. 26,049 MBOE is due to a combination of positive performance, reduction in operating costs and other factors. Previously estimated quantities of 2,292 MBOE were removed due to derecognizing certain proved undeveloped locations and proved developed non-producing targets due to changes in development and drilling plans. In addition, 10,325 MBOE of revisions is due to proved undeveloped locations that were removed from the development plan in prior years, four of these locations were drilled in 2016 and seven were scheduled to be drilled in 2017. Extensions, discoveries and other additions of 24,940 MBOE during the year ended December 31, 2016 consisted of 13,302 MBOE that resulted from new wells drilled during the year and 11,638 MBOE that resulted from new horizontal proved undeveloped locations added during the year.

e. Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil, NGL and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of proved properties and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2018, 2017 and 2016 are based on the Realized Prices, which reflect adjustments to the Benchmark Prices for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. All Realized Prices are held flat over the forecast period for all reserve categories in calculating the discounted future net revenues.

Any effect from the Company's commodity hedges is excluded. In accordance with SEC regulations, the proved reserves were anticipated to be economically producible from the "as of date" forward based on existing economic conditions, including prices and costs at which economic producibility from a reservoir was determined. These costs, held flat over the forecast period, include development costs, operating costs, ad valorem and production taxes and abandonment costs after salvage. Future income tax expenses are computed using the appropriate year-end statutory tax rates applied to the future pretax net cash flows from proved oil, NGL and natural gas reserves, less the tax basis of the Company's oil and natural gas properties. The estimated future net cash flows are then discounted at a rate of 10%. The Company's unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling as of March 31, 2016, but did not record any similar impairments for the years ended December 31, 2018 or 2017. See Note 6.a for discussion of the Benchmark Prices, Realized Prices and the 2016 full cost ceiling impairment recorded.

The following table presents the standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves:

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Future cash inflows	$ 6,266,862	$ 5,777,533	$ 3,548,567
Future production costs	(1,977,401)	(1,675,837)	(1,238,369)
Future development costs	(257,310)	(307,689)	(290,505)
Future income tax expenses	(226,183)	(237,153)	—
Future net cash flows	3,805,968	3,556,854	2,019,693
10% discount for estimated timing of cash flows	(1,691,731)	(1,786,533)	(1,041,199)
Standardized measure of discounted future net cash flows	$ 2,114,237	$ 1,770,321	$ 978,494

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, prices and costs as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

The following table presents the changes in the standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves:

	For the years ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Standardized measure of discounted future net cash flows, beginning of year	$ 1,770,321	$ 978,494	$ 830,747
Changes in the year resulting from:			
Sales, less production costs	(656,080)	(508,656)	(322,573)
Revisions of previous quantity estimates	(179,912)	289,150	179,297
Extensions, discoveries and other additions	521,605	296,129	133,472
Net change in prices and production costs	365,902	474,831	(80,102)
Changes in estimated future development costs	7,246	10,989	22,153
Previously estimated development costs incurred during the period	207,865	192,332	189,085
Acquisitions of reserves in place	11,411	—	3,422
Divestitures of reserves in place	(6,015)	(793)	—
Accretion of discount	181,693	97,849	83,075
Net change in income taxes	(10,340)	(46,610)	—
Timing differences and other	(99,459)	(13,394)	(60,082)
Standardized measure of discounted future net cash flows, end of year	$ 2,114,237	$ 1,770,321	$ 978,494

Estimates of economically recoverable oil, NGL and natural gas reserves and of future net revenues are based upon a number of variable factors and assumptions, all of which are, to some degree, subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of oil, NGL and natural gas may differ materially from the amounts estimated.

Note 19—Supplemental quarterly financial data (unaudited)

The Company's results by quarter for the periods presented are as follows:

	Year ended December 31, 2018			
(in thousands, except per share data)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Revenues	$ 259,696	$ 351,046	$ 279,746	$ 215,287
Operating income	93,192	94,767	104,410	56,123
Net income	86,520	33,452	55,050	149,573
Net income per common share:				
Basic	$ 0.36	$ 0.14	$ 0.24	$ 0.65
Diluted	$ 0.36	$ 0.14	$ 0.24	$ 0.65

	Year ended December 31, 2017			
(in thousands, except per share data)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter(1)**
Revenues	$ 189,006	$ 187,001	$ 205,818	$ 240,337
Operating income	51,326	52,061	60,452	85,833
Net income	68,276	61,110	11,027	408,561
Net income per common share:				
Basic	$ 0.29	$ 0.26	$ 0.05	$ 1.71
Diluted	$ 0.28	$ 0.25	$ 0.05	$ 1.70

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(1) See Note 4.c for discussion of the Medallion Sale that occurred in the fourth quarter of 2017.

EXHIBIT 21.1

List of Subsidiaries of Laredo Petroleum, Inc.

Name of Subsidiary	Jurisdiction of Organization
Laredo Midstream Services, LLC	Delaware
Garden City Minerals, LLC	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 14, 2019, with respect to the consolidated financial statements, and internal control over financial reporting included in the Annual Report of Laredo Petroleum, Inc. on Form 10-K for the year ended December 31, 2018. We consent to the incorporation by reference of said reports in the Registration Statements of Laredo Petroleum, Inc. on Form S-3 (File No. 333-209887) and on Forms S-8 (File No. 333-178828 and File No. 333-211610).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 14, 2019

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

Ryder Scott Company, L.P. hereby consents to the references to its firm in the form and context in which they appear in this Annual Report on Form 10-K filed by Laredo Petroleum, Inc. (the “Annual Report”). Ryder Scott Company, L.P. hereby further consents to the use and incorporation by reference of information from its reports regarding those quantities estimated by Ryder Scott of proved reserves of Laredo Petroleum, Inc. and its subsidiaries, the future net revenues from those reserves and their present value for the years ended December 31, 2018, 2017 and 2016, and to the inclusion of its summary report dated January 7, 2019 as an exhibit to the Annual Report. We further consent to the incorporation by reference thereof into Laredo Petroleum, Inc.'s Registration Statements on Form S-8 (File No. 333-178828, effective December 30, 2011 and File No. 333-211610, effective May 25, 2016) and the Registration Statement of Laredo Petroleum, Inc. on Form S-3 (File No. 333-209887, effective March 2, 2016).

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 14, 2019

EXHIBIT 31.1

CERTIFICATION

I, Randy A. Foutch, certify that:

1. I have reviewed this Annual Report on Form 10-K 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: February 14, 2019

/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 Annual Report on Form 10-K 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: February 14, 2019

/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 Annual Report on Form 10-K of the Company for the period ending December 31, 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 result of operations of the Company.

February 14, 2019

/s/ Randy A. Foutch

Randy A. Foutch

Chairman and Chief Executive Officer

February 14, 2019

/s/ Richard C. Buterbaugh

Richard C. Buterbaugh

Executive Vice President and Chief Financial officer

LAREDO PETROLEUM, INC.

SUMMARY REPORT

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC PARAMETERS

As of

December 31, 2018

/s/ Val Rick Robinson

Val Rick Robinson, P.E.
TBPE License No. 105137
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

[SEAL]

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 7, 2019

Laredo Petroleum, Inc.
15 West 6th Street, Suite 900
Tulsa, Oklahoma 74119

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Laredo Petroleum, Inc. (Laredo) as of December 31, 2018. The subject properties are located in the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 3, 2019 and presented herein, was prepared for public disclosure by Laredo in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Laredo as of December 31, 2018.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2018 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SUITE 800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2R 3N9 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
Laredo Petroleum, Inc.
As of December 31, 2018

	Proved		
	Developed Producing	Undeveloped	Total Proved
Net Reserves			
Oil/Condensate - MBBL	55,893	6,001	61,894
Plant Products - MBBL	79,241	7,406	86,647
Gas - MMCF	491,828	45,928	537,756
MBOE	217,105	21,062	238,167
Income Data (M$)			
Future Gross Revenue	$ 5,377,478	$ 546,555	$ 5,924,033
Deductions	1,668,692	223,190	1,891,882
Future Net Income (FNI)	$ 3,708,786	$ 323,365	$ 4,032,151
Discounted FNI @ 10%	$ 2,032,427	$ 138,760	$ 2,171,187

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBBL). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (M$).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Laredo. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 88 percent and gas reserves account for the remaining 12 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income (M$) As of December 31, 2018
Discount Rate Percent	Total Proved
5	$ 2,781,449
9	$ 2,266,650
15	$ 1,810,477
20	$ 1,570,214

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined under the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Laredo's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Laredo's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Laredo owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, analogy, or a combination of methods. Approximately 94 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through December 2018 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Laredo or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 6 percent of the proved producing reserves were estimated by analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

All of the proved undeveloped reserves included herein were estimated by analogy, or a combination of methods. The data utilized from the analogues were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Laredo has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Laredo with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Laredo. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange

Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Laredo. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Laredo furnished us with the above mentioned average prices in effect on December 31, 2018. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Laredo. The differentials furnished by Laredo were reviewed by us for their reasonableness using information furnished by Laredo for this purpose.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Plains Pipeline	$62.04/Bbl	$59.29/Bbl
	NGLs	Mont Belvieu	$31.46/Bbl	$21.42/Bbl
	Gas	El Paso Permian	$1.76/MMBTU	$1.38/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by Laredo and are based on the operating expense reports of Laredo and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Laredo. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Laredo and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Laredo were accepted without independent verification.

The proved undeveloped reserves in this report have been incorporated herein in accordance with Laredo’s plans to develop these reserves as of December 31, 2018. The implementation of Laredo’s development plans as presented to us and incorporated herein is subject to the approval process adopted by Laredo’s management. As the result of our inquiries during the course of preparing this report, Laredo has informed us that the development activities included herein have been subjected to and received the internal approvals required by Laredo’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Laredo. Where appropriate, Laredo has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Laredo has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2018, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Laredo were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Laredo. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Laredo.

Laredo makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Laredo has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Laredo, of the references to our name, as well as to the references to our third party report for Laredo, which appears in the December 31, 2018 annual report on Form 10-K of Laredo. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Laredo.

We have provided Laredo with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Laredo and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Val Rick Robinson

Val Rick Robinson, P.E.
TBPE License No. 105137
Managing Senior Vice President

[SEAL]

VRR (FWZ)/pl

Professional Qualifications of Primary Technical Engineer

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Val Rick Robinson was the primary technical person responsible for the estimate of the reserves, future production and income presented herein.

Mr. Robinson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Robinson served in a number of engineering positions with ExxonMobil Corporation. For more information regarding Mr. Robinson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com.

Mr. Robinson earned a Bachelor of Science degree in Chemical Engineering from Brigham Young University in 2003 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Robinson fulfills. As part of his 2018 continuing education hours, Mr. Robinson attended 21 hours of formalized training including the 2018 RSC Reserves Conference and various professional society presentations covering such topics as the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, overviews of the various productive basins of North America, computer software, and professional ethics.

Based on his educational background, professional training and more than 15 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Robinson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

> *(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and*
>
> *(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.*

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals that are open at the time of the estimate but which have not yet started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) *Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.*

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.