Laredo Petroleum, Inc.
Form 10-K
February 17, 2016

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

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2015
or

o 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<br>(State or other jurisdiction of incorporation or organization) | 45-3007926<br>(I.R.S. Employer Identification No.) |
| 15 W. Sixth Street, Suite 900<br>Tulsa, Oklahoma<br>(Address of principal executive offices) | 74119<br>(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 ý No o
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 o No ý
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 ý No o
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 ý No o
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. ý
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller

reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

| | | | |
|---|---|---|---|
| Large accelerated filer ý | Accelerated filer o | Non-accelerated filer o (Do not check if a smaller reporting company) | Smaller reporting company o |

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates was approximately $1.2 billion on June 30, 2015, based on $12.58 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 12, 2016: 213,747,873

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2016 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2015, are incorporated by reference into Part III of this report for the year ended December 31, 2015.

Laredo Petroleum, Inc.
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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.

"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.

"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"—An integrated workflow process combining geoscience and engineering data with multivariate statistics.

"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.

"Facies"—A lateral change in a stratigraphic rock unit due to variance in the formation's petrophysical attribute(s).

"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.

"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 or from existing wells where a relatively major expenditure is required for recompletion.
"Recompletion"—The process of re-entering an existing wellbore that is either producing or not producing and completing 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. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.
"Standardized measure"—Discounted future net cash flows estimated by applying year-end 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.
"Two stream"—Production or reserve volumes of oil and wet natural gas, where the natural gas liquids have not been removed from the natural gas stream and the economic value of the natural gas liquids is included in the wellhead natural gas price.

"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 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 and natural gas reserves, drilling program capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation or other 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 and continued decline in, oil, NGL and natural gas prices;
- revisions to our reserve estimates as a result of changes in commodity prices and uncertainties;
- impacts to our financial statements as a result of impairment write-downs;
- our ability to discover, estimate, develop and replace oil, NGL and natural gas reserves;
- uncertainties about the estimates of our oil, NGL and natural gas reserves;
- changes in domestic and global production, supply and demand for oil, NGL and natural gas;
- 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;
- the ongoing instability and uncertainty in the U.S. and international financial and consumer markets that could adversely affect the liquidity available to us and our customers and the demand for commodities, including oil, NGL and natural gas;
- capital requirements for our operations and projects;
- 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;
- 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 generate sufficient cash to service our indebtedness, fund our capital requirements and generate future profits;
- 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, including but not limited to our hedging strategies;
- competition in the oil and natural gas industry;
- changes in the regulatory environment and changes in international, legal, political, administrative or economic conditions;
- drilling and operating risks, including risks related to hydraulic fracturing activities;
- risks related to the geographic concentration of our assets;
- 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 comply with federal, state and local regulatory requirements; and
- our ability to recruit and retain the qualified personnel necessary to operate our business.

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

On December 31, 2013, Laredo Petroleum Holdings, Inc., a Delaware corporation, completed an internal corporate reorganization and changed its name to Laredo Petroleum, Inc. See "Item 1. Business - Corporate history and structure" for more information. On October 24, 2014, Laredo formed Garden City Minerals, LLC, a Delaware limited liability company ("GCM"), as a wholly-owned subsidiary. Unless the context otherwise requires, references in this Annual Report to "Laredo," the "Company," "we," "our," "us," or similar terms refer to Laredo Petroleum Holdings, Inc. and its subsidiaries, including Laredo Petroleum, Inc., a Delaware corporation, before the completion of our internal corporate reorganization and to Laredo Petroleum, Inc. and its subsidiaries, Laredo Midstream Services, LLC ("LMS") and GCM, as of the completion of our internal corporate reorganization and thereafter, as applicable.

In this Annual Report, the consolidated and historical financial information, operational data and reserve information for Laredo and our acquired subsidiary, Broad Oak Energy, Inc., a Delaware corporation ("Broad Oak"), present the assets and liabilities of Laredo and its subsidiaries and Broad Oak at historical carrying values and their operations as if they were consolidated for all periods presented prior to July 1, 2011. Although the financial and other information is reported on a consolidated basis, such presentation is not necessarily indicative of the results that would have been obtained if Laredo had owned and operated Broad Oak from its inception.

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 the transportation of oil and natural gas from such properties, primarily in the Permian Basin in 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. We operate and analyze our results of operations through our two principal business segments:

- Exploration and production of oil and natural gas properties - conducted principally by Laredo Petroleum, Inc. through the exploration and development of our acreage in the Permian Basin. As of December 31, 2015, we had assembled 135,408 net acres in the Permian Basin and had total proved reserves, presented on a three-stream basis, of 125,698 MBOE.
- Midstream and marketing - conducted principally by our wholly-owned subsidiary, LMS. LMS buys, sells, gathers and transports oil, natural gas and water primarily for the account of Laredo. In addition, LMS owns a 49% interest in Medallion Gathering & Processing, LLC ("Medallion"), which, upon completion of current projects, will own and operate 500 miles of pipeline in the Permian Basin. This system gathered, transported and delivered 69,000 Bbls per day in the fourth quarter of 2015.

Financial information and other disclosures relating to our business segments are provided in the notes to our consolidated financial statements included elsewhere in this Annual Report (see Note 17 to our consolidated financial statements included elsewhere in this Annual Report).

### 2015 segment operation highlights

#### Exploration and production

- Produced a Company record 16.3 MMBOE in 2015, an increase of 18% from 2014
- Received $255.3 million of cash settlements on commodity derivatives that matured during 2015
- Reduced general and administrative ("G&A") expenses to $5.53 per BOE in 2015, a decrease of 28% from 2014
- Reduced capital expenditures in exploration and development activities and other fixed assets to $530.2 million in 2015, a decrease of 60% from 2014, to more appropriately align capital with expected cash flows
- Utilized the Company's proprietary Earth Model to design the drilling plan for the majority of horizontal wells drilled in 2015

Midstream and marketing

- Gathered 4.6 million barrels of crude oil, an increase of 190% from 2014
- Gathered 28.5 Bcf of natural gas, an increase of 55% from 2014
- Supplied 12.9 Bcf of natural gas lift supply, an increase of 480% from 2014
- Commenced commercial operations of the Medallion crude oil gathering system, in which LMS owns a 49% interest, growing Medallion transported volumes of oil to 69,000 Bbls per day in the fourth quarter and 15.2 million barrels of crude oil for the year
- Commenced operations of our water treatment facility in the second half of the year that provided 1.2 million barrels of recycled water for completion operations in the second half of the 2015 and 800,000 barrels during the last seven weeks of the year
- Invested capital of $159.6 million in pipelines and related infrastructure held by LMS, including investments in the Medallion pipeline system

Our core assets

Exploration and production

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 counties of Howard, Glasscock, Reagan, Sterling and Irion, Texas. We refer to this acreage block in this Annual Report as our "Permian-Garden City" area. As of December 31, 2015, we held 135,408 net acres in the Permian Basin, with 131,763 of the net acres held in 250 sections in the Permian-Garden City area, with an average working interest of 95% in all Laredo-operated producing wells.

We believe our acreage in the Permian-Garden City area is a resource play for multiple producing formations that partially make up the vertical Wolfberry interval. To date, we have focused the majority of our development activities in four targets for horizontal drilling (Upper, Middle and Lower Wolfcamp and Cline formations), although we have established the existence of additional producing zones, including the Spraberry and Canyon. From our inception in 2006 through December 31, 2015, we have drilled and completed (i.e., the particular well is flowing) 230 horizontal wells in these initial four identified target zones and 967 vertical wells in the Wolfberry interval. We have completed 97 horizontal Upper Wolfcamp wells, 48 horizontal Middle Wolfcamp wells, 30 horizontal Lower Wolfcamp wells and 55 horizontal Cline wells.

Beginning in mid-2012, we started focusing our horizontal activity on drilling longer laterals (typically 7,000 to 7,500 feet). Where our contiguous acreage position allows, we have now evolved to drilling 10,000-foot laterals.

Due to the sharp decline in oil, NGL and natural gas prices that began in the second half of 2014 and continued through 2015 and the beginning of 2016, we reduced our 2016 planned capital program. In connection with the reduced capital program, we have approved a capital budget of $345 million for 2016. Of this budget, $330 million is allocated to our exploration and production segment and $15 million is allocated to our midstream and marketing segment. Substantially all of the planned capital budget is anticipated to be invested in the Permian-Garden City area for both of our segments. Our near-term goal is to concentrate our drilling activities along our previously established production corridors that have the infrastructure in place to allow us the flexibility to most efficiently and economically drill wells at an attractive rate of return, even during the current period of depressed commodity prices. We will also continue to seek cost saving measures to more efficiently deploy our capital, including decreasing our unit lease operating and G&A expenses. We anticipate that in conjunction with the continued downward trend in commodity prices, capital and service costs may continue to decline as well, although there can be no assurance of any such decline.

In connection with our reduced capital budget, we are decreasing the number of horizontal drilling rigs and eliminating vertical drilling rigs working our properties in the Permian-Garden City area as we do not believe that any vertical drilling is currently necessary under our leases. On December 31, 2015, we had a total of three operated drilling rigs drilling horizontal wells. Our current drilling schedule anticipates that we will average 2.5 horizontal rigs and no vertical rigs in 2016.

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

We expect our Permian-Garden City acreage to continue to be the primary driver 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, including our July 2011 acquisition of Broad Oak. Our net proved reserves were estimated at 125,698 MBOE on a three-stream basis as of December 31, 2015, of which 80% are classified as proved developed reserves and 42% are attributed to oil reserves. For all periods prior to January 1, 2015, our reserves and production were reported in two streams: crude oil and liquids-rich natural gas. This means the economic value of the natural gas liquids in our natural gas was included in the wellhead natural gas price and total volumes on a BOE-basis are lower. Beginning on January 1, 2015, we started reporting our production volumes on a three-stream basis, which separately reports NGL from crude oil and natural gas. 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, 2015, and average daily production presented on a three-stream basis for the year ended December 31, 2015. Based on estimates in the report prepared by Ryder Scott, we operated wells that represent 99% of the economic value of our proved developed oil, NGL and natural gas reserves as of December 31, 2015.

| | As of December 31, 2015 Estimated net proved reserves[(1)] | | | | | Producing wells | | Year ended December 31, 2015 |
|---|---|---|---|---|---|---|---|---|
| | MBOE | % of total reserves | % Oil | Net acreage | | Gross | Net | average daily production (BOE/D) |
| Permian Basin | 125,698 | 100 % | 42 % | 135,408 | | 1,195 | 1,109 | 44,782 |
| Other properties | — | — % | — % | 17,612 | | — | — | — |
| Total | 125,698 | 100 % | 42 % | 153,020 | | 1,195 | 1,109 | 44,782 |

(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, 2015 was 44,782 BOE/D, 47% of which was oil, 26% of which was NGLs and 27% of which was natural gas.

As discussed previously in this Annual Report, during 2015 commodity prices for crude oil, NGL and natural gas experienced sharp declines, and this downward trend has accelerated further into the first quarter of 2016, with crude oil prices reaching a twelve-year low in February 2016. We have significantly reduced our capital budget for 2016. In addition, we have purposely significantly reduced the portion of our reserves that have historically been categorized as "proved undeveloped" or "PUD." We have adjusted our long-range five-year SEC PUD bookings methodology because given the current economic price environment, coupled with (i) our efforts to develop our acreage in the most efficient manner possible and determine which potential locations will be most profitable and (ii) the uncertain effect that such environment will have on the industry’s access to the capital markets, we believe that we can optimize the value for our shareholders by maintaining greater flexibility in choosing the specific drilling locations that may yield the greatest rates of return.

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 economic return and enhance shareholder value, and 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 reserve-booking status. 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, we have reduced our booked PUD locations to those we have reasonable certainty to believe that we will develop in at least a two-year time horizon while maintaining the flexibility to add new PUD locations and convert other locations to proved developed reserves as our plans deem appropriate and opportunistic.

We have built an extensive proprietary technical database that includes 398 in-house, core-calibrated petrophysical logs, 992 square miles of 3D seismic, 44 microseismic surveys, more than 1,090 open and cased-hole logging suites, including 133 dipole sonic logs, 2,866 feet of proprietary whole cores in 13 wells, 859 sidewall cores, 39 single-zone tests and 42 production logs. Our strategic interest in assembling a rich database is directed at efficiently gaining a knowledge base on our resource play in the Permian-Garden City area and maximizing value during the field development phase.

A key component of our reservoir characterization process is internally referred to as the "Earth Model," which represents a proprietary integrated workflow combining geoscience and engineering data with multivariate statistics. The workflow employed in the Earth Model process differs from the more conventional earth science/engineering approach in that the Earth Model involves parallel workflows, multivariate statistics and significant input from multiple disciplines. The goal of the Earth Model is to develop a predictive three-dimensional model that can forecast production rates through associating empirical subsurface data with proved methods.

We have been developing the Earth Model process over a period of four years, covering an area where calibrated pre-stack inversion attributes have been extensively developed and tested to determine fundamental controls on reservoir performance. The four major components of the Earth Model are (i) geophysical data (i.e., 3D seismic and micro-seismic surveys), (ii) logs (i.e., conventional open-hole, dipole sonic, and in-house core calibrated petrophysical logs), (iii) cores (both whole and sidewall) and (iv) production history, production logs and single-zone tests. By integrating data that represent mechanical properties, natural fractures, reservoir properties and lithology within a multivariate statistical model, we were generally able to develop a relationship to production with correlation coefficients for our 2016 targeted zones.

We consider the Earth Model a potentially significant tool in planning development wells in complex geology by optimizing landing points, lateral lengths and geo-steering targets while integrating horizontal and vertical spacing considerations for well laterals.

We estimate that more than 90% of our horizontal wells to be drilled in 2016 will utilize at least some aspects of the Earth Model, demonstrating evolution from a calibrated backward-looking model into a primary tool for development and delineation well planning. If our preliminary applications of the Earth Model are replicated in forward-looking well planning, we anticipate that the Earth Model may positively impact our ability to increase initial production rates and estimated ultimate recoveries.

Midstream and marketing

We are actively involved in seeking midstream solutions for our oil, NGL and natural gas production. Capitalizing on our large acreage blocks, we have built crude oil, natural gas and/or water systems in four production corridors on our Permian-Garden City acreage. These production corridors provide high-pressure centralized natural gas lift systems and crude oil and natural gas gathering, with certain corridors also capable of water delivery, takeaway and recycling (including 77 miles of fresh, produced and recycled water lines). In 2015, we commenced operations at our water treatment facility, which is capable of recycling more than 28,000 Bbls of water per day and has a storage capacity of 1.4 million Bbls. We believe the fact that these production corridors and associated facilities and infrastructure are already in place will enable us to more economically undertake our anticipated 2016 drilling program.

Additionally, we have built and maintain more than 40 miles of crude oil gathering pipelines to connect Laredo-operated wells in our Permian-Garden City asset, providing a safer and more economic transportation alternative than trucking. We have also installed and maintain 175 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.

LMS is a 49% owner in the Medallion crude oil gathering system which commenced operations in March of 2015. Upon completion of current projects, the system will have 500 miles of laid pipeline in the following counties in Texas: Mitchell, Howard, Martin, Midland, Glasscock, Reagan, Upton, Crane and Crockett. During the portion of the year in 2015 that it was operational, the system transported 15.2 million Bbls of crude oil. See Notes 15 and 16.a to our consolidated financial statements included elsewhere in this Annual Report for a discussion of Medallion.

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.

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 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, which agreements will enhance our ability to move our crude oil out of the Permian Basin and give us access to potentially more favorable Gulf Coast pricing.

As of December 31, 2015, 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 | 2016 | 2017 | 2018 | 2019 and after |
|---|---|---|---|---|---|
| Crude oil (MBbl) | | | | | |
| Sales commitments | 24,340 | 10,304 | 8,030 | 6,006 | — |
| Transportation commitments: | | | | | |
| Field | 100,995 | 9,736 | 13,106 | 12,410 | 65,743 |
| To U.S. gulf coast | 33,450 | 3,660 | 3,650 | 3,650 | 22,490 |
| Natural gas (MMcf) | | | | | |
| Sales commitments | 66,971 | 5,220 | 5,966 | 7,373 | 48,412 |
| Total commitments (MBOE)(1) | 169,947 | 24,570 | 25,780 | 23,295 | 96,302 |

(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 the major market hubs of Midland, Texas and Colorado City, Texas. We also have a firm transportation agreement to move oil from Colorado City, Texas to the U.S. Gulf Coast. We expect to fulfill these firm transportation commitments primarily by utilizing the volumes under our firm sales commitments.

Our production has been equivalent or greater than our delivery commitments during the three most recent years, and we expect such production will continue to exceed our future commitments. However, 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. 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 10% or more of our oil, NGL and natural gas revenues during the last three calendar years, see Note 11 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."

Corporate history and structure

Laredo Petroleum, Inc. was founded in October 2006 by our Chairman and Chief Executive Officer, Randy Foutch. In 2007, Laredo Petroleum, LLC was formed pursuant to the laws of the State of Delaware by affiliates of Warburg Pincus LLC ("Warburg Pincus"), our institutional investor, and the management of Laredo Petroleum, Inc., to acquire Laredo Petroleum, Inc. and through such subsidiary, to develop and operate oil and natural gas properties in the Permian and Mid-Continent regions of the United States. In August 2011, we incorporated Laredo Petroleum Holdings, Inc. ("Holdings"), pursuant to the laws of the State of Delaware for purposes of a corporate reorganization and initial public offering ("IPO"). The corporate reorganization, pursuant to which Laredo Petroleum, LLC was merged with and into Holdings, with Holdings surviving the merger, was completed on December 19, 2011 (the "Corporate Reorganization"). In the Corporate Reorganization, all of the outstanding preferred equity interests and certain of the incentive equity interests in Laredo Petroleum, LLC were exchanged for shares of common stock of Holdings. Holdings completed an IPO of its common stock on December 20, 2011. As of December 31, 2015, Warburg Pincus owned 41.0% of our common stock.

On July 1, 2011, we completed the acquisition of Broad Oak, which became a wholly-owned subsidiary of Laredo Petroleum, Inc. Broad Oak was formed in 2006 with financial support from its management and Warburg Pincus. On July 19, 2011, we changed the name of Broad Oak to Laredo Petroleum-Dallas, Inc.

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On August 1, 2013, we completed the sale of our assets in the Anadarko Basin in the Texas Panhandle and Western Oklahoma (the "Anadarko Basin Sale"), which represented 15% of our proved reserve volumes as of December 31, 2012.

Effective December 31, 2013, we completed an internal corporate reorganization, which simplified our corporate structure. Our two former subsidiaries, Laredo Petroleum Texas, LLC and Laredo Petroleum-Dallas, Inc. were merged with and into Laredo Petroleum, Inc. The then sole remaining wholly-owned subsidiary of Laredo Petroleum, Inc., formerly known as Laredo Gas Services, LLC, changed its name to Laredo Midstream Services, LLC. Laredo Petroleum, Inc., a wholly-owned subsidiary of Holdings, merged with and into Holdings with Holdings surviving and changing its name to "Laredo Petroleum, Inc." We refer to the events described in this paragraph collectively as the "Internal Consolidation."

On October 24, 2014, GCM, a wholly-owned subsidiary of Laredo Petroleum, Inc., was formed primarily to hold certain mineral interests owned by the Company. The creation of GCM, the Corporate Reorganization, the IPO and the Internal Consolidation are discussed in Note 1 to our consolidated financial statements included elsewhere in this Annual Report.

Laredo Petroleum, Inc. is the borrower under our Fourth Amended and Restated Senior Secured Credit Facility (as amended, the "Senior Secured Credit Facility"), as well as the issuer of our $350 million of 6 1/4% senior unsecured notes due 2023 (the "March 2023 Notes"), our $500 million of 7 3/8% senior unsecured notes due 2022 (the "May 2022 Notes") and our $450 million of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes"). We refer to the March 2023 Notes, the May 2022 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. On April 6, 2015 (the "Redemption Date"), we used the proceeds of the March 2023 Notes offering to fund a portion of the complete redemption of the Company’s then outstanding $550 million of 9 1/2% senior unsecured notes due 2019 (the "January 2019 Notes") at a redemption price of 104.75% of the principal amount of such notes, plus accrued and unpaid interest.

Our business strategy

Our goal is to enhance shareholder value by protecting and potentially growing our reserves, production and cash flow by executing the following strategy:

Exploration and production

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, operation efficiencies, hedging, reducing G&A and developing oil and natural gas takeaway capacity with multiple delivery points.

Develop our acreage in the most cost-efficient manner possible and target our wells with the highest rate of return potential

- In the current price environment, we believe the best way to develop our acreage is to take a long-term approach and develop at a deliberate pace that targets our locations with the potential highest rates of return.
- We believe that our entire acreage position and multiple zones will be a part of our future strategy if prices for commodities rise and/or further cost reductions and technological advances make wells more economic.

Deploy our capital in a conservative and strategic manner and review opportunities to bolster our liquidity

- In the current economic environment, maintaining liquidity is critical. Therefore, we will be highly selective in the projects that we fund and will review opportunities to bolster our liquidity and financial position through accessing the capital markets, utilizing our Senior Secured Credit Facility and asset dispositions.

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

- During 2015, we realized a significant benefit through our hedging program and the certainty that it provided to our cash flow. In the future, we will seek hedging opportunities to further protect our cash flows from commodity price fluctuations.

Maintain our operational flexibility

- As reflected in our December 31, 2015 reserves, we deliberately reduced our PUD bookings. While this decision impacts our booked reserves on a current basis, we also believe that it provides us with the crucial flexibility necessary to allow us to alter our drilling plans as may be necessary to develop our highest rate of return properties to benefit our shareholders.

Evaluate and pursue value-enhancing acquisitions, mergers, joint ventures and divestitures

- We will continue to monitor the market for strategic acquisitions that we believe could be accretive and enhance shareholder value. However, as a result of our past years of data collection and delineation drilling, we have established the production capability of a substantial portion of our acreage in multiple zones, which provides us with a significant drilling inventory even at the current depressed commodity prices.

Capitalize on technical expertise and database

- We will continue to leverage our operating and technical expertise to further delineate and develop our core acreage positions. We believe the development and use of the Earth Model will enable us to better identify the best locations and drill them more efficiently, thereby capturing more hydrocarbons than would otherwise be possible.

Midstream and marketing

Expand the use of our previously built infrastructure and look for 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. 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.

Participate in the growth and expansion of Medallion

- We believe the Medallion pipeline is a valuable and unique asset in our area of operations that provides benefit to us both in terms of transporting our production and financially through our 49% ownership. We will continue to closely monitor all proposed expansions and participate in those that we feel will be beneficial to our shareholders.

Our competitive strengths

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

Exploration and production

Extensive Permian technical database and expertise

- We have made a substantial upfront investment to understand the geology, geophysics and reservoir parameters of the rock formations and production characteristics that define our drilling and development program. We have utilized this information in the creation of the Earth Model, which we believe will assist us in optimizing our well results.

Contiguous acreage position that contains multiple zones with a substantial drilling inventory

- We have 131,763 net acres in the Permian-Garden City area that are largely contiguous, have identified at least seven zones from which we can produce and have a significant drilling inventory even at the current depressed commodity prices. Our contiguous acreage position also allows us to drill long laterals (10,000 feet or greater) in many locations, which we estimate will provide an even greater rate of return as we continue to refine our spacing, drilling and completion techniques.

Significant operational control

- We operate wells that represent 99% of the economic value of our proved developed reserves as of December 31, 2015, 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, completion and stimulation techniques. We expect to maintain operating control over most of our potential drilling locations.

Significant hedges in place to guard against price volatility

- We engage in an active hedging program in an effort to decrease the volatility of our cash flow due to changes in commodity prices. We currently have hedges in place for oil that represent 85% to 90% of anticipated oil sales in 2016 with a weighted-average floor price of $70.84 per Bbl, and hedges in place for natural gas that represent 70% to 75% of anticipated natural gas sales in 2016 with a weighted-average floor price of $3.00 per MMBtu. For 2017, we have hedges in place for 2,628,000 barrels of oil with a weighted-average floor price of $77.22 per Bbl and hedges for natural gas for 13,515,000 MMBtu with a weighted-average floor price of $2.70 per MMBtu. For 2018, we have hedges in place for natural gas for 8,220,000 MMBtu with a weighted-average floor price of $2.50 per MMBtu. We believe that the price certainty associated with these hedges enables us to better plan and forecast our upcoming capital and operational spending.

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. During the last two decades, Warburg Pincus has been the lead investor in many such companies, including Broad Oak and two previous companies operated by members of our management team.

Midstream and marketing

Owned gathering infrastructure

- We own and operate more than 200 miles of pipeline in our crude oil and natural gas gathering systems in the Permian Basin as of December 31, 2015. Additionally, through our joint venture with Medallion, upon completion of current projects we will have access to 500 miles of oil gathering systems and pipelines connected to Colorado City, Texas. As a 49% owner of Medallion, we financially benefit from our share of the net income from the shipment of crude oil on the system. These systems and pipelines provide greater operational efficiency and potentially lower price differentials for our production and enable us to coordinate our activities to connect our wells to market upon completion with minimal pipeline delays.

Our production corridors allow us to more efficiently develop our acreage and utilize/dispose of water

- We have built production corridors on our contiguous acreage position that we believe increase efficiencies in oil and natural gas takeaway capacity, water supply and field level operations. We believe 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. In addition, we believe that drilling wells within these corridors increases our production consistency and allows 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 take away capacity for flowback and produced water.

- Our water treatment facility allows us to more sustainably utilize recycled flowback and produced water in our completion operations and reduce our capital and operating expenses for water supply and disposal.

Other properties

In addition to our Permian-Garden City acreage, as of December 31, 2015 we held 21,257 net acres in other areas, including the Palo Duro Basin and Permian-China Grove area. We anticipate little or no activity on these other properties in 2016. Approximately 29% of this acreage will expire in 2016, absent drilling or renegotiation of the applicable leases.

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 the rules and regulations of the SEC applicable to the periods presented.

Per SEC guidelines, companies are required 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 held constant and utilized to calculate estimated reserves and the associated future cash flows. The following table presents the Benchmark Prices and Realized Prices as of the periods presented.

| | For the years ended | |
|---|---|---|
| | December 31, 2015 | December 31, 2014(1) |
| Benchmark Prices | | |
| Oil ($/Bbl) | $46.79 | $91.48 |
| NGL ($/Bbl) | $18.75 | $— |
| Natural gas ($/MMBtu) | $2.47 | $4.25 |
| Realized Prices | | |
| Oil ($/Bbl) | $45.58 | $89.57 |
| NGL ($/Bbl) | $12.50 | $— |
| Natural gas ($/Mcf) | $1.89 | $6.39 |

(1) For periods prior to January 1, 2015, the Company presented reserves for oil and natural gas, which combined NGL with the natural gas stream, and did not separately report NGL. This change impacts the comparability of 2015 with prior periods.

Our net proved reserves were estimated at 125,698 MBOE on a three-stream basis as of December 31, 2015, of which 80% were classified as proved developed reserves and 42% are attributable to oil reserves. The following table presents summary data for our core operating area as of December 31, 2015. Our estimated proved reserves as of December 31, 2015 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. Decreases in commodity prices, or negative revisions to reserve estimates or assumptions as to future oil, NGL and natural gas prices, may lead to decreased earnings, losses or impairment of oil and natural gas assets."

| | As of December 31, 2015 | |
|---|---|---|
| Area: | Proved reserves (MBOE) | % of total |
| Permian Basin | 125,698 | 100 % |
| Other properties | — | — % |
| Total | 125,698 | 100 % |

The following table sets forth more information regarding our estimated proved reserves as of December 31, 2015 and 2014 (with 2014 results presented on a two-stream basis). Ryder Scott estimated 100% of our proved reserves as of December 31, 2015 and 2014. The reserve estimates as of December 31, 2015 and 2014 were prepared in accordance with the SEC's rules regarding oil and natural gas reserve reporting applicable to the periods presented.

| | As of December 31, | |
|---|---|---|
| | 2015 | 2014 |
| Proved developed producing: | | |
| Oil and condensate (MBbl) | 40,493 | 53,270 |
| NGL (MBbl) | 29,009 | — |
| Natural gas (MMcf) | 178,519 | 272,674 |
| Total proved developed producing (MBOE) | 99,255 | 98,715 |
| | | |
| Proved developed non-producing: | | |
| Oil and condensate (MBbl) | 451 | 3,705 |
| NGL (MBbl) | 340 | — |
| Natural gas (MMcf) | 2,094 | 18,819 |
| Total proved developed non-producing (MBOE) | 1,140 | 6,842 |
| | | |
| Proved undeveloped: | | |
| Oil and condensate (MBbl) | 11,695 | 83,215 |
| NGL (MBbl) | 6,718 | — |
| Natural gas (MMcf) | 41,339 | 351,301 |
| Total proved undeveloped (MBOE) | 25,303 | 141,765 |
| | | |
| Estimated proved reserves: | | |
| Oil and condensate (MBbl) | 52,639 | 140,190 |
| NGL (MBbl) | 36,067 | — |
| Natural gas (MMcf) | 221,952 | 642,794 |
| Total estimated proved reserves (MBOE) | 125,698 | 247,322 |
| Percent developed | 80 % | 43 % |

Technology used to establish proved reserves

Under the 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, 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 and completion using similar techniques.

As discussed previously in this Annual Report, during 2015 commodity prices for crude oil, NGL and natural gas experienced sharp declines, and this downward trend has accelerated further into the first quarter of 2016, with crude oil prices reaching a twelve-year low in February 2016. We have significantly reduced our capital budget for 2016. In addition, we have purposely significantly reduced the portion of our reserves that have historically been categorized as "proved undeveloped" or "PUD." We have adjusted our long-range five-year SEC PUD bookings methodology because given the current economic price environment, coupled with (i) our efforts to develop our acreage in the most efficient manner possible and determine which potential locations will be most profitable and (ii) the uncertain effect that such environment will have on the industry’s access to the capital markets, we believe that we can optimize the value for our shareholders by maintaining greater flexibility in choosing the specific drilling locations that may yield the greatest rates of return.

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 economic return and enhance shareholder value, and 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 reserve-booking status. 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, we have reduced our booked PUD locations to those we have reasonable certainty to believe that we will develop in at least a two-year time horizon while maintaining the 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 and guidelines established by the SEC, Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserve information as of December 31, 2015 and 2014 included in this Annual Report. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

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 reserves estimates. The Ryder Scott reserve report is reviewed with representatives of Ryder Scott and our internal technical staff before dissemination of the information. Additionally, our senior management reviews the Ryder Scott reserve report.

Our Vice President of Reservoir Modeling and Field Development Planning, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. He has more than 40 years of practical experience with 32 years of this experience being in the estimation and evaluation of reserves. He has a Bachelors of Science degree in Chemical Engineering and is a life member in good standing of the Society of Petroleum Engineers. Our Vice President of Reservoir Modeling and Field Development Planning reports directly to our Chairman and Chief Executive Officer. Reserves 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 and then submitted to our board of directors for final approval.

Proved undeveloped reserves

Our proved undeveloped reserves decreased from 141,765 MBOE, reported on a two-stream basis, as of December 31, 2014, to 25,303 MBOE, reported on a three-stream basis, as of December 31, 2015. We estimate that we incurred $162 million of costs to convert 10,563 MBOE of proved undeveloped reserves from 37 locations into proved developed reserves in 2015. New proved undeveloped reserves of 2,669 MBOE were added during the year from four new horizontal Middle Wolfcamp locations. Negative revisions to proved undeveloped reserves of 106,883 MBOE were due to the combined effect of our adjusted booking methodology with the removal of 378 proved undeveloped locations and the net effect of reinterpreting 34 undeveloped locations. The 378 locations that were removed were comprised of 182 vertical Wolfberry wells due to lower commodity prices and 196 horizontal wells to better align the timing of their development with our future drilling plans. In addition, 1,685 MBOE were removed due to the sale of nine undeveloped locations in August 2015.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2015 reserve report are $266 million. Based on this report, the capital estimated to be spent in 2016 and 2017 to develop the proved undeveloped reserves is $192 million and $74 million, respectively, and $0 for each of

2018, 2019 and 2020. 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 a two-year period. 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 factors may lead to changes in development plans.

Sales volume, revenues and price history

The following table sets forth information regarding sales volumes, revenues, average sales prices and average costs per BOE sold for the years ended December 31, 2015, 2014 and 2013. For the 2013 and 2014 periods, our reserves and production were reported in two streams: crude oil and liquids-rich natural gas, and for 2015, 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) | 2015 | 2014 | 2013 |
| Sales volumes:(1) | | | |
| Oil (MBbl) | 7,610 | 6,901 | 5,487 |
| NGL (MBbl) | 4,267 | — | — |
| Natural gas (MMcf) | 26,816 | 28,965 | 34,348 |
| Oil equivalents (MBOE)(2)(3) | 16,346 | 11,729 | 11,211 |
| Average daily sales volumes (BOE/D)(3) | 44,782 | 32,134 | 30,716 |
| Oil, NGL and natural gas revenues (in thousands):(1) | | | |
| Oil | $329,301 | $571,620 | $494,676 |
| NGL | $50,604 | $— | $— |
| Natural gas | $51,829 | $165,583 | $170,168 |
| Average sales prices without hedges:(1) | | | |
| Index oil ($/Bbl)(4) | $48.80 | $93.00 | $97.97 |
| Oil, realized ($/Bbl)(5) | $43.27 | $82.83 | $90.16 |
| Index NGL ($/Bbl)(4) | $18.81 | $— | $— |
| NGL, realized ($/Bbl)(5) | $11.86 | $— | $— |
| Index natural gas ($/MMBtu)(4) | $2.66 | $4.41 | $3.65 |
| Natural gas, realized ($/Mcf)(5) | $1.93 | $5.72 | $4.95 |
| Average price, realized ($/BOE)(5) | $26.41 | $62.86 | $59.29 |
| Average sales prices with hedges:(1)(6) | | | |
| Oil, hedged ($/Bbl) | $74.41 | $85.77 | $88.68 |
| NGL, hedged ($/Bbl) | $11.86 | $— | $— |
| Natural gas, hedged ($/Mcf) | $2.42 | $5.73 | $4.98 |
| Average price, hedged ($/BOE) | $41.71 | $64.62 | $58.66 |
| Average cost per BOE sold:(1) | | | |
| Lease operating expenses | $6.63 | $8.23 | $7.06 |
| Production and ad valorem taxes | $2.01 | $4.29 | $3.78 |
| Midstream service expenses | $0.36 | $0.46 | $0.30 |
| General and administrative(7) | $5.53 | $9.04 | $8.00 |
| Depletion, depreciation and amortization | $16.99 | $21.01 | $20.87 |

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

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

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

(4) Index oil prices are the simple average of the daily settlement price for NYMEX West Texas Intermediate Light Sweet Crude Oil each month for the period indicated. Index NGL price is the simple arithmetic average of the monthly average of the daily high and low prices for each NGL component, during the month of delivery as reported for Mont Belvieu, Texas by the Oil Price Information Service using the Purity Ethane price for the ethane component and the Non-TET prices for the propane, butane and natural gasoline components multiplied by the simple arithmetic average of the monthly average percentage makeup of each NGL component in Laredo's composite NGL barrel. Index natural gas prices are the simple arithmetic average of each month's settlement price of the NYMEX Henry Hub natural gas First Nearby Month Contract upon expiration.

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

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

(7) General and administrative includes non-cash stock-based compensation, net of amounts capitalized, of $24.5 million, $23.1 million and $21.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Productive wells

The following table sets forth certain information regarding productive wells in each of our core areas as of December 31, 2015. All but two 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 | Average WI % | |
| | Vertical | Horizontal | Total | Total | | |
| Permian Basin: | | | | | | |
| Operated Permian-Garden City | 913 | 236 | 1,149 | 1,095 | 95 | % |
| Non-operated Permian-Garden City | 40 | 6 | 46 | 14 | 29 | % |
| Other properties | — | — | — | — | — | % |
| Total | 953 | 242 | 1,195 | 1,109 | 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, 2015 for each of our core operating areas, including acreage held by production ("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: | | | | | | | | |
| Permian-Garden City | 122,706 | 106,765 | 29,717 | 24,998 | 152,423 | 131,763 | 81 | % |
| Permian-China Grove | — | — | 4,686 | 3,645 | 4,686 | 3,645 | — | % |
| Permian total | 122,706 | 106,765 | 34,403 | 28,643 | 157,109 | 135,408 | | |
| Other properties | — | — | 23,746 | 17,612 | 23,746 | 17,612 | — | % |
| Total | 122,706 | 106,765 | 58,149 | 46,255 | 180,855 | 153,020 | 70 | % |

Undeveloped acreage expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2015 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.

| | 2016 | | 2017 | | 2018 | | 2019 | |
|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Permian Basin: | | | | | | | | |
| Permian-Garden City | 7,684 | 5,408 | 3,290 | 2,449 | 10,556 | 9,772 | — | — |
| Permian-China Grove | 4,686 | 3,645 | — | — | — | — | — | — |
| Permian total | 12,370 | 9,053 | 3,290 | 2,449 | 10,556 | 9,772 | — | — |
| Other properties | 1,641 | 2,418 | 15,787 | 10,902 | 6,148 | 4,122 | 170 | 170 |
| Total | 14,011 | 11,471 | 19,077 | 13,351 | 16,704 | 13,894 | 170 | 170 |

Of the total undeveloped acreage identified as expiring over the next four years, 40 net acres have associated PUD reserves, which we anticipate drilling to hold the associated leases. These PUD reserves represent an insignificant amount of our overall PUD reserves.

Of the 3,165 net acres of leasehold that were identified at December 31, 2014 as attributable to PUD reserves and potentially expiring, 80 net acres actually expired in 2015. As of December 31, 2015, the locations from those expired acres were no longer classified as PUD reserves. The remainder of such acreage was retained either through lease extensions or drilling.

Drilling activity

The following table summarizes our drilling activity for the years ended December 31, 2015, 2014 and 2013. 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.

| | 2015 | | 2014 | | 2013 | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Development wells: | | | | | | |
| Productive | 93 | 80.4 | 219 | 183.9 | 171 | 127.2 |
| Dry | — | — | — | — | — | — |
| Total development wells | 93 | 80.4 | 219 | 183.9 | 171 | 127.2 |
| Exploratory wells: | | | | | | |
| Productive | 2 | 2.0 | 2 | 1.8 | 2 | 2.0 |
| Dry | — | — | 1 | 1.0 | — | — |
| Total exploratory wells | 2 | 2.0 | 3 | 2.8 | 2 | 2.0 |

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 profits 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 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, 2015, 70% of all of our net leasehold acreage was held by production and 81% of our Permian-Garden City acreage was held by production.

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 carry on 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 both our vertical and horizontal 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 developed non-producing and 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 zones, and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. It is believed that this well design effectively eliminates 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 approved disposal wells, so as to minimize the potential for impact to nearby surface water.

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 on a limited number of wells, we have constructed and operate a water recycle facility on one of our production corridors and anticipate expanding our recycling activities in the future. 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-Water and other waste discharges and spills." 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, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. The state of Texas has statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area and the pooling of crude oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. 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 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 production of oil and natural gas

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 conservation matters, including provisions for the pooling of oil and natural gas properties, including the permitting of allocation wells, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil 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. State laws also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, pooling of oil and natural gas properties and establishment of maximum rates of production from oil and natural gas wells. Texas further has the power to prorate production to the market demand for oil and natural gas. 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.

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 increased dramatically in recent years. 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, as amended ("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." 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. 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 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. Under this assertion of authority, the EPA requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations, specifically in Class II wells, which are those wells injecting fluids associated with oil and natural gas production activities. The U.S. Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. 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, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014. The EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism-regulatory, voluntary or a combination of both-to collect data on hydraulic fracturing chemical substances and mixtures. 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 April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to publicly owned treatment works ("POTWs"). The EPA asserts that wastewater from such facilities can be generated in large quantities and can contain constituents that may disrupt POTW operations and/or be discharged, untreated, from the POTW to receiving waters. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to POTWs. The public comment period ended on July 17, 2015, and the EPA is expected to publish a final rule by August 2016. 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 standards may have on our business at this time, but these standards 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. The rule took effect on June 24, 2015, although it is the subject of several pending lawsuits filed by industry groups and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. On September 30, 2015, the United States District Court for Wyoming issued a preliminary injunction preventing the BLM from implementing the rule nationwide. This order has been appealed to the Tenth Circuit Court of Appeals.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, the EPA has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health. In June 2015, the EPA released its draft assessment report for peer review and public comment, finding that, while there are certain mechanisms by which hydraulic fracturing activities could potentially impact drinking water resources, there is no evidence available showing that those mechanisms have led to widespread, systemic impacts. 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 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. 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. 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. 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.

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. 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 rule includes NSPS for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rule seeks 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. For example, in September 2013 and December 2014, the EPA amended its rules to extend compliance deadlines and to clarify the NSPS. Further, on July 31, 2015, the EPA finalized two updates to the NSPS to address the definition of low-pressure wells and references to tanks that are connected to one another (referred to as connected in parallel). In addition, on September 18, 2015, the EPA published a suite of proposed rules to reduce methane and VOC emissions from the oil and gas industry, including new "downstream" requirements covering equipment in the natural gas transmission segment of the industry that was not regulated by the 2012 rules. The public comment period closed on December 4, 2015. Also, on January 22, 2016, the BLM announced a proposed rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The proposed rule would require 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 would also clarify when operators owe the government royalties for flared gas. 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 utilize 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

Congress has from time to time considered legislation to reduce emissions of greenhouse gases ("GHGs") and almost one-half of the states have already taken legal measures to reduce emissions of GHGs through the planned development of GHG emission inventories and/or regional GHG cap and trade programs, although in recent years some states have scaled back their commitment to GHG initiatives. Most cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in July 2010, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it became effective in January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration ("PSD") and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA ("UARG v. EPA"), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court's decision in UARG v. EPA. In its preliminary guidance, the EPA indicated it would promulgate a rule to rescind any PSD permits issued under the portions of the tailoring rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

In September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including NGL fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

The EPA has continued to adopt GHG regulations applicable to other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants, including final Carbon Pollution Standards for new, modified and reconstructed power plants, a final Clean Power Plan to cut carbon dioxide pollution from existing power plants, and a proposed federal plan to implement the Clean Power Plan emission guidelines. Upon publication of the Clean Power Plan on October 23, 2015, more than two dozen States as well as industry and labor groups challenged the Clean Power Plan in the D.C. Circuit Court of Appeals. On February 9, 2016, the U.S. Supreme Court stayed the Clean Power Plan pending disposition of the legal challenges. Nevertheless, as a result of the continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

In December 2015, the United States joined the international community at the 21st Conference of the Parties ("COP-21") 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, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG emissions.

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 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, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While our business is not a party to 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, tornados 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 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.

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. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands 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' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on federal oil and natural gas leases in areas where certain species, such as the lesser prairie chicken, that are listed as threatened or endangered and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA exist. The U.S. Fish and Wildlife Service 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 in 2015, 2014 or 2013.

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 equity interests of, and have the right to designate members of the board of directors of, Endurance International Group ("Endurance") and Santander Asset Management Investment Holdings Limited ("SAMIH"). Endurance



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and SAMIH 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 Endurance and SAMIH and their respective affiliates. 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 Endurance or SAMIH, 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.

As to SAMIH:

Laredo understands that SAMIH's affiliates intend to disclose in their next annual or quarterly SEC report that:

"Santander UK plc ("Santander UK") holds frozen savings accounts and one current account for two customers resident in the U.K. who are currently designated by the U.S. for terrorism. The accounts held by each customer were blocked after the customer's designation and remained blocked and dormant throughout 2015. Revenue generated by Santander UK on these accounts is negligible.

An Iranian national, resident in the U.K., who is currently designated by the U.S. under the Iranian Financial Sanctions Regulations and the Weapons of Mass Destruction Proliferators Sanctions Regulations ("NPWMD sanctions program"), holds a mortgage with Santander UK that was issued prior to any such designation. No further drawdown has been made (or would be permitted) under this mortgage although Santander UK continues to receive repayment installments. In 2015, total revenue in connection with the mortgage was approximately £3,876 and net profits were negligible relative to the overall profits of Santander UK. The same Iranian national also holds two investment accounts with Santander Asset Management UK Limited. The funds within both accounts are invested in the same portfolio fund. The accounts have remained frozen during 2015. The investment returns are being automatically reinvested, and no disbursements have been made to the customer. Total revenue for the Santander Group in connection with the investment accounts was £188 and net profits in 2015 were negligible relative to the overall profits of Banco Santander, S.A.

During the third quarter 2015, two additional Santander UK customers were designated. First, a U.K. national designated by the U.S. under the Specially Designated Global Terrrorist ("SDGT") sanctions program who is on the U.S. Specially Designated National ("SDN") list. This customer holds a bank account which generated revenue of approximately £180 during the third and fourth quarters of 2015. The account is blocked. Net profits in the third and fourth quarters of 2015 were negligible relative to the overall profits of Santander. Second, a U.K. national also designated by the U.S. under the SDGT sanctions program who is on the U.S. SDN list, held a bank account. No transactions were made in the third and fourth quarter of 2015 and the account is blocked and in arrears.

In addition, during the fourth quarter of 2015, Santander UK has identified one additional customer. A U.K. national designated by the U.S. under the SDGT sanctions program who is on the U.S. SDN list, held a bank account which generated negligible revenue during the fourth quarter of 2015. The account was closed during the fourth quarter of 2015. Net profits in the fourth quarter of 2015 were negligible relative to the overall profits of Banco Santander, S.A."

As to Endurance:

Laredo understands that Endurance's affiliates intend to disclose in their next annual or quarterly SEC report that:

"On December 2, 2015, Endurance terminated a subscriber account ("the Subscriber Account") that Endurance believes to be associated with Issam Shammout and Sky Blue Bird Aviation ("Shammout") identified by the Office of Foreign Assets Control ("OFAC"), as a Specially Designated National, or ("SDN"), on May 21, 215, pursuant to 31 C.F.R. Part 594. The Subscriber Account was inadvertently migrated to Endurance's servers following its acquisition of the assets of Arvixe LLC ("Arvixe") on October 31, 2014. Pursuant to the terms of the asset purchase agreement between Endurance and Arvixe, any customer accounts prohibited by OFAC were expressly excluded from the acquisition. Accordingly, Endurance does not believe it took legal ownership of the Subscriber Account, and no revenue was collected by Endurance in connection with the Subscriber Account since the date on which Shammout was added to the SDN list. Nonetheless, upon identifying that the Subscriber Account had been migrated to its servers, Endurance promptly suspended all services and terminated the Subscriber Account. Endurance reported the Subscriber Account to OFAC as potentially the property of a SDN subject to blocking pursuant to Executive Order 13223. As of

January 25, 2016, Endurance has not received any correspondence from OFAC regarding this matter."

## Employees

As of December 31, 2015, we had 340 full-time employees. We also employed a total of 22 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, Texas. On January 20, 2015, we announced the closing of our Dallas, Texas area office. We are currently still subject to the lease covering this office space, but are actively exploring alternative arrangements for its use.

## Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also 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." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

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 at 15 W. Sixth Street, Suite 900, Tulsa, Oklahoma 74119. 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 decline 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 in the second half of 2014 which has continued through 2015 and into the first quarter of 2016. This 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;
- the level of global oil, NGL and natural gas exploration and production;
- the level of global oil, NGL and natural gas 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;
- political conditions in or affecting other oil, NGL and natural gas-producing countries, including the current conflicts in the Middle East, and conditions in South America, Africa, Ukraine and Russia;
- 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 extent to which U.S. shale producers become "swing producers" adding or subtracting to the world supply totals 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 and will 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 continuing decrease in oil, NGL and natural gas prices could render uneconomic an even larger 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 on each May 1 and November 1, and the lenders have the right to call for an interim redetermination of the borrowing base one time between any two redetermination dates and in other specified circumstances. We expect that the extended decline in oil, NGL and natural gas prices will adversely impact our borrowing base in future borrowing base redeterminations, which could trigger repayment obligations under the Senior Secured Credit Facility to the extent our outstanding loans under the Senior Secured Credit Facility exceed the redetermined borrowing base and otherwise materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. In addition, lower oil, NGL and natural gas prices may cause a further decline in our stock price.

Currently, we receive incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at attractive 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 swaps, collars, puts and basis swaps. In accordance with applicable accounting principles, we are required to record our derivatives at fair market value, and they are included on 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. Although our current hedges provide us with a benefit as they are priced above the current depressed prices for oil, NGL and natural gas, as these hedges expire, there is significant uncertainty that we will be able to put new hedges in place that will provide us with similar benefit.

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.

For additional information regarding our hedging activities, please see "Item 7. Management's discussion and analysis of financial condition and results of operations—Results of operations—Commodity derivatives."

Estimating reserves and future net revenues involves uncertainties. Decreases in oil, NGL and natural gas prices, increases in service costs or negative revisions to reserve estimates or assumptions as to future oil, NGL and natural gas prices, may lead to decreased earnings and losses or impairment of oil, NGL and natural gas assets.

The reserve 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 higher decline curves in the first year of production and many other factors beyond the control of the producer. 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. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. A production decline may be rapid and irregular when compared to a well's initial production.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Changes to oil, NGL and natural gas prices in the markets for such commodities may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserves estimates. In 2015, negative revisions of 124,180 MBOE of previously estimated quantities are primarily attributable to the removal of 106,883 MBOE due to the combined effect of the removal of 378 proved undeveloped locations and the net effect of reinterpreting 34 undeveloped locations. The 378 locations that were removed were comprised of 182 vertical Wolfberry wells due to lower commodity prices and 196 horizontal wells to better align the timing of their development with our future drilling plans. The remaining 17,297 MBOE of negative revisions are due to a combination of pricing, performance and other changes to the proved developed producing and proved developed non-producing wells.

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 20.d to our consolidated financial statements included elsewhere in this Annual Report.

Also, the substantial decrease in oil, NGL and natural gas prices has had the effect of rendering uneconomic a portion of our exploration, development and exploitation projects. This resulted in our having to make downward adjustments to our estimated proved reserves. It is possible that we may need to make additional downward adjustments in the future (which could be significant).

As a result of the sustained decrease 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.

Oil, NGL and natural gas prices have significantly declined since mid-2014 and have remained low in the first-quarter of 2016. Primarily as a result of these lower prices, our December 31, 2015 estimated proved reserves decreased 171 MMBOE from our December 31, 2014 reserves, converted to three streams. Additionally, we recorded non-cash full cost ceiling impairments of $488.0 million, $906.4 million and $975.0 million in the second, third and fourth quarters of 2015, respectively. If prices remain at or below current levels and all other factors remain the same, we will incur further charges in the future. Such charges could have a material adverse effect on our results of operations for the periods in which they are taken. See Note 2.g to our consolidated financial statements included elsewhere in this Annual Report for additional information.

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 $1.15 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). Given the ongoing decline in commodity prices for oil, NGL and natural gas, it is likely that 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 crude oil, NGL and natural gas reserve 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 16, 2016, we had $170.0 million of borrowings outstanding under our Senior Secured Credit Facility. We may make further borrowings 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.

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, borrowings on our Senior Secured Credit Facility, equity offerings and proceeds from the sale of our Senior Unsecured Notes. 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.

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 16, 2016 we had $1.0 billion of elected commitment 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 $1.0 billion elected commitment on our Senior Secured Credit Facility would result in increased annual interest expense of $10.0 million and a decrease in our net income before income taxes. Recent and continuing 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.

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 and 2015 of $6.1 million, $192.0 million, $184.5 million and $2.2 billion, 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."

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.

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, we are limited in the manner in which we may conduct our business and we may be



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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 working capital ratio and minimum interest coverage 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.

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 carry forwards to reduce future tax payments may be limited if our taxable income does not reach sufficient levels.

As of December 31, 2015, we had a net operating loss ("NOL") carryforward for federal income tax purposes of $1.4 billion. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code of 1986, as amended (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, under the Code, NOL can generally be carried forward to offset future taxable income for a period of 20 years. 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, 2015, based on evidence available to us, including projected future cash flows from our oil 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, 2015 a valuation allowance has been recorded against our NOL tax assets.

The potential drilling locations for our future wells that we have tentatively internally identified 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, which in certain instances could prevent production prior to the expiration date of leases for such locations.

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, the availability of drilling services and equipment, drilling results (including the impact of increased horizontal drilling and longer laterals), 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. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, it is likely our actual drilling activities, especially in the long term, could materially differ from those presently anticipated.

Drilling for and producing oil, NGL and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploration, exploitation, development and production activities. Our oil, NGL and natural gas exploration, exploitation, development and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil, NGL and natural gas production. Our decisions to purchase, explore, develop or otherwise exploit locations or properties will depend in part on the evaluation of information obtained through geophysical and geological analyses, production data, engineering studies and our Earth Model, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Estimating reserves and future net revenues involves uncertainties. Decreases in oil, NGL and natural gas prices, or negative revisions to reserves estimates or assumptions as to future oil, NGL and natural gas prices, may lead to decreased earnings, losses or impairment of oil, NGL and natural gas assets." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- declines in oil, NGL and natural gas prices;
- limited availability of financing or capital at acceptable rates or terms;
- limitations in the market for oil, NGL and natural gas;
- delays imposed by or resulting from compliance with regulatory and contractual requirements and related lawsuits, which may include limitations on hydraulic fracturing or the discharge of greenhouse gases;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- fires and blowouts;
- adverse weather conditions, such as hurricanes, blizzards and ice storms; and
- title problems.

We are involved as a passive minority-interest partner in joint ventures and are subject to risks associated with joint venture partnerships.

We are involved as a passive minority-interest partner in joint venture relationships and may initiate future joint venture projects. Entering into a joint venture as a passive minority-interest partner involves certain risks that include: the need to contribute funds to the joint venture to support its operating and capital needs; the inability to exercise voting control over the joint venture; economic or business interests that are not aligned with our venture partners, including the holding period and timing of ultimate sale of the ventures' underlying assets; and the inability for the venture partner to fulfill its commitments and obligations due to financial or other difficulties. Our interest in Medallion is as a passive minority-interest partner.

In many instances (including Medallion), we depend on the venture partner for elements of the arrangements that are important to the success of the joint venture, such as agreed payments of substantial development costs pertaining to the joint venture and its share of other costs of the joint venture. The performance of these venture partner obligations or the ability of the venture partner to meet its obligations under these arrangements is outside our control. If the venture partner does not meet or satisfy its obligations under these arrangements, the performance and success of these arrangements, and their value to us, may be adversely affected.

If our current or future venture partners are unable to meet their obligations because of insolvency, bankruptcy or other reasons, we may be forced to undertake the obligations ourselves and/or incur additional expenses in order to have some other party perform such obligations. In addition, the insolvency of a venture partner could result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the joint venture’s suppliers and vendors and to other third parties. In such cases, we may also be required to enforce our rights, which may cause disputes among our venture partners and us. If any of these events occur, they may adversely impact us, our financial performance and results of operations, the joint ventures and/or our ability to enter into future joint ventures. Likewise, we may have similar obligations to third parties for properties we operate.

Some of our drilling and development activities are subject to joint ventures or operations controlled by third parties, which could negatively impact our control over these operations and have a material adverse effect on our business, results of operations, financial condition and prospects.

A portion of our drilling and development activities is conducted through joint operating agreements under which we own partial interests in oil and natural gas properties. If we do not operate the properties in which we own an interest, (i) we have limited ability to influence or control the day-to-day operation of such properties, including compliance with environmental, safety and other regulations, (ii) we cannot control the amount of capital expenditures that we are required to fund with respect to properties or the future development plans for the properties, (iii) we are dependent on third parties to fund their required share of capital expenditures the same as our dependency on third parties where we are the operator and (iv) we may have restrictions or limitations on our ability to sell our interests in these jointly owned assets. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could materially reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others, therefore, depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in most wells that we do not operate, we may not be in a position to remove the operator in the event of poor performance.

In addition, the insolvency of an operator of any of our properties, the failure of an operator of any of our properties to adequately perform operations or an operator’s breach of applicable agreements could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and gas leases jointly owned with the operator or another insolvent owner. Finally, an operator of our properties may have the right, if another non-operator fails to pay its share of costs because of its insolvency or otherwise, to require us to pay our proportionate share of the defaulting party's share of costs.

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 commodity derivative contracts, our principal exposure to credit risk is through net joint operations receivables ($21.4 million as of December 31, 2015) and the sale of our oil, NGL and natural gas production ($25.6 million in receivables as of December 31, 2015), which we market to energy marketing companies, refineries and affiliates. 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 production receivables with several significant customers. The largest purchaser of our oil, NGL and natural gas production accounted for 37.5% of our total oil, NGL and natural gas revenues for the year ended December 31, 2015 and our sales of purchased oil are made to one customer. See Note 11 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.

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. During the past several years, Texas has experienced the lowest inflows of water in recent history. 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 drilling procedures produce large volumes of water that we must properly dispose. The Clean Water Act of 1977, as amended, the Safe Drinking Water Act of 1974, as amended, the Oil Pollution Act of 1990, as amended, 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. In October 2014, the RRC adopted new regulations effective as of November 17, 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 April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to publicly owned treatment works ("POTWs"). The EPA asserts that wastewater from such facilities can be generated in large quantities and can contain constituents that may disrupt POTW operations and/or be discharged, untreated, from the POTW to receiving waters. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to POTWs. The public comment period ended on July 17, 2015, and the EPA is expected to publish a final rule by August 2016. 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 drilling 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 the oil and natural gas industry" for a further description of the laws and regulations that affect us.

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 involves the injection of water, propants and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. Nearly all of our proved non-producing and proved undeveloped reserves associated with future drilling, recompletion and refracture stimulation projects require hydraulic fracturing. If we are unable to apply hydraulic fracturing to our wells or the process is prohibited or significantly regulated or restricted, we would lose the ability to (i) drill and complete the projects for such proved reserves and (ii) maintain the associated acreage, which would have a material adverse effect on our future business, financial condition, operating results and prospects.

The federal Safe Drinking Water Act ("SDWA") regulates the underground injection of substances through the Underground Injection Control ("UIC") Program. However, hydraulic fracturing is generally exempt from regulation under the UIC Program, 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 Program. Under this assertion of authority, the EPA requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations. The U.S. Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. On February 12, 2014, the EPA published a revised UIC Program guidance for oil, NGL and natural gas hydraulic fracturing activities using diesel fuel. The guidance document describes how regulations of Class II wells, which are those wells injecting fluids associated with oil, NGL and natural gas production activities, 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 the above-mentioned 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.

On May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014. The EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism, regulatory, voluntary, or a combination of both, to collect data on hydraulic fracturing chemical substances and mixtures.

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. The rule took effect on June 24, 2015, although it is the subject of several pending lawsuits filed by industry groups and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. On September 30, 2015, the United States District Court for Wyoming issued a preliminary injunction preventing the BLM from implementing the rule nationwide. This order has been appealed to

the Tenth Circuit Court of Appeals.
Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, the EPA has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health. In June 2015, the EPA released its draft assessment report for peer review and public comment, finding that, while there are certain mechanisms by which hydraulic fracturing activities could potentially impact drinking water resources, there is no evidence available showing that those mechanisms have led to widespread, systemic impacts. 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.

On August 16, 2012, the EPA published final rules that subject oil, NGL 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") programs. The rule includes NSPS Standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rule seeks 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. For example, in September 2013 and December 2014, the EPA amended its rules to extend compliance deadlines and to clarify the NSPS. Further, on July 31, 2015, the EPA finalized two updates to the NSPS to address the definition of low-pressure wells and references to tanks that are connected to one another (referred to as connected in parallel). In addition, on September 18, 2015, the EPA published a suite of proposed rules to reduce methane and VOC emissions from oil and gas industry, including new "downstream" requirements covering equipment in the natural gas transmission segment of the industry that was not regulated by the 2012 rules. The public comment period closed on December 4, 2015. Also, on January 22, 2016, the BLM announced a proposed rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The proposed rule would require 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 would also clarify when operators owe the government royalties for flared gas.

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 utilize 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.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances 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, 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.

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 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 or water disposal wells are enacted into law.

We are subject to 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.

Our oil, NGL and natural gas exploration, production and gathering operations are subject to 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.

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 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.

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.

Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, through the planned development of GHG emission inventories and/or regional GHG cap and trade programs or other mechanisms. Most cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in July 2010, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it became effective in January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration ("PSD") and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA ("UARG v. EPA"), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court's decision in UARG v. EPA. In its preliminary guidance, the EPA indicated it would promulgate a rule to rescind any PSD permits issued under the portions of the tailoring rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

In September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil, NGL and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add the reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

The EPA has continued to adopt GHG regulations applicable to other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants, including final Carbon Pollution Standards for new, modified and reconstructed power plants, a final Clean Power Plan to cut carbon dioxide pollution from existing power plants, and a proposed federal plan to implement the Clean Power Plan emission guidelines. Upon publication of the Clean Power Plan on October 23, 2015, more than two dozen States as well as industry and labor groups challenged the Clean Power Plan in the D.C. Circuit Court of Appeals. On February 9, 2016, the U.S. Supreme Court stayed the Clean Power Plan pending disposition of the legal challenges. Nevertheless, as a result of the continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

In December 2015, the United States joined the international community at 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, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG emissions.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and natural 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, 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 may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While we are currently not a party to 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 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 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 which 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 crude 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 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, 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 increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude 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 action is 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.

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 currently 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.
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 declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration, development and exploitation activities 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.
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 crude 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 ten 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.
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 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;
- 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 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.

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 and storage facilities owned by us or third parties. We do not control many of the trucks and other third-party transportation facilities necessary for the transportation of our products and our access to them may be limited or denied. Our failure to provide or obtain such services on acceptable terms could materially harm our business.

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 crude oil pipelines that transport our crude oil to market have quality specifications, including a Reid Vapor Pressure ("RVP") specification. While our tank batteries and equipment are designed to deliver crude oil that meets all pipeline specifications, including RVP, there is a risk that our crude 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 crude oil that does not meet their quality specifications, including RVP, be shut in until such crude 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.

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, 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.

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 the quantities under the swaps in which we participate are well within applicable limits under the Re-Proposed Position Limit Rule, 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, which we refer to collectively as "Foreign Regulations" which may apply to our transactions with counterparties subject to such Foreign Regulations. 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. 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.

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, 2015, 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 supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought-related conditions or interruption of the processing or transportation of oil or natural gas.

Seasonal weather conditions and lease stipulations 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 weather conditions and lease stipulations designed to protect various wildlife. This limits our ability to operate in those areas and can later intensify competition during certain months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. In addition, the Permian Basin has recently experienced severe winter weather and, as a consequence, our operating results during similar periods may ultimately be adversely affected.

Our use of 2D and 3D seismic and other data, including our Earth Model, 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 and other data, such as that incorporated into our Earth Model 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 with respect to 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.

The Earth Model is reliant upon data that is subject to interpretation and is itself the product of interpretation. Therefore, there is no guarantee that the data it produces or our interpretation of that data will be correct. The Earth Model is a new process and there is no guarantee that the initial rates of correlation will be duplicated.

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 unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services 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 wells and conduct field operations, 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 been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. In particular, in recent years the high level of drilling activity in the Permian Basin has resulted in equipment shortages in those areas. 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 as well as rig 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.

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.

Technological advancements and trends in our industry affect the demand for certain types of equipment.

Technological advancements and trends in our industry affect the demand for certain types of equipment. Especially in times when commodity prices are high, the demand for drilling rigs that are able to drill horizontally in the Permian Basin increases. In addition, oil and gas exploration and production companies have increased the use of "pad drilling" in recent years whereby a series of horizontal wells are drilled in succession by walking or skidding a drilling rig at a single-site location. If we are unable to secure such rigs in a timely or cost-efficient manner it could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Randy Foutch, our Chairman and Chief Executive Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

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, 2015, Warburg Pincus owned 41.0% 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.

We may be subject to risks in connection with acquisitions of properties.

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 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 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 properties 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 will not be able to fulfill its contractual obligations. Problems with properties we acquire could have a material adverse effect on our business, financial condition and results of operations.

We may incur significant additional amounts of debt.

As of February 16, 2016, we had total long-term indebtedness of $1.5 billion. In addition, 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.

We may incur more taxes and certain of our projects may become uneconomic if certain federal income tax deductions currently available with respect to oil and natural gas exploration and development are eliminated as a result of future legislation.

Legislation has been proposed that would, if enacted, eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. In addition, the President of the United States recently proposed adding a $10.25 per Bbl tax on crude oil produced in the United States. It is unclear whether any of the foregoing changes will actually be enacted or how soon any such changes could become effective. Any such change or similar other change could materially adversely affect our financial condition and results of operations by increasing the costs we incur which would in turn make it uneconomic to drill some locations if commodity prices are not sufficiently high, resulting in lower revenues and decreases in production and reserves.

Loss of our information and computer systems could adversely affect our business.

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.

Our business could be negatively impacted by security threats, including cyber-security threats, and other disruptions.
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. Cyber-security attacks in particular 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.
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, 2015, Warburg Pincus owned 41.0% 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.

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 all or any part of 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.

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

During 2015, the SEC issued comment letters relating to the Company's previously filed annual report on Form 10-K for the fiscal year ended December 31, 2014 inquiring about the potential impact of current commodity prices and our development plans for our reserves. The Company responded to these comment letters and was notified by the SEC that it completed its review on February 11, 2016. No amendments to any prior filings were required.

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 have insurance coverage. As of the date hereof, we are not party to any legal proceedings that we currently believe will have a material adverse effect on our business, financial position, results of operations or liquidity.

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." The following table sets forth the range of high and low sales prices of our common stock as reported by the NYSE:

| | Price per share | |
|---|---|---|
| | High | Low |
| 2015: | | |
| Fourth Quarter | $13.96 | $7.05 |
| Third Quarter | $12.02 | $7.79 |
| Second Quarter | $15.80 | $12.58 |
| First Quarter | $14.61 | $8.31 |
| 2014: | | |
| Fourth Quarter | $22.82 | $7.39 |
| Third Quarter | $30.80 | $21.36 |
| Second Quarter | $30.98 | $25.43 |
| First Quarter | $28.08 | $22.91 |

On February 16, 2016, the last sale price of our common stock, as reported on the NYSE, was $4.79 per share.

Holders. As of February 12, 2016, there were 56 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.

Repurchase of Equity Securities.

| Period | Total number of shares withheld[1] | Average price per share | Total number of shares purchased as part of publicly announced plans | Maximum number of shares that may yet be purchased under the plan |
|---|---|---|---|---|
| October 1, 2015 - October 31, 2015 | 2,846 | $11.18 | — | — |
| November 1, 2015 - November 30, 2015 | 597 | $11.64 | — | — |
| December 1, 2015 - December 31, 2015 | 2,810 | $8.37 | — | — |

(1) Represents shares that were withheld by us to satisfy employee tax withholding obligations that arose upon the lapse of restrictions on restricted stock.

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 shows the cumulative total return to our common stockholders from December 15, 2011, the date on which our common stock began trading on the NYSE, through December 31, 2015, as compared to the returns on the Standard and Poor's 500 Index ("S&P 500") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P O&G E&P"). The comparison was prepared based upon the following assumptions:

1. $100 was invested in our common stock at its initial public offering price of $17 per share and invested in the S&P 500 and the S&P O&G E&P on December 15, 2011 at the closing price on such date; 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. You should read the following data 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, 2015, 2014 and 2013 and the balance sheet data as of December 31, 2015 and 2014 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, 2012 and 2011 and the balance sheet data as of December 31, 2013, 2012 and 2011 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) | 2015[2] | 2014 | 2013[3] | 2012 | 2011 |
| Statement of operations data[1]: | | | | | |
| Total revenues | $606,640 | $793,885 | $665,257 | $583,894 | $506,347 |
| Total costs and expenses | 3,078,154 | 567,499 | 450,906 | 411,954 | 303,827 |
| Operating income (loss) | (2,471,514) | 226,386 | 214,351 | 171,940 | 202,520 |
| Non operating income (expense), net | 84,633 | 203,473 | (23,267) | (77,176) | (36,932) |
| Income (loss) from continuing operations before income taxes | (2,386,881) | 429,859 | 191,084 | 94,764 | 165,588 |
| Income tax benefit (expense) | 176,945 | (164,286) | (74,507) | (33,003) | (59,612) |
| Income (loss) from continuing operations | (2,209,936) | 265,573 | 116,577 | 61,761 | 105,976 |
| Income (loss) from discontinued operations, net of tax | — | — | 1,423 | (107) | (422) |
| Net income (loss) | $(2,209,936) | $265,573 | $118,000 | $61,654 | $105,554 |
| Net income (loss) per common share: | | | | | |
| Basic: | | | | | |
| Income (loss) from continuing operations | $(11.10) | $1.88 | $0.88 | $0.49 | $0.99 |
| Income from discontinued operations, net of tax | — | — | 0.01 | — | (0.01) |
| Net income (loss) per share | $(11.10) | $1.88 | $0.89 | $0.49 | $0.98 |
| Diluted: | | | | | |
| Income (loss) from continuing operations | $(11.10) | $1.85 | $0.87 | $0.48 | $0.98 |
| Income from discontinued operations, net of tax | — | — | 0.01 | — | — |
| Net income (loss) per share | $(11.10) | $1.85 | $0.88 | $0.48 | $0.98 |

(1) The oil and natural gas properties that were a component of the Anadarko Basin Sale are not presented as held for sale nor are their results of operations presented as discontinued operations for the historical periods presented pursuant to the rules governing full cost accounting for oil and gas properties. The results of operations of the associated pipeline assets and various other associated property and equipment are presented as results of discontinued operations, net of tax.

(2) Includes full cost ceiling impairment expense of $2.4 billion for the year ended December 31, 2015.

(3) See Note 4.d to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our Anadarko Basin Sale.

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| (in thousands) | 2015 | 2014 | 2013 | 2012 | 2011 |
| Balance sheet data: | | | | | |
| Cash and cash equivalents | $31,154 | $29,321 | $198,153 | $33,224 | $28,002 |
| Net property and equipment | 1,200,255 | 3,354,082 | 2,204,324 | 2,113,891 | 1,378,509 |
| Total assets(1) | 1,813,287 | 3,910,701 | 2,606,610 | 2,318,368 | 1,615,381 |
| Current liabilities | 216,815 | 353,834 | 253,969 | 262,068 | 214,361 |
| Long-term debt, net(1) | 1,416,226 | 1,779,447 | 1,038,022 | 1,196,824 | 624,690 |
| Stockholders' equity | 131,447 | 1,563,201 | 1,272,256 | 831,723 | 760,013 |

| | For the years ended December 31, | | | | |
|---|---|---|---|---|---|
| (in thousands) | 2015 | 2014 | 2013(2) | 2012 | 2011 |
| Other financial data: | | | | | |
| Net cash provided by operating activities | $315,947 | $498,277 | $364,729 | $376,776 | $344,076 |
| Net cash used in investing activities | (667,507) | (1,406,961) | (329,884) | (940,751) | (706,787) |
| Net cash provided by financing activities | 353,393 | 739,852 | 130,084 | 569,197 | 359,478 |

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(1) Amounts have been reclassified to conform to the 2015 presentation. See Notes 2.c, 2.k, 5.h, 7 and 14 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

(2) Net cash used in investing activities for the year ended December 31, 2013 is offset by proceeds received for the Anadarko Basin Sale. See Note 4.d to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Non-GAAP financial measure

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for income tax expense or benefit, depletion, depreciation and amortization, bad debt expense, impairment expense, non-cash stock-based compensation, restructuring expenses, gains or losses on derivatives, cash settlements of matured commodity derivatives, cash settlements on early terminated and modified commodity derivatives, premiums paid for derivatives that matured during the period, interest expense, write-off of debt issuance costs, gains or losses on disposal of assets, loss on early redemption of debt and buyout of minimum volume commitment. Adjusted EBITDA provides no information regarding a company’s capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures and working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

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

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

The following presents a reconciliation of net income (loss) for continuing and discontinued operations to Adjusted EBITDA:

| (in thousands, unaudited) | For the years ended December 31, 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|
| Net income (loss) | $(2,209,936) | $265,573 | $118,000 | $61,654 | $105,554 |
| Plus: | | | | | |
| Deferred income tax (benefit) expense | (176,945) | 164,286 | 75,288 | 32,949 | 59,374 |
| Depletion, depreciation and amortization | 277,724 | 246,474 | 234,571 | 243,649 | 176,366 |
| Bad debt expense | 255 | 342 | 653 | — | — |
| Impairment expense | 2,374,888 | 3,904 | — | — | 243 |
| Non-cash stock-based compensation, net of amounts capitalized | 24,509 | 23,079 | 21,433 | 10,056 | 6,111 |
| Restructuring expenses | 6,042 | — | — | — | — |
| Gain on derivatives, net | (214,291) | (327,920) | (79,878) | (8,388) | (19,736) |
| Cash settlements received for matured commodity derivatives, net | 255,281 | 28,241 | 4,046 | 27,025 | 3,719 |
| Cash settlements received for early terminations and modification of commodity derivatives, net | — | 76,660 | 6,008 | — | — |
| Premiums paid for derivatives that matured during the period[(1)] | (5,167) | (7,419) | (11,292) | (9,135) | (4,104) |
| Interest expense | 103,219 | 121,173 | 100,327 | 85,572 | 50,580 |
| Write-off of debt issuance costs | — | 124 | 1,502 | — | 6,195 |
| Loss on disposal of assets, net | 2,127 | 3,252 | 1,508 | 52 | 40 |
| Loss on early redemption of debt | 31,537 | — | — | — | — |
| Buyout of minimum volume commitment | 3,014 | — | — | — | — |
| Adjusted EBITDA | $472,257 | $597,769 | $472,166 | $443,434 | $384,342 |

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

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 appearing 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. Some of the key factors that could cause actual results to vary from our expectations include changes in oil, NGL and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, joint ventures and dispositions, uncertainties in estimating proved reserves and forecasting production results, potential failure to achieve production from development projects, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital and financial markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. 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 the transportation of oil and natural gas from such properties, primarily in the Permian Basin in 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, 2015 included the following:
- Oil, NGL and natural gas sales of $431.7 million, compared to $737.2 million for the year ended December 31, 2014;
- Average daily sales volumes of 44,782 BOE/D, compared to 32,134 BOE/D for the year ended December 31, 2014;
- Net loss of $2.2 billion, including an after-tax non-cash full cost ceiling impairment of $2.4 billion, compared to net income of $265.6 million for the year ended December 31, 2014; and
- Adjusted EBITDA (a non-GAAP financial measure) of $472.3 million, compared to $597.8 million for the year ended December 31, 2014.

Three-stream reporting
As of January 1, 2015, all of our natural gas processing agreements with various processors had been modified to allow us to take title to the NGL resulting from the processing of our natural gas. This enables us to report reserves, sales volumes, prices and revenues for NGL and natural gas separately for periods after January 1, 2015. As such, our reserves as of December 31, 2015 are reported in three streams: oil, NGL and natural gas. Our sales volumes, prices and reserves as of December 31, 2014 and 2013 were reported in two streams: crude oil and liquids-rich natural gas with the economic value of the NGL in our natural gas included in the wellhead natural gas price. This change impacts the comparability of 2015 with prior periods.
Reserves and non-cash full cost ceiling impairment
Our results of operations are heavily influenced by oil, NGL and natural gas prices, which have significantly declined and have remained low. These oil, NGL and natural gas price fluctuations are caused by changes in the global and regional supply of and demand for oil, NGL and natural gas, market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, commodity prices have experienced significant fluctuations, and additional changes in commodity prices may affect the economic viability of and our ability to fund drilling projects, as well as the economic valuation and economic recovery of oil, NGL and natural gas reserves.
As discussed previously in this Annual Report, during 2015 commodity prices for crude oil, NGL and natural gas experienced sharp declines, and this downward trend has accelerated further into the first quarter of 2016, with crude oil prices reaching a twelve-year low in February 2016. We have significantly reduced our capital budget for 2016. In addition, we have purposely significantly reduced the portion of our reserves that have historically been categorized as

"proved undeveloped" or "PUD." We have adjusted our long-range five-year SEC PUD bookings methodology because given the current economic price environment, coupled with (i) our efforts to develop our acreage in the most efficient manner possible and determine which

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potential locations will be most profitable and (ii) the uncertain effect that such environment will have on the industry's access to the capital markets, we believe that we can optimize the value for our shareholders by maintaining greater flexibility in choosing the specific drilling locations that may yield the greatest rates of return.

As our activities to date have indicated, the majority of our acreage represents a resource play, and with the benefit of improved technology, infrastructure investments and focused cost reduction efforts, we believe we have a significant number of acreage locations to drill even at the current commodity prices. In the near-term, our goal is to drill those locations that we anticipate have the potential to provide the greatest economic return and enhance shareholder value, and 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 reserve-booking status. 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, we have reduced our booked PUD locations to those we have reasonable certainty to believe that we will develop in at least a two-year time horizon while maintaining the flexibility to add new PUD locations and convert other locations to proved developed reserves as our plans deem appropriate and opportunistic.

Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves as of December 31, 2015, 2014 and 2013. As of December 31, 2015, we had 125,698 MBOE of estimated proved reserves as compared to 247,322 MBOE of estimated proved reserves as of December 31, 2014 and 203,615 MBOE of estimated proved reserves as of December 31, 2013. For prices used to value our reserves, see Note 2.g to our consolidated financial statements included elsewhere in this Annual Report. Our net book value of evaluated oil and natural gas properties exceeded the full cost ceiling amount during the second, third and fourth quarters of 2015, and as such, we recorded non-cash full cost ceiling impairments during these periods of $488.0 million, $906.4 million and $975.0 million, respectively. See Note 2.g to our consolidated financial statements included elsewhere in this Annual Report for additional discussions of our full cost impairments.

We have entered into a number of commodity derivatives, which have enabled us to offset a portion of the changes in our cash flow caused by price fluctuations on our oil and natural gas production as discussed in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Potential future low commodity price impact on our development plans, reserves and full cost impairment

Oil, NGL and natural gas prices have remained low in the first quarter of 2016. If prices remain at or below the current low levels, subject to numerous factors and inherent limitations, and all other factors remain constant, we will incur an additional non-cash full cost impairment in the first quarter of 2016, 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 and (viii) the inherent significant volatility in the commodity prices for oil and natural gas recently exemplified by the large 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 internal reserve estimation utilized in our quarterly accounting estimates. We use our internal reserve estimates to evaluate, also on a quarterly basis, the reasonableness of our reserve 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 reserve development plans.

We have set forth below a calculation of a potential future further reduction of our proved reserves. Such implied impairment and decrease in reserves 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 the following scenario.

Both our hypothetical first-quarter 2016 full cost ceiling calculation and our hypothetical reserves estimates have been prepared by substituting (i) $41.38 per barrel for oil, (ii) $11.33 per barrel for NGL and (iii) $1.78 per MMBtu for natural gas (the "Pro Forma Prices") for the respective Realized Prices as of December 31, 2015. All other inputs and assumptions have been held constant. Accordingly, this estimation strictly isolates the estimated impact of more current commodity prices on the first-quarter 2016 Realized Prices that will be utilized in our full cost ceiling calculation and our reserves estimate. The Pro Forma 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 on the first day of the month for the 11 months ended February 1, 2016, with the price for February 1, 2016 held constant for the remaining twelfth month of the calculation. Based solely on the substitution of the Pro Forma Prices into our December 31, 2015 reserve estimates, the implied first-quarter impairment would be $132 million and the implied impact to our December 31, 2015 reserves of 126 MMBOE would be a reduction of 9 MMBOE. We believe that substituting the Pro Forma Prices into our December 31, 2015 internal reserve estimates may help provide users with an understanding of the potential first-quarter price impact on our March 31, 2016 full cost ceiling test and in preparing our year-end reserve estimates.

Mergers and acquisitions

Our use of capital for development and acquisitions allows us to direct our capital resources toward what we believe to be the most attractive opportunities as market conditions evolve. We have historically developed properties that we believe will meet or exceed our rate of return criteria. For acquisitions of properties with additional development and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. We also make acquisitions in core, mature areas where management can leverage knowledge and experience to identify upside potential in the assets.

On September 6, 2013, we completed the acquisition of evaluated and unevaluated oil and natural gas properties located in Glasscock County, Texas in the Permian Basin, from private parties for $36.7 million consisting of cash and 123,803 shares of our restricted common stock, subject to customary closing adjustments.

On February 25, 2014, we completed the acquisition of the mineral interests underlying 278 net acres in Glasscock County, Texas in the Midland Basin for $7.3 million. These mineral interests entitle us to receive royalties on all production from this acreage with no additional future capital or operating expenses required.

On June 11, 2014, we completed the acquisition of evaluated and unevaluated oil and natural gas properties, totaling 460 net acres, located in Reagan County, Texas in the Midland Basin for $4.7 million, net of closing adjustments.

On June 23, 2014, we completed the acquisition of evaluated and unevaluated oil and natural gas properties, totaling 24 net acres, located in Glasscock County, Texas for $1.8 million.

On August 26, 2014, we completed a material acquisition of leasehold interests totaling 8,156 net acres in the Midland Basin, primarily within our core development area, for $192.5 million.

Divestitures

On August 1, 2013, we completed the Anadarko Basin Sale, consisting of oil and natural gas properties located in the Anadarko Granite Wash, Eastern Anadarko and Central Texas Panhandle (the "Anadarko Basin") in the State of Oklahoma and the State of Texas, associated pipeline assets and various other related property and equipment for a purchase price of $438.0 million. The purchase price (including the buyers' deposits) consisted of $400.0 million from certain affiliates of EnerVest, Ltd. and $38.0 million from other third parties in connection with the exercise of such third parties' preferential rights associated with certain of the oil and gas properties. Approximately $388.0 million of the purchase price, excluding closing adjustments, was allocated to oil and natural gas properties pursuant to the rules governing full cost accounting. After transaction costs and adjustments at closing reflecting an economic effective date of April 1, 2013, the net proceeds were $428.3 million, net of working capital adjustments. The net proceeds were used to pay off our Senior Secured Credit Facility and for working capital purposes.

Effective August 1, 2013, the operations and cash flows of these properties were eliminated from our ongoing operations, and we do not have continued involvement in the operation of these properties. The oil and natural gas properties, which are a component of the assets sold, are not presented as discontinued operations pursuant to the rules governing full cost accounting for oil and gas properties. The results of operations of the associated pipeline assets and various other related property and equipment have been presented as results of discontinued operations, net of tax. Accordingly, we have reclassified certain prior period amounts in the consolidated financial statements included elsewhere in this Annual Report as discontinued operations. See Note 4.d to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of these reclassifications and the Anadarko Basin Sale.

On December 20, 2013, we completed the sale of 37,000 net acres in the Dalhart Basin, including one producing well, for $20.4 million, subject to customary closing adjustments. The net proceeds were used for working capital purposes.

On September 15, 2015, we completed the sale of non-strategic and primarily non-operated properties and associated production totaling 6,060 net acres and 123 producing properties in the Midland Basin to a third-party buyer for a purchase price of $65.5 million. After transaction costs reflecting an economic effective date of July 1, 2015, the net proceeds were $64.8

million, net of working capital and post-closing adjustments. The net proceeds were used for working capital purposes. This divestiture did not represent a strategic shift and will not have a major effect on our operations or financial results.

Core area of operations

The oil and liquids-rich Permian Basin is characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. As of December 31, 2015, we had assembled 135,408 net acres in the Permian Basin.

Sources of our revenue

Our revenues are primarily derived from the sale of oil, NGL and natural gas and the sale of purchased oil within the continental United States and do not include the effects of derivatives. For the year ended December 31, 2015, our revenues were comprised of sales of 54% oil, 8% NGL, 9% natural gas, 28% purchased oil and 1% midstream service revenues. Our oil, NGL and natural gas revenues may vary significantly from period to period as a result of changes in volumes of production and/or changes in commodity prices. Our midstream service revenues may vary due to the level of services provided to third parties for (i) gathered natural gas, (ii) gas lift fees, (iii) oil throughput fees and (iv) water services. Our sales of purchased oil revenue may vary due to changes in oil prices.

Principal components of our cost structure

Lease operating expenses. These are daily costs incurred to bring oil 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 paid on oil, NGL and natural gas sold based on a percentage of revenues from products sold at market prices or at fixed rates established by federal, state or local taxing authorities. We take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil, NGL and natural gas revenues. Ad valorem taxes are property taxes based on the value of our reserves attributed to our properties.

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 associated with purchasing oil from other producers and the transportation costs to bring it to market.

Drilling rig fees. These are costs incurred for the early termination of drilling rig contracts.

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, performance awards and option awards granted which have been recognized on a straight-line basis over the vesting period associated with the award.

Accretion of asset retirement obligations. Accretion is a non-cash charge that represents changes in our asset retirement liability due to the passage of time.

Depletion, depreciation and amortization. Under the full cost accounting method, we capitalize all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of finding oil and natural gas within a cost center and then systematically expense those costs on a units of production basis based on evaluated oil, NGL and natural gas reserve quantities. We calculate depletion on the following types of costs: (i) all capitalized costs, other than the cost of investments in unevaluated properties and major development projects for which evaluated reserves cannot yet be assigned, less accumulated amortization; (ii) the estimated future expenditures to be incurred in developing evaluated reserves; and (iii) the estimated dismantlement and abandonment costs, net of estimated salvage values. We calculate depreciation on the cost of fixed assets related to our pipelines and other fixed assets utilizing the straight-line method over the useful life of the asset, 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.

Impairment expense. Long-lived assets are considered impaired when their net carrying value is greater than the future undiscounted cash flows. Once an asset is recognized as impaired, costs are incurred to write the asset down. With the

continuing volatility in commodity prices, we may incur additional write-downs on our oil and natural gas properties.
Materials

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and supplies and line-fill are recorded at the lower of cost or market ("LCM"), with costs determined using the weighted-average cost method.

Other income (expense)

Gain (loss) on commodity derivatives. We utilize commodity derivatives to reduce our exposure to fluctuations in the price of crude oil and natural gas. This amount represents (i) the recognition of gains and losses associated with our open derivatives as commodity prices change and commodity derivatives expire or new ones are entered into, and (ii) our gains and losses on the settlement of these commodity derivatives. We classify these gains and losses as operating activities in our consolidated statements of cash flows.

Gain (loss) on interest rate derivatives. In prior periods, we utilized interest rate swaps and caps to reduce our exposure to fluctuations in interest rates on our outstanding debt. This amount represents (i) the recognition of gains and losses associated with interest rate derivatives as interest rates change and interest rate derivatives expire or new ones are entered into, and (ii) our gains and losses on the settlement of these interest rate contracts. We classify these gains and losses as operating activities in our consolidated statements of cash flows. During each of the years ended December 31, 2013 and 2012, we had one interest rate swap and one interest rate cap outstanding for a total notional amount of $100.0 million with fixed pay rates ranging from 1.11% to 3.00% until their expiration in September 2013. We had no interest rate derivatives in place in 2015 or 2014.

Income (loss) from equity method investee. We have invested in a company where we own 49% of the ownership units. As such, we account for this investment under the equity method of accounting with our proportionate share of net income (loss) reflected in the consolidated statements of operations as "Loss from equity method investee" and the carrying amount reflected in the consolidated balance sheet as "Investment in equity method investee." See Note 15 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding this investment.

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. In prior periods, we entered into various interest rate derivatives to mitigate the effects of interest rate changes. We do not designate these derivatives as hedges and therefore hedge accounting treatment is not applicable. Gains or losses on these interest rate contracts are included in non-operating income (expense) as discussed above. We reflect interest paid to the lenders and bondholders in interest expense. In addition, we include the amortization of debt issuance costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense.

Interest and other income. This represents the interest received on our cash and cash equivalents as well as other miscellaneous income.

Loss on early redemption of debt. This represents the loss on extinguishment recognized in the early redemption of our January 2019 Notes in April 2015, related to the difference between the redemption price and the net carrying amount.

Write-off of debt issuance costs. Debt issuance fees, 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.

Loss on disposal of assets, net. This represents losses recorded from selling or disposing of property and equipment. Sale proceeds are compared with the recorded net book value of the asset and the appropriate gain (loss) is recorded.

Income tax expense. Income taxes in our financial statements are generally presented on a consolidated basis. We are subject to federal and state corporate income taxes and 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 considered all available evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance was needed on either the federal or Oklahoma net operating loss carry-forwards. Such consideration included estimated future projected earnings based on existing reserves and projected future cash flows from our oil and natural gas reserves (including

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the timing of those cash flows), the reversal of deferred tax liabilities recorded as of December 31, 2015, our 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. During the year ended December 31, 2015, we determined it is more likely than not that we will not realize our net deferred tax assets. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our valuation allowance.

Results of operations consolidated

For the year ended December 31, 2015 as compared to the year ended December 31, 2014, and for the year ended December 31, 2014 as compared to the year ended December 31, 2013

Sales volume, revenue and pricing

The following table sets forth information regarding oil, NGL and natural gas sales volumes, revenues and average sales prices from continuing operations per BOE sold, for the periods presented:

| | For the years ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Sales volumes:[1] | | | |
| Oil (MBbl) | 7,610 | 6,901 | 5,487 |
| NGL (MBbl) | 4,267 | — | — |
| Natural gas (MMcf) | 26,816 | 28,965 | 34,348 |
| Oil equivalents (MBOE)[2][3] | 16,346 | 11,729 | 11,211 |
| Average daily sales volumes (BOE/D)[3] | 44,782 | 32,134 | 30,716 |
| % Oil | 47 % | 59 % | 49 % |
| Oil, NGL and natural gas revenues (in thousands):[1] | | | |
| Oil | $329,301 | $571,620 | $494,676 |
| NGL | 50,604 | — | — |
| Natural gas | 51,829 | 165,583 | 170,168 |
| Oil, NGL and natural gas sales | $431,734 | $737,203 | $664,844 |
| Average sales prices:[1] | | | |
| Oil, realized ($/Bbl)[4] | $43.27 | $82.83 | $90.16 |
| NGL, realized ($/Bbl)[4] | 11.86 | — | — |
| Natural gas, realized ($/Mcf)[4] | 1.93 | 5.72 | 4.95 |
| Average price, realized ($/BOE)[4] | 26.41 | 62.86 | 59.29 |
| Oil, hedged ($/Bbl)[5] | 74.41 | 85.77 | 88.68 |
| NGL, hedged ($/Bbl)[5] | 11.86 | — | — |
| Natural gas, hedged ($/Mcf)[5] | 2.42 | 5.73 | 4.98 |
| Average price, hedged ($/BOE)[5] | 41.71 | 64.62 | 58.66 |

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

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

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

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

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

The following table presents cash settlements received (paid) for matured commodity derivatives and premiums incurred previously or upon settlement attributable to instruments that settled during the periods utilized in our calculation of the hedged prices presented above:

| | For the years ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2015 | 2014 | 2013 |
| Cash settlements received (paid) for matured commodity derivatives: | | | |
| Oil | $241,391 | $26,803 | $(149) |
| Natural gas | 13,890 | 1,438 | 4,195 |
| Total | $255,281 | $28,241 | $4,046 |
| Premiums paid attributable to contracts that matured during the respective period: | | | |
| Oil | $(4,464) | $(6,497) | $(7,970) |
| Natural gas | (703) | (922) | (3,322) |
| Total | $(5,167) | $(7,419) | $(11,292) |

Changes in prices and volumes caused the following changes to our oil, NGL and natural gas revenues between the years ended December 31, 2015, 2014 and 2013:

| (in thousands) | Oil | NGL | Natural gas | Total net dollar effect of change |
|---|---|---|---|---|
| 2013 Revenue | $494,676 | $— | $170,168 | $664,844 |
| Effect of changes in price | (50,587) | — | 22,303 | (28,284) |
| Effect of changes in volumes | 127,544 | — | (26,645) | 100,899 |
| Other | (13) | — | (243) | (256) |
| 2014 Revenue | 571,620 | — | 165,583 | 737,203 |
| Effect of changes in price | (301,036) | 50,603 | (101,631) | (352,064) |
| Effect of changes in volumes | 58,660 | — | (12,293) | 46,367 |
| Other | 57 | 1 | 170 | 228 |
| 2015 Revenue | $329,301 | $50,604 | $51,829 | $431,734 |

Oil revenue. Our oil revenue is a function of oil production volumes sold and average sales prices received for those volumes. The decrease in oil revenue of $242.3 million, or 42%, for the year ended December 31, 2015 as compared to the year ended December 31, 2014, is mainly due to a 48% decrease in average oil prices realized, partially offset by a 10% increase in oil production.

NGL and natural gas revenues. On January 1, 2015, we began utilizing three-stream reporting, which impacts the comparability of 2015 with prior periods. Our NGL and natural gas revenues are a function of NGL and natural gas production, volumes sold and average sales prices received for those volumes. The total decrease in NGL and natural gas revenues from the year ended December 31, 2015 as compared to the year ended December 31, 2014, is mainly due to a decrease in average prices realized on our NGL and natural gas production. Stripping out the NGL component from our liquids-rich natural gas results in a lower price received for residue natural gas during the year ended December 31, 2015 as compared to the year ended December 31, 2014 in which we received revenues from liquids-rich natural gas. The decrease in prices is partially offset by an increase in NGL and natural gas production during the year ended December 31, 2015 as compared to the year ended December 31, 2014, converted to a three-stream basis.

The following table sets forth information regarding midstream service revenue and sales of purchased oil revenues for the periods presented:

| | For the years ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2015 | 2014 | 2013 |
| Revenues: | | | |

| | | | |
|---|---|---|---|
| Midstream service revenues | $6,548 | $2,245 | $413 |
| Sales of purchased oil | 168,358 | 54,437 | — |
| Total revenues | $174,906 | $56,682 | $413 |

Midstream service revenues. Our midstream service revenues from operations increased by $4.3 million during the year ended December 31, 2015 as compared to the year ended December 31, 2014, and $1.8 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013. These increases were due to the increased sale of natural gas, NGL and condensate off our pipelines and facilities during each respective period as well as an increase in third-party volumes transported through our oil and natural gas gathering and transportation systems and related facilities.

Sales of purchased oil. During the year ended December 31, 2014, in order to fulfill our firm transportation commitment on the Bridgetex pipeline, we began purchasing oil in West Texas, transporting the product on the Bridgetex Pipeline and selling the product to a third party in the Houston market. Our revenues from sales of purchased oil increased by $113.9 million during the year ended December 31, 2015 as compared to the year ended December 31, 2014 due to a full year of activity in 2015 compared to a three month period during 2014.

Costs and expenses

The following table sets forth information regarding costs and expenses from continuing operations and average costs per BOE sold for the periods presented:

| | For the years ended December 31, | | |
|---|---|---|---|
| (in thousands except for per BOE sold data) | 2015 | 2014 | 2013 |
| Costs and expenses: | | | |
| Lease operating expenses | $108,341 | $96,503 | $79,136 |
| Production and ad valorem taxes | 32,892 | 50,312 | 42,396 |
| Midstream service expenses | 5,846 | 5,429 | 3,368 |
| Minimum volume commitments | 5,235 | 2,552 | 891 |
| Costs of purchased oil | 174,338 | 53,967 | — |
| Drilling rig fees | — | 527 | — |
| General and administrative[1] | 90,425 | 106,044 | 89,696 |
| Restructuring expenses | 6,042 | — | — |
| Accretion of asset retirement obligations | 2,423 | 1,787 | 1,475 |
| Depletion, depreciation and amortization | 277,724 | 246,474 | 233,944 |
| Impairment expense | 2,374,888 | 3,904 | — |
| Total costs and expenses | $3,078,154 | $567,499 | $450,906 |
| Average costs per BOE sold:[2] | | | |
| Lease operating expenses | $6.63 | $8.23 | $7.06 |
| Production and ad valorem taxes | 2.01 | 4.29 | 3.78 |
| Midstream service expenses | 0.36 | 0.46 | 0.30 |
| General and administrative[1] | 5.53 | 9.04 | 8.00 |
| Depletion, depreciation and amortization | 16.99 | 21.01 | 20.87 |
| Total | $31.52 | $43.03 | $40.01 |

(1) General and administrative includes non-cash stock-based compensation, net of amounts capitalized, of $24.5 million, $23.1 million and $21.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.

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

Lease operating expenses. Lease operating expenses, which include workover expenses, increased by $11.8 million, or 12%, for the year ended December 31, 2015 compared to 2014. On a three-stream per BOE sold comparable basis, lease operating expenses decreased to $6.63 per BOE sold for the year ended December 31, 2015 compared to $6.98 per BOE sold for the year ended December 31, 2014 due to (i) derived efficiencies from wells drilled along our production corridors resulting in reduced service costs from water handling and disposal and utilization of our centralized compression facilities, (ii) our initiative to reduce field electricity costs by working with electric service providers to build infrastructure to our facilities, (iii) reduced fuel costs from natural gas lift and (iv) lower workover expenses.

Lease operating expenses, which include workover expenses, increased by $17.4 million, or 22%, compared to a 5% increase in production, for the year ended December 31, 2014 compared to 2013. On a per BOE sold basis, lease operating expenses increased in total to $8.23 per BOE sold as of December 31, 2014 from $7.06 per BOE sold as of December 31, 2013. The increases were mainly due to (i) higher average lease operating expenses per BOE sold on our higher oil-weighted Permian production following the Anadarko Basin Sale, (ii) an increase in well count and (iii) higher well service and workover expenses.

Production and ad valorem taxes. Production and ad valorem taxes decreased by $17.4 million, or 35%, for the year ended December 31, 2015 compared to 2014. This change is mainly due to a decrease in production taxes of $16.9 million for the year ended December 31, 2015 compared to 2014 as a result of the corresponding decrease in oil, NGL and natural gas revenues. Production taxes are based on and fluctuate in proportion to our oil, NGL and natural gas revenue.

Production and ad valorem taxes increased to $50.3 million for the year ended December 31, 2014 from $42.4 million for the year ended December 31, 2013, an increase of $7.9 million, or 19%. Ad valorem taxes decreased by $1.6 million for the year ended December 31, 2014 compared to 2013, primarily as a result of the Anadarko Basin Sale. The ad valorem tax decreases were partially offset by the ad valorem tax expense incurred for new wells drilled during the year ended December 31, 2014.

Midstream service expenses. See "—Results of Operations - midstream and marketing" for a discussion of these costs.

Minimum volume commitments. Minimum volume commitments increased by $2.7 million for the year ended December 31, 2015 compared to 2014, mainly as a result of the second-quarter 2015 negotiated buyout of a minimum volume commitment to Medallion, which was related to natural gas gathering infrastructure constructed by Medallion on acreage that we do not plan to develop.

Costs of purchased oil. See "—Results of Operations - midstream and marketing" for a discussion of these costs.

General and administrative. The table below shows the changes in the significant components of G&A expense for the periods presented:

| (in thousands) | Year ended December 31, 2015 compared to 2014 | Year ended December 31, 2014 compared to 2013 |
|---|---|---|
| Changes in G&A: | | |
| Professional fees | $(6,066) | $6,851 |
| Salaries, benefits and bonuses, net of amounts capitalized | (4,084) | 6,249 |
| Charitable contributions | (3,208) | 3,106 |
| Performance unit awards | 3,481 | (4,132) |
| Stock-based compensation, net of amounts capitalized[1] | 1,430 | 1,646 |
| Other | (7,172) | 2,628 |
| Total change in G&A | $(15,619) | $16,348 |

(1) On January 1, 2014, we began capitalizing a portion of stock-based compensation for employees who are directly involved in the acquisition and exploration of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included as an addition to "Oil and natural gas properties" in the consolidated balance sheets included elsewhere in this Annual Report.

Year ended December 31, 2015 compared to 2014. G&A expense, excluding stock-based compensation, decreased by $17.0 million, or 21%, for the year ended December 31, 2015 compared to 2014. The decrease is primarily due to (i) professional fees paid to a consulting company in 2014 that was engaged to assist us with the optimization of our development operations, (ii) reduced personnel expenses as a result of the reduction in force (the "RIF") which occurred early in the first quarter of 2015 and (iii) our $3.0 million charitable contribution pledge expensed in 2014, which will be paid in annual installments through 2024.

Stock-based compensation, net of amount capitalized, increased by $1.4 million, or 6% for the year ended December 31, 2015 compared to 2014 due to the varying service periods of our award types, partially offset by forfeitures of restricted stock awards and restricted stock option awards as a result of the first-quarter 2015 RIF.

The fair values for each of our restricted stock awards issued were calculated based on the value of our stock price on the grant date in accordance with GAAP and are being expensed on a straight-line basis over their associated requisite service periods. The fair values for each of our non-qualified restricted stock options awards were determined using a Black-Scholes valuation model in accordance with GAAP and are being expensed on a straight-line basis over their associated four-year requisite service periods.

Our performance share awards are accounted for as equity awards and are included in stock-based compensation expense. The fair values of the performance share awards issued were based on a projection of the performance of our stock price relative to a peer group, defined in each performance share awards' agreement, utilizing a forward-looking Monte Carlo simulation. The fair values for each of our performance share awards will not be re-measured after their initial grant-date valuation and are being expensed on a straight-line basis over their associated three-year requisite service periods.

Our performance unit awards were accounted for as liability awards. The associated expense for these awards increased by $3.5 million for the year ended December 31, 2015 compared to 2014, mainly due to the 2013 performance unit awards fair value at the end of the performance period compared to their quarterly re-measurement value as of December 31, 2014 that was based on the performance of our stock price relative to the peer group utilized in the forward-looking Monte Carlo simulation. The fair value and corresponding liability related to the 2013 performance unit awards as of December 31, 2015 was $6.4 million. The 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. The 2012 performance unit awards had a performance period of January 1, 2012 to December 31, 2014 and, as their performance criteria were satisfied, they were paid at $100 per unit during the first quarter of 2015.

Year ended December 31, 2014 compared to 2013. G&A expense, excluding stock-based compensation, increased to $83.0 million for the year ended December 31, 2014 from $68.3 million for the year ended December 31, 2013, an increase of $14.7 million, or 22%. The increase is primarily due to the growth of our business, and accordingly our professional fees and salaries and benefits have increased $13.1 million for the year ended December 31, 2014 compared to 2013. The increase during the year ended December 31, 2014 was offset by the $6.4 million combined decrease in the fair value of our performance unit awards and increase in production income and reduced employee bonuses. Professional fees increased mainly due to fees paid to a consulting company engaged in 2014 to assist us with the optimization of our development operations. We also pledged a $3.0 million charitable contribution during the year ended December 31, 2014, which will be paid in annual payments through 2024. On a per BOE sold basis, G&A expense, excluding stock-based compensation, increased to $7.07 per BOE sold during the year ended December 31, 2014 from $6.09 per BOE sold during the year ended December 31, 2013. This increase was a result of the growth in our overhead combined with our Permian production growth being partially offset by the production associated with the divestiture of our Anadarko Basin assets.

Stock-based compensation increased to $27.7 million for the year ended December 31, 2014 from $21.4 million for the year ended December 31, 2013, an increase of $6.3 million, mainly due to the issuance of 1,234,255 restricted stock awards at a weighted-average grant price of $25.68 per share and 336,140 non-qualified restricted stock options to new and existing employees and non-employee directors in the year ended December 31, 2014 compared to the issuance of 1,469,295 restricted stock awards at a weighted-average grant price of $18.17 per share and 1,018,849 non-qualified restricted stock options to new and existing employees and non-employee directors in 2013. Additionally, during the year ended December 31, 2014, we issued 271,667 performance share awards to management and the associated expense amounted to $2.1 million for the year ended December 31, 2014. No comparable awards were issued during 2013. This increase in stock-based compensation was partially offset by management's decision to begin capitalizing a portion of stock-based compensation for employees who are directly involved in the acquisition and exploration of our oil and natural gas properties into the full cost pool in 2014. Capitalized stock-based compensation amounted to $4.7 million for the year ended December 31, 2014. No amounts were capitalized during 2013.

The associated expense for our 2013 and 2012 performance unit awards awards decreased by $4.1 million for the year ended December 31, 2014 compared to 2013 due to (i) the quarterly re-measurement of the 2013 performance unit awards based on the performance of our stock price relative to the peer group utilized in the forward-looking Monte Carlo simulation and (ii) the final pay-out value of the 2012 performance unit awards due to the performance of our stock relative to the peer group during the corresponding performance period. The fair value and corresponding liability related to the 2012 performance unit awards as of December 31, 2014 was $2.7 million and represents the cash payment made in the first quarter of 2015.

See Notes 2.r and 6 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our stock and performance based compensation.

Restructuring expenses. Restructuring expenses relate to the first-quarter 2015 RIF which was an effort to reduce costs and better position ourselves for ongoing efficient growth. Restructuring expenses of $6.0 million were incurred in the first quarter of 2015. See Note 13 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of the RIF.

Depletion, depreciation and amortization ("DD&A"). The following table provides components of our DD&A expense from continuing operations for the periods presented:

| | For the years ended December 31, | | |
|---|---|---|---|
| (in thousands except for per BOE sold data) | 2015 | 2014 | 2013 |
| Depletion of evaluated oil and natural gas properties | $263,666 | $237,067 | $227,992 |
| Depreciation of midstream service assets | 7,529 | 4,303 | 1,510 |
| Depreciation and amortization of other fixed assets | 6,529 | 5,104 | 4,442 |
| Total DD&A | $277,724 | $246,474 | $233,944 |
| DD&A per BOE sold | $16.99 | $21.01 | $20.87 |

DD&A increased by $31.3 million, or 13%, for the year ended December 31, 2015 as compared to 2014, mainly due to (i) the reduction in our reserves volume, (ii) the impact of $152.5 million in unevaluated properties' carrying costs being added to the depletion base during the year ended December 31, 2015 and (iii) higher total production levels. These contributors were partially offset by our second-quarter and third-quarter 2015 impairments. We expect DD&A per BOE will decrease in the first quarter of 2016 due to our fourth-quarter 2015 impairment.

DD&A increased by $12.5 million, or 5%, for the year ended December 31, 2014 as compared to 2013. The increase is mainly due to (i) increased book value on new reserves added, (ii) higher total production levels, (iii) increased capitalized costs for new wells completed in the year ended December 31, 2014, (iv) the impact of the Anadarko Basin Sale to the year ended December 31, 2013 depletion and (v) the impact of $35.5 million in unevaluated properties' carrying costs being added to the depletion base during the three months ended December 31, 2014, as management determined that we do not intend to drill this non-core acreage.

Impairment expense. Our net book value of evaluated oil and natural gas properties exceeded the full cost ceiling amount as of June 30, 2015, September 30, 2015 and December 31, 2015. As a result, we recorded non-cash full cost ceiling impairments for the second quarter, third quarter and fourth quarter of 2015 of $488.0 million, $906.4 million and $975.0 million, respectively. There were no comparable full cost impairments in 2014 or 2013. During the years ended December 31, 2015 and 2014, we reduced materials and supplies by $2.8 million and $1.8 million, respectively, in order to reflect the balance at LCM. There were no comparable materials and supplies impairments in 2013. Beginning in the fourth quarter of 2014, we owned oil line-fill in third-party pipelines, which is accounted for at LCM. For the years ended December 31, 2015 and 2014, we recorded LCM adjustments of $1.3 million and $2.1 million, respectively, related to our line-fill.

Non-operating income and expense. The following table sets forth the components of non-operating income and expense from continuing operations for the periods presented:

| | For the years ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2015 | 2014 | 2013 |
| Non-operating income (expense): | | | |
| Gain (loss) on derivatives: | | | |
| Commodity derivatives, net | $214,291 | $327,920 | $79,902 |
| Interest rate derivatives, net | — | — | (24) |
| Income (loss) from equity method investee | 6,799 | (192) | 29 |
| Interest expense | (103,219) | (121,173) | (100,327) |
| Interest and other income | 426 | 294 | 163 |
| Loss on early redemption of debt | (31,537) | — | — |
| Write-off of debt issuance costs | — | (124) | (1,502) |
| Loss on disposal of assets, net | (2,127) | (3,252) | (1,508) |
| Non-operating income (expense), net | $84,633 | $203,473 | $(23,267) |

Commodity derivatives, net. The table below shows the changes in the components of gain on commodity derivatives, net for the periods presented:

| (in thousands) | Year ended December 31, 2015 compared to 2014 | Year ended December 31, 2014 compared to 2013 |
|---|---|---|
| Changes in gain on commodity derivatives, net: | | |
| Fair value of commodity derivatives outstanding | $(264,009) | $153,171 |
| Early terminations and modification of commodity derivatives received | (76,660) | 70,652 |
| Cash settlements received for matured commodity derivatives | 227,040 | 24,195 |
| Total change in gain on commodity derivatives, net | $(113,629) | $248,018 |

The year ended December 31, 2015 compared to 2014 decrease in fair value of commodity derivatives outstanding is the result of some of our contracts expiring and the changing relationship between our outstanding contract prices and the associated forward curves used to calculate the fair value of our derivatives in relation to expected market prices. During the year ended December 31, 2014, we received $76.7 million in net proceeds from the early termination of our oil basis swap differential between the Light Louisiana Sweet Argus and the Brent International Petroleum Exchange index oil prices and the related physical contract. There were no comparable early termination amounts in 2015. Net cash settlements received for matured derivatives are based on the cash settlement prices of our matured derivatives compared to the prices specified in the derivative contracts.

The year ended December 31, 2014 compared to 2013 increase in fair value of commodity derivatives outstanding is the result of the changing relationship between our contract prices and the associated forward curves used to calculate the fair value of our commodity derivatives in relation to expected market prices. In general, we experience gains during periods of decreasing market prices and losses during periods of increasing market prices. During the year ended December 31, 2014, we received $76.7 million in net proceeds from the early termination of our oil basis swap differential between the Light Louisiana Sweet Argus and the Brent International Petroleum Exchange index oil prices and the related physical contract. During the year ended December 31, 2013, we received net cash settlements on early terminations and modifications of derivatives of $6.0 million as a result of unwinding nine natural gas commodity contracts in connection with the Anadarko Basin Sale.

See Notes 2.f, 8 and 9 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 commodity derivatives.

Income (loss) from equity method investee. Income (loss) from equity method investee increased by $7.0 million for the year ended December 31, 2015 compared to 2014, and decreased by $0.2 million for the year ended December 31, 2014 compared to 2013. During the year ended December 31, 2015, Medallion, our equity method investee, continued expansion activities on existing portions of its pipeline infrastructure in order to gather additional third-party oil production and began recognizing revenue due to its main pipeline becoming fully operational.

Interest expense and interest rate swaps. The table below shows the changes in the significant components of interest expense for the periods presented:

| (in thousands) | Year ended December 31, 2015 compared to 2014 | Year ended December 31, 2014 compared to 2013 |
|---|---|---|
| Changes in interest expense: | | |
| January 2019 Notes | $(38,002) | $(162) |
| March 2023 Notes | 17,135 | — |
| Senior Secured Credit Facility, net of capitalized interest[1] | 1,969 | (2,587) |
| January 2022 Notes | 1,477 | 23,836 |
| Other | (533) | (241) |
| Total change in interest expense | $(17,954) | $20,846 |

(1) Our Senior Secured Credit Facility was paid in full on August 1, 2013 and remained undrawn until September 3, 2014.

Interest expense decreased by $18.0 million, or 15%, for the year ended December 31, 2015 compared to 2014. The decrease is primarily due to the early redemption of the January 2019 Notes on April 6, 2015, which is partially offset by the

issuance of the March 2023 Notes. The March 2023 Notes, which began accruing interest on March 18, 2015, have both a lower interest rate and a lower principal amount than the January 2019 Notes.
Interest expense increased by $20.8 million, or 21%, for the year ended December 31, 2014 compared to 2013. The increase is primarily due to the issuance of the January 2022 Notes in January 2014, which was partially offset by the reduction in the amount outstanding under our Senior Secured Credit Facility and the related commitment fees on the unused portion of the banks' commitment on our Senior Secured Credit Facility.
We had entered into certain variable-to-fixed interest rate derivatives that hedged our exposure to interest rate variations on our variable interest rate debt that expired in September 2013. During the year ended December 31, 2013 we had one interest rate swap and one interest rate cap outstanding for a total notional amount of $100.0 million with fixed pay rates ranging from 1.11% to 3.00% until their expiration in September 2013.
Loss on early redemption of debt. During the year ended December 31, 2015, we redeemed the entire $550.0 million outstanding principal amount of the January 2019 Notes at a redemption price of 104.750% of the principal amount, plus accrued and unpaid interest up to the Redemption Date. We recognized a loss on extinguishment of $31.5 million related to the difference between the redemption price and the net carrying amount of the January 2019 Notes. There were no comparable early redemption of debt amounts in 2014 and 2013.
Write-off of debt issuance costs. In January 2014, we wrote-off $0.1 million of debt issuance costs as a result of changes in the borrowing base under our Senior Secured Credit Facility due to the issuance of the January 2022 Notes. In August 2013, we wrote-off $1.5 million in debt issuance costs as a result of changes in the borrowing base under our Senior Secured Credit Facility due to the Anadarko Basin Sale. There was no comparable amount in 2015.
Loss on disposal of assets, net. Loss on disposal of assets, net decreased by $1.1 million for the year ended December 31, 2015 compared to 2014 as a result of lower losses related to the sales and write-off of materials and supplies and other fixed assets during 2015 as compared to 2014.
Loss on disposal of assets, net increased by $1.7 million for the year ended December 31, 2014 compared to 2013. The 2014 increase over the prior year is a result of losses related to sales of materials and supplies, vehicles and a write-off of abandoned internally developed software during 2014, compared to a net gain recorded in 2013 mainly related to the sale of pipeline assets and various other property and equipment associated with the Anadarko Basin Sale.
Income tax benefit (expense). The fluctuations in income (loss) from continuing operations before income taxes is shown in the table below:

| | For the years ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2015 | 2014 | 2013 |
| Income (loss) from continuing operations before income taxes | $(2,386,881) | $429,859 | $191,084 |
| Income tax benefit (expense) | 176,945 | (164,286) | (74,507) |
| Income (loss) from continuing operations | $(2,209,936) | $265,573 | $116,577 |

Our effective tax rate is affected by recurring changes in valuation allowances, recurring permanent differences and discrete items that may occur in any given year but are not consistent from year to year. The effective tax rate on income (loss) before income taxes was 7%, 38% and 39% for the years ended December 31, 2015, 2014 and 2013, respectively. For the year ended December 31, 2015, we recorded a valuation allowance of $676.0 million for our deferred tax assets due to uncertainty regarding their realization. For further discussion of our valuation allowance, see Note 7 to our consolidated financial statements located elsewhere in this Annual Report.
During the years ended December 31, 2015, 2014 and 2013, certain shares related to restricted stock awards vested at times when our stock price was lower than the fair value of those shares on the grant date. As a result, the income tax deduction related to such shares is less than the expense previously recognized for book purposes. During the years ended December 31, 2014 and 2013, certain restricted stock options were exercised, for which the related income tax deduction was less than the expense previously recognized for book purposes. There were no stock options exercised during the year ended December 31, 2015. As a result of these differences in book compensation cost and related tax deduction, the tax impact of these shortfalls increased by $3.1 million for the year ended December 31, 2015 compared to 2014, and decreased by $0.3 million for the year ended December 31, 2014 compared to 2013.

We utilize a one-pool approach when accounting for the pool of windfall tax benefits in which employees and non-employees are grouped into a single pool. As of December 31, 2015, 2014 and 2013, we did not have any eligible windfall tax benefits to offset future shortfalls as no excess tax benefits had been recognized, and therefore the tax impact of these shortfalls

is included in income tax expense for these respective periods. We expect income tax provisions for future reporting periods will be impacted by this stock compensation tax deduction shortfall; however, we cannot predict the stock compensation shortfall impact because of dependency upon the future market price of our stock. See Notes 6.a, 6.b and 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information.
Income from discontinued operations, net of tax. The table below shows our income from discontinued operations, net of tax for the periods presented:

| | For the years ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2015 | 2014 | 2013 |
| Income from discontinued operations, net of tax | $— | $— | $1,423 |

Effective on the August 1, 2013 completion of the Anadarko Basin Sale, the operations and cash flows of these properties were eliminated from our ongoing operations and we do not have continuing involvement in the operations of these properties.

Results of operations - midstream and marketing

The following table presents selected financial information regarding our midstream and marketing operating segment on a stand-alone basis for the periods presented:

| | For the years ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2015 | 2014 | 2013 |
| Natural gas sales | $1,692 | $1,660 | $— |
| Midstream service revenues | 27,965 | 7,838 | 8,824 |
| Sales of purchased oil | 168,358 | 54,437 | — |
| Total revenues | 198,015 | 63,935 | 8,824 |
| Midstream service expenses, including minimum volume commitments | 18,393 | 9,641 | 1,571 |
| Costs of purchased oil | 174,338 | 53,967 | — |
| General and administrative[1] | 8,174 | 6,969 | 2,745 |
| Depletion, depreciation and amortization[2] | 8,093 | 4,640 | 2,241 |
| Impairment expense | 2,592 | 2,102 | — |
| Other operating costs and expenses[3] | 342 | 66 | — |
| Operating income (loss) | $(13,917) | $(13,450) | $2,267 |

Other financial information: