Laredo Petroleum, Inc.
Form 10-K
February 27, 2014

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, 2013
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 (State or other jurisdiction of incorporation or organization)	45-3007926 (I.R.S. Employer Identification No.)
15 W. Sixth Street, Suite 1800 Tulsa, Oklahoma (Address of principal executive offices)	74119 (Zip code)

(918) 513-4570
(Registrant's telephone number, including area code)
Securities Registered Pursuant to Section 12(b) of the Act:

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

Securities Registered Pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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. o
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 $870.1 million on June 28, 2013, based on $20.56 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 24, 2014: 142,618,804

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2014 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2013, are incorporated by reference into Part III of this report for the year ended December 31, 2013.

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.

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

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

"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.

"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 differs from nearby rock.

"Fracturing ("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.

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

"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, condensate and natural gas liquids.

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

"MBOE"—One thousand 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 liquid"—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 total 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.
"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 ("PDNP")"—Developed non-producing reserves.
"Proved developed reserves ("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 which 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 ("PUD")"—Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
"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 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.
"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.
"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, 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 recent instability and uncertainty in the U.S. and international financial and consumer markets that is adversely affecting the liquidity available to us and our customers and is adversely affecting the demand for commodities, including oil and natural gas;
- the volatility of oil and natural gas prices;
- the possible introduction of regulations that prohibit or restrict our ability to apply hydraulic fracturing to our oil and natural gas wells;
- the possible introduction of regulations that prohibit or restrict our ability to drill new allocation wells;
- discovery, estimation, development and replacement of oil and natural gas reserves, including our expectations that estimates of our proved reserves will increase;
- uncertainties about the estimates of our oil and natural gas reserves;
- competition in the oil and natural gas industry;
- the availability and costs of drilling and production equipment, labor and oil and natural gas processing and other services;
- drilling and operating risks, including risks related to hydraulic fracturing activities;
- risks related to the geographic concentration of our assets;
- changes in domestic and global demand for oil and natural gas, as well as the continuation of restrictions on the export of domestic crude oil;
- the availability of sufficient pipeline and transportation facilities and gathering and processing capacity;
- changes in the regulatory environment and changes in international, legal, political, administrative or economic conditions;
- our ability to comply with federal, state and local regulatory requirements;
- our ability to execute our strategies, including but not limited to our hedging strategies;
- our ability to recruit and retain the qualified personnel necessary to operate our business;
- evolving industry standards and adverse changes in global economic, political and other conditions;
- restrictions contained in our debt agreements, including our senior secured credit facility and the indentures governing our senior unsecured notes, as well as debt that could be incurred in the future;
- our ability to access additional borrowing capacity under our senior secured credit facility or other means of providing liquidity; and
- our ability to generate sufficient cash to service our indebtedness and to generate future profits.

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. 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 subsidiary, Laredo Midstream Services, LLC, as of the completion of our internal corporate reorganization and thereafter.

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. ("Broad Oak"), a Delaware corporation, 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. See Notes A and B in our audited consolidated financial statements included elsewhere in this Annual Report for more information.

All amounts, 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 exploration, development and acquisition of oil and natural gas properties primarily in the Permian region of the United States. The oil and liquids-rich Permian Basin in West Texas 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, 2013, we had assembled 202,084 net acres in the Permian Basin and had total proved reserves, presented on a two-stream basis, of 203,615 MBOE.

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. Following the Anadarko Basin Sale, the percentage of our proved reserves attributable to oil increased to 55% as of December 31, 2013 from 52% prior to such sale.

Our primary exploration and production fairway in the Permian Basin is centered on the eastern side of the basin 35 miles east of Midland, Texas and extends 20 miles wide (east/west) and 85 miles long (north/south) in Glasscock, Howard, Reagan, Sterling and Tom Green counties, and is referred to in this Annual Report as the "Permian-Garden City" area. As of December 31, 2013, we held 143,212 net acres in more than 300 sections in the Permian-Garden City area, with an average working interest of 96% in all Laredo-operated producing wells.

We believe our acreage in the Permian-Garden City area is a resource play for the Wolfberry interval, comprised of multiple producing formations, including the initial four identified shale zones targeted for horizontal drilling (Upper, Middle and Lower Wolfcamp and Cline shales). From our inception through December 31, 2013, we have drilled and completed 96 horizontal wells in these four target zones, and 818 vertical wells in the Wolfberry interval. We have completed (i.e., the particular well is flowing) 40 horizontal Upper Wolfcamp wells, 13 horizontal Middle Wolfcamp wells, six horizontal Lower Wolfcamp wells and 37 horizontal Cline wells. Our horizontal activity since mid-2012 has moved toward drilling longer laterals (typically 7,000 to 7,500 feet) and increased frac density (typically 25 to 28 stages) as we continue the optimization of our completion techniques.

As illustrated in the following table, as a result of our drilling activity through 2013 coupled with our technical data and well performance, we believe that as of December 31, 2013 we have confirmed the horizontal development potential for the equivalent of 360,000 net acres from the four zones, as well as our entire Permian-Garden City acreage position for vertical development.

	Horizontal development de-risked net acreage as of December 31, 2013
Upper Wolfcamp	80,000
Middle Wolfcamp	80,000
Lower Wolfcamp	73,000
Cline	127,000
Total	360,000

Going forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage, as reflected in our 2014 capital drilling budget allocation. As a result, we expect our Permian-Garden City acreage to be the primary driver of our reserves, production and cash flow growth for the foreseeable future.

Laredo was founded in October 2006 by our Chairman and Chief Executive Officer Randy A. Foutch, who was later joined by other members of our management team. Prior to founding Laredo, Mr. Foutch formed, built and sold three private oil and natural gas companies. All of these companies executed the same fundamental business strategy employed by Laredo and created significant economic value through growth in reserves, production and cash flow. In December 2011, we completed a Corporate Reorganization and IPO and in December 2013, we completed a separate internal corporate reorganization. See "—Corporate history and structure."

Since our inception, we have rapidly grown our reserves, production and cash flow through both our drilling program and strategic acquisitions, including our July 2011 acquisition of Broad Oak. Our net proved reserves were estimated at 203,615 MBOE as of December 31, 2013, of which 35% are classified as proved developed reserves and 55% are attributed to oil reserves. Our reserves and production are reported in two streams: crude oil and liquids-rich natural gas. The economic value of the natural gas liquids in our natural gas is included in the wellhead natural gas price. 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 two-stream basis, net acreage and producing wells as of December 31, 2013, and average daily production presented on a two-stream basis for the year ended December 31, 2013. Based on estimates in the report prepared by Ryder Scott, we operate wells that represent 98% of the economic value of our proved developed oil and natural gas reserves as of December 31, 2013.

	As of December 31, 2013									Year ended December 31, 2013
	Estimated net proved reserves[1][2]						Producing wells			average daily
	MBOE	% of total reserves		% Oil		Net acreage	Gross	Net		production[3] (BOE/D)
Permian	203,564	99	%	55	%	202,084	1,060	940		24,897
Anadarko Granite Wash[4]	—	—	%	—	%	—	—	—		4,615
Other Areas[5]	—	—	%	—	%	—	—	—		1,141
New Ventures[6]	51	1	%	100	%	80,143	1	1		63
Total	203,615	100	%	55	%	282,227	1,061	941		30,716

(1) Our estimated net proved reserves were prepared by Ryder Scott, presented on a two-stream basis as of December 31, 2013 and are based on reference oil and natural gas prices. In accordance with applicable rules of the SEC, the reference oil and natural gas prices are derived from the average trailing 12-month index prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the applicable 12-month period), held constant throughout the life of the properties. The reference prices were $93.52 per Bbl for oil and $3.57 per MMBtu for natural gas for the 12 months ended December 31, 2013.

(2) Because our reserves are reported in two streams, the economic value of the natural gas liquids in our natural gas is included in the wellhead natural gas price. The reference prices referred to above that were utilized in the December 31, 2013 reserve report prepared by Ryder Scott are adjusted for natural gas liquids content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The adjusted reference price was $5.52 per Mcf.

(3) Our average daily production volumes are reported in two streams: crude oil and liquids-rich natural gas. The economic value of the natural gas liquids in our natural gas is included in the wellhead natural gas price.

(4) We sold these assets on August 1, 2013.

(5) We sold these assets on August 1, 2013, which included our acreage in the gas prone Eastern Anadarko (21,000 net acres) and Central Texas Panhandle (43,450 net acres).

(6) On December 20, 2013, we completed the sale of certain properties in the Dalhart Basin, which included 37,000 net acres. The remaining 50,000 net acres that we own in the Dalhart Basin are included in New Ventures. See "—New Ventures."

Our net average daily production for the year ended December 31, 2013 was 30,716 BOE/D, 49% of which was oil and 51% of which was primarily liquids-rich natural gas. Our drilling activity has been and is expected to continue to be focused on oil opportunities in the Permian Basin.

Following the sale of our assets in the Anadarko Basin and Dalhart Basin, we continue to focus on horizontal drilling in the Permian Basin. This Permian Basin horizontal drilling program comprises an extensive, multi-year, multiple-zone inventory of exploratory and development opportunities.

As of December 31, 2013 we had completed 96 gross horizontal Wolfcamp and Cline shale wells in our Permian-Garden City area.

Substantially all of our $1 billion planned capital budget for 2014 is anticipated to be invested in the Permian Basin. We anticipate that we will continue to drill vertical wells for purposes of further delineating our Permian Basin acreage and holding all prospective targeted zones. We are increasingly allocating a greater percentage of both capital and human resources towards our horizontal drilling activity, which generally produces even more attractive economics than our vertical program. Because of the stacked multiple-zone horizontal targets underlying our acreage, we are continuing to refine the optimal geometry relative to well spacing, both vertically and horizontally, lateral placement, completion and production practices. Work to date has included the pad drilling of side-by-side wells within the same zone, stacked lateral wells and extensive reservoir modeling.

On December 31, 2013 we had a total of 11 operated drilling rigs working on our properties in the Permian-Garden City area, consisting of six rigs drilling vertical wells and five rigs drilling horizontal wells.
We have assembled a multi-year inventory of development drilling and exploitation projects as a result of our early acquisition of technical data, early establishment of significant concentrated acreage positions and successful exploratory drilling.
While our horizontal drilling programs will be focused primarily on developing the four zones already identified in the liquids-rich Wolfcamp and Cline intervals underlying our Permian-Garden City properties, we believe, based on petrophysical analysis, additional potential may exist in both shallower and deeper formations. The testing of these new targeted intervals will be integrated into our drilling program during 2014 and beyond.
We maintain a financial profile that provides operational flexibility. At December 31, 2013, we had $825 million available for borrowings under our Fourth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility") and total debt of $1.05 billion, of which no amount was outstanding under our Senior Secured Credit Facility. Our total debt, less available cash on the balance sheet, was 1.8 times our Adjusted EBITDA (a non-GAAP financial measure, see "Item 6. Selected Historical Financial Data—Non-GAAP financial measures and reconciliations") for the year ended December 31, 2013. We believe that our operating cash flow and the aforementioned liquidity sources provide us with the capability to implement our planned exploration and development activities as well as the ability to accelerate our capital program, if deemed appropriate. We use derivatives to reduce exposure to fluctuations in the prices of oil and natural gas. By removing a significant portion of the price volatility associated with future production, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices.
We carefully assess and monitor many factors in our drilling and exploration projects. Our drilling activities in areas containing extensive historical industry activity have enabled us to determine whether a prospective reservoir underlies our acreage position, and whether it can be defined both vertically and horizontally. We use a number of proven mapping techniques to understand the physical extent of the targeted reservoir. This includes 2D and 3D seismic data, as well as Laredo-owned and historical public well databases (which in the Permian Basin may extend back more than 80 years). We also utilize our laboratory and field derived data from whole cores, sidewall cores, well cuttings, mudlogs and open-hole well logs to understand the petrophysics of the rock characteristics prior to the commencement of any completion operations. Finally, after defining the reservoir, our engineers utilize their technical expertise to develop completion programs that we believe will maximize the amount of hydrocarbons that can be economically recovered. As more wells are completed in the targeted reservoir and additional data becomes available, the process is further refined. Based on these and other factors, we consider our acreage to be "de-risked" (i.e., having reduced the risk and uncertainty associated therewith) when we believe we have established the ability to commercially produce from a certain area.
In the Permian-Garden City area, the Wolfberry interval, comprised of multiple producing formations, including the Wolfcamp and Cline shale formations targeted for horizontal drilling in four zones (Upper, Middle and Lower Wolfcamp and Cline shales), is considered a resource play. While the vertical component of the drilling program will continue, our emphasis is now centered on bringing forward the upside potential in the Wolfcamp and Cline shales in our Permian-Garden City acreage through horizontal drilling. As resource plays, the mapping of the gross interval for each of the producing formations underlying a majority of our acreage position is the primary factor in identifying our potential drilling locations. In the general region and immediately around our acreage position, publicly available well data exists from a significant number of vertical wells (in excess of several thousand for the Wolfcamp and Cline shales alone) that allows us to better define the potential areal extent of each of the producing intervals. In addition to the publicly available well data, we have also incorporated our internally generated information from cores, 3D seismic, open-hole logging, production and reservoir engineering data into defining the extent of the targeted formations, the ability of such formations to produce commercial quantities of hydrocarbons, and the viability of the potential locations. We are refining a development plan for a portion of our Permian-Garden City area in order to minimize costs and maximize recoveries and began its implementation in 2013. As of December 31, 2013, we had drilled and completed 10 horizontal wells as a part of our pad drilling program.

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

Corporate history and structure

Laredo Petroleum Holdings, Inc. was incorporated in August 2011 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 Laredo Petroleum Holdings, Inc., with Laredo Petroleum Holdings, Inc.

surviving the merger, was completed on December 19, 2011 (the "Corporate Reorganization"). Laredo Petroleum, LLC was formed in 2007 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., which was founded in 2006 by Randy A. Foutch, our Chairman and Chief Executive Officer, to acquire, develop and operate oil and natural gas properties in the Permian and Mid-Continent regions of the United States. 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 Laredo Petroleum Holdings, Inc. Laredo Petroleum Holdings, Inc. completed an IPO of its common stock on December 20, 2011. As of December 31, 2013, Warburg Pincus owned 49.1% 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.

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 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 Laredo Petroleum Holdings, Inc. ("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." The Corporate Reorganization, IPO and Internal Consolidation are discussed in Note A to our audited consolidated financial statements included elsewhere in this Annual Report.

Laredo Petroleum, Inc. is the borrower under our Senior Secured Credit Facility, as well as the issuer of our $550 million 9 1/2% senior unsecured notes due 2019 (the "2019 senior unsecured notes") issued in January and October 2011, our $500 million 7 3/8% senior unsecured notes due 2022 issued in April 2012 (the "2022 senior unsecured notes") and our $450 million 5 5/8% senior unsecured notes due 2022 issued in January 2014 (the "new senior unsecured notes"). We refer to the 2019 senior unsecured notes, the 2022 senior unsecured notes and the new senior unsecured notes collectively as the "senior unsecured notes." Our subsidiary, Laredo Midstream Services, LLC ("Laredo Midstream"), is a guarantor of the obligations under our Senior Secured Credit Facility and senior unsecured notes.

Our business strategy

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

Grow reserves, production and cash flow. As of December 31, 2013, we had 143,212 net acres in the Permian-Garden City area. As of such date we believe we have established the economic horizontal potential of 80,000 net acres for horizontal Upper Wolfcamp drilling, 80,000 net acres for horizontal Middle Wolfcamp drilling, 73,000 net acres for Lower Wolfcamp drilling and 127,000 net acres for horizontal Cline drilling. We are continuing to de-risk the remaining acreage for these zones, although at a slower pace than in the past. We believe the opportunities afforded in our Permian-Garden City area will support consistent, predictable, annual growth in reserves, production and cash flow.

Initiating a development plan for our Permian-Garden City acreage. We believe our Permian-Garden City acreage will be the primary driver of our reserves, production and cash flow growth for the foreseeable future. Based on additional drilling results through December 31, 2013, coupled with our technical data and well performance, we believe we have confirmed the vertical development potential of our entire Permian-Garden City acreage position (utilizing more than 800 vertical wells across our acreage position, of which more than 300 have been drilled through the Wolfcamp, Cline and Atoka formations). The equivalent of 360,000 net acres for commercial horizontal development has been proven from all four targeted zones based on 96 horizontal wells drilled and completed as of December 31, 2013. We further believe this de-risked acreage position provides a multi-year development inventory to support consistent growth of reserves, production and cash flow. We are implementing a systematic pad development drilling program that will allow us to optimize spacing, minimize drainage interference and maximize our frac design. Because of the complexities of developing a field that has multi-dimensional aspects (vertical and horizontal reservoir components), we have drilled and tested side-by-side horizontal wells (same reservoir) with the initial results supporting 660-ft. spacing at or above our internal production estimates. The stacked lateral program (up to four different zones) has been initiated with multiple tests planned in several areas of our acreage in 2014. Our objectives with the stacked lateral program are to optimize the vertical distance between the laterals, minimize interference, enhance frac design and maximize scheduling of rig operations on multi-well pads. The plan also calls for having the flexibility to include the de-risking of additional acreage for both the Wolfcamp and the Cline shale intervals while furthering the development of the Middle and Lower Wolfcamp zones in the southern half of the Permian-Garden City acreage. The drilling and testing of other potential zones (i.e., Spraberry and ABW) will likely also be part of the 2014 drilling program. Going

forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage position.
Capitalize on technical expertise and database. We are leveraging our operating and technical expertise to further delineate and develop our core acreage positions. We believe that we have de-risked a significant portion of our Permian-Garden City acreage through the utilization of an extensive technical petrophysical database, a vertical drilling program covering a majority of our core acreage position, numerous vertical single-zone tests in our horizontal targets, and the production data from the 96 completed horizontal wells in all three Wolfcamp zones and the Cline shale zones.
We intend to continue to make upfront investments in technology to understand the geology, geophysics and reservoir parameters of the rock formations that define our exploration and development programs. Through comprehensive coring programs, acquisition and evaluation of high-quality 3D seismic data and advance logging/simulation technologies, we expect to continue to both economically de-risk our remaining property sets to the extent possible before committing to a drilling program, and assist in the evaluation of emerging opportunities.
Enhance returns through prudent capital allocation, optimization of our development program and continued improvements in operational and cost efficiencies. In the current commodity price environment, we have directed our capital spending toward oil and liquids-rich drilling opportunities that provide attractive returns. We believe by emphasizing our horizontal program, we can increase the efficiency of our resource recovery in the multiple vertically stacked producing horizons on our acreage in our Permian-Garden City area. We initiated a development plan for a portion of our Permian-Garden City area in order to minimize costs and maximize recoveries. We began implementing this plan in 2013, commencing with a single zone side-by-side test and vertically stacked horizontal wellbores in multiple zones to test optimal spacing of the laterals, both vertically and horizontally, in the four initial zones targeted for horizontal development. We are now drilling longer laterals and optimizing our completion process to enhance the cost-efficient recovery of our resource potential. In addition, horizontal drilling may be economic in areas where vertical drilling is currently not economical or logistically viable. We will continue to utilize our vertical drilling program to de-risk additional acreage for all zones. Our management team is focused on continuous improvement of our operating practices and has significant experience in successfully converting exploration programs into cost-efficient development projects. We are the operator for 88% of our Permian-Garden City wells which allows us to more effectively manage operating costs, the pace of development activities, technical applications, the gathering and marketing of our production and capital allocation.
Evaluate and pursue value-enhancing acquisitions, mergers, joint ventures and divestitures. While we believe our multi-year inventory of potential drilling locations provides us with significant growth opportunities, we continue to evaluate strategically compelling and/or value enhancing asset acquisitions, mergers, joint ventures and divestitures. Any transaction we pursue will either generally complement our asset base, provide an anticipated competitive economic proposition relative to our existing opportunities or market conditions, or provide an avenue to accelerate the development of our potentially higher return acreage and maximize the value of the total Company.
Proactively manage risk to limit downside. We continually monitor and control our business and operating risks through various risk management practices, including maintaining a flexible financial profile, making upfront investment in research and development as well as data acquisition, seeking multiple sales outlets, minimizing long-term contracts, maintaining an active commodity hedging program and employing prudent safety and environmental practices.
Our competitive strengths
We have a number of competitive strengths that we believe will help us to successfully execute our business strategy:
Significant de-risked Permian Basin acreage position and multi-year drilling inventory. From our inception in 2006 through December 31, 2013, we have completed 818 gross vertical and 98 gross horizontal wells with a success rate of 99% in our Permian-Garden City area. The 98 gross horizontal wells are comprised of 96 wells in the Upper, Middle and Lower Wolfcamp and Cline shales and two wells in other zones. Based on our drilling results through December 31, 2013, we believe we had confirmed the economic horizontal development potential of the equivalent of 360,000 net acres from the four zones that includes 80,000 net acres in the Upper Wolfcamp, 80,000 net acres in the Middle Wolfcamp, 73,000 net acres in the Lower Wolfcamp and 127,000 net acres in the Cline shale. We believe these locations provide a multi-year drilling inventory supporting future growth in reserves, production and cash flow.

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 that define our drilling and development program. We have an extensive library of data applicable to our Permian-Garden City acreage base that includes 774 square miles of proprietary/licensed 3D seismic (covering 95% of our acreage position), 225 proprietary petrophysical logs (fully core calibrated), and more than 13,500 historical open-hole logs from the general area, as of December 31, 2013. We have also run 96 dipole sonic longs which play a key role in our petrophysical analysis. Approximately 470 square miles of the total 3D seismic coverage has been merged into one volume, allowing for maximum utilization and interpretation of the data set. In addition, membership in an industry core consortium has provided us access to additional petrophysical data across a larger area outside our core Permian-Garden City acreage position. In coordination with a major oil-field consultant, we are in the process of creating a model (utilizing a majority of the data listed above) that we anticipate will assist in developing our Permian-Garden City acreage with the best reservoir characteristics early in the life of the field. Another important objective of the modeling program includes how to maximize hydrocarbon recovery by utilizing the minimum required number of wells through proper well spacing.

Significant operational control. We operate wells that represent 98% of the economic value of our proved developed reserves as of December 31, 2013, based on a report prepared by Ryder Scott. We believe that maintaining operating control permits us to better pursue our strategies of enhancing returns through operational and cost efficiencies and maximizing ultimate hydrocarbon recoveries from mature producing basins 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.

Owned gathering infrastructure. Our wholly-owned subsidiary, Laredo Midstream, has more than 125 miles of pipeline in our natural gas gathering systems in the Permian Basin as of December 31, 2013. These systems and flow lines provide greater operational efficiency and lower price differentials for our natural gas production in our liquids-rich Permian play and enable us to coordinate our activities to connect our wells to market upon completion with minimal days waiting on pipeline. Additionally, on a portion of our production, this provides us with multiple sales outlets through interconnection pipelines, potentially minimizing the risks of both shut-ins awaiting pipeline connection and curtailment of downstream pipelines. We continue to expand this concept by building out our crude oil transportation infrastructure in order to attempt to minimize the risks of shut-in or curtailment. We have constructed crude oil truck stations in Glasscock and Reagan counties, Texas. We have also commenced construction of a crude oil gathering system in Reagan County, Texas.

Financial strength and flexibility. We maintain a financial profile that provides operational flexibility. As of December 31, 2013, we had $825 million available for borrowings under our Senior Secured Credit Facility and total liquidity of $1.0 billion, with no amounts outstanding on our Senior Secured Credit Facility. As of such date, we had $1.05 billion of total debt consisting of two series of senior unsecured notes with maturities in 2019 and 2022. We use derivatives to reduce exposure to fluctuations in the prices of oil and natural gas. By removing a portion of the price volatility associated with future production, we expect to mitigate, but not eliminate, the potential volatility in cash flows from operations due to fluctuations in commodity prices.

Subsequent to December 31, 2013, we issued the new senior unsecured notes that increased our total long-term indebtedness to $1.5 billion and decreased the amount available for borrowings under our Senior Secured Credit Facility to $812.5 million.

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, which is comprised of Laredo management and representatives of Warburg Pincus, our institutional investor, as well as independent individuals, 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 dozens of such companies, including Broad Oak and two previous companies operated by members of our management team.

Focus areas

Our properties are currently located in the prolific Permian region of the United States, where we leverage our experience and knowledge to identify, exploit and acquire additional upside potential. We have been successful in delivering repeatable results through internally generated vertical and horizontal drilling programs. We expect our Permian-Garden City acreage, which is characterized by a high oil content, to be the primary driver of our reserves, production and cash flow growth for the foreseeable future.

Permian Basin

The oil and liquids-rich Permian Basin, located in West Texas and Southeastern New Mexico, where we have assembled 202,084 net acres as of December 31, 2013, is one of the most productive onshore oil and natural gas producing regions in the United States. It is characterized by an extensive production history, mature infrastructure, long reserve life and hydrocarbon potential in multiple intervals. Our primary production and exploitation fairway (Permian-Garden City area) is centered on the eastern side of the basin 35 miles east of Midland, Texas and extends 20 miles wide (east/west) and 85 miles long (north/south) in Howard, Glasscock, Reagan, Sterling and Tom Green counties. As of December 31, 2013, we held

143,212 net acres in more than 300 sections in the Permian-Garden City area with an average working interest of 96% in all Laredo-operated producing wells.

During 2013, we continued to expand our horizontal development program for the Wolfberry and Cline shales. Our results indicate that our acreage in the Permian-Garden City area can be produced horizontally, with even stronger economic results than our vertical program. Within the Wolfcamp, we have three distinct zones; the Upper, Middle and Lower Wolfcamp shales, which together with the Cline shale provide at least four horizontal targets in the Permian-Garden City area. During 2013, we drilled and completed 36 horizontal wells and now have a total of 96 horizontal wells, confirming production and attractive returns from all four zones. Today, we are continuing our drilling focus on a horizontal development and exploitation program supported by vertical wells that help us define and optimize the horizontal targets.

As of December 31, 2013, our proprietary and industry data includes 774 square miles of proprietary/licensed 3D seismic, 13 whole and more than 335 sidewall cores in the four zones we are currently targeting, providing extensive production and reservoir engineering data. From our analysis of this data, we believe each of these zones has the potential to be a stand-alone resource play with significant areal extent, the ability to produce commercial quantities of hydrocarbons and the viability of repeatable well performance from multiple potential locations. Based on our analysis, we also believe the Wolfcamp and Cline shales exhibit similar petrophysical attributes to other large, domestic oil and liquids-rich shale plays, such as the Eagle Ford and Bakken.

The Wolfcamp shale resource play

The Wolfcamp shale continues to be a focus of active drilling by the industry and is encountered at depths ranging from 7,000 to 9,000 feet under our Permian-Garden City acreage. We have been able to further define the gross Wolfcamp shale formation into three discernible zones: the Upper, Middle and Lower Wolfcamp. Under our Permian-Garden City acreage, each of these zones ranges in thickness between 300 and 600 feet. Based on our proprietary data and analysis, we believe we have confirmed that all three Wolfcamp zones share many similar petrophysical and production attributes.

As of December 31, 2013, we had successfully drilled and completed 40 horizontal wells in the Upper Wolfcamp, 13 horizontal wells in the Middle Wolfcamp and six horizontal wells in the Lower Wolfcamp.

Upper Wolfcamp. As of December 31, 2013, we estimated that 80,000 net acres of our Permian-Garden City area had been de-risked for horizontal Upper Wolfcamp development. In the Upper Wolfcamp, we have identified a facies change progressing from west to east across our acreage, with the shale becoming increasingly carbonate. To date we have drilled and completed more wells in the southern third of our de-risked Upper Wolfcamp acreage, while continuing to explore and develop the entire area.

Middle and Lower Wolfcamp. In the Middle and Lower Wolfcamp, we continue to expand our evaluation efforts across our acreage. Production from our vertical drilling program has confirmed that both the Middle and Lower Wolfcamp zones underlie the majority of our acreage. As with the Upper Wolfcamp, there appears to be a similar facies change in these zones. As of December 31, 2013, we had drilled and completed 13 horizontal wells in the Middle Wolfcamp zone and six horizontal wells in the Lower Wolfcamp zone. As of the same date we estimated that 80,000 net acres in the Middle Wolfcamp and 73,000 net acres in the Lower Wolfcamp had been de-risked for horizontal development. Through the combination of our drilling activities, the initial production results from these wells and our extensive technical database, we will continue our efforts to fully evaluate the potential of both the Middle and Lower Wolfcamp over our whole Permian-Garden City acreage position.

The Cline shale resource play

As of December 31, 2013, we estimated that 127,000 net acres of our Permian-Garden City area had been de-risked for horizontal Cline development. In 2013, we successfully drilled and completed three horizontal wells and now have a total of 37 horizontal wells in the Cline shale.

We first recognized the potential of the Cline shale in 2008, took our first Cline cores in 2009 and drilled our first horizontal well in the formation in early 2010. We are now in the horizontal development phase on this de-risked acreage. We believe the petrophysical data indicates that this is a repeatable economic resource play, and we continue to delineate and define the Cline potential on our remaining Permian-Garden City acreage. Industry activity relative to the Cline shale has also been initiated with several horizontal wells being drilled and/or permitted immediately north and east of our Permian-Garden City acreage position.

The Cline shale is encountered at a depth of 9,000 to 9,500 feet in our Permian-Garden City acreage. Our proprietary petrophysical data indicates that the Cline is a laterally extensive, high-quality, over-pressured source rock with an abundance of oil-prone organic matter and high generation potential. Cline conventional cores contain numerous vertical extension fractures that are partially open, significantly enhancing system permeability across the matrix. Multiple thermal maturity indices show the Cline to be in a "peak liquids" stage in the late oil to early gas/condensate window. As our drilling and data acquisition programs progress, we are beginning to define those areas that show commonality in terms of reservoir type, quality and repeatability.

Other areas

On August 1, 2013 we completed the sale of our assets in the Anadarko Basin in the Texas Panhandle and Western Oklahoma. Included in this sale were 43,450 net acres in the Central Texas Panhandle and 21,000 net acres in the eastern end of the Anadarko Basin, in Caddo, Grady and Comanche counties, Oklahoma.

New Ventures

In addition to our Permian Basin acreage, we continue to evaluate new opportunities in other areas within our core operating regions, which we refer to as our "New Ventures."

The Dalhart Basin is located on the western side of the Texas Panhandle. On December 20, 2013 we completed the sale of 37,000 net acres of our position in the Dalhart Basin. As of December 31, 2013, we held 50,000 net acres in the Dalhart Basin, which is included in New Ventures.

In addition, as of December 31, 2013, we held 29,459 net acres in other New Venture areas.

Our operations

Estimated proved reserves

Our reserves are reported in two streams: crude oil and liquids-rich natural gas. The economic value of the natural gas liquids in our natural gas is included in the wellhead natural gas price. In this Annual Report, the information with respect to our estimated proved reserves presented below has been prepared by Ryder Scott, our independent reserve engineers, in accordance with the rules and regulations of the SEC applicable to the periods presented. Our net proved reserves were estimated at 203,615 MBOE as of December 31, 2013, of which 35% were classified as proved developed reserves, and 55% are attributable to oil reserves. The following table presents summary data for each of our core operating areas as of December 31, 2013. Our estimated proved reserves as of December 31, 2013 assume our ability to fund the capital costs necessary for their development and are affected by pricing assumptions. In addition, we may not be able to raise the amounts of capital that would be necessary to drill a substantial portion of our proved undeveloped reserves. See "Item 1A. Risk Factors—Risks related to our business—Estimating reserves and future net revenues involves uncertainties. Decreases in oil and natural gas prices, or negative revisions to reserve estimates or assumptions as to future oil and natural gas prices, may lead to decreased earnings, losses or impairment of oil and natural gas assets."

	As of December 31, 2013		
Area:	Proved reserves (MBOE)	% of total	
Permian Basin	203,564	99	%
New Ventures[1]	51	1	%
Total	203,615	100	%

(1) Includes Dalhart Basin and other New Ventures.

The following table sets forth more information regarding our estimated proved reserves as of December 31, 2013 and 2012. Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves as of December 31, 2013 and 2012. The reserve estimates as of December 31, 2013 and 2012 were prepared in accordance with the SEC's rules regarding oil and natural gas reserve reporting currently in effect. The information does not give any effect to our commodity hedges.

	As of December 31,	
	2013	2012(1)
Estimated proved reserves:		
Oil and condensate (MBbl)	111,498	98,141
Natural gas (MMcf)	552,702	542,946
Total estimated proved reserves (MBOE)	203,615	188,632
Proved developed producing (MBOE)	67,968	76,777
Proved developed non-producing (MBOE)	3,757	4,713
Proved undeveloped (MBOE)	131,890	107,142
Percent developed	35 %	43 %

(1) Includes proved reserves attributable to the acreage sold in the Anadarko Basin Sale.

Technology used to establish proved reserves. Under the SEC rules, proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil 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 using pore volume calculations and performance from analogous wells in the surrounding area and 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.

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, 2013 and 2012 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.

Gary B. Smallwood, 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 38 years of practical experience with 30 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.
Mr. Smallwood reports directly to our President and Chief Operating Officer. Reserves estimates are reviewed and approved by our senior engineering staff with final approval by our President and Chief Operating Officer and certain other members of our senior management. Our senior management also reviews our independent engineers' reserves estimates and related reports with our senior reservoir engineering staff and other members of our technical staff.
Proved undeveloped reserves
Our proved undeveloped reserves, reported on a two-stream basis, increased from 107,142 MBOE as of December 31, 2012 to 131,890 MBOE as of December 31, 2013. During 2013, 5,782 MBOE of proved undeveloped reserves from 25 locations were converted to proved developed reserves. New proved undeveloped reserves of 47,643 MBOE were added during the year, with 96% coming from new horizontal Upper, Middle and Lower Wolfcamp and Cline locations. Negative revisions of 11,944 MBOE were due to the combined effect of removing 174 proved locations and the net effect of redetermining 501 undeveloped locations. The 174 locations that were removed were comprised of vertical Wolfberry and short horizontal laterals. They were replaced with longer horizontal laterals to better align with future drilling plans.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2013 reserves report are $2.2 billion. Based on this report, the capital estimated to be spent in 2014, 2015, 2016, 2017 and 2018 to develop the proved undeveloped reserves is $359 million, $482 million, $558 million, $499 million and $232 million, respectively. All of the proved undeveloped locations are expected to be drilled within a five-year period.

Production, revenues and price history

The following table sets forth information regarding production, revenues and realized prices and production costs for the years ended December 31, 2013, 2012 and 2011. Our reserves and production are reported in two streams: crude oil and liquids-rich natural gas. The economic value of the natural gas liquids in our liquids-rich natural gas is included in the wellhead natural gas price. 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)	2013	2012	2011
Production data:			
Oil (MBbl)	5,487	4,775	3,368
Natural gas (MMcf)	34,348	39,148	31,711
Oil equivalents (MBOE)(1)	11,211	11,300	8,654
Average daily production (BOE/D)(1)	30,716	30,874	23,709
Revenues (in thousands):			
Oil	$494,676	$414,932	$306,481
Natural gas	$170,168	$168,637	$199,774
Average sales prices without hedges:			
Benchmark oil ($/Bbl)(2)	$97.97	$94.20	$95.01
Realized oil ($/Bbl)(3)	$90.16	$86.89	$91.00
Benchmark natural gas ($/MMBtu)(2)	$3.65	$2.80	$4.02
Realized natural gas ($/Mcf)(3)	$4.95	$4.31	$6.30
Average price ($/BOE)	$59.29	$51.65	$58.50
Average sales prices with hedges(4):			
Oil ($/Bbl)	$88.68	$85.59	$88.16
Natural gas ($/Mcf)	$4.98	$4.92	$6.59
Average price ($/BOE)	$58.66	$53.22	$58.47
Average cost per BOE:			
Lease operating expenses	$7.06	$5.96	$5.00
Production and ad valorem taxes	$3.78	$3.33	$3.70
Depletion, depreciation and amortization	$20.87	$21.33	$20.12
General and administrative(5)	$8.00	$5.50	$5.90

(1) The volumes presented for the years ended December 31, 2013, 2012 and 2011 are based on actual results and are not calculated using the rounded numbers in the table above.

(2) Benchmark 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. Benchmark natural gas prices are the simple arithmetic average of the last day settlement price for NYMEX natural gas each month for the period indicated.

(3) Realized crude oil and natural gas prices are the actual prices realized at the wellhead after all adjustments for natural gas liquids content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price at the wellhead.

(4) 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 derivative instruments in accordance with the applicable generally accepted accounting principles in the United States of America (“GAAP”) and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments 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

(5) General and administrative includes non-cash stock-based compensation of $21.4 million, $10.1 million and $6.1 million for the years ended December 31, 2013, 2012 and 2011, respectively. Excluding stock-based compensation from the above metric results in average general and administrative cost per BOE of $6.09, $4.61 and $5.19 for the years ended December 31, 2013, 2012 and 2011, respectively.

Productive wells

The following table sets forth certain information regarding productive wells in each of our core areas as of December 31, 2013. Our wells are classified as oil wells, all of which also produce natural gas, condensate and natural gas liquids. Wells are classified as oil or gas wells according to the predominant production stream, except that a well with multiple completions is classified as an oil well if one or more of the completions is an oil completion. We only have two wells that primarily produce gas; however, they both also have completions that produce oil. 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				Average WI %	
	Gross					
	Vertical	Horizontal	Total	Net		
Permian Basin:						
Operated Permian-Garden City	838	97	935	902	96	%
Non-Operated Permian Garden City	122	1	123	36	29	%
Operated Permian-China Grove[(1)]	1	1	2	2	99	%
Operated New Ventures[(2)]	1	—	1	1	95	%
Total	962	99	1,061	941	89	%

(1) Located primarily in Mitchell County, Texas.
(2) Includes Dalhart Basin and other New Ventures.

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2013 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	102,355	93,149	75,968	50,063	178,323	143,212	65	%
Permian-China Grove	478	454	74,737	58,418	75,215	58,872	1	%
New Ventures[(1)]	640	502	89,495	79,641	90,135	80,143	1	%
Total	103,473	94,105	240,200	188,122	343,673	282,227	33	%

(1) Includes Dalhart Basin and other New Ventures.

Undeveloped acreage expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2013 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.

	2014		2015		2016		2017	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin:								
Permian-Garden City	11,319	10,929	23,596	15,214	5,409	2,515	—	—
Permian-China Grove	21,734	16,692	48,318	38,083	4,686	3,643	—	—
New Ventures(1)	39,981	35,825	31,742	26,804	2,741	2,411	10,841	10,714
Total	73,034	63,446	103,656	80,101	12,836	8,569	10,841	10,714

(1) Includes Dalhart Basin and other New Ventures.

Drilling activity

The following table summarizes our drilling activity for the years ended December 31, 2013, 2012 and 2011. 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.

	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	171	127.2	199	183.2	260	233.2
Dry	—	—	—	—	—	—
Total development wells	171	127.2	199	183.2	260	233.2
Exploratory wells:						
Productive	2	2.0	1	1.0	2	1.4
Dry	—	—	1	0.9	—	—
Total exploratory wells	2	2.0	2	1.9	2	1.4

Marketing and major customers

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 to a variety of purchasers under contracts ranging from one month to several years, all at market prices. We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. We have committed a portion of our Permian crude oil production under firm transportation agreements which 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, 2013, we were committed to deliver the following fixed quantities of production under certain contractual arrangements that specify the delivery of a fixed and determinable quantity.

	Total	2014	2015	2016	2017 and beyond
Oil and condensate (MBbl)	100,314	6,570	9,490	11,802	72,453
Natural gas (MMcf)	70,192	1,170	3,393	4,796	60,833
Total (MBOE)	112,013	6,765	10,055	12,601	82,591

Subsequent to December 31, 2013, we entered into additional agreements to deliver fixed quantities of production. As of February 26, 2014, we were committed to deliver the following fixed quantities of production under certain contractual

arrangements that specify the delivery of a fixed and determinable quantity.

	Total	2014	2015	2016	2017 and beyond
Oil and condensate (MBbl)	131,948	6,570	9,490	14,235	101,653
Natural gas (MMcf)	70,192	1,170	3,393	4,796	60,833
Total (MBOE)	143,646	6,765	10,055	15,034	11,791

We expect to fulfill our delivery commitments over the next three years with production from our proved reserves. We expect to fulfill our longer-term delivery commitments beyond three years primarily with our proved undeveloped reserves.

Our proved reserves have been sufficient to satisfy our delivery commitments during the three most recent years, and we expect such reserves will continue to satisfy our future commitments. However, should our proved reserves not be sufficient to satisfy our delivery commitments, we can and may use spot market purchases to fulfill the commitments.

Based on the current demand for oil and natural gas and the availability of alternate purchasers, we believe 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. For information regarding each of our customers that accounted for 10% or more of our oil and natural gas revenues during the last three calendar years, see Note I in our audited 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."

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 natural 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, 2013, 33% of our leasehold acreage was HBP.

Seasonality

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

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do, especially in our focus areas. Many of these 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. These companies may be able to pay more for productive properties and exploratory locations or define, 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 development 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 we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage 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 (including the U.S. Bureau of Land Management on federal acreage) 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 discharge 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. We are in the process of testing recycled flowback/produced water in our fracing operations, and are evaluating the performance of the limited number of wells in which we have used this process to determine if there is any impact on productivity.

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 could prohibit projects or result in materially increased costs and additional operating restrictions or delays because of the significance of hydraulic fracturing 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, natural gas and natural gas liquids 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, which 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 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 and joint and several liability penalties that could impose liability upon us regardless of fault. 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 of $350 million. 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. It is possible, however, 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 in reportable quantities 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. Although hydraulic fracturing has historically been regulated by state oil and gas commissions, the EPA recently asserted federal regulatory authority over the process under the SDWA's Underground Injection Control ("UIC") Program. 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. On November 3, 2011, the EPA released its Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. The study will include both analysis of existing data and investigative activities designed to generate future data. The EPA issued a progress report in December 2012, and expects to release a draft report for public comment and peer review in 2014. In addition, legislation is pending in 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. Finally, on October 20, 2011, the EPA announced its plan to propose federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting "flowback," as well as "produced water." The EPA asserts that this water may contain radioactive materials and other pollutants and, therefore, may deteriorate drinking water quality if not properly treated before discharge. The Clean Water Act prohibits the discharge of wastewater into federal or state waters. Thus, "flowback" and "produced water" must either be injected into permitted disposal wells, transported to public or private treatment facilities for treatment, or recycled. The EPA asserts that due to some contaminants in hydraulic fracturing wastewater, most treatment facilities are unable to treat the wastewater before introducing it into public waters. If adopted, the new pre-treatment rules will require shale gas operations to pre-treat wastewater before transferring it to treatment facilities. A proposed rule is expected in April 2014. 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.

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. 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. Furthermore, on May 16, 2013, the United States Department of the Interior ("DOI") issued a revised proposed rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm its wells meet certain construction standards and (iii) establish site plans to manage flowback water. Under current federal law, there is no requirement for operators to disclose the use of such chemicals, although Laredo has already commenced similar disclosure with state regulators.

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 adopted rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or 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. These rules may require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by 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. The EPA intends to issue revised rules that may be responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rule addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. 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

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" ("GHGs") and including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere and other climatic changes. In response to such studies, Congress has from time to time considered legislation to reduce emissions of GHGs. One bill approved by the House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, would have required an 80% reduction in 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, 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 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 January 2011, 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, although on October 15, 2013, the U.S. Supreme Court granted review of certain issues related to the EPA's authority to regulate such emissions from stationary sources. Oral arguments on the issues before the Supreme Court were heard on February 24, 2014, and a decision is expected by July 2014. 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 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 addition, the EPA has continued to adopt GHG regulations of other industries, such as a September 2013 proposed GHG rule that, if finalized, would set NSPS for new coal-fired and natural-gas fired power plants.

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.

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 that are listed as threatened or endangered and where other species, such as the sage grouse, 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 2012 or 2013.

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

Under the Iran Threat Reduction and Syrian Human Rights Act of 2012 (the “Act”), which added 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 (“EIG”) and Santander Asset Management Investment Holdings Limited (“SAMIH”). EIG 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.

As to EIG:
The disclosure below relates solely to activities conducted by EIG and its 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 EIG, and neither Laredo nor Warburg Pincus has independently verified or participated in the preparation of the disclosure. Neither Laredo nor Warburg Pincus is representing as to the accuracy or completeness of the disclosure nor do we or Warburg Pincus undertake any obligation to correct or update it.
Laredo understands that EIG's affiliates intend to disclose in their next annual or quarterly SEC report that:
"EIG's business activities are subject to various restrictions under U.S. export controls and trade and economic sanctions laws, including the U.S. Commerce Department's Export Administration Regulations and economic and trade sanctions regulations maintained by the U.S. Treasury Department's Office of Foreign Assets Control, or OFAC. If EIG fails to comply with these laws and regulations, EIG could be subject to civil or criminal penalties and reputational harm. In addition, if EIG's third-party resellers fail to comply with these laws and regulations in their dealings, EIG could face potential liability or penalties for violations. Furthermore, U.S. export control laws and economic sanctions laws prohibit certain transactions with U.S. embargoed or sanctioned countries, governments, persons and entities.
Although EIG takes precautions to prevent transactions with U.S. sanctions targets, EIG has in the past identified limited instances of non-compliance with these rules and believes EIG has taken appropriate corrective actions in such instances. For example, on May 1, 2013, during a routine compliance scan of EIG's new and existing subscriber accounts, EIG discovered a new subscriber account that was created on April 6, 2013 with information matching ORT France, identified by OFAC as a Specially Designated National, or SDN, under the Global Terrorism Sanctions Regulations, 31 C.F.R. Part 594. EIG had charged the subscriber $114.10 for web hosting and domain name registration services at the time the account was opened and without knowledge of any SDN issue. Upon discovery of the potential SDN match, EIG promptly suspended the subscriber account, deactivated the website, locked the domain name to prevent it from being transferred and ceased providing services to the subscriber. EIG also promptly reported the potential SDN match to OFAC. To date, EIG has not received any correspondence from OFAC regarding the matter.
Although EIG has implemented compliance measures that are designed to prevent transactions with U.S. sanction targets, there is risk that in the future EIG or its resellers could provide its solutions or services to such targets despite such compliance measures. This could result in negative consequences to EIG, including government investigations, penalties and reputational harm.
Changes in EIG's solutions or changes in export and import regulations may create delays in the introduction and sale of EIG's solutions in international markets, prevent EIG's subscribers with international operations from deploying its solutions or, in some cases, prevent the export or import of EIG's solutions to certain countries, governments or persons altogether. Any change in export or import regulations, shift in the enforcement or scope of existing regulations, or change in the countries, governments, persons or technologies targeted by such regulations, could result in decreased use of EIG's solutions or decreased ability to export or sell its solutions to existing or potential subscribers with international operations. Any decreased use of EIG's solutions or limitation on its ability to export or sell its solutions could adversely affect EIG's business, financial condition and operating results."
As to SAMIH:
The disclosure below relates solely to activities conducted by SAMIH and its non-U.S. 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 has had any involvement in or control over the disclosed activities of 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 to the accuracy or completeness of the disclosure nor do we or Warburg Pincus undertake any obligation to correct or update it.
Laredo understands that SAMIH's affiliates intend to disclose in their next annual or quarterly SEC report that an Iranian national, resident in the U.K., who is currently designated by the U.S. and the U.K. under the Iran Sanctions regime, holds two investment accounts with Santander Asset Management UK Limited, a subsidiary of SAMIH and

part of the Banco Santander group. The accounts have remained frozen throughout 2013. The investment returns are being automatically reinvested, and no disbursements have been made to the customer. Total revenue in connection with the investment accounts in 2013 was £247 and net profits in 2013 were negligible relative to the overall profits of Banco Santander, S.A.

Employees

As of December 31, 2013, we had 340 full-time employees. We also employed a total of 31 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 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 1800, Tulsa, Oklahoma 74119, and the phone number at this address is (918) 513-4570. We also lease corporate offices in Midland and Dallas, Texas.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. 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 1800, 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 and natural gas prices are volatile. A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our oil and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil 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 and natural gas has been volatile. 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 and natural gas;
- the price and quantity of imports of foreign oil and natural gas, including liquefied natural gas;
- political conditions in or affecting other oil and natural gas-producing countries, including the current conflicts in the Middle East, and conditions in South America, Africa and Russia;
- the level of global oil and natural gas exploration and production;
- future regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells;
- the level of global oil and natural gas inventories;
- prevailing prices on local oil 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 and natural gas prices will 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 and natural gas reserves as existing reserves are depleted. Substantial decreases in oil and natural gas prices could render uneconomic a significant portion of our exploration, development and exploitation projects. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

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 and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, capital contributions, borrowings on our Senior Secured Credit Facility, equity offerings and proceeds from 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 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 financing 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 and natural gas production or reserves and, in some areas, a loss of properties.

Drilling for and producing oil 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 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 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 and engineering studies, 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 and natural gas prices, or negative revisions to reserves estimates or assumptions as to future oil and natural gas prices, may lead to decreased earnings, losses or impairment of oil 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:

- 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;
- declines in oil and natural gas prices;
- limited availability of financing at acceptable rates;
- title problems; and
- limitations in the market for oil and natural gas.

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, sand 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 process is typically regulated by state oil and gas commissions. The U.S. Environmental Protection Agency (the "EPA"), however, recently asserted federal regulatory authority over hydraulic fracturing under the federal Safe Drinking Water Act's ("SDWA") Underground Injection Control ("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 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 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 draft guidance. On November 3, 2011, the EPA released its Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. The study will include both analysis of existing data and investigative activities designed to generate future data. The EPA issued a progress report in December 2012, held several technical workshops during 2013, and expects to release a draft report for public comment and peer review in 2014.

In August 2012, the EPA adopted 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") 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 became effective October 15, 2012; however, a number of the requirements did not take immediate effect. The rule established a phase-in period to allow for the manufacture and distribution of required emissions reduction technology. During the first phase, ending December 31, 2014, owners and operators of gas wells must either flare their emissions or use emissions reduction technology called "green completions" technologies already deployed at wells. On or after January 1, 2015, all newly fractured gas wells will be required to use green completions. Controls for certain storage vessels and pneumatic controllers may phase-in over one year beginning August 16, 2012, while certain compressors, dehydrators and other equipment must comply with the final rule immediately or up to three years and 60 days after the August 16, 2012 publication of the final rule, depending on the construction date and/or nature of the unit. We continue to evaluate the EPA's final rule, as it may require changes to our operations, including the installation of new emissions control equipment. Furthermore, with respect to our operations that occur on federally managed public lands, on May 16, 2013, the United States Department of the Interior ("DOI") issued a revised proposed rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm their wells meet certain construction standards and (iii) establish site plans to manage flowback water. The revised proposed rule is presently subject to an extended 90-day public comment period, which ends on August 23, 2013. DOI is expected to issue a final rule in 2014. Under current federal law, there is no requirement for operators to disclose the use of such chemicals, although we have already commenced similar disclosure with state regulators. In addition, legislation is pending in 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. Finally, on October 20, 2011, the EPA announced its plan to propose federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting "flowback," as well as "produced water." The EPA asserts that this water may contain radioactive materials and other pollutants and, therefore, may deteriorate drinking water quality if not properly treated before discharge. The Clean Water Act prohibits the discharge of wastewater into federal or state waters. Thus, "flowback" and "produced water" must either be injected into permitted disposal wells or transported to public or private treatment facilities for treatment, or recycled. The EPA asserts that due to some contaminants in hydraulic fracturing wastewater, most treatment facilities are unable to properly treat the wastewater before introducing it into public waters. If adopted, the new pre-treatment rules will require shale gas operations to pre-treat wastewater before transferring it to treatment facilities. A proposed rule is expected in April 2014.

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 Railroad Commission of Texas (“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” takes 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.

Studies have been commissioned to determine if the use of water disposal wells increases the likelihood, frequency and/or severity of seismic activity. Water disposal wells are used to store the water produced during the drilling and production activities of our wells.

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 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.

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 owned by the producer. We are active in drilling and producing allocation wells. The RRC has not provided definitive rules on the allocation well permitting process. If the RRC denies or significantly delays the permitting of allocation wells, 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.

Estimating reserves and future net revenues involves uncertainties. Decreases in oil and natural gas prices, or negative revisions to reserve estimates or assumptions as to future oil and natural gas prices, may lead to decreased earnings, losses or impairment of oil 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 and natural gas that cannot be measured in an exact manner. Reserves that are "proved reserves" are those estimated quantities of oil 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 projects for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain will commence within a reasonable time.

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 many 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 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. Negative revisions of 11,944 MBOE were due to the combined effect of removing 174 proved locations and the net effect of redetermining 501 undeveloped locations. The 174 locations that were removed were comprised of vertical Wolfberry and short horizontal laterals. They were replaced with longer horizontal laterals to better align with future drilling plans

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 P.4 in our audited consolidated financial statements included elsewhere in this Annual Report.

The potential drilling locations for our future wells that we have tentatively identified are scheduled out over many years, making 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. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our identified potential drilling locations.

Although our management team has scheduled certain potential drilling locations as an estimation of our future multi-year drilling activities on our existing acreage, our ability to drill and develop these locations depends on a number of uncertainties, including oil 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 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, our actual drilling activities may materially differ from those presently anticipated.

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, 2013, substantially 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 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.

If commodity prices decrease, we may be required to take 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 may be required to write down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. See Note B.8 to our audited consolidated financial statements included elsewhere in this Annual Report for additional information.

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 and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. We do not control many of the trucks and other third-party transportation facilities necessary for the transportation of our product and our access to them may be limited or denied. 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 and natural gas and thereby cause a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements 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 and natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations.

Our oil 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 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 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. The current United States restrictions on the export of oil and natural gas increase the possibility of an oversupply in any of the markets into which we sell our products.

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

Producing oil and natural gas reservoirs generally are 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 decline as those reserves are produced. Our future oil 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.

Currently, we receive incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at effective prices consistent with those we have received to date and oil and natural gas prices do not improve, our cash flows and financial condition may be adversely impacted.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, as of December 31, 2013, we have entered into hedge contracts for 14.5 million Bbls of our projected crude oil production and 17.8 million MMBtu of our projected natural gas production for settlement between January 2014 and December 2016. If we are unable to enter into new hedge contracts in the future at favorable pricing and for a sufficient amount of our production, our financial condition and results of operations could be materially adversely affected. 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."

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we enter into derivative instrument contracts for a portion of our oil 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 statement of operation gain (loss) on derivatives. Losses 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. Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

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

In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition.

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 ($16.6 million as of December 31, 2013) and the sale of our oil and natural gas production ($57.6 million in receivables as of December 31, 2013), which we market to energy marketing companies, refineries and affiliates. Joint interest receivables arise from billing entities who own partial interest 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 and natural gas receivables with several significant customers. The largest purchaser of our oil and natural gas accounted for 28.3% of our total oil and natural gas revenues for the year ended December 31, 2013. We do not require our customers to post collateral. 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.

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 and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil 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;

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- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil 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.

Locations that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Locations that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. In this Annual Report, we describe some of our current drilling locations and our plans to explore those drilling locations. Our drilling locations are in various stages of evaluation, ranging from those that are ready to drill to those that will require substantial additional seismic data processing and interpretation before a decision can be made to proceed with the drilling of such locations. There is no way to predict in advance of drilling and testing whether any particular drilling location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will result in successfully locating oil or natural gas in commercial quantities on our prospective acreage.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of oil 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 visualization techniques 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.

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.

Market conditions, the unavailability of satisfactory oil and natural gas gathering, processing or transportation arrangements or operational impediments may adversely affect our access to oil, natural gas and natural gas liquids markets or delay our production.

The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines, trucking and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, trucking and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of oil and natural gas pipeline, trucking, gathering system or processing capacity. In addition, if oil or natural gas quality specifications for the third-party oil or natural gas pipelines with which we connect change so as to restrict our ability to transport oil or natural gas, our access to oil and natural gas markets could be impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

Our operations are substantially dependent on the availability, use and disposal of water. Restrictions on our ability to obtain or dispose of water may have an adverse effect on our operations, cash flow and financial condition.

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 this severe drought, 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 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. If we are unable, due to government regulations or otherwise, to dispose of our water or face increased costs and procedures for disposal, it could have an adverse effect on our results of operations, cash flows and financial condition.

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 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" for a further description of the laws and regulations that affect us.

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 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 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 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.

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 and natural gas prices, causing periodic shortages. Historically, 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, the high level of drilling activity in the Permian Basin has resulted in equipment shortages in those areas. We committed to several short-term drilling contracts with various third parties in order to complete various drilling projects. An early termination clause in these contracts requires us to pay significant penalties to the third party should we cease drilling efforts. These penalties could significantly impact our financial statements upon contract termination. As a result of these commitments, $1.6 million in stacked rig fees were incurred in 2009. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. The 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.

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 and natural gas we produce.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" ("GHGs"), including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere and other climatic changes. In response to such studies, Congress has from time to time considered legislation to reduce emissions of GHGs. One bill approved by the House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, would have required an 80% reduction in 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 January 2011, 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, although on October 15, 2013, the U.S. Supreme Court granted review of certain issues related to the EPA's authority to regulate such emissions from stationary sources. Oral arguments on the issues before the Supreme Court were heard on February 24, 2014 and a decision is expected by July 2014. 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 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 addition, the EPA has continued to adopt GHG regulations of other industries, such as a September 2013 proposed GHG rule that, if finalized, would set NSPS for new coal-fired and natural-gas fired power plants.

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.

The derivatives reform legislation adopted by the U.S. Congress could have a negative impact on our ability to hedge risks associated with our business.

In 2010, Congress adopted the Dodd Frank Wall Street Reform and Consumer Protection Act (the “Dodd Frank Act”), which, among other matters, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market. The Dodd Frank Act mandates that the Commodity Futures Trading Commission (“CFTC”) adopt rules and regulations implementing the Dodd Frank Act and further define certain terms used in the Dodd Frank Act. The Dodd Frank Act also requires the CFTC and the banking regulators to establish margin requirements for uncleared swaps. Although there is an exception from swap clearing and trade execution requirements for commercial end users that meet certain conditions (the “End User Exception”), certain market participants, including most if not all of our counterparties, will also be required to clear many of their swap transactions with entities that do not satisfy the End User Exception and will have to transact many of their swaps on swap execution facilities or designated contract markets, rather than over-the-counter on a bilateral basis. These requirements may increase the cost to our counterparties of hedging the swap positions they enter into with us, and thus may increase the cost to us of entering into our hedges. The changes in the regulation of swaps may result in certain market participants deciding to curtail or cease their derivatives activities. While many regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing, and the ultimate effect of the adopted rules and regulations and any future rules and regulations on our business remains uncertain.

A rule adopted under the Dodd Frank Act imposing position limits in respect of transactions involving certain commodities, including oil and natural gas, was vacated and remanded to the CFTC for further proceedings by order of the United States District Court for the District of Columbia, U.S. District Judge Robert L. Wilkins on September 28, 2012. The CFTC appealed this decision and on November 5, 2013, filed a consensual motion to dismiss its appeal. The same day, the CFTC proposed a new position limits rule which would limit trading in NYMEX contracts for Henry Hub Natural Gas, Light Sweet Crude Oil, New York Harbor Ultra Low Sulfur No. 2 Diesel and Reformulated Blendstock for Oxygen Blending Gasoline and other futures and swap contracts that are economically equivalent to such NYMEX contracts. Comments on the proposed rule were due on February 10, 2014. We cannot predict whether or when the proposed rule will be adopted or the effect of the proposed rule on our business. The Dodd Frank Act, the rules already promulgated thereunder and the proposed rule, if adopted, could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our potential exposure to less creditworthy counterparties. In addition, 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. If we reduce our use of derivatives or commodity prices decline as a result of the Dodd Frank Act and 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 and our results of operations. Any of these consequences could have a material and adverse effect on our business, financial condition and results of operations.

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

Our ability to acquire additional locations and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil 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 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. The cost to attract and retain qualified personnel has increased due to competition and may increase substantially in the future. 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. During 2013, the demand for traditional drilling rigs in vertical markets has softened due to increased demand for drilling rigs that are able to drill horizontally. 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. As a result, the demand for rigs capable of carrying out pad drilling techniques has increased. 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 materially 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 A. 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, 2013, Warburg Pincus owned 49.1% 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 sell all or a substantial portion of or otherwise reduce its ownership interest in us. 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 have limited control over activities on properties we do not operate, which could materially reduce our production and revenues.

A portion of our business 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, we do not have control over normal operating procedures, expenditures or future development of the underlying properties. 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.

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 which 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 which 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.

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 available for drilling and place us at a competitive disadvantage. For example, as of February 26, 2014 we have $812.5 million of borrowing capacity 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 $812.5 million available on our Senior Secured Credit Facility would result in increased annual interest expense of $8.1 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 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 and natural gas prices and their applicable differentials;
- 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 be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to incorporate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

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 and 2009 of $6.1 million, $192.0 million and $184.5 million, respectively. Our financial statements include deferred tax assets, which require management's judgment when evaluating whether they will be realized. 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 and natural gas reserves and realize our deferred tax assets. 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."
The inability of one or more of our customers to meet their obligations may adversely affect our financial results.
Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. As of December 31, 2013, the Company had two customers accounting for 36.0% and approximately 15.7% of oil and natural gas sales accounts receivable. As of December 31, 2013, we had four customers whose joint operations accounts receivable accounted for 16.0%, 14.1%, 13.1% and 10.9% of our total joint operations accounts receivable. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our oil and natural gas hedging arrangements expose us to credit risk in the event of nonperformance by counterparties. Current economic circumstances may further increase these risks.
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.
We may incur significant additional amounts of debt.
As of February 26, 2014, 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.
Our debt agreements contain restrictions that will 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 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.

We have substantial cash balances that we invest in what we believe to be relatively short-term, highly-liquid and high credit quality investments. In addition, our management has broad discretion as to the use of our cash and might invest or spend our cash in ways that may not yield a return. This could result in a material adverse effect on our results of operations, liquidity or financial condition.

We have substantial cash balances that we maintain for working capital and general corporate purposes, which may include acquisitions. Our management has considerable discretion in the use of our cash, and might not be able to use our cash for purposes that increase our operating results or market value. Until the cash is used, it may from time to time be invested in what we believe to be relatively short-term, highly-liquid and high credit quality investments. We intend the investment risks, including counterparty default and lack of liquidity, on these types of investments to be relatively low, but market rates of return on these types of investments are also generally relatively low. Our efforts to manage the investment risks could be unsuccessful and this could result in a material adverse effect on our results of operations, liquidity or financial condition.

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. It is unclear whether any of the foregoing changes will actually be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development. Any such 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 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

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 concentration of our capital stock ownership among our largest stockholder will limit your ability to influence corporate matters.

As of December 31, 2013, Warburg Pincus owned 49.1% 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.

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.

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

In the future, we may issue securities to raise cash for acquisitions. 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, or 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.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

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

Item 3. Legal Proceedings

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we have insurance coverage. As of the date hereof, we are not party to any legal proceedings which 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
2013:		
Fourth Quarter	$33.52	$25.30
Third Quarter	$30.00	$20.21
Second Quarter	$20.85	$15.95
First Quarter	$20.03	$16.56
2012:		
Fourth Quarter	$22.37	$17.11
Third Quarter	$24.09	$21.10
Second Quarter	$26.63	$18.79
First Quarter	$26.80	$20.84

On February 26, 2014, the last sale price of our common stock, as reported on the NYSE, was $27.43 per share.

Holders. As of February 24, 2014, there were 59 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 will 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, 2013 - October 31, 2013	1,911	$32.42	—	—
November 1, 2013 - November 30, 2013	8,317	$28.91	—	—
December 1, 2013 - December 31, 2013	11,618	$26.24	—	—

(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, 2013, 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 audited 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 and 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, 2013, 2012 and 2011 and the balance sheet data as of December 31, 2013 and 2012 are derived from our audited consolidated financial statements and the notes thereto included elsewhere in this Annual Report. The historical financial data for the years ended December 31, 2010 and 2009 and the balance sheet data as of December 31, 2011, 2010 and 2009 are derived from our audited financial statements not included in this Annual Report.

	For the years ended December 31,				
(in thousands, except per share data)	2013[1]	2012	2011	2010	2009
Statement of operations data[2]:					
Total revenues	$665,257	$583,894	$506,347	$239,791	$94,347
Total costs and expenses	450,906	411,954	303,827	164,230	345,613
Operating income (loss)	214,351	171,940	202,520	75,561	(251,266)
Non operating expense, net	(23,267)	(77,176)	(36,932)	(12,516)	(4,888)
Income (loss) from continuing operations before income taxes	191,084	94,764	165,588	63,045	(256,154)
Income tax (expense) benefit	(74,507)	(33,003)	(59,612)	24,847	73,181
Income (loss) from continuing operations	116,577	61,761	105,976	87,892	(182,973)
Income (loss) from discontinued operations, net of tax	1,423	(107)	(422)	(1,644)	(1,522)
Net income (loss)	$118,000	$61,654	$105,554	$86,248	$(184,495)
Net income per common share:					
Basic:					
Income from continuing operations	$0.88	$0.49	$0.99		
Income (loss) from discontinued operations	0.01	—	(0.01)		
Net income per share	$0.89	$0.49	$0.98		
Diluted:					
Income from continuing operations	$0.87	$0.48	$0.98		
Income (loss) from discontinued operations	0.01	—	—		
Net income per share	$0.88	$0.48	$0.98		

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(1) See Note C to our audited consolidated financial statements included elsewhere in this Annual Report for additional information regarding our Anadarko Basin Sale.

(2) 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.

	As of December 31,				
(in thousands)	2013	2012	2011	2010	2009
Balance sheet data:					
Cash and cash equivalents	$198,153	$33,224	$28,002	$31,235	$14,987
Net property and equipment	2,204,324	2,113,891	1,378,509	809,893	396,100
Total assets	2,623,760	2,338,304	1,627,652	1,068,160	625,344
Current liabilities	253,969	262,068	214,361	150,243	79,265
Long-term debt	1,051,538	1,216,760	636,961	491,600	247,100
Stockholders' equity	1,272,256	831,723	760,013	411,099	289,107

	For the years ended December 31,				
(in thousands)	2013	2012	2011	2010	2009
Other financial data:					
Net cash provided by operating activities	$364,729	$376,776	$344,076	$157,043	$112,669
Net cash used in investing activities[(1)]	(329,884)	(940,751)	(706,787)	(460,547)	(361,333)
Net cash provided by financing activities	130,084	569,197	359,478	319,752	250,139

(1) 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 C to our audited consolidated financial statements included elsewhere in this Annual Report for additional information.

	For the years ended December 31,				
(in thousands, unaudited)	2013	2012	2011	2010	2009
Adjusted EBITDA[(1)]	$472,166	$443,434	$384,342	$188,568	$97,823

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income (loss) see "—Non-GAAP financial measures and reconciliations" below.

Non-GAAP financial measures and reconciliations

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for interest expense, depletion, depreciation and amortization, impairment of long-lived assets, write-off of deferred loan costs, bad debt expense, gains or losses on disposal of assets, total gains or losses on derivatives, cash settlements of matured commodity derivatives, cash settlements on early terminated derivatives, premiums paid for derivatives that matured during the period, non-cash stock-based compensation and income tax expense or benefit. 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, 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:

	For the years ended December 31,				
(in thousands, unaudited)	2013	2012	2011	2010	2009
Net income (loss)	$118,000	$61,654	$105,554	$86,248	$(184,495)
Plus:					
Interest expense	100,327	85,572	50,580	18,482	7,464
Depletion, depreciation and amortization	234,571	243,649	176,366	97,411	58,005
Impairment of long-lived assets	—	—	243	—	246,669
Write-off of deferred loan costs	1,502	—	6,195	—	—
Bad debt expense	653	—	—	—	—
Loss on disposal of assets, net	1,508	52	40	30	85
Gain on derivatives, net	(79,878)	(8,388)	(19,736)	(5,815)	(2,350)
Cash settlements received for matured commodity derivatives, net	4,046	27,025	3,719	22,701	52,117
Cash settlements received for early terminations and modifications of derivatives, net	6,008	—	—	—	—
Premiums paid for derivatives that matured during the period[1]	(11,292)	(9,135)	(4,104)	(5,934)	(7,085)
Non-cash stock-based compensation	21,433	10,056	6,111	1,257	1,419
Income tax expense (benefit)	75,288	32,949	59,374	(25,812)	(74,006)
Adjusted EBITDA	$472,166	$443,434	$384,342	$188,568	$97,823

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

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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 which could cause actual results to vary from our expectations include changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, 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."

Executive overview

We are an independent energy company focused on the exploration, development and acquisition of oil and natural gas properties primarily in the Permian Basin in West Texas. On August 1, 2013, we sold our properties in the Anadarko Granite Wash, Eastern Anadarko and Central Texas Panhandle (the "Anadarko Basin") in the Mid-Continent region of the United States.

We have grown rapidly through our drilling program and by making strategic acquisitions and joint ventures. In December 2011, we completed the Corporate Reorganization and IPO and in December 2013, we completed the Internal Consolidation. See Note A to our consolidated financial statements included elsewhere in this Annual Report for definitions of and additional information regarding the Corporate Reorganization, the IPO and the Internal Consolidation.

Our financial and operating performance for the year ended December 31, 2013 included the following:

- Oil and natural gas sales of $664.8 million, compared to $583.6 million for the year ended December 31, 2012;
- Average daily production of 30,716 BOE/D, compared to 30,874 BOE/D for the year ended December 31, 2012;
- Estimated net proved reserves of 203,615 MBOE as of December 31, 2013, compared to 188,632 MBOE as of December 31, 2012; and
- Adjusted EBITDA (a non-GAAP financial measure) of $472.2 million, compared to $443.4 million for the year ended December 31, 2012.

Recent Developments

Notes Offering

On January 23, 2014, we completed an offering of $450.0 million in aggregate principal amount of 5 5/8% senior unsecured notes due 2022, and entered into an indenture among Laredo, Laredo Midstream and Wells Fargo Bank, National Association, as trustee. The new senior unsecured notes will mature on January 15, 2022 with interest accruing at a rate of 5 5/8% per annum and payable semi-annually in cash in arrears on January 15 and July 15 of each year, commencing July 15, 2014. The new senior unsecured notes are guaranteed on a senior unsecured basis by Laredo Midstream.

The new senior unsecured notes were issued pursuant to the indenture in a transaction exempt from the registration requirements of the Securities Act. The new senior unsecured notes were offered and sold only to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the United States pursuant to Regulation S under the Securities Act. We received net proceeds of $442.2 million from the offering, after deducting the initial purchasers’ discount and offering expenses. We plan to use the net proceeds of the offering for general working capital purposes.

In connection with the issuance of the new senior unsecured notes, Laredo and Laredo Midstream entered into a registration rights agreement with the initial purchasers of the new senior unsecured notes and have agreed to use commercially reasonable efforts to file a registration statement with the SEC relating to an offer to exchange the new senior unsecured notes for substantially identical notes (other than with respect to restrictions on transfer or any increase in annual interest rate) that are registered under the Securities Act so as to permit the exchange offer to be consummated within 365 days after the issuance of the new senior unsecured notes. Under certain circumstances, Laredo and Laredo Midstream will be obligated to pay additional interest if they fail to comply with their obligations to register the new senior unsecured notes within the specified time periods.

Unwinding of commodity contract

In February 2014, we unwound a physical commodity contract with a Light Louisiana Sweet Argus reference price and the associated oil basis swap financial derivative contract which hedged the differential between the Light Louisiana Sweet Argus and the Brent International Petroleum Exchange index oil prices. We received net proceeds of $76.7 million from the early termination of these contracts. We agreed to settle the contracts early due to our counterparty's decision to exit the physical commodity trading business. It is not our past practice nor do we expect to settle physical contracts financially in the future.

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 upsides in the assets.

On July 1, 2011, we consummated the acquisition of Broad Oak for consideration consisting of (i) cash payments totaling $82.0 million to certain members of Broad Oak management and employees, (ii) equity issuances of 86.5 million preferred Laredo Petroleum, LLC units to Warburg Pincus, (iii) equity issuances of 2.4 million preferred Laredo Petroleum, LLC units to certain directors and management of Broad Oak and (iv) repayment of the $265.4 million of outstanding debt under the Broad Oak credit facility. Immediately following the consummation of such transaction, Laredo Petroleum, LLC assigned 100% of its ownership interest in Broad Oak to Laredo Petroleum, Inc. as a contribution to capital.

On July 12, 2012, we completed the acquisition of additional working interest in certain oil and natural gas properties located in Glasscock County, Texas, for a contract price of $20.5 million from a private company, net of closing purchase price adjustments.

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

Divestitures

On August 1, 2013, we completed the sale of oil and gas properties located in the Anadarko Basin in the State of Oklahoma and the State of Texas, associated pipeline assets and various other related property and equipment (the "Anadarko Basin Sale") 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 associated 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 Notes B.3 and C 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.

Management and board changes

During the year ended December 31, 2013, our board of directors appointed Jay P. Still to become President and Chief Operating Officer, effective July 8, 2013. Our board of directors also appointed Mr. Still to become a member of the board of directors, effective July 8, 2013, and hold office until the next annual meeting of stockholders or until his successor has been duly elected and qualified. Jerry R. Schuyler, our former President and Chief Operating Officer and formerly one of our directors, resigned as an officer and director of Laredo effective July 8, 2013, and continued with Laredo in an advisory capacity until he retired on November 21, 2013. In connection with Mr. Schuyler's retirement, the compensation committee of our board of directors elected to accelerate the vesting of all of his restricted stock and restricted stock options, as well as all of his performance unit awards (as if the performance criteria had been fully satisfied) to the date of his retirement.

John E. Minton, who had been with us since October 2007, elected to retire from his position as Senior Vice President - Reservoir Engineering effective December 6, 2013. In connection with his retirement, the compensation committee of our board of directors elected to accelerate the vesting of all of his restricted stock and restricted stock options, as well as all of his performance unit awards (as if the performance criteria had been fully satisfied) to the date of his retirement.

Common stock transactions

On August 19, 2013, we, together with certain affiliates of Warburg Pincus and members of our management (together with Warburg Pincus, the "Selling Stockholders") completed the sale of (i) 13,000,000 shares of our common stock by us and (ii) 3,000,000 shares of our common stock by the Selling Stockholders, at a price to the public of $23.75 per share ($22.9781 per share, net of underwriting discounts) (the "Follow-on Offering"). On August 27, 2013, certain of the Selling Stockholders sold an additional 1,577,583 shares of our common stock pursuant to the option to purchase additional shares of our common stock granted to the associated underwriters. We intend to use the $298.1 million net proceeds from the Follow-on Offering to implement our planned exploration and development activities, accelerate our capital program and for general working capital purposes. We did not receive any proceeds from the sale of the shares of our common stock by the Selling Stockholders.

On September 6, 2013, we issued 123,803 restricted shares of our common stock to third parties as partial consideration for an acquisition of proved and unproved oil and natural gas properties. See Note C to our audited consolidated financial statements included elsewhere in the Annual Report for additional information.

During the year ended December 31, 2013, Warburg Pincus distributed our common stock pro rata to certain of the Warburg Pincus limited partners. As of February 24, 2014, Warburg Pincus owned 49.1% of our outstanding common stock. The following details the distributions throughout the year ended December 31, 2013:

Date of distribution	Number of shares distributed	Distribution % of Warburg Pincus' holdings of our common stock prior to the distribution	
June 25, 2013	3,515,263	4	%
August 19, 2013	2,890,000	3	%
August 27, 2013	1,577,583	2	%
September 24, 2013	3,515,263	4	%
November 25, 2013	6,008,476	8	%

Derivative terminology modifications

We have modified our terminology describing gains and losses on derivatives. In our revised presentation, "Cash settlements received for matured derivatives" describe the gain or loss from contracts that settled during the current period, calculated as the difference between the contract price and the market settlement price of the matured derivatives. In addition, we have revised our non-GAAP financial measure Adjusted EBITDA and our average hedged sale price calculation to include "Premiums paid for derivatives that matured during the period" which represents current period settlements of matured derivatives and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments settled in the period.

Related Party

We have a gathering and processing arrangement with affiliates of Targa Resources, Inc. ("Targa"). Until May 2013, Warburg Pincus Private Equity IX, L.P., a major stockholder of Laredo, and other affiliates of Warburg Pincus, held material investment interests in Targa. We considered Targa a related party until May 2013, and accordingly have continued our disclosure of our net oil and natural gas sales and our oil and natural gas sales receivable attributable to Targa throughout 2013. As we no longer consider Targa a related party, we will discontinue this disclosure in 2014.

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, 2013, we had assembled 202,084 net acres in the Permian Basin.

Reserves and pricing

Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves, reported on a two-stream basis, as of December 31, 2013, 2012 and 2011. As of December 31, 2013, we had 203,615 MBOE of estimated net proved reserves as compared to 188,632 MBOE of estimated net proved reserves as of December 31, 2012 and 156,453 MBOE of estimated net proved reserves as of December 31, 2011.

Our results of operations are heavily influenced by commodity prices. Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil 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 drilling projects, as well as the economic valuation and economic recovery of oil and natural gas reserves.

Our reserves are reported in two streams: crude oil and liquids-rich natural gas. The economic value of the natural gas liquids in our natural gas is included in the wellhead natural gas price. The unweighted arithmetic average first-day-of-the-month index prices for the prior 12 months were $93.52 per Bbl for oil and $3.57 per MMBtu for natural gas as of December 31, 2013, $91.21 per Bbl for oil and $2.63 per MMBtu for natural gas as of December 31, 2012 and $92.71 per Bbl for oil and $3.99 per MMBtu for natural gas as of December 31, 2011. The prices used to estimate proved reserves for all periods did not give effect to derivative transactions. These prices were held constant throughout the life of the properties and have been adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

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

Sources of our revenue

Our revenues are derived from the sale of oil and natural gas within the continental United States and do not include the effects of derivatives. For the year ended December 31, 2013, our revenues from continuing operations are comprised of sales of 74% oil and 26% gas. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Principal components of our cost structure

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

Production and ad valorem taxes. Production taxes are paid on produced oil and natural gas 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 and natural gas revenues. Ad valorem taxes are property taxes based on the value of our reserves attributed to our properties located in Texas.

Drilling and production. These are costs incurred to maintain facilities that support our drilling activities.

General and administrative. 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 and legal compliance.

Stock-based compensation. These are costs incurred for compensation expense related to employee and director stock 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 which represents changes in our asset retirement liability due to the passage of time.

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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 proved oil 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 unproved properties and major development projects for which proved reserves cannot yet be assigned, less accumulated amortization; (ii) the estimated future expenditures to be incurred in developing proved 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.

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. 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.

Income 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 gain (loss) reflected in the consolidated statements of operations as "Income from equity method investee" and the carrying amount reflected in the audited consolidated balance sheet as "Investment in equity method investee." See Note M to our audited 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, our senior unsecured notes and, prior to its termination on July 1, 2011, the Broad Oak credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We have 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 deferred financing 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.

Income tax expense. Income taxes in our financial statements are generally presented on a consolidated basis. However, U.S. tax laws do not allow tax losses of Laredo Petroleum—Dallas, Inc. to offset income and losses of another entity until after the consummation of the Broad Oak acquisition on July 1, 2011. As such, the financial accounting for the income tax consequences of each taxable entity is calculated separately for all periods prior to July 1, 2011.

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 its oil and natural gas reserves (including the

timing of those cash flows), the reversal of deferred tax liabilities recorded as of December 31, 2013, 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.

Results of operations

For the year ended December 31, 2013 as compared to the year ended December 31, 2012, and for the year ended December 31, 2012 as compared to the year ended December 31, 2011

Production, revenue and pricing

The following table sets forth information regarding production and revenue and average sales prices from continuing operations per BOE, for the periods presented:

	For the years ended December 31,		
(unaudited)	2013	2012	2011
Production data:			
Oil (MBbl)	5,487	4,775	3,368
Natural gas (MMcf)	34,348	39,148	31,711
Oil equivalents (MBOE)(1)	11,211	11,300	8,654
Average daily production (BOE/D)(1)	30,716	30,874	23,709
% Oil	49 %	42 %	39 %
Revenues (in thousands):			
Oil	$494,676	$414,932	$306,481
Natural gas	170,168	168,637	199,774
Transportation and treating	413	325	92
Total revenues	$665,257	$583,894	$506,347
Average sales prices:			
Oil, realized ($/Bbl)(2)	$90.16	$86.89	$91.00
Natural gas, realized ($/Mcf)(2)	4.95	4.31	6.30
Average price, realized ($/BOE)(2)	59.29	51.65	58.50
Oil, hedged ($/Bbl)(3)	88.68	85.59	88.16
Natural gas, hedged ($/Mcf)(3)	4.98	4.92	6.59
Average price, hedged ($/BOE)(3)	58.66	53.22	58.47

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

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

(3) 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)	2013	2012	2011
Cash settlements received (paid) for matured commodity derivatives:			
Oil	$(149)	$(944)	$(7,973)
Natural gas	4,195	27,969	11,692
Total	$4,046	$27,025	$3,719
Premiums paid attributable to contracts that matured during the respective period:			
Oil	$(7,970)	$(5,278)	$(1,549)
Natural gas	(3,322)	(3,857)	(2,555)
Total	$(11,292)	$(9,135)	$(4,104)

The changes in volumes and prices shown in the production, revenue and pricing table above caused the following changes to our oil and natural gas revenue between the years ended December 31, 2011 and 2012 and 2013:

(in thousands)	Oil	Natural gas	Total net dollar effect of change
2011 Revenue	$306,481	$199,774	$506,255
Effect of changes in price	(19,627)	(77,904)	(97,531)
Effect of changes in volumes	128,032	46,848	174,880
Other	46	(81)	(35)
2012 Revenue	$		