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Filed Pursuant to Rule 424(A)
Registration No. 333-184232

Subject to completion, dated October 5, 2012

The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities, and we are not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

Prospectus

12,500,000 shares

LAREDO PETROLEUM

Common stock

Affiliates of Warburg Pincus LLC ("Warburg Pincus"), the selling stockholders, are offering 12,500,000 shares of Laredo Petroleum Holdings, Inc.'s common stock. We will not receive any proceeds from the sale of shares of common stock offered by the selling stockholders.

Our common stock is listed on the New York Stock Exchange (the "NYSE") under the symbol "LPI." On October 4, 2012, the last sale price of our common stock as reported on the NYSE was $21.96 per share.

Investing in our common stock involves a high degree of risk. Please read "Risk factors" beginning on page 15.

	Per share	Total
Public offering price	$	$
Underwriting discounts and commissions	$	$
Proceeds to selling stockholders, before expenses	$	$

The selling stockholders have granted the underwriters an option, for a period of 30 days from the date of this prospectus, to purchase up to 1,875,000 additional shares of our common stock. We will not receive any proceeds from the sale of shares of common stock to be offered by the selling stockholders.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the accuracy or adequacy of this prospectus. Any representation to the contrary is a criminal offense.

Delivery of the shares of common stock will be made on or about , 2012.

J.P. Morgan

Goldman, Sachs & Co.

BofA Merrill Lynch

Wells Fargo Securities

BMO Capital Markets
Capital One Southcoast
Scotiabank / Howard Weil
SOCIETE GENERALE

BB&T Capital Markets
BOSC, Inc.
Comerica Securities
Mitsubishi UFJ Securities

, 2012

Company Overview

Total Company

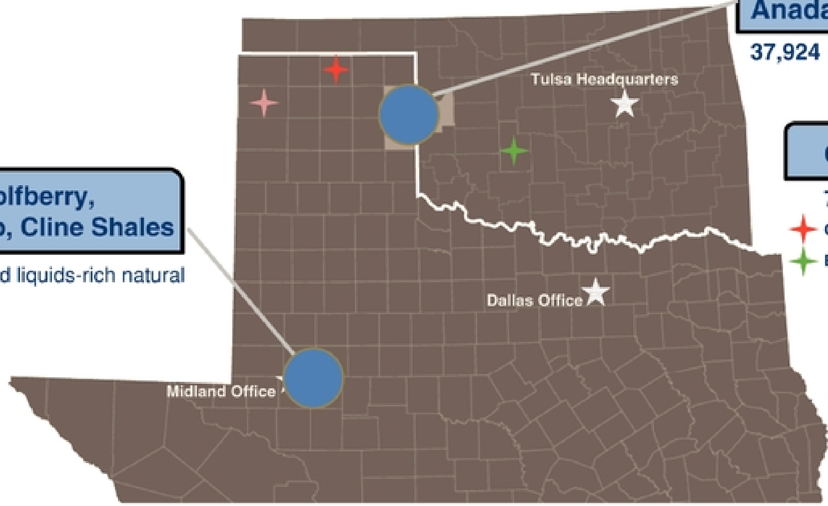
- 29,690 BOE/D average daily production during the six months ended June 30, 2012 [1]
- 156.5 MMBOE proved reserves at December 31, 2011 [1]
- 538,685 gross / 404,276 net acres [2]
- Drilling inventory of greater than 10 years
- Currently operating 14 drilling rigs

Anadarko: Granite Wash

37,924 net acres [2], Liquids-rich natural gas

Permian: Vertical Wolfberry, Horizontal Wolfcamp, Cline Shales

188,014 net acres [2], Oil and liquids-rich natural gas



Other Areas

71,550 net acres [2]

- Central Texas Panhandle – 44,621 net acres [2]
- Eastern Anadarko Basin – 26,929 net acres [2]

New Ventures

106,788 net acres [2]

- Dalhart Basin – 99,144 net acres [2]
- Other – 7,643 net acres [2]

LAREDO PETROLEUM

[1] Production and proved reserves reported on a two-stream basis. Proved reserves are gas price adjusted to reflect NGL benefit. Proved reserves per Ryder Scott's evaluation at 12/31/2011, at SEC pricing.
[2] Acreage figures as of 6/30/12

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You should rely only on the information contained in this prospectus or in any free writing prospectus we may authorize to be delivered to you. Neither we, the selling stockholders, nor the underwriters have authorized anyone to provide you with additional or different information. If anyone provides you with different or inconsistent information, you should not rely on it. The selling stockholders are offering to sell, and seeking offers to buy, our common stock only in jurisdictions where offers and sales are permitted. The information in this prospectus is accurate as of the date of this prospectus, regardless of the time of delivery of this prospectus or any sale of our common stock. Our business, financial condition, results of operation and prospects may have changed since that date.

Through and including , 2012 (25 days after the commencement of this offering), all dealers that effect transactions in our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This delivery requirement is in addition to a dealer's obligation to deliver a prospectus when acting as an underwriter and with respect to their unsold allotments or subscriptions.

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. See "Risk factors" and "Forward-looking statements."

Industry and market data

This prospectus includes industry and market data that we obtained from independent industry publications, government publications or other published independent sources. These publications generally state that the information contained therein has been obtained from sources believed to be reliable, although they do not guarantee the accuracy or completeness of such information. While we believe that each of these publications is reliable, we have not independently verified any of the data from third-party sources nor have we ascertained the underlying economic or operational assumptions relied upon therein.

Prospectus summary

This summary highlights selected information contained elsewhere in this prospectus. You should read the entire prospectus, including the information presented under the headings "Risk factors," "Forward-looking statements" and "Management's discussion and analysis of financial condition and results of operations" and th unaudited consolidated financial statements and condensed notes thereto and the audited consolidated financial statements and notes thereto included elsewhere i this prospectus before making an investment decision with respect to our common stock. Unless otherwise indicated, information presented in this prospectus assumes that the underwriters' option to purchase additional shares of common stock is not exercised. We have provided definitions for certain oil and natural gas terms used in this prospectus in the "Glossary of oil and natural gas terms" beginning on page A-1 of this prospectus.

In this prospectus, the consolidated and historical financial information, operational data and reserve information for Laredo and our acquired subsidiary Broad Oak Energy, Inc., a Delaware corporation ("Broad Oak" and subsequently renamed Laredo Petroleum—Dallas, Inc.), present the assets and liabilities of Laredo Petroleum Holdings, Inc. 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.

Unless the context otherwise requires, references in this prospectus to "Laredo," "we," "our," "us" or similar terms refer to Laredo Petroleum, LLC, a Delaware limite liability company, and its subsidiaries before the completion of our corporate reorganization in December 2011, and to Laredo Petroleum Holdings, Inc., a Delaware corporation, and its subsidiaries as of the completion of our corporate reorganization and thereafter. For a description of the corporate reorganization, see "—Corporate history and structure" and "Certain relationships and related party transactions—Corporate reorganization."

Laredo Petroleum Holdings, Inc.

Overview

We are an independent energy company focused on the exploration, development and acquisition of oil and natural gas primarily in the Permian and Mid-Continent regions of the United States. The oil and liquids-rich Permian Basin in West Texas and the liquids-rich Anadarko Granite Wash in the Texas Panhandle and Westerr Oklahoma are characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. As of June 30, 2012, we have assembled 188,014 net acres in the Permian Basin and 37,924 net acres in the Anadarko Granite Wash.

Our primary exploration and production fairway in the Permian Basin is centered on the eastern side of the basin approximately 35 miles east of Midland, Texas anc extends approximately 20 miles wide (east/west) and 80 miles long (north/south) in Glasscock, Howard, Reagan and Sterling Counties, and is referred to in this prospectus as the "Permian-Garden City" area. As of June 30, 2012, we held 142,274 net acres in more than 300 sections (each square mile, a "section") in the Permian-Garden City area, with an average working interest of approximately 94% in all 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 four identified shale zones targeted for horizontal drilling (Upper, Middle and Lower Wolfcamp and Cline shales). Through September 17, 2012, we have drilled and completed 49 horizontal wells in these four horizontal target zones. We have completed 33 horizontal Cline wells and 14 horizontal Upper Wolfcamp wells. Our recent horizontal activity has moved toward drilling longer laterals (up to 7,500 feet) and increased frac density (up to 28 stages) as we continue the optimization of our completion techniques. Through September 2012, we have completed nine horizontal Cline wells and ten horizontal Upper Wolfcamp wells which have at least 30 days of production history. The average 30-day initial production ("IP") per stage of fracture stimulation for the nine horizontal Cline wells is 31 BOE/D per stage. The average 30-day IP per stage of fracture stimulation for the ten horizontal Upper Wolfcamp wells is approximately 30 BOE/D per stage. Additionally, we have completed one horizontal well in each of the Middle and Lower Wolfcamp zones. The one Middle Wolfcamp well that we have completed has a 30-day IP per stage of fracture stimulation of 36 BOE/D. We are still drilling our second Middle Wolfcamp horizontal well. Our first horizontal Lower Wolfcamp well is producing oil but does not have 30 days of production. Based on our technical data and well performance, we believe we have to date confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 50% and 45%, respectively, of our Permian-Garden City acreage. Going forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage, as reflected in our 2012 capital drilling budget allocation. As a result, we expect our Permian-Garden City acreage will be the primary driver of our reserves, production and cash flow growth for the foreseeable future.

Our Anadarko Granite Wash play extends within a large area in the western part of the Anadarko Basin in Hemphill County, Texas and Roger Mills County, Oklahoma. Currently, we are drilling horizontal opportunities targeting the liquids-rich Granite Wash formation. The Granite Wash is a conventional play requiring precise drilling techniques to ensure maximum production per well.

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, many of whom have worked together for a decade or more. Prior to founding Laredo, Mr. Foutch and members of our management team successfully formed, built and sold three private oil and gas companies, all of which were focused on the same general areas of the Permian and Mid-Continent regions in which Laredo currently operates. All of these companies executed the same fundamental business strategy employed by Laredo in the same general operating areas and created significant growth in reserves, production and cash flow.

Since our inception, we have rapidly grown our reserves, production and cash flow through both our drilling program and strategic acquisitions, as evidenced by our July 2011 acquisition of Broad Oak. Our net proved reserves were estimated at 156,453 MBOE as of December 31, 2011, of which 40% were classified as proved developed and 36% as oil. 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. Unless otherwise specifically identified in this prospectus, 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.

Our net average daily production for the six months ended June 30, 2012 was 29,690 BOE/D, 41% of which was oil and 59% 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 and, to a lesser extent, liquids-rich opportunities in the Anadarko Granite Wash.

In 2012, more emphasis has been placed on our horizontal drilling program than in prior periods. Approximately 85% of our planned drilling capital for 2012 will be invested in the Permian Basin, and we are increasingly allocating it towards our horizontal drilling activity. As of September 17, 2012, we had completed 49 gross horizontal Wolfcamp and Cline shale wells in the Permian and 21 gross horizontal Granite Wash wells. The horizontal drilling program comprises an extensive, mult year, multiple-zone inventory of exploratory and development opportunities.

In December 2011, we completed a corporate reorganization and an initial public offering of Laredo Petroleum Holdings, Inc.'s common stock (the "IPO"). See "—Corporate history and structure."

The following table summarizes our net acreage and producing wells as of June 30, 2012, total estimated net proved reserves as of December 31, 2011, and average daily production for the six months ended June 30, 2012 in our principal operating regions. Based on estimates in the report prepared by Ryder Scott, we operate wells that represent approximately 97% of the value of our proved developed oil and natural gas reserves as of December 31, 2011. In addition, the table shows our gross identified potential drilling locations and our proved undeveloped locations as of December 31, 2011.

	At December 31, 2011					Six months ended June 30, 2012 average daily production(6)	At June 30, 2012		
	Estimated net proved reserves(1)(2)			Identified potential drilling locations(4)				Producing wells	
	MBOE(3)	% of total reserves	% Oil	Total	PUD locations(5)	(BOE/D)	Net acreage	Gross	Net
Permian Basin									
Permian—Garden City	101,441	65%	52%	5,669	872	19,316	142,274	759	713
Permian—Other	—			—	—	—	45,740	—	—
Anadarko Granite Wash	45,101	29%	8%	335	207	7,931	37,924	184	138
Other Areas(7)	9,911	6%	3%	—	—	2,443	71,550	347	174
New Ventures(8)	—	—		—	—	—	106,788	1	1
Total	156,453	100%	36%	6,004	1,079	29,690	404,276	1,291	1,026

(1) Our estimated net proved reserves were prepared by Ryder Scott as of December 31, 2011 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 twelve-month index prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the applicable twelve-month period), held constant throughout the life of the properties. The reference prices were $92.71/Bbl for oil and $3.99/MMBtu for natural gas for the twelve months ended December 31, 2011.

(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, 2011 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 prices were $7.48/Mcf in the Permian area and $4.88/Mcf in the Anadarko Granite Wash area.

(3) MBbl equivalents ("MBOE") are calculated using a conversion rate of six MMcf per one MBbl.

(4) See the Glossary of Oil and Natural Gas Terms for the definition of "identified potential drilling locations" and "Business—Overview" for more information regarding the processes and criteria through which these potential drilling locations were identified.

(5) Represents the number of identified potential drilling locations to which proved undeveloped reserves are attributable.

(6) 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.

(7) Includes our acreage in the gas prone Eastern Anadarko (26,929 net acres) and Central Texas Panhandle (44,621 net acres).

(8) Includes 99,144 net acres in the Dalhart Basin, which is an exploration effort targeting liquids-rich formations that are less than 7,000 feet in depth, and 7,643 net acres in othe New Ventures. See 'Business—New ventures."

At September 17, 2012, we had a total of 14 operated drilling rigs working. Ten of these rigs were working on our properties in the Permian Basin, six drilling vertica wells and four drilling horizontal wells. Three rigs were working on our properties in the Anadarko Granite Wash, all drilling horizontal wells. One rig was drilling an exploratory well in our New Ventures.

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. Our drilling programs are focused primarily on horizontal drilling in the Permian Basin and, to a lesser extent, the Anadarko Granite Wash.

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. We have an inventory of approximately 6,000 identified potential drilling locations as of December 31, 2011. As of June 30, 2012, such locations are on 142,274 net acres in the Permian-Garden City area and 37,924 net acres in the Anadarko Granite Wash. We believe this inventory will support consistent, predictable, annual growth in reserves, production and cash flow.

Implement a development plan for our Permian-Garden City acreage. We expect our Permian-Garden City acreage will be the primary driver of our reserves, production and cash flow growth for the foreseeable future. As a result of our technical data and the performance of our 33 horizontal Cline wells and 14 horizontal Upper Wolfcamp wells, we believe we have confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 50% and 45%, respectively, of our Permian-Garden City acreage. We further believe this de-risked acreage position (as described below) provides a multi-year development inventory to support consistent growth of reserves and production. This enables us to create a plan to systematically and efficiently develop this acreage position as a resource play. Our future implementation plan will provide flexibility to include potential development of the Middle and Lower Wolfcamp zones as we continue to further de-risk these zones and our remaining Permian-Garden City acreage. Going forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage position, as reflected in our 2012 capital budget allocation.

Capitalize on technical expertise. We intend to leverage our operating and technical expertise to further delineate our core acreage positions. Through the utilization of an extensive technical petrophysical database, a vertical drilling program covering a majority of our core acreage position, and a number of horizontal tests to date, primarily in the Upper Wolfcamp and Cline shales in the Permian-Garden City area, we believe we have reduced the risk and uncertainty associated with (or "de-risked") a significant portion of such acreage.

We intend to continue to make substantial 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 emphasizing our horizontal program, we can increase the efficiency of our resource recovery in the multiple vertically stacked producing horizons on our acreage in both our Permian and Anadarko Granite Wash plays. We are drilling longer laterals with increased density of frac stages 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. 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. Operational control 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 and joint ventures. While we believe our multi-year inventory of identified potential drilling locations provides us with significant growth opportunities, we will continue to evaluate strategically compelling asset acquisitions, mergers and joint ventures. Any transaction we pursue will either generally complement our asset base or provide an anticipated competitive economic proposition relative to our existing opportunities or market conditions. Our Laredo-operated joint ventures with ExxonMobil and Linn Energy, our 2008 acquisition of properties from Linn Energy and our 2011 acquisition of Broad Oak are examples of this strategy.

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 significant upfront investment in research and development as well as data acquisition, owning and operating our natural gas gathering systems with 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 formation in 2006 through September 17, 2012, we have completed more than 700 gross vertical and 51 gross horizontal wells with a success rate of approximately 99%. Based on this drilling success, coupled with our technical data, we have confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 70,000 and 60,000 acres, respectively, of our Permian Basin acreage and are working to de-risk the remaining acreage and zones. As of December 31, 2011, we had identified approximately 5,600 gross potential drilling locations in the Permian-Garden City area, in addition to the 335 gross potential locations in our Anadarko Granite Wash acreage which we believe have been significantly de-risked through our focus on data-rich, mature producing basins with well studied geology, past drilling activity, engineering practices and concentrated operations, combined with our use of new technologies. We believe these potential locations provide a multi-year drilling inventory supporting future growth in reserves, production and cash flow.

Extensive 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 exploration and development programs. We have a large library of data that is applicable to our acreage base that includes approximately 740 square miles of 3D seismic data, 130 proprietary petrophysical logs and more than 13,500 historical open-hole logs. On our Permian-Garden City acreage, we have 10 whole cores and more than 300 sidewall cores in our four horizontal target zones. We have correlated this data across our Permian-Garden City acreage with more than 700 gross vertical and 51 gross horizontal wells. Our management team has extensive industry experience. Each of Mr. Foutch's previous companies focused on the same general areas of the Permian and Anadarko Basins in which Laredo currently operates. Most members of our senior management team have more than twenty years of experience and knowledge directly associated with our current primary operating areas. As of September 17, 2012, approximately 50% of our full-time staff are experienced technical employees, including 24 engineers, 16 geoscientists, 17 landmen and 46 technical support staff.

Significant operational control. We operate wells that represent approximately 97% of the value of our proved developed reserves as of December 31, 2011 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 identified potential drilling locations.

Owned gathering infrastructure. Our wholly-owned subsidiary, Laredo Gas Services, LLC, has invested approximately $64 million in more than 270 miles of pipeline in our natural gas gathering systems in the Permian and Anadarko Basins as of June 30, 2012. These systems and flow lines provide greater operational efficiency and lower differentials for our natural gas production in our liquids-rich Permian and Anadarko Granite Wash plays 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 interconnecting pipelines, potentially minimizing the risks both of shut-ins awaiting pipeline connection and curtailment by downstream pipelines.

Financial strength and flexibility. We maintain a financial profile that enables operational flexibility. At June 30, 2012, we had approximately $785 million available for borrowings on our senior secured credit facility and total debt of approximately $1.05 billion. Our total debt, less available cash, was approximately $905 million, or approximately 2.0 times our annualized Adjusted EBITDA (a non-GAAP financial measure) for the first six months of 2012. We also use derivative financial instruments 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 believe that our operating cash flow and the aforementioned liquidity sources provide us with the ability to implement our planned exploration and development activities. As of September 30, 2012, we had $50 million outstanding on our senior secured credit facility.

Strong institutional investor support and corporate governance. Our institutional investor, 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 i dozens of such companies, including Broad Oak and two previous companies operated by members of our management team. Warburg Pincus did not sell shares of our common stock in the IPO and after this offering will retain a majority interest in Laredo. In addition to the support we receive from Warburg Pincus, we also believe that our board of directors is well qualified and represents a significant resource. Our board, which is comprised of Laredo management and representatives of Warburg Pincus as well as independent individuals, has extensive oil and 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.

Recent developments

Preliminary results for the third quarter ended September 30, 2012. We are finalizing our financial results for the three and nine months ended September 30, 2012. Set forth below are certain preliminary estimates of the results of operations that we expect to report for the third quarter of 2012. Our actual results will be different, and could differ materially, from these estimates due to the completion of our financial closing procedures, final adjustments and other developments that may arise between now and the time the financial results for our third quarter are finalized. All percentage comparisons to the prior year and the second quarter of 2012 are measured at the mid-point of the ranges provided for the third quarter of 2012.

The following are our preliminary estimates for the three months ended September 30, 2012:

- Oil and natural gas production is expected to be between 2,776 MBOE and 2,815 MBOE, a 25% increase from 2,242 MBOE in the corresponding prior-year period and within 98% of the second-quarter 2012 production level.

- Oil and natural gas revenues are expected to be between $136 million and $143 million, a 6% increase from $132 million in the corresponding prior-year period. The estimated increase in revenues is due primarily to an increase in volumes sold.

- At September 30, 2012, we had approximately $28 million of cash and cash equivalents and $735 million of available borrowing capacity on our senior secured credit facility. We anticipate borrowing an additional $50 million on our senior secured credit facility during the week of October 8, 2012.

The estimates above represent the most current information available to management. A range for the preliminary results described above is provided because our financial closing procedures for the month and quarter ended September 30, 2012 are not yet complete. As a result, our final results will vary from these preliminary estimates. Such variances may be material; accordingly, you should not place undue reliance on these preliminary estimates. We currently expect that our final results will be within the ranges described above; however, it is possible that they will not be within these ranges. The estimates for the three months ended September 30, 2012 are not necessarily indicative of any future period and should be read together with "Risk factors," "Forward-looking statements," "Management's discussion and analysis of financial condition and results of operations," "Selected historical consolidated financial data" and our audited and unaudited consolidated financial statements and notes thereto included elsewhere in this prospectus.

The preliminary financial and operating data included in this prospectus has been prepared by, and is the responsibility of, our management and has not been reviewed or audited by our independent registered public accounting firm. Accordingly, our independent registered public accounting firm does not express an opinion or any other form of assurance with respect to this preliminary data.

We expect our closing procedures with respect to the quarter ended September 30, 2012 to be completed in November 2012. Accordingly, our financial statements as of and for the three and nine months ended September 30, 2012 will not be available until after this offering is completed.

Borrowing on senior secured credit facility. Refer to Note N to our unaudited consolidated financial statements included elsewhere in this prospectus for further discussion of the borrowing of $50 million on our senior secured credit facility on August 28, 2012.

Other. See "Management's discussion and analysis of financial condition and results of operations," "Business" and "Management—Committees of the board of directors—Audit committee" for further discussion of our recent developments, including with respect to our core areas of operations and additional derivative contracts.

Risk factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile oil and natural gas prices and other material factors. In particular, the following considerations may offset our competitive strengths or have a negative effect on our business strategy as well as on activities on our properties, which could cause a decrease in the price of our common stock and result in a loss of all or a portion of your investment:

- 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.
- Our business requires substantial capital expenditures, and we may be unable to obtain needed capital or financing on satisfactory terms or at all.
- 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. Regulation could prohibit or restrict our ability to apply hydraulic fracturing to our wells.

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

This list is not exhaustive. Please read the full discussion of these risks and other risks described under "Risk factors."

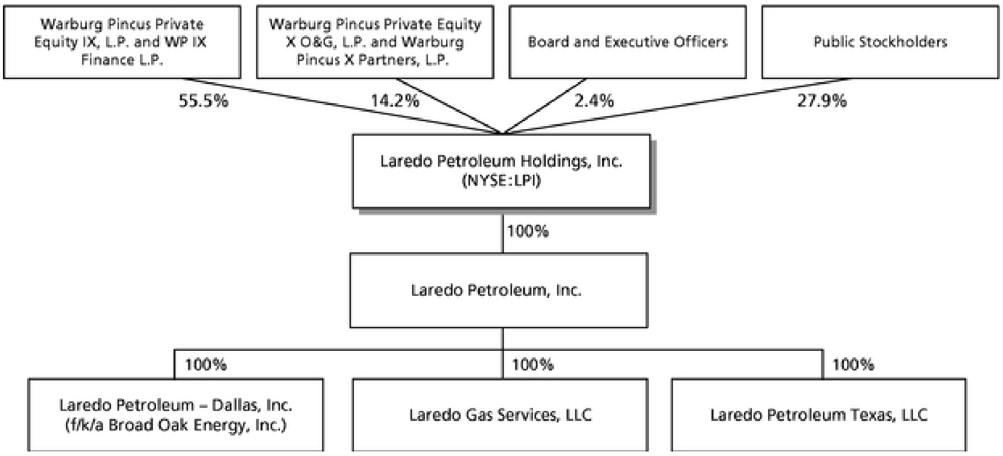
Corporate history and structure

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 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 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. Our business continues to be conducted through Laredo Petroleum, Inc., a wholly-owned subsidiary of Laredo Petroleum Holdings, Inc., and through Laredo Petroleum Inc.'s subsidiaries. The Corporate Reorganization and IPO are discussed in Notes A and D to our audited consolidate financial statements included elsewhere in this prospectus.

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 and our \$500 million $7^3/_8\%$ senior unsecured notes due 2022 issued in April 2012 (the "2022 senior unsecured notes"). We refer to the 2019 senior unsecured notes and the 2022 senior unsecured notes collectively as the "senior unsecured notes." Laredo Petroleum Holdings, Inc. and all of its subsidiaries (other than Laredo Petroleum, Inc.) are guarantors of the obligations under our senior secured credit facility and senior unsecured notes.

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.

The following diagram depicts our ownership structure after giving effect to this offering assuming no exercise of the underwriters' option to acquire additional share
of common stock.



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. Our website address is www.laredopetro.com. We make our periodic reports and other information filed with or furnished to the SEC available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this prospectus.

The offering

Selling stockholders	Affiliates of Warburg Pincus LLC
Common stock offered by the selling stockholders	12,500,000 shares.
	14,375,000 shares, if the underwriters exercise their option to acquire additional shares of common stock in full.
Underwriters' option to purchase additional common stock	1,875,000 shares.
Common stock outstanding after this offering(1)	128,230,576 shares. The number of shares of common stock outstanding will not change as a result of this offering.
Use of proceeds	We will not receive any proceeds from the sale of shares in this offering. See "Use of proceeds."
Dividend policy	We do not anticipate paying any cash dividends on our common stock. In addition, our senior secured credit facility and the indentures governing our senior unsecured notes prohibit us from paying cash dividends. See "Dividend policy."
NYSE symbol	LPI.
Risk factors	Investing in our common stock involves risks. See "Risk factors" for a discussion of certain factors you should consider in evaluating whether or not to invest in our common stock.

(1) The shares to be outstanding after this offering are based on 128,230,576 shares of common stock outstanding as of September 28, 2012 and exclude (i) 485,403 shares issuable upon the exercise of stock options outstanding as of September 28, 2012, with a weighted average exercise price of $24.11 per share, and (ii) 8,812,710 shares reserved for issuance under our 2011 Omnibus Equity Incentive Plan.

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Summary historical consolidated financial data

The following summary historical consolidated financial data should be read in conjunction with "Management's discussion and analysis of financial condition and results of operations" and our unaudited consolidated financial statements and condensed notes thereto and our audited consolidated financial statements and notes thereto included elsewhere in this prospectus. We believe that the assumptions underlying the preparation of our financial statements are reasonable. The financial information included in this prospectus may not be indicative of our future results of operations, financial position and cash flows.

Presented below is our summary historical consolidated financial data for the periods and as of the dates indicated. The summary historical consolidated financial data for the years ended December 31, 2011, 2010 and 2009 and the consolidated balance sheets as of December 31, 2011 and 2010 are derived from our audite consolidated financial statements and the notes thereto included elsewhere in this prospectus. The summary historical consolidated financial data for the six month ended June 30, 2012 and 2011 and the consolidated balance sheet as of June 30, 2012 are derived from our unaudited consolidated financial statements and the condensed notes thereto included elsewhere in this prospectus. The summary historical consolidated financial data for the year ended December 31, 2008 and the consolidated balance sheet data as of December 31, 2009 and 2008 are derived from our audited consolidated financial statements not included in this prospectus. The summary historical consolidated financial data for the year ended December 31, 2007 and the consolidated balance sheet data as of December 31, 2007 are derived from our unaudited consolidated financial statements not included in this prospectus.

(in thousands, except per share data)	For the six months ended June 30, 2012	2011	2011	2010	For the years ended December 31, 2009	2008(1)	2007(2)
		(unaudited)					(unaudited)
Statement of operations data:							
Total revenues	$ 290,972	$ 238,838	$ 510,270	$ 242,000	$ 96,574	$ 74,187	$ 9,628
Total costs and expenses	194,060	131,205	308,371	169,018	350,103	350,653	17,251
Operating income (loss)	96,912	107,633	201,899	72,982	(253,529)	(276,466)	(7,623)
Non-operating income (expense), net	(7,521)	(36,154)	(36,971)	(12,546)	(4,972)	30,702	167
Income (loss) before income taxes	89,391	71,479	164,928	60,436	(258,501)	(245,764)	(7,456)
Net income (loss)	57,210	45,742	105,554	86,248	(184,495)	(192,047)	(6,051)
Pro forma net income per common share:							
Basic	$ 0.45		$ 0.98				
Diluted	$ 0.45		$ 0.98				

(1) The year ended December 31, 2008 contains the results of operations for the acquisition of properties from Linn Energy beginning August 15, 2008, the closing date of the property acquisition.

(2) The year ended December 31, 2007 contains the results of operations for the acquisition of properties from Jones Energy beginning June 5, 2007, the closing date of the property acquisition.

(in thousands)	As of June 30, 2012	As of December 31, 2011	2010	2009	2008	2007
	(unaudited)					(unaudited)
Balance sheet data:						
Cash and cash equivalents	$ 146,485	$ 28,002	$ 31,235	$ 14,987	$ 13,512	$ 6,937
Net property and equipment	1,756,405	1,378,509	809,893	396,100	350,702	137,852
Total assets	2,115,938	1,627,652	1,068,160	625,344	578,387	171,799
Current liabilities	224,026	214,361	150,243	79,265	101,864	16,809
Long-term debt	1,051,863	636,961	491,600	247,100	148,600	44,500
Stockholders' / unit holders' equity	822,058	760,013	411,099	289,107	318,364	109,707

(in thousands)	For the six months ended June 30, 2012	2011	For the years ended December 31, 2011	2010	2009	2008	2007
	(unaudited)						(unaudited)
Other financial data:							
Net cash provided by operating activities	$ 199,790	$ 162,058	$ 344,076	$ 157,043	$ 112,669	$ 25,332	$ 5,019
Net cash used in investing activities	(485,831)	(359,449)	(706,787)	(460,547)	(361,333)	(490,897)	(131,153)
Net cash provided by financing activities	404,524	188,208	359,478	319,752	250,139	472,140	126,726

(in thousands, unaudited)	For the six months ended June 30, 2012	2011	For the years ended December 31, 2011	2010	2009	2008	2007
Adjusted EBITDA(1)	$ 227,821	$ 183,796	$ 388,446	$ 194,502	$ 104,908	$ 49,305	$ (1,522)

(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 "Selected historical consolidated financial data—Non-GAAP financial measures and reconciliations."

Summary historical reserve data

The following table sets forth certain unaudited information concerning our proved oil and natural gas reserves as of December 31, 2011 based on estimates in a reserve report prepared by Ryder Scott, our independent reserve engineers. 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. Reserves cannot be measured exactly because reserve estimates involve subjective judgments. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes.

	December 31, 2011			
	Reserve category			
	PDP	PDNP	PUD	Total
Proved Reserves:				
Oil and condensate (MBbls)	20,882	880	34,505	56,267
Natural gas (MMcf)	232,495	16,103	352,519	601,117
Oil equivalents(1) (MBOE)	59,631	3,564	93,258	156,453
% Oil and condensate	35%	25%	37%	36%
% Natural gas	65%	75%	63%	64%

(1) MBbl equivalents ("MBOE") are calculated using a conversion rate of six MMcf per one MBbl.

Risk factors

Investing in our common stock involves a high degree of risk. You should carefully consider the risks and uncertainties described below, as well as other information contained in this prospectus, before purchasing our common stock. If any of the following risks actually occur, our business, financial condition, operating results or cash flow could be materially and adversely affected. Additional risks and uncertainties not presently known to us or not believed by us to be material may also negatively impact 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 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 would 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 or 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 exploitation, exploration, 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 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." 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 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.

Hydraulic fracturing is a practice that is used to stimulate production of hydrocarbons, particularly 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, or approximately 62% of our total estimated proved reserves as of December 31, 2011, will 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 May 4, 2012, the EPA published a draft UIC Program guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document is designed for use by employees of the EPA that draft the UIC permits and 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 and Oklahoma, where we maintain acreage, the EPA is encouraging state programs to review and consider use of the above-mentioned draft guidance. The draft guidance underwent an extended public comment process, which concluded on August 23, 2012. The EPA is presently evaluating the public comments and will likely issue a final guidance document at a later date. 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 intends to release an interim report by late 2012 and a final report in 2014 synthesizing the longer-term research projects.

On April 17, 2012, the EPA issued a final rule that subjects 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 EPA's final rule includes NSPS standards for completions of hydraulically fractured 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 becomes effective October 15, 2012; however, a number of the requirements will not take immediate effect. The final rule establishes 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 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 wells will be required to use green completions. Controls for certain storage vessels and pneumatic controllers may phase-in over one year beginning on the date the final rule is published in the Federal Register, while certain compressors, dehydrators and other equipment must comply with the final rule immediately or up to three years and 60 days after 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, on May 4, 2012, the United States Department of the Interior ("DOI") issued a draft 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. 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. Proposed rules are expected in 2013 for coalbed methane and 2014 for shale gas.

A committee of the House of Representatives is conducting an investigation of hydraulic fracturing practices. Further, certain members of Congress have called upon: (i) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; (ii) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and (iii) the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. The Shale Gas Subcommittee of the Secretary of Energy Advisory Board released an interim report on August 11, 2011, proposing recommendations to reduce the potential environmental impacts from shale gas production. On November 18, 2011, the Subcommittee issued its final report, which focuses on implementation of the interim report's recommendations. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, pursuant to legislation adopted by the State of Texas in June 2011, 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 (the "RRC") and the public beginning February 1, 2012. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from conventional or 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.

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 prospectus represent estimates. Reserve 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 crude oil, natural gas and natural gas liquids 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 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 reserve estimates.

If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization 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 noncash charge to earnings. See Note P.4 in our audited consolidated financial statements included elsewhere in this prospectus.

Our identified potential drilling locations 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.

Our management team has specifically identified and scheduled certain potential drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These potential drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these potential drilling 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 system, 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 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 identified.

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.9 to our audited consolidated financial statements included elsewhere in this prospectus for additional information.

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 significant 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 September 30, 2012, we have entered into hedge contracts for approximately 5.1 million Bbls of our crude oil production and 59.8 million MMBtu of our natural gas production for settlement between October 2012 and December 2015. We are currently realizing a significant benefit from these hedge positions. If future oil and natural gas prices remain comparable to current prices, we expect that this benefit will decline materially over the life of the hedges, which cover decreasing volumes at declining prices through 2015. 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 "Management's discussion and analysis of financial condition and results of operations—Commodity derivative financial instruments."

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 collars, puts and basis swaps. In accordance with applicable accounting principles, we are required to record our derivative financial instruments at fair market value, and they are included on our consolidated balance sheet as assets or liabilities and in our consolidated statement of operation as realized or unrealized gains. 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 (approximately $31.1 million at June 30, 2012) and the sale of our oil and natural gas production (approximately $38.9 million in receivables at June 30, 2012), 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 approximately 36% of our total oil and natural gas revenues for the six months ended June 30, 2012. 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;
- 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 prospectus, 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 new, unproven and unconventional, 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.

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 "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 "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 and Anadarko Granite Wash 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, approximately $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 from sources within the U.S. between 2012 and 2050 but was not approved by the Senate in the 2009-2010 legislative session. Congress is likely to continue to consider similar bills. Moreover, almost 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 manufactured in model years 2012-2016; however, it does not require immediate reductions in GHG emissions. A recent rulemaking proposal by the EPA and the Department of Transportation's National Highway Traffic Safety Administration seeks to expand the motor vehicle rule to include vehicles manufactured in model years 2017-2025. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it also became effective January 2011, although it remains the subject of several pending lawsuits filed by industry groups. The tailoring rule establishes new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. The permitting requirements of the PSD program apply only to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Phase I of the tailoring rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the tailoring rule, which became effective on July 1, 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the tailoring rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. Finally, in October 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. On March 27, 2012, the EPA issued a proposed rule establishing carbon pollution standards for new fossil-fuel-fired electric utility generating units. The proposed rule underwent an extended public comment process, which concluded on June 25, 2012. The EPA is presently evaluating the public comments and is expected to issue a final rule at a later date. The EPA plans to implement GHG emissions standards for refineries in November 2012.

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 Congress could have a material adverse impact on our ability to hedge risks associated with our business.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market, was signed into law on July 21, 2010. The new legislation required the Commodities Futures Trading Commission ("CFTC") and the SEC to promulgate rules implementing the new legislation within 360 days from the date of enactment. These rules have been adopted and those rules which are not yet effective will take effect, depending on the rule, on October 12, 2012, October 14, 2012, January 10, 2013 or April 10, 2013.

In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions are exempt from these position limits. The CFTC has also issued final rules further defining "swap," "swap dealer" and "major swap participant" and specifying the reporting and other requirements for "non-financial entities" to elect the exception to the clearing requirement under the Commodity Exchange Act ("CEA"). We qualify as a non-financial entity under the CEA and intend to comply with the reporting and other requirements of the exception and utilize the exception. Although the rules will not impose clearing requirements on us, they will impose additional reporting and recordkeeping requirements on us and clearing, capital, margin and reporting and recordkeeping on swap dealers and major swap participants and will also require certain of our potential swap counterparties to conduct their swap activities through affiliates which may be less creditworthy than existing potential swap counterparties. This 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. If we reduce our use of derivatives or commodity prices decline as a result of the legislation 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.

Many of the anticipated benefits of acquiring Broad Oak may not be realized.

Laredo acquired Broad Oak in July 2011 with the expectation that the acquisition would result in various benefits, including, among other things, incremental scale and significant additional exposure to attractive vertical and horizontal oil and liquids-rich natural gas opportunities. However, to realize these anticipated benefits, we must successfully integrate Broad Oak into Laredo. If we are not able to achieve these objectives, the anticipated benefits of the acquisition may not be realized fully or at all or may take longer to realize than expected. It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees or the disruption of our ongoing businesses or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, which could adversely affect our ability to achieve the anticipated benefits of the acquisition. Our consolidated results of operations could also be adversely affected by any issues attributable to either company's operations that arise or are based on events or actions that occurred prior to the closing of the acquisition. Laredo may have difficulty addressing possible differences in corporate cultures and management philosophies. Integration efforts will also divert management attention and resources. These integration activities could have an adverse effect on our business during the transition period. The integration process is subject to a number of uncertainties and no assurance can be given regarding when, or even if, the anticipated benefits will be realized. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect Laredo's future business, financial condition, operating results and prospects.

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.

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 September 28, 2012, Warburg Pincus owns approximately 79.4% of our outstanding common stock, and upon completion of this offering (assuming the underwriters exercise their option to acquire additional shares in full), Warburg Pincus will own approximately 68.3% 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, subject to the restrictions set forth in the lock-up agreement that Warburg Pincus will enter into in connection with this offering, Warburg Pincus is not obligated to maintain its ownership interest in us following this offering 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.

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 intensify competition during those 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.

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 September 30, 2012, we have approximately $735 million of additional 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 $785 million available on our senior secured credit facility would result in increased annual interest expense of approximately $7.9 million and a corresponding decrease in our net income before taking into account the effects of increased interest rates on the value of our interest rate contracts. 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 approximately $1.8 million and for each of the years ended December 31, 2007, 2008 and 2009 of approximately $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 "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. At June 30, 2012, five customers accounted for 10% or greater of our oil and gas sales receivables: 40%, 18%, 14%, 13% and 13%. 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 borrowings will be available to us under our senior secured credit facility or otherwise 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 September 30, 2012, we had total long-term indebtedness of approximately $1.1 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 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.

The President's proposed budget for fiscal year 2013 contains a proposal to 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 the budget proposal or any other similar change in U.S. federal income tax law could eliminate 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 this offering and ownership of our common stock

The market price of our common stock may be volatile, and your investment in our stock could suffer a decline in value.

The market price of our common stock could fluctuate significantly due to a number of factors, including, but not limited to:

- our quarterly or annual earnings, or those of other companies in our industry;

- actual or anticipated fluctuations in our operating results;
- changes in accounting standards, policies, guidance, interpretations or principles;
- public reaction to our press releases, our other public announcements and our filings with the SEC;
- announcements by us or our competitors of significant acquisitions, dispositions, innovations, or new programs and services;
- changes in financial estimates and recommendations by securities analysts following our stock, or the failure of securities analysts to cover our common stock after this offering;
- changes in earnings estimates by securities analysts or our ability to meet those estimates;
- the operating and stock price performance of other comparable companies;
- general economic conditions and overall market fluctuations;
- the trading volume of our common stock;
- changes in business, legal or regulatory conditions, or other developments affecting participants in, and publicity regarding our business or any of our significant customers or competitors;
- results of operations that vary from the expectations of securities analysts and investors or those of our competitors;
- the failure of securities analysts to publish research about us after this offering or to make changes in their financial estimates;
- future sales of our common stock by us, directors, executives and significant stockholders; and
- changes in economic and political conditions in our markets.

In particular, the realization of any of the risks described in these "Risk factors" could have a material and adverse impact on the market price of our common stock in the future and cause the value of your investment to decline. In addition, the stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock over the short, medium or long term, regardless of our actual performance. If the market price of our common stock reaches an elevated level following this offering, it may materially and rapidly decline. In the past, following periods of volatility in the market price of a company's securities, stockholders have often instituted securities class action litigation. If we were to be involved in a class action lawsuit, it could divert the attention of senior management and, if adversely determined, have a material adverse effect on our business, results of operations and financial condition.

Your percentage ownership in us may be diluted by future issuances of common stock or securities or instruments that are convertible into our common stock, which could reduce your influence over matters on which stockholders vote.

Our board of directors has the authority, without action or vote of our stockholders, to issue all or any part of our authorized but unissued shares of common stock, including shares issuable upon the exercise of options, shares that may be issued to satisfy our obligations under our incentive plans, shares of our authorized but unissued preferred stock and securities and instruments that are convertible into or exchangeable for our common stock. Issuances of common stock or voting preferred stock would reduce your influence over matters on which our stockholders vote and, in the case of issuances of preferred stock, likely would result in your interest in us being subject to the prior rights of holders of that preferred stock.

The requirements of being a public company may strain our resources and divert management's attention.

We are subject to the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act"), Dodd-Frank, the listing requirements of the NYSE and other applicable securities rules and regulations. Compliance with these rules and regulations has increased and will continue to increase our legal and financial compliance costs, make some activities more difficult, time consuming or costly, and increase demand on our systems and resources. The SEC recently adopted rules under Dodd-Frank that require each "resource extraction issuer" to publicly disclose information relating to any payment of $100,000 or more made by the issuer to the U.S. or a foreign government for the purpose of the commercial development of oil, natural gas or minerals. While the rules will become effective on November 13, 2012, our first report under the rules will be required for fiscal year ending December 31, 2013, which will cover the partial effective period from October 1, 2013 to year end. The Sarbanes-Oxley Act requires, among other things, that we maintain effective disclosure controls and procedures and internal control over financial reporting. In order to maintain and, if required, improve our disclosure controls and procedures and internal control over financial reporting to meet this standard, significant resources and management oversight may be required. As a result, management's attention may be diverted from other business concerns, which could harm our business and operating results. We may need to hire additional employees in the future to comply with these requirements, which will increase our costs and expenses.

In addition, changing laws, regulations and standards relating to corporate governance and public disclosure are creating uncertainty for public companies, increasing legal and financial compliance costs and making some activities more time consuming. These laws, regulations and standards are subject to varying interpretations, in many cases due to their lack of specificity, and, as a result, their application in practice may evolve over time as new guidance is provided by regulatory and governing bodies. This could result in continuing uncertainty regarding compliance matters and higher costs necessitated by ongoing revisions to disclosure and governance practices. We invest resources to comply with evolving laws, regulations and standards, and this investment may result in increased general and administrative expenses and a diversion of management's time and attention from revenue-generating activities to compliance activities. If our efforts to comply with new laws, regulations and standards differ from the activities intended by regulatory or governing bodies due to ambiguities related to practice, regulatory authorities may initiate legal proceedings against us and our business may be adversely affected.

We do not anticipate paying any dividends on our common stock in the foreseeable future. As a result, you will need to sell your shares of common stock to receive any income or realize a return on your investment.

We do not anticipate paying any dividends on our common stock in the foreseeable future. Any declaration and payment of future dividends to holders of our common stock may be limited by the provisions of the Delaware General Corporation Law and certain restrictive covenants in our senior secured credit facility and the indentures governing our senior unsecured notes. The future payment of dividends will be at the sole discretion of our board of directors and will depend on many factors, including our earnings, capital requirements, financial condition and other considerations that our board of directors deem relevant. As a result, to receive any income or realize a return on your investment, you will need to sell your shares of common stock. You may not be able to sell your shares of common stock at or above the price you paid for them.

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.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock and to determine the designations, powers, preferences and relative, participating, optional, or other special rights, if any, and the qualifications, limitations, or restrictions of our preferred stock, including the number of shares, in any series, 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 your 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;

- at such time as Warburg Pincus no longer beneficially owns more than 50% of our outstanding common stock, any action by stockholders may no longer be effected by written consent of the stockholders;

- at such time as Warburg Pincus no longer beneficially owns more than 50% of our outstanding common stock, our board of directors will be divided into three classes with each class serving staggered three year terms;

- 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; 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.

For a further description of these provisions of our amended and restated certificate of incorporation, amended and restated bylaws, and Delaware law, see "Description of capital stock—Anti-takeover effects of provisions of our certificate of incorporation, our bylaws and Delaware law."

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

Upon completion of this offering (assuming no exercise of the underwriters' option to acquire additional shares of common stock), Warburg Pincus will own approximately 69.7% of our outstanding common stock. Consequently, Warburg Pincus will continue to have 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 will limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

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, among other things, in 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. See "—Our amended and restated certificate of incorporation contains a provision renouncing our interest and expectancy in certain corporate opportunities, which could adversely affect our business or prospects."

Our amended and restated certificate of incorporation contains a provision renouncing our interest and expectancy in certain corporate opportunities, which could adversely affect our business or prospects.

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.

As a result, Warburg Pincus or its affiliates may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, 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. See "Description of capital stock—Corporate opportunity."

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Future sales or the availability for sale of substantial amounts of our common stock in the public market could adversely affect the prevailing market price of our common stock and could impair our ability to raise capital through future sales of equity securities. Our amended and restated certificate of incorporation authorizes us to issue 450,000,000 shares of common stock, of which 128,230,576 shares are and will be outstanding upon consummation of this offering. This number includes 20,125,000 shares registered and sold in the IPO and up to 14,375,000 shares that the selling stockholders are selling in this offering (assuming the underwriters exercise their option to acquire additional shares in full), which will be freely transferable without restriction or further registration under the Securities Act of 1933, as amended (the "Securities Act"). Of the remaining shares, 90,574,391 shares, including the shares of common stock owned by Warburg Pincus upon completion of this offering (assuming the underwriters exercise their option to acquire additional shares in full) and the shares of common stock owned by our directors and executive officers, will be restricted from immediate resale under the federal securities laws and in some cases by the lock-up agreements between the selling stockholders, our directors and executive officers, and the underwriters, which generally provide for a lock-up period of 60 days following the date of this prospectus (unless the representatives of the underwriters waive such lock-up period), but may be sold in the near future. See "Underwriting." Following the expiration of the applicable lock-up period, all these shares of our common stock will be eligible for resale under Rule 144 of the Securities Act, subject to volume limitations and applicable holding period requirements. In addition, Warburg Pincus will have the ability to cause us to register the resale of its shares, and Mr. Foutch will have the ability to include his shares in the registration. See "Shares eligible for future sale" for a discussion of the shares of our common stock that may be sold into the public market in the future.

We may issue shares of our common stock or other securities from time to time as consideration for future acquisitions and investments and pursuant to compensation and incentive plans. If any such acquisition or investment is significant, the number of shares of our common stock, or the number or aggregate principal amount, as the case may be, of other securities that we may issue may in turn be substantial. We may also grant registration rights covering those shares of our common stock or other securities issued in connection with any such acquisitions and investments.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares of our common stock issued in connection with an acquisition or compensation or incentive plan), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

We are a "controlled company" within the meaning of the NYSE rules and, if applicable, would qualify for and could rely on exemptions from certain corporate governance requirements.

Upon the closing of this offering, Warburg Pincus will continue to control a majority of our voting common stock. As a result, we will continue to be a "controlled company" as that term is set forth in Section 303A of the NYSE Listed Company Manual. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a "controlled company" and may elect not to comply with certain NYSE corporate governance requirements, including:

- the requirement that a majority of our board of directors consist of independent directors;
- the requirement that our nominating and corporate governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- the requirement that our compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

These requirements will not apply to us as long as we remain a "controlled company." We may utilize some or all of these exemptions in the future. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE. Warburg Pincus' significant ownership interest could adversely affect investors' perceptions of our corporate governance.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income.

If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code, our ability to offset taxable income arising after the ownership change with net operating losses ("NOLs") arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. Although we do not expect that the offering itself will result in an ownership change, without taking into account the effects or likelihood of future transactions in our common stock, we could be nearing the ownership change threshold upon completion of this offering. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Internal Revenue Code) at any time during a rolling three-year period.

Forward-looking statements

This prospectus contains "forward-looking statements." Such statements can generally be identified by the use of forward-looking terminology such as "could," "believe," "anticipate," "intend," "estimate," "expect," "project," "may," "will," "should," "plan," "predict," "potential," "foresee," "goal," "pursue," "target," "continue," "suggest" or the negative thereof or other variations thereon or comparable terminology, or by discussions of strategy. Investors are cautioned that any such forward-looking statements are not guarantees of future performance and may involve significant risks and uncertainties, and that actual results may vary materially from those in the forward-looking statements as a result of various factors. Among the factors that significantly impact our business and could impact our business in the future are:

- the ongoing 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 crude oil and natural gas;
- 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;
- discovery, estimation, development and replacement of oil and gas reserves, including our expectations that estimates of our proved reserves will increase;
- competition in the oil and gas industry;
- availability and costs of drilling and production equipment, labor, and oil and gas processing and other services;
- changes in domestic and global demand for oil and natural gas;
- the availability of sufficient pipeline and transportation facilities and gathering and processing capacity;
- uncertainties about the estimates of our oil and natural gas reserves;
- changes in the regulatory environment and changes in international, legal, political, administrative or economic conditions;
- successful results from our identified drilling locations;
- our ability to execute our strategies;
- our ability to recruit and retain the qualified personnel necessary to operate our business;
- our ability to comply with federal, state and local regulatory requirements;
- 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; 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 prospectus under "Risk factors," in "Management's discussion and analysis of financial condition and results of operations" and elsewhere in this prospectus. In light of such risks and uncertainties, we caution you not to place undue reliance on these forward-looking statements in deciding whether to invest in our common stock.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas that are ultimately recovered.

These forward-looking statements speak only as of the date of this prospectus, and we do not undertake any obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances after the date of this prospectus or to reflect the occurrence of unanticipated events, except as required by applicable securities laws.

Use of proceeds

We will not receive any of the proceeds from the sale of shares by the selling stockholders in this offering. See "Principal and selling stockholders."

Dividend policy

We have not declared or paid cash dividends to holders of our common stock and do not anticipate declaring or paying any cash dividends in the foreseeable future. We currently intend to retain our future earnings, if any, to support the growth and development of our business. The payment of future cash dividends, if any, will be at the discretion of our board of directors and will depend upon, among other things, our financial condition, results of operations, capital requirements and development expenditures, future business prospects and any restrictions imposed by future debt instruments. In addition, our senior secured credit facility and the indentures governing our senior unsecured notes prohibit us from paying cash dividends.

Market price of our common stock

In connection with the closing of our IPO in December 2011, we listed our common stock on the NYSE under the symbol "LPI." The first quarter of 2012 was the first full quarter in which our common stock traded on the NYSE. On October 4, 2012, the last reported sale price for our common stock on the NYSE was $21.96 per share. As of September 28, 2012, we had approximately 128,230,576 shares of common stock issued and outstanding and 174 stockholders of record. The following table sets forth, for the periods indicated, the reported high and low sale prices for our common stock on the NYSE.

	Common Stock	
	High	Low
2012:		
First Quarter	$ 27.91	$ 19.78
Second Quarter	$ 26.87	$ 18.29
Third Quarter	$ 24.10	$ 20.44

Capitalization

The following table sets forth the capitalization of Laredo Petroleum Holdings, Inc. as of June 30, 2012 on an actual basis.

You should read the following table in conjunction with "Selected historical consolidated financial data," "Management's discussion and analysis of financial condition and results of operations" and our consolidated financial statements and notes thereto included elsewhere in this prospectus.

(in thousands)	As of June 30, 2012 Actual
	(unaudited)
Cash and cash equivalents	$ 146,485
Long-term debt, including current maturities	
Senior secured credit facility(1)	$ —
Senior unsecured notes due 2019	$ 551,863
Senior unsecured notes due 2022	$ 500,000
Stockholders' equity	$ 822,058
Total capitalization	$ 1,873,921

(1) As of September 30, 2012, we had $50 million outstanding under our senior secured credit facility.

Selected historical consolidated financial data

The following historical consolidated financial data should be read in conjunction with "Management's discussion and analysis of financial condition and results of operations" and our unaudited consolidated financial statements and condensed notes thereto and our audited consolidated financial statements and notes thereto included elsewhere in this prospectus. We believe that the assumptions underlying the preparation of our financial statements are reasonable. The financial information included in this prospectus may not be indicative of our future results of operations, financial position and cash flows.

Presented below is our historical consolidated financial data for the periods and as of the dates indicated. The historical consolidated financial data for the years ended December 31, 2011, 2010 and 2009 and the consolidated balance sheets as of December 31, 2011 and 2010 are derived from our audited consolidated financial statements and the notes thereto included elsewhere in this prospectus. The historical consolidated financial data for the six months ended June 30, 2012 and 2011 and the consolidated balance sheet as of June 30, 2012 are derived from our unaudited consolidated financial statements and the condensed notes thereto included elsewhere in this prospectus. The historical consolidated financial data for the year ended December 31, 2008 and the consolidated balance sheet data as of December 31, 2009 and 2008 are derived from our audited consolidated financial statements not included in this prospectus. The historical consolidated financial data for the year ended December 31, 2007 and the consolidated balance sheet data as of December 31, 2007 are derived from our unaudited consolidated financial statements not included in this prospectus.

	For the six months ended June 30, 2012		For the years ended December 31,				
(in thousands, except per share data)	2012	2011	2011	2010	2009	2008(1)	2007(2)
	(unaudited)						(unaudited)
Statement of operations data:							
Total revenues	$290,972	$238,838	$510,270	$242,000	$96,574	$74,187	$9,628
Total costs and expenses	194,060	131,205	308,371	169,018	350,103	350,653	17,251
Operating income (loss)	96,912	107,633	201,899	72,982	(253,529)	(276,466)	(7,623)
Non-operating income (expense), net	(7,521)	(36,154)	(36,971)	(12,546)	(4,972)	30,702	167
Income (loss) before income taxes	89,391	71,479	164,928	60,436	(258,501)	(245,764)	(7,456)
Net income (loss)	57,210	45,742	105,554	86,248	(184,495)	(192,047)	(6,051)
Pro forma net income per common share:							
Basic	$0.45		$0.98				
Diluted	$0.45		$0.98				

(1) The year ended December 31, 2008 contains the results of operations for the acquisition of properties from Linn Energy beginning August 15, 2008, the closing date of the property acquisition.

(2) The year ended December 31, 2007 contains the results of operations for the acquisition of properties from Jones Energy beginning June 5, 2007, the closing date of the property acquisition.

(in thousands)	As of June 30, 2012	As of December 31, 2011	2010	2009	2008	2007
	(unaudited)					(unaudited)
Balance sheet data:						
Cash and cash equivalents	$ 146,485	$ 28,002	$ 31,235	$ 14,987	$ 13,512	$ 6,937
Net property and equipment	1,756,405	1,378,509	809,893	396,100	350,702	137,852
Total assets	2,115,938	1,627,652	1,068,160	625,344	578,387	171,799
Current liabilities	224,026	214,361	150,243	79,265	101,864	16,809
Long-term debt	1,051,863	636,961	491,600	247,100	148,600	44,500
Stockholders' / unit holders' equity	822,058	760,013	411,099	289,107	318,364	109,707

(in thousands)	For the six months ended June 30, 2012	2011	For the years ended December 31, 2011	2010	2009	2008	2007
	(unaudited)						(unaudited)
Other financial data:							
Net cash provided by operating activities	$ 199,790	$ 162,058	$ 344,076	$ 157,043	$ 112,669	$ 25,332	$ 5,019
Net cash used in investing activities	(485,831)	(359,449)	(706,787)	(460,547)	(361,333)	(490,897)	(131,153)
Net cash provided by financing activities	404,524	188,208	359,478	319,752	250,139	472,140	126,726

(in thousands, unaudited)	For the six months ended June 30, 2012	2011	For the years ended December 31, 2011	2010	2009	2008	2007
Adjusted EBITDA(1)	$ 227,821	$ 183,796	$ 388,446	$ 194,502	$ 104,908	$ 49,305	$ (1,522)

(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, depreciation, depletion and amortization, impairment of long-lived assets, write-off of deferred financing fees and other, gains or losses on sale of assets, unrealized gains or losses on derivative financial instruments, realized losses on interest rate derivatives, non-cash equity and stock-based compensation and income tax expense or benefit. Adjusted EBITDA, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Adjusted EBITDA should not be considered in isolation or as a substitute for operating income or loss, net income or loss, cash flows provided by operating activities, used in investing activities and provided by financing activities, or statement of operations or statement of cash flow data prepared in accordance with GAAP. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital increases, working capital decreases or its 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 team 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 and 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 team for various purposes, including as a measure of operating performance, in presentations to our board of directors, and as a basis for strategic planning and forecasting.

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

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

	For the six months ended June 30,		For the years ended December 31,				
(in thousands, unaudited)	**2012**	**2011**	**2011**	**2010**	**2009**	**2008**	**2007**
Net income (loss)	$ 57,210	$ 45,742	$ 105,554	$ 86,248	$ (184,495)	$ (192,047)	$ (6,051)
Plus:							
Interest expense	36,358	22,252	50,580	18,482	7,464	4,410	2,046
Depreciation, depletion and amortization	112,220	75,917	176,366	97,411	58,005	33,102	4,986
Impairment of long-lived assets	—	243	243	—	246,669	282,587	—
Write-off of deferred loan costs	—	3,246	6,195	—	—	—	—
Loss on disposal of assets	8	35	40	30	85	2	—
Unrealized losses (gains) on derivative financial instruments	(16,929)	7,192	(20,890)	11,648	46,003	(27,174)	(1,098)
Realized losses on interest rate derivatives	1,938	2,556	4,873	5,238	3,764	278	—
Non-cash equity and stock-based compensation	4,835	876	6,111	1,257	1,419	1,864	—
Income tax expense (benefit)	32,181	25,737	59,374	(25,812)	(74,006)	(53,717)	(1,405)
Adjusted EBITDA	$ 227,821	$ 183,796	$ 388,446	$ 194,502	$ 104,908	$ 49,305	$ (1,522)

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 prospectus. 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 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 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 prospectus, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Forward-looking statements" and "Risk factors."

Overview

We are an independent energy company focused on the exploration, development and acquisition of oil and natural gas properties primarily in the Permian and Mid-Continent regions of the United States. Laredo was founded in October 2006 to explore, develop and operate oil and natural gas properties and has grown rapidly through its drilling program and by making strategic acquisitions and joint ventures. On July 1, 2011, we completed the acquisition of Broad Oak, whereby Broad Oak became a wholly-owned subsidiary of Laredo Petroleum, Inc. This acquisition was considered a combination of entities under common control and the historical and financial operating data presented herein are shown on a consolidated basis. In December 2011, we completed the Corporate Reorganization and IPO.

Our financial and operating performance for the six months ended June 30, 2012 included the following:

- Oil and natural gas sales of approximately $288.6 million, compared to approximately $236.5 million for the six months ended June 30, 2011;
- Average daily production of 29,690 BOE/D, compared to 22,070 BOE/D for the six months ended June 30, 2011; and
- Adjusted EBITDA (a non-GAAP financial measure) of $227.8 million compared to $183.8 million for the six months ended June 30, 2011.

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 generally seek acquisitions in core, mature areas where management can leverage knowledge and experience to identify upsides in assets.

On May 30, 2008 and August 6, 2008, we entered into purchase and sale agreements with Linn Energy to acquire ownership interests in oil and gas properties located in the Verden area in Caddo, Grady and Comanche Counties, Oklahoma, for a total purchase price of $185.0 million, subject to certain adjustments. The first purchase and sale agreement had an effective date of July 1, 2008, and was closed on August 15, 2008. The second purchase and sale agreement completed the acquisition of the remaining property, had an effective date of July 1, 2008 and was closed on August 7, 2008. There were no significant acquisitions during 2009 and 2010.

As noted above, 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 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. Refer to Note A to our audited consolidated financial statements included elsewhere in this prospectus for further discussion of the Broad Oak acquisition.

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 total purchase price of $20.5 million from a private company, subject to certain purchase price adjustments.

Core areas of operations

The oil and liquids-rich Permian Basin in West Texas and the liquids-rich Anadarko Granite Wash in the Texas Panhandle and Western Oklahoma are characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. As of June 30, 2012, we have assembled 188,014 net acres in the Permian Basin and 37,924 net acres in the Anadarko Granite Wash.

Reserves and pricing

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 significantly affect the economic viability of drilling projects, as well as the economic valuation and economic recovery of oil and natural gas reserves.

Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves at December 31, 2011 and 2010. Ryder Scott also estimated the proved reserves for the legacy Laredo properties as of December 31, 2009. Ryder Scott did not perform evaluations of the Broad Oak properties as of December 31, 2009. Our estimates of the proved reserves at December 31, 2009 are a combination of the Ryder Scott reports on the legacy Laredo properties and Laredo's internal proved reserve estimates of the Broad Oak properties. Based upon the reserve estimates we calculated for Broad Oak, we believe the legacy Laredo properties represented 92% of such combined proved reserves at year end 2009.

The unweighted arithmetic average first-day-of-the-month index prices for the prior 12 months ended June 30, 2012 and June 30, 2011 used to value our reserves were $92.17 per Bbl for oil and $3.01 per MMBtu for natural gas, and $86.60 per Bbl for oil and $4.00 per MMBtu for natural gas, respectively. As of December 31, 2011, we had 156,453 MBOE of estimated net proved reserves as compared to 136,560 MBOE of estimated net proved reserves at December 31, 2010 and 52,519 MBOE of estimated net proved reserves at December 31, 2009. The unweighted arithmetic average first-day-of-the-month index prices for the prior 12 months were $92.71 per Bbl for oil and $3.99 per MMBtu for natural gas at December 31, 2011, $75.96 per Bbl for oil and $4.15 per MMBtu for natural gas at December 31, 2010, and $57.04 per Bbl for oil and $3.15 per MMBtu for natural gas at December 31, 2009. The prices used to estimate proved reserves for all periods did not give effect to derivative transactions, 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 gas production as discussed in "—Hedging" below.

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 six months ended June 30, 2012, our revenues are comprised of sales of approximately 70% oil, 29% natural gas and 1% for transportation and treating. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Hedging

Due to the inherent volatility in oil and natural gas prices, we use commodity derivative instruments, such as collars, swaps, puts and basis swaps to hedge price risk associated with a significant portion of our anticipated oil and natural gas production. By removing a majority of the price volatility associated with future production, we expect to reduce, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. We have not elected hedge accounting on these derivatives; therefore, the unrealized gains and losses on open positions are reflected currently in earnings. At each period end, we estimate the fair value of our commodity derivatives using an independent third party valuation and recognize an unrealized gain or loss. During the six months ended June 30, 2012 and 2011, we recognized an unrealized gain on our commodity derivatives of

$15.3 million and an unrealized loss of $8.7 million on our commodity derivatives, respectively, based on market price fluctuations compared to prices in our commodity derivative contracts.

Subsequent to June 30, 2012, we entered into 15 additional derivative contracts to hedge the price risk associated with approximately 8,760,000 MMBtu, 11,160,000 MMBtu and 15,480,000 MMBtu of our natural gas production for the twelve months ending December 31, 2013, 2014 and 2015, respectively. These derivative contracts have associated deferred premiums totaling approximately $4.2 million. See Note N to our unaudited consolidated financial statements included elsewhere in this prospectus for additional information regarding these derivative contracts.

Our hedged positions as of June 30, 2012 are as follows:

	Remaining year 2012	Year 2013	Year 2014	Year 2015	Total
Oil(1)					
Total volume hedged with ceiling price (Bbls)	969,000	1,368,000	726,000	252,000	3,315,000
Weighted average ceiling price ($/Bbl)	$ 108.81	$ 110.55	$ 129.09	$ 135.00	$ 115.96
Total volume hedged with floor price (Bbls)	1,305,000	2,448,000	1,266,000	708,000	5,727,000
Weighted average floor price ($/Bbl)	$ 79.90	$ 77.19	$ 75.26	$ 75.00	$ 77.11
Natural Gas(2)					
Total volume hedged with ceiling price (MMBtu)	5,140,000	7,300,000	6,960,000	—	19,400,000
Weighted average ceiling price(3) ($/MMBtu)	$ 5.54	$ 6.72	$ 7.03	$ —	$ 6.51
Total volume hedged with floor price (MMBtu)	7,300,000	13,900,000	6,960,000	—	28,160,000
Weighted average floor price(3) ($/MMBtu)	$ 4.59	$ 3.95	$ 4.00	$ —	$ 4.13
Natural Gas basis swaps (MMbtu)					
Total volume hedged(4) (MMBtu)	1,440,000	1,200,000	—	—	2,640,000
Weighted average price ($/MMBtu)	$ 0.31	$ 0.33	$ —	$ —	$ 0.32

(1) The oil derivatives are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude Oil.

(2) The natural gas derivatives are settled based on NYMEX natural gas futures, the Northern Natural Gas Co. demarcation price or the Panhandle Eastern Pipe Line spot price of natural gas for the calculation period. The basis swap derivatives are settled based on the differential between the NYMEX natural gas futures and the West Texas WAHA index gas price.

(3) The cash settlement price of our basis swaps is calculated on the difference between our natural gas futures contracts that settle on the NYMEX index and the NYMEX index price at the time of settlement. At June 30, 2012, we had 200,000 MMBtu for the remainder of 2012 and 500,000 MMBtu for 2013 in basis swaps that did not have corresponding volumes hedged with a NYMEX index price. As such, the weighted average price of the basis differential attributable to these volumes has not been included in the weighted average ceiling and floor prices presented above as these basis contracts are not expected to settle based on our June 30, 2012 hedge positions.

(4) Total volume hedged for natural gas basis swaps includes 200,000 MMBtu for the remainder of 2012 and 500,000 MMBtu for 2013 in basis swaps that did not have corresponding volumes hedged with a NYMEX index price at June 30, 2012.

Principal components of our cost structure

Lease operating and natural gas transportation and treating expenses. These are daily costs incurred to bring oil and 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 gas properties.

Production and ad valorem taxes. Production taxes are paid on produced oil and 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 gas revenues. Ad valorem taxes are property taxes assessed based on a flat rate per oil or natural gas equivalent produced on our properties located in Texas.

Drilling rig fees. These are costs incurred under short-term drilling contracts for fees paid to various third parties if we terminate our drilling or cease efforts, including for stacked drilling rigs in lieu of drilling.

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.

Equity and stock-based compensation. These are costs incurred for compensation expense related to employee unit awards granted prior to December 19, 2011 and employee stock awards granted on or after December 19, 2011, which have been recognized on a straight-line basis over the vesting period associated with the award.

Depreciation, depletion and amortization. Under the full cost accounting method, we capitalize costs 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.

Impairment expense. This is the cost to reduce proved oil and gas properties to the calculated full cost ceiling value and the write-downs of our materials and supplies inventory, consisting of pipe and well equipment, to the lower of cost or market value at the end of the respective period.

Other income (expense)

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

Realized and unrealized gain (loss) on interest rate derivative instruments. We utilize 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 unrealized gains and losses associated with our open interest rate derivative contracts as interest rates change and interest rate contracts expire or new ones are entered into, and (ii) our realized 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.

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 derivative contracts to mitigate the effects of interest rate changes. We do not designate these derivative contracts as hedges; therefore, hedge accounting treatment is not applicable. Realized and unrealized 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, in light of the historic ownership structure of Laredo, U.S. tax laws do not allow tax losses of one entity 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.

Laredo Petroleum Holdings, Inc. and its subsidiaries are subject to federal and state corporate income taxes. These income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating losses and tax credit carry-forwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income 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.

Results of operations

The following table sets forth information regarding production, average sales prices and average costs per BOE for the six months ended June 30, 2012 and 2011 and the years ended December 31, 2011, 2010 and 2009:

	Six months ended June 30,		Years ended December 31,		
	2012	2011	2011	2010	2009
Production data:					
Oil and condensate (MBbl)	2,231	1,517	3,368	1,648	513
Natural gas (MMcf)	19,034	14,866	31,711	21,381	18,302
Oil equivalents (MBOE)(1)(2)	5,404	3,995	8,654	5,212	3,563
Average daily production (BOE/d)	29,690	22,070	23,709	14,278	9,762
% Oil and condensate	41%	38%	39%	32%	14%
Average sales prices:					
Oil and condensate, realized(3) ($/Bbl)	$ 91.23	$ 94.57	$ 91.00	$ 77.00	$ 58.37
Natural gas, realized(3) ($/Mcf)	4.47	6.26	6.30	5.28	3.52
Oil equivalents, realized ($/BOE)	53.40	59.21	58.50	46.01	26.48
Oil and condensate, hedged(4) ($/Bbl)	90.20	90.31	88.62	77.26	65.42
Natural gas, hedged(4) ($/Mcf)	5.31	6.63	6.67	6.32	6.17
Oil equivalents, hedged ($/BOE)	55.95	58.97	58.93	50.37	41.10
Average costs per BOE:					
Lease operating expenses	$ 5.67	$ 4.53	$ 5.00	$ 4.16	$ 3.52
Production and ad valorem taxes	3.00	3.75	3.70	3.01	1.72
General and administrative(5)	5.91	4.95	5.90	5.93	6.34
DD&A	20.77	19.00	20.38	18.69	16.28
Total	$ 35.35	$ 32.23	$ 34.98	$ 31.79	$ 27.86

(1) MBbl equivalents ("MBOE") are calculated using a conversion rate of six MMcf per one MBbl.

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

(3) Realized crude oil and natural gas prices are the actual prices realized at the wellhead after all adjustments for NGL 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 realized gains and losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting. See Note G.4 to our audited consolidated financial statements and Note F.4 to our unaudited consolidated financial statements included elsewhere in this prospectus for additional information regarding our realized gains and losses on commodity derivatives.

(5) General and administrative includes non-cash, stock-based compensation of $4.8 million and $0.9 million for the six months ended June 30, 2012 and 2011, respectively, and $6.1 million, $1.3 million and $1.4 million for the years ended December 31, 2011, 2010 and 2009, respectively. Excluding stock-based compensation from the above metric results in average general and administrative cost per BOE of $5.02 and $4.73 for the six months ended June 30, 2012 and 2011, respectively, and $5.19, $5.69 and $5.94 for the years ended December 31, 2011, 2010 and 2009, respectively.

Six months ended June 30, 2012 as compared to the six months ended June 30, 2011

The following table sets forth selected operating data for the six months ended June 30, 2012 compared to the six months ended June 30, 2011:

	Six months ended June 30,	
(in thousands)	**2012**	**2011**
Revenues		
Oil	$ 203,529	$ 143,464
Natural gas	85,031	93,068
Natural gas transportation and treating	2,412	2,306
Total revenues	290,972	238,838
Costs and expenses		
Lease operating expenses	30,644	18,112
Production and ad valorem taxes	16,237	14,999
Natural gas transportation and treating	691	1,167
Drilling and production	1,771	693
General and administrative (including non-cash stock-based compensation of $4,835 and $876 for the six months ended June 30, 2012 and 2011, respectively)	31,941	19,770
Accretion of asset retirement obligations	556	304
Depreciation, depletion and amortization	112,220	75,917
Impairment expense	—	243
Total costs and expenses	194,060	131,205
Non-operating income (expense):		
Realized and unrealized gain (loss):		
Commodity derivative financial instruments, net	29,137	(9,585)
Interest rate derivatives, net	(323)	(1,094)
Interest expense	(36,358)	(22,252)
Interest and other income	31	58
Write-off of deferred loan costs	—	(3,246)
Loss on disposal of assets	(8)	(35)
Non-operating expense, net	(7,521)	(36,154)
Income tax expense	(32,181)	(25,737)
Net income	$ 57,210	$ 45,742

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $52.0 million, or 22%, to $288.6 million during the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Our revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 7,620 BOE/D during the six months ended June 30, 2012 as compared to the same period in 2011. The total increase in revenue of approximately $52.0 million is largely attributable to higher oil and natural gas production volumes for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Production increased by 714 MBbls for oil and 4,168 MMcf for natural gas for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. The net dollar effect of the decrease in prices of approximately $41.5 million (calculated as the change in period-to-period average prices times current year-to-date production volumes for oil and natural gas) and the net dollar effect of the increase in production of approximately $93.6 million (calculated as the increase in period-to-period volumes for oil and natural gas times the prior period average prices) are shown below.

	Change in prices(1)	Production volumes for the six months ended 6/30/2012(2)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ (3.34)	2,231	$ (7,452)
Natural gas	$ (1.79)	19,034	$ (34,071)
Total revenues due to change in price			$ (41,523)

	Change in production volumes(2)	Prices at 6/30/2011(1)	Total net dollar effect of change (in thousands)
Effect of changes in volumes:			
Oil	714	$ 94.57	$ 67,523
Natural gas	4,168	$ 6.26	$ 26,092
Total revenues due to change in volumes			$ 93,615
Rounding differences			$ (64)
Total change in revenues			$ 52,028

(1) Prices shown are realized, unhedged $/Bbl for oil and are realized, unhedged $/Mcf for natural gas.

(2) Production volumes are presented in MBbls for oil and in MMcf for natural gas.

Lease operating expenses. Lease operating expenses, which include workover expenses, increased to $30.6 million for the six months ended June 30, 2012 from $18.1 million for the six months ended June 30, 2011, an increase of approximately 69%. The increase was primarily due to an increase in drilling activity, which resulted in additional producing wells during the first six months of 2012 compared to the same period in 2011. The increase in well count also led to increases in routine repairs and maintenance. Additionally, a portion of the increase is due to approximately $1.1 million in additional workover expenses incurred during the first six months of 2012 as compared to the same period in 2011 resulting largely from costs incurred for the workover of one well. This workover is not indicative of costs typically incurred for workovers and was fully completed in the first quarter of 2012.

On a per-BOE basis, lease operating expenses increased in total to $5.67 per BOE for the six months ended June 30, 2012 from $4.53 per BOE for the six months ended June 30, 2011. Excluding the one-time workover expense noted above, lease operating expense per BOE at June 30, 2012 was $5.44 per BOE.

Production and ad valorem taxes. Production and ad valorem taxes increased to approximately $16.2 million for the six months ended June 30, 2012 from $15.0 million for the six months ended June 30, 2011, an increase of 8%. This increase was primarily due to the significant increase in production of approximately 1,409 MBOE, or 35%, for the first six months of 2012 as compared to the same period in 2011.

Drilling and production. Drilling and production costs increased to approximately $1.8 million for the six months ended June 30, 2012 from $0.7 million for the six months ended June 30, 2011 as a result of increased maintenance costs related to the increase in drilling during the first six months of 2012 as compared to the same period in 2011.

General and administrative ("G&A"). G&A expense increased to approximately $31.9 million for the six months ended June 30, 2012 from $19.8 million for the six months ended June 30, 2011, an increase of $12.1 million, or 61%. Increases in salaries, benefits and bonuses accounted for approximately $6.3 million of the increase due to the payment of performance bonuses totaling $2.0 million in February 2012 as well as an increase in the number of employees as we continue to grow our business.

Additionally, stock-based compensation increased by approximately $4.0 million to $4.8 million for the first six months of 2012 as compared to the same period in 2011 due to the issuance of 776,711 restricted stock awards and 602,948 non-qualified stock options during 2012. The fair value of the restricted stock awards issued during the first and second quarters of 2012 was calculated based on the value of our stock price on the date of grant in accordance with Generally Accepted Accounting Principles in the United States of America ("GAAP") and is being recognized on a straight-line basis over the three year requisite service period of the awards. The fair value of our non-qualified restricted stock options was determined using a Black-Scholes valuation model in accordance with applicable GAAP accounting and is being recognized on a straight-line basis over the four year requisite service period of the awards. The issuance of our cash-settled performance unit liability awards in February 2012, which are revalued at the end of each reporting period using a Monte Carlo simulation, accounted for approximately $1.0 million of the total change for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011.

On a per-BOE basis, G&A expense increased to $5.91 per BOE during the six months ended June 30, 2012 from $4.95 per BOE for the six months ended June 30, 2011. Excluding non-cash, stock-based compensation, G&A expense per BOE was $5.02 and $4.73 for the six months ended June 30, 2012 and 2011, respectively.

See Notes B and D to our unaudited consolidated financial statements included elsewhere in this prospectus for additional information regarding our stock and performance based compensation.

Depreciation, depletion and amortization ("DD&A"). DD&A increased to approximately $112.2 million for the six months ended June 30, 2012 from $75.9 million for the six months ended June 30, 2011, an increase of $36.3 million, or 48%. The following table provides components of our DD&A expense for the six months ended June 30, 2012 and 2011.

(in thousands except for per BOE data)	Six months ended June 30, 2012	2011
Depletion of proved oil and natural gas properties	$ 109,178	$ 73,670
Depreciation of pipeline assets	1,505	1,151
Depreciation of other property and equipment	1,537	1,096
Total DD&A	$ 112,220	$ 75,917
Depletion of proved oil and natural gas properties per BOE	$ 20.20	$ 18.44
DD&A per BOE	$ 20.77	$ 19.00

The increase in depletion of proved oil and natural gas properties of $35.5 million and the increase in the depletion rate of $1.76 per BOE resulted primarily from (i) increased net book value on new reserves added, (ii) higher total production levels and (iii) increased capitalized costs for new wells completed in 2012.

Impairment expense. Impairment expense decreased to zero for the six months ended June 30, 2012 from $0.2 million for the six months ended June 30, 2011. Impairment expense incurred in the first six months of 2011 was to reflect our materials and supplies inventory at the lower of cost or market value calculated as of June 30, 2011. It was determined at June 30, 2012 that a lower of cost or market value adjustment was not needed for materials and supplies.

We evaluate the impairment of our oil and natural gas properties on a quarterly basis according to the full cost method prescribed by the SEC. If the carrying amount exceeds the calculated full cost ceiling, we reduce the carrying amount of the oil and natural gas properties to the calculated full cost ceiling amount, which is determined to be the estimated fair value. At June 30, 2012 and 2011, it was determined that our oil and natural gas properties were not impaired.

Commodity derivative financial instruments. Due to the inherent volatility in oil and natural gas prices, we use commodity derivative instruments, including puts, swaps, collars and basis swaps to hedge price risk associated with a significant portion of our anticipated oil and natural gas production. At each period end, we estimate the fair value of our commodity derivatives using a valuation prepared by an independent third party and recognize an unrealized gain or loss. We have not elected hedge accounting on these derivatives, and therefore, the unrealized gains and losses on open positions are reflected in current earnings. For the six months ended June 30, 2012 and 2011, our commodity derivatives resulted in a realized gain of $13.8 million and a realized loss of $0.9 million, respectively. For the six months ended June 30, 2012 and 2011, our commodity derivatives resulted in an unrealized gain of $15.3 million and an unrealized loss of $8.7 million, respectively. At June 30, 2012, we had 18 commodity derivatives contracts with associated deferred premiums totaling approximately $27.5 million. The estimated fair value of our total deferred premiums was approximately $23.6 million at June 30, 2012. The fair market value of these premiums is deducted from our unrealized gain or loss at each period end.

Interest expense and realized and unrealized gains and losses on interest rate swaps. Interest expense increased to approximately $36.4 million for the six months ended June 30, 2012 from $22.3 million for the six months ended June 30, 2011, largely due to the issuance of our $350.0 million and $200.0 million 2019 senior unsecured notes in January 2011 and October of 2011, respectively, as well as the issuance of our $500.0 million 2022 senior unsecured notes in April of 2012 as shown in the table below.

	Six months ended June 30, 2012		Six months ended June 30, 2011	
(in thousands except for percentages)	**Weighted average principal**	**Weighted average interest rate(3)**	**Weighted average principal**	**Weighted average interest rate(3)**
Senior secured credit facility	$ 190,085	0.72%	$ 68,056	0.75%
2019 senior unsecured notes	550,000	4.73%	350,000	4.19%
2022 senior unsecured notes	500,000	1.29%	—	—
Term loan(1)	—	—	100,000	0.31%
Broad Oak credit facility(2)	—	—	122,904	3.07%

(1) The term loan was entered into on July 7, 2010 and was paid-in-full and terminated on January 20, 2011.

(2) The Broad Oak credit facility was paid-in-full and terminated on July 1, 2011 in connection with the Broad Oak acquisition.

(3) Interest rates presented are annual rates which have been prorated to reflect the portion of the year for which they have been incurred.

We have entered into certain variable-to-fixed interest rate swaps that hedge our exposure to interest rate variations on our variable interest rate debt. At June 30, 2012, we had interest rate swaps outstanding for a notional amount of $100.0 million with fixed pay rates ranging from 1.11% to 3.00% and terms expiring through September 2013. At June 30, 2011, we had interest rate swaps outstanding for a notional amount of $260.0 million with fixed pay rates ranging from 1.11% to 3.41% and terms expiring through September 2013. We realized losses on interest rate swaps of $1.9 million and $2.6 million for the six months ended June 30, 2012 and 2011, respectively. Additionally, we recorded unrealized gains on interest rate swaps of $1.6 million and $1.5 million for the six months ended June 30, 2012 and June 30, 2011, respectively. At June 30, 2012, the estimated fair value of our interest rate swaps was in a net liability position of $0.4 million compared to a net liability position of $2.0 million at December 31, 2011.

Income tax expense. We recorded a deferred income tax expense of $32.2 million for the six months ended June 30, 2012, compared to a deferred income tax expense of $25.7 million for the six months ended June 30, 2011. The estimated annual effective tax rate was 36% for each of the six months ended June 30, 2012 and 2011. Our effective tax rate is based on our estimated annual permanent tax differences and estimated annual pre-tax book income. Our estimates involve assumptions we believe to be reasonable at the time of the estimation.

Year ended December 31, 2011 as compared to the year ended December 31, 2010

The following table sets forth selected operating data for the year ended December 31, 2011 compared to the year ended December 31, 2010:

(in thousands)	Years ended December 31, 2011	2010
Operating results:		
Revenues		
Oil	$ 306,481	$ 126,891
Natural gas	199,774	112,892
Natural gas transportation and treating	4,015	2,217
Total revenues	510,270	242,000
Costs and expenses		
Lease operating expenses	43,306	21,684
Production and ad valorem taxes	31,982	15,699
Natural gas transportation and treating	977	2,501
Drilling and production	3,817	340
General and administrative (including non-cash stock-based compensation of $6,111 and $1,257 for the years ended December 31, 2011 and 2010, respectively)	51,064	30,908
Accretion of asset retirement obligations	616	475
Depreciation, depletion and amortization	176,366	97,411
Impairment expense	243	—
Total costs and expenses	308,371	169,018
Non-operating income (expense):		
Realized and unrealized gain (loss):		
Commodity derivative financial instruments, net	21,047	11,190
Interest rate derivatives, net	(1,311)	(5,375)
Interest expense	(50,580)	(18,482)
Interest and other income	108	151
Write-off of deferred loan costs	(6,195)	—
Loss on disposal of assets	(40)	(30)
Non-operating expense, net	(36,971)	(12,546)
Income tax expense	(59,374)	25,812
Net income	$ 105,554	$ 86,248

Oil and gas revenues. Our oil and gas revenues increased by approximately $266.5 million, or 111%, to $506.3 million during the year ended December 31, 2011 as compared to the year ended December 31, 2010. Our revenues are a function of oil and gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 9,431 BOE/D during the year ended December 31, 2011 as compared to the same period in 2010. The total increase in revenue of approximately $266.5 million is largely attributable to higher oil and gas production volumes as well as an increase in oil prices being realized for the year ended December 31, 2011 as compared to the year ended December 31, 2010. Production increased by 1,720 MBbls for oil and 10,330 MMcf for gas for the year ended December 31, 2011 as compared to the year ended December 31, 2010. The net dollar effect of the increase in prices of approximately $79.5 million (calculated as the change in year-to-year average prices times current year production volumes for oil and gas) and the net dollar effect of the change in production of approximately $187.0 million (calculated as the increase in year-to-year volumes for oil and gas times the prior year average prices) are shown below.

	Change in prices(1)	Production volumes at December 31, 2011(2)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 14.00	3,368	$ 47,152
Natural gas	$ 1.02	31,711	$ 32,345
Total revenues due to change in price			$ 79,497

	Change in production volumes(2)	Prices at December 31, 2010(1)	Total net dollar effect of change (in thousands)
Effect of changes in volumes:			
Oil	1,720	$ 77.00	$ 132,440
Natural gas	10,330	$ 5.28	$ 54,542
Total revenues due to change in volume			$ 186,982
Rounding differences			$ (7)
Total change in revenues			$ 266,472

(1) Prices shown are realized, unhedged $/Bbl for oil and are realized, unhedged $/Mcf for natural gas.

(2) Production volumes are presented in MBbls for oil and in MMcf for natural gas.

Natural gas transportation and treating. Our revenues related to natural gas transportation and treating increased by $1.8 million during the year ended December 31, 2011 as compared to the year ended December 31, 2010. This increase was due to the sale of oil condensate from our pipeline assets during 2011, which occurs on an infrequent basis, as well as an increase in the volumes transported through our pipeline.

Lease operating expenses. Lease operating expenses, which include workover expenses, increased to $43.3 million for the year ended December 31, 2011 from $21.7 million for the year ended December 31, 2010, an increase of approximately 100%. The increase was primarily due to an increase in drilling activity, which resulted in additional producing wells during 2011 compared to 2010. On a per-BOE basis, lease operating expenses increased in total to $5.00 per BOE at December 31, 2011 from $4.16 per BOE at December 31, 2010. The majority of the increase is due to approximately $3.5 million in additional workover expenses incurred during 2011 as compared to the same period in 2010 as market conditions for oil and gas became more favorable.

Production and ad valorem taxes. Production and ad valorem taxes increased to approximately $32.0 million for the year ended December 31, 2011 from $15.7 million for the year ended December 31, 2010, an increase of $16.3 million, or approximately 104%, primarily due to the increase in market prices (not including the effects of hedging), as well as a significant increase in production for 2011 as compared to the same period in 2010. The average realized prices excluding derivatives for the year ended December 31, 2011 were $91.00 per Bbl for oil and $6.30 per Mcf for gas as compared to $77.00 per Bbl for oil and $5.28 per Mcf for gas for the year ended December 31, 2010.

Drilling and production. Drilling and production costs increased to approximately $3.8 million for the year ended December 31, 2011 from $0.3 million for the year ended December 31, 2010 as a result of increased maintenance costs related to the increase in drilling during 2011 as compared to 2010.

General and administrative ("G&A"). G&A expense increased to approximately $51.1 million at December 31, 2011 from $30.9 million at December 31, 2010, an increase of $20.2 million, or 65%. Increases in professional fees incurred relating to the issuance of the 2019 senior unsecured notes, the Broad Oak acquisition, the filing of a registration statement relating to the 2019 senior unsecured notes with the SEC and other matters accounted for approximately $7.4 million, or 37%, of the change in G&A, as well as approximately $7.2 million in additional salary, benefits and bonus expenditures due to the Broad Oak acquisition and the growth of our business and employee base.

Equity and stock-based compensation increased to approximately $6.1 million at December 31, 2011 from $1.3 million at December 31, 2010, an increase of approximately $4.8 million. Approximately $4.1 million of this increase was attributed largely to new series of units issued in conjunction with the Broad Oak acquisition in the third quarter of 2011. On December 19, 2011, as a result of our Corporate Reorganization, the outstanding units in Laredo Petroleum, LLC that had been previously issued to management, directors and employees were exchanged for 2,500,807 vested and 912,038 unvested shares of common stock in Laredo Petroleum Holdings, Inc. The fair value of the unit awards immediately prior to the exchange was determined to be equal to the fair value of the common shares immediately after the exchange and as such, the basis in the former unvested units was carried over to the unvested shares of common stock. This resulted in no additional incremental compensation cost being recognized at the date of conversion.

On a per-BOE basis, G&A expense decreased to $5.90 per BOE during the year ended December 31, 2011 from $5.93 per BOE during the year ended December 31, 2010. This decrease was a result of a significant increase in production during the year ended December 31, 2011 as compared to the year ended December 31, 2010. Additionally, on a per-BOE basis, excluding the costs of the Broad Oak acquisition, G&A expense was approximately $4.22 per BOE for the year ended December 31, 2011.

We have a 2011 Omnibus Equity Incentive Plan, which allows for the issuance of restricted stock awards, stock options and performance units to current and prospective directors, officers, employees, consultants and advisors. There were no issuances under the plan of restricted stock awards, stock options or performance units during the year ended December 31, 2011. In February 2012, we issued 593,939 restricted stock awards, 602,948 stock options and 49,244 performance units to employees and officers and will record compensation expense related to these issuances in accordance with GAAP in future periods. See Note O to our audited consolidated financial statements included elsewhere in this prospectus for additional information.

Depreciation, depletion and amortization ("DD&A"). DD&A increased to approximately $176.4 million at December 31, 2011 from $97.4 million at December 31, 2010, an increase of $79.0 million, or 81%. The following table provides components of our DD&A expense for the years ended December 31, 2011 and 2010.

(in thousands except for per BOE data)	Years ended December 31, 2011	2010
Depletion of proved oil and natural gas properties	$ 171,517	$ 93,815
Depreciation of pipeline assets	2,466	1,982
Depreciation of other property and equipment	2,383	1,614
Total depletion, depreciation and amortization	$ 176,366	$ 97,411
Depletion of proved oil and natural gas properties per BOE	$ 19.82	$ 18.00
DD&A per BOE	$ 20.38	$ 18.69

The increase in depletion of proved oil and natural gas properties of $77.7 million and the increase in the depletion rate of $1.82 per BOE resulted primarily from (i) increased net book value on new reserves added, (ii) higher total production levels, (iii) increased capitalized costs for new wells completed in 2011 and (iv) a corresponding offset caused by the increase in oil and natural gas prices between periods used to calculate proved reserves.

The increase in depreciation for pipeline and gas gathering assets of $0.5 million was primarily due to the expansion of our gas gathering system.

The increase in depreciation for other fixed assets of $0.8 million was primarily due to an increase in fixed asset additions as we continued to grow our business.

Impairment expense. Impairment expense increased to $0.2 million for the year ended December 31, 2011 from zero for the year ended December 31, 2010. This increase is due to a write-down of our materials and supplies inventory to reflect the balance at the lower of cost or market value calculated as of December 31, 2011. It was determined at December 31, 2010 that a lower of cost or market adjustment was not needed for materials and supplies.

We evaluate the impairment of our oil and gas properties on a quarterly basis according to the full cost method prescribed by the SEC. If the carrying amount exceeds the calculated full cost ceiling, we reduce the carrying amount of the oil and gas properties to the calculated full cost ceiling amount, which is determined to be their estimated fair value. For the years ended December 31, 2011 and 2010, it was determined that our oil and gas properties were not impaired.

Commodity derivative financial instruments. Due to the inherent volatility in oil and gas prices, we use commodity derivative instruments, including puts, swaps, collars and basis swaps to hedge price risk associated with a significant portion of our anticipated oil and gas production. At each period end, we estimate the fair value of our commodity derivatives and recognize an unrealized gain or loss. We have not elected hedge accounting on these derivatives, and therefore, the unrealized gains and losses on open positions are reflected in current earnings. For the years ended December 31, 2011 and 2010, our commodity derivatives resulted in realized gains of $3.7 million and $22.7 million, respectively. For the years ended December 31, 2011 and 2010, our commodity derivatives resulted in an unrealized gain of

$17.3 million and an unrealized loss of $11.5 million, respectively. During the fourth quarter ended December 31, 2009 and the years ended December 31, 2010 and 2011, we entered into a number of new commodity derivatives of which twelve had associated deferred premiums totaling approximately $19.8 million. The estimated fair value of our total deferred premiums was approximately $18.9 million at December 31, 2011. The fair market value of these premiums is deducted from our unrealized gains at December 31, 2011. The overall gain at December 31, 2011 is largely due to the decrease in market prices to levels lower than those specified in our fixed price commodity derivative contracts during the year ended December 31, 2011.

Interest expense and realized and unrealized gains and losses on interest rate swaps. Interest expense increased to approximately $50.6 million for the year ended December 31, 2011 from $18.5 million for the year ended December 31, 2010, largely due to higher weighted average interest rates and higher weighted average outstanding debt balances on our senior secured credit facility and due to the issuance of the 2019 senior unsecured notes during 2011 as compared to 2010 as shown in the table below. Additionally, we had approximately $3.5 million in amortized deferred loan costs and $0.7 million in other fees and deferred option premium amortization that were charged to interest expense for the year ended December 31, 2011 as compared to $2.0 million in amortized deferred loan costs and $0.4 million in other fees and deferred option premium amortization for the year ended December 31, 2010.

	Year ended December 31, 2011		Year ended December 31, 2010	
(in thousands except for percentages)	**Weighted average principal**	**Weighted average interest rate**	**Weighted average principal**	**Weighted average interest rate**
Senior secured credit facility	$299,502	2.07%	$180,788	3.38%
2019 senior unsecured notes	392,319	8.98%	—	—
Term loan(1)	100,000	0.51%	100,000	4.49%
Broad Oak credit facility(2)	122,904	3.07%	123,782	4.27%

(1) The term loan was entered into on July 7, 2010 and was paid-in-full and terminated on January 20, 2011.

(2) The Broad Oak credit facility was paid-in-full and terminated on July 1, 2011 in connection with the Broad Oak acquisition.

During 2010, we entered into certain variable-to-fixed interest rate swaps that hedge our exposure to interest rate variations on our variable interest rate debt. At December 31, 2011, we had interest rate swaps outstanding for a notional amount of $260.0 million with fixed pay rates ranging from 1.11% to 3.41% and terms expiring through September 2013. At December 31, 2010, we had interest rate swaps outstanding for a notional amount of $300.0 million with fixed pay rates ranging from 1.11% to 3.41% and terms expiring through September 2013. We realized losses on interest rate swaps of $4.9 million and $5.2 million for the years ended December 31, 2011 and 2010, respectively. Additionally, we recorded an unrealized gain on interest rate swaps of $3.6 million as of December 31, 2011 compared to an unrealized loss of $0.1 million at December 31, 2010. At December 31, 2011, the estimated fair value of our interest rate swaps was in a net liability position of $2.0 million compared to a net liability position of $5.5 million at December 31, 2010.

Write-off of deferred loan costs. In January 2011, we used a portion of the net proceeds from the issuance of the 2019 senior unsecured notes to pay in full and retire our term loan. Additionally, concurrent with the issuance of the 2019 senior unsecured notes, the borrowing base on our senior secured credit facility was lowered from $220.0 million to $200.0 million. As a result, we took a charge to expense for the debt issuance costs attributable to our term loan and a proportionate percentage of the costs incurred for our senior secured credit facility, which totaled $2.9 million and $0.3 million, respectively. As of December 31, 2011, the borrowing base on our senior secured credit facility is $712.5 million. On July 1, 2011, in connection with the Broad Oak acquisition, the Broad Oak credit facility was paid in full and terminated, and the related debt issuance costs of $2.9 million were charged to expense.

Income tax expense. We prepared separate tax returns for Laredo Petroleum, LLC, Laredo Petroleum, Inc. and Broad Oak for the period prior to July 1, 2011. We recorded a deferred income tax expense of $59.4 million for the year ended December 31, 2011, compared to a deferred income tax benefit of $25.8 million for the year ended December 31, 2010. The estimated annual effective tax rates were 36% and 37% for the years ended December 31, 2011 and 2010, respectively; however, during the first nine months of 2010, Broad Oak had a valuation allowance against its net deferred federal tax asset which decreased our deferred income tax expense for the year ended December 31, 2010. Our effective tax rate is based on our estimated annual permanent tax differences and estimated annual pre-tax book income. Our estimates involve assumptions we believe to be reasonable at the time of the estimation.

Year ended December 31, 2010 as compared to year ended December 31, 2009

The following table sets forth selected operating data for the year ended December 31, 2010 compared to the year ended December 31, 2009:

(in thousands)	Years ended December 31, 2010	Years ended December 31, 2009
Operating results:		
Revenues		
Oil	$ 126,891	$ 29,946
Natural gas	112,892	64,401
Natural gas transportation and treating	2,217	2,227
Total revenues	242,000	96,574
Costs and expenses		
Lease operating expenses	21,684	12,531
Production and ad valorem taxes	15,699	6,129
Natural gas transportation and treating	2,501	1,416
Drilling rig fees	—	1,606
Drilling and production	340	758
General and administrative (including non-cash stock-based compensation of $1,257 and $1,419 for the years ended December 31, 2010 and 2009, respectively)	30,908	22,583
Accretion of asset retirement obligations	475	406
Depreciation, depletion and amortization	97,411	58,005
Impairment expense	—	246,669
Total costs and expenses	169,018	350,103
Non-operating income (expense):		
Realized and unrealized gain (loss):		
Commodity derivative financial instruments, net	11,190	5,744
Interest rate derivatives, net	(5,375)	(3,394)
Interest expense	(18,482)	(7,464)
Interest and other income	151	227
Loss on disposal of assets	(30)	(85)
Non-operating expense, net	(12,546)	(4,972)
Income tax benefit	25,812	74,006
Net income (loss)	$ 86,248	$ (184,495)

Oil and gas revenues. Our oil and gas revenues increased by approximately $145.4 million, or 154%, to approximately $239.8 million during the year ended December 31, 2010 as compared to the year ended December 31, 2009. Our revenues are a function of oil and gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 4,516 BOE/D during the year ended December 31, 2010 as compared to the year ended December 31, 2009. The total increase in revenue of approximately $145.4 million is largely attributable to an increase in oil and gas production volumes as well as an increase in oil and gas prices realized for the year ended December 31, 2010 as compared to the year ended December 31, 2009. Production increased by 1,135 MBbls for oil and by 3,079 MMcf for gas during 2010 as compared to 2009. The net dollar effect of the increase in prices of approximately $68.3 million (calculated as the change in year-to-year average prices times current year production volumes for oil and gas) and the net dollar effect of the change in production of approximately $77.1 million (calculated as the change in year-to-year volumes for oil and gas times the prior year average prices) are shown below.

	Change in prices(1)	Production volumes at December 31, 2010(2)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 18.63	1,648	$ 30,702
Natural gas	$ 1.76	21,381	$ 37,631
Total revenues due to change in price			$ 68,333

	Change in production volumes(2)	Prices at December 31, 2009(1)	Total net dollar effect of change (in thousands)
Effect of changes in volumes:			
Oil	1,135	$ 58.37	$ 66,250
Natural gas	3,079	$ 3.52	$ 10,838
Total revenues due to change in volumes			$ 77,088
Rounding differences			$ 15
Total change in revenues			$ 145,436

(1) Prices shown are realized, unhedged $/Bbl for oil and are realized, unhedged $/Mcf for gas.

(2) Production volumes are presented in MBbls for oil and in MMcf for natural gas.

Lease operating expenses. Lease operating expenses increased to approximately $21.7 million for the year ended December 31, 2010 from $12.5 million for the year ended December 31, 2009, an increase of 74%, primarily due to the increase in the number of owned properties during 2010 as compared to 2009. On a per-BOE basis, lease operating expenses increased in total to $4.16 per BOE at December 31, 2010 from $3.52 per BOE at December 31, 2009. This increase was largely a result of lower production for the first nine months of 2010 as we scaled back our drilling program in response to lower oil and gas prices, while continuing to incur lease operating expenses on properties with normal declining production.

Production and ad valorem taxes. Production and ad valorem taxes increased to approximately $15.7 million for the year ended December 31, 2010 from $6.1 million for the year ended December 31, 2009, an increase of $9.6 million, or 157%, primarily due to the increase in market prices (not including the effects of hedging) for 2010 as compared to 2009. The average realized prices excluding derivatives for the year ended December 31, 2010 were $77.00 per Bbl for oil and $5.28 per Mcf for natural gas as compared to $58.37 per Bbl for oil and $3.52 per Mcf for natural gas for the year ended December 31, 2009.

Drilling rig fees. We have committed to several short-term drilling contracts with various third parties to complete our drilling projects. The contracts contain an early termination clause that requires us to pay significant penalties to the third parties if we cease drilling efforts. For the year ended December 31, 2009, we incurred approximately $1.6 million in stacked rig fees. In 2010, we did not incur any stacked rig fees related to our drilling rig contracts.

Drilling and production. Drilling and production costs decreased to approximately $0.3 million at December 31, 2010 from $0.8 million at December 31, 2009 as a result of improved cost control measures related to our activities.

General and administrative ("G&A"). G&A expense increased to approximately $30.9 million at December 31, 2010 from $22.6 million at December 31, 2009, an increase of $8.3 million, or 37%. Increases in salaries, benefits and bonus expense (net of capitalized salary and benefits) accounted for approximately $5.4 million, or 64%, of the change in G&A expense as we continued to grow our employee base during 2010. Equity and stock-based compensation decreased to approximately $1.3 million at December 31, 2010 from $1.4 million at December 31, 2009 due largely to a lower average grant date fair value and number of awards granted and vested during 2010 as compared to 2009. The remainder of the increase largely consisted of additional expenditures for technology, travel costs and professional fees.

On a per-BOE basis, G&A expense decreased to $5.93 per BOE during the year ended December 31, 2010 from $6.34 per BOE at December 31, 2009. This decrease was a result of a larger overall increase in production volumes between the two periods.

Depreciation, depletion and amortization ("DD&A"). DD&A increased to approximately $97.4 million at December 31, 2010 from $58.0 million at December 31, 2009, an increase of $39.4 million, or 68%. The following table provides components of our DD&A expense for the years ended December 31, 2010 and 2009.

	Years ended December 31,	
	2010	**2009**
Depletion of proved oil and natural gas properties	$ 93,815	$ 55,399
Depreciation of pipeline assets	1,982	1,461
Depreciation of other property and equipment	1,614	1,145
Total depletion, depreciation and amortization	$ 97,411	$ 58,005
Depletion of proved oil and natural gas properties per BOE	$ 18.00	$ 15.54
DD&A per BOE	$ 18.69	$ 16.28

The increase in depletion of proved oil and natural gas properties of approximately $38.4 million and the increase in the depletion rate of $2.46 per BOE were due largely to additions to the full cost pool related to our increase in drilling in 2011 as compared to 2010.

The increase in depreciation for pipeline and gas gathering assets of approximately $0.5 million was primarily due to the expansion of our gas gathering system.

The increase in depreciation for other fixed assets of approximately $0.5 million was primarily due to an increase in fixed asset additions as we grew the company.

Impairment expense. We evaluate the impairment of our oil and gas properties on a quarterly basis according to the full cost method prescribed by the SEC. If the carrying amount exceeds the calculated full cost ceiling, we reduce the carrying amount of the oil and gas properties to the calculated full cost ceiling amount, which is determined to be their estimated fair value.

Impairment expense at December 31, 2009 reflects the impairment of our oil and gas properties of approximately $245.9 million due to declining market prices for oil and gas, and the write-down to lower of cost of market of our materials and supplies of approximately $0.8 million, consisting of pipe and well equipment, due to declining market prices. For oil and natural gas assets, the full cost ceiling calculation was computed using the unweighted arithmetic average first-day-of-the-month prices for the 12-months ended December 31, 2009 of $57.04 per Bbl for oil and $3.15 per MMBtu for natural gas, adjusted for energy content, transportation fees and regional price differentials. It was determined that oil and natural gas properties were not impaired for the year ended December 31, 2010 as their carrying amount did not exceed the calculated full cost ceiling. Additionally, a write-down of our materials and supplies was not necessary at December 31, 2010 based on our lower of cost or market analysis.

Commodity derivative financial instruments. Due to the inherent volatility in oil and gas prices, we use commodity derivative instruments including puts, swaps, collars, and basis swaps to hedge future price risk associated with a significant portion of our anticipated oil and gas production. At each period end, we estimate the fair value of our commodity derivatives and recognize an unrealized gain or loss. We have not elected hedge accounting on these derivatives, therefore, the unrealized gains and losses on open positions are reflected in current earnings. For the years ended December 31, 2010 and 2009, our hedges resulted in realized gains of approximately $22.7 million and $52.1 million, respectively. For the years ended December 31, 2010 and 2009, our hedges resulted in unrealized losses of approximately $11.5 million and $46.4 million, respectively. During 2009, some of our hedge contracts matured and commodity prices began to recover, creating an unrealized loss at December 31, 2009. During 2010, we entered into a number of new commodity derivatives of which seven had associated deferred premiums totaling approximately $13.4 million. The estimated fair value of our total deferred premiums was approximately $12.5 million at December 31, 2010. The fair market value of these premiums is deducted from our unrealized gains and losses and largely accounts for the overall unrealized loss on commodity derivatives at December 31, 2010.

Interest expense and realized and unrealized gains and losses on interest rate derivatives. Interest expense increased to approximately $18.5 million for the year ended December 31, 2010 from $7.5 million for the year ended December 31, 2009, largely due to a higher weighted average interest rate and a higher weighted average outstanding debt balance on the Broad Oak credit facility and the issuance of our term loan during 2010 as compared to 2009. Additionally, we had approximately $2.0 million in amortized deferred loan costs and $0.4 million in other fees and deferred premium amortization that were charged to interest expense for the year ended December 31, 2010 as compared to $0.6 million in amortized deferred loan costs and an insignificant amount of other fees and amortization for the year ended December 31, 2009.

	Year ended December 31, 2010		Year ended December 31, 2009	
(in thousands except for percentages)	**Weighted average principal**	**Weighted average interest rate**	**Weighted average principal**	**Weighted average interest rate**
Senior secured credit facility	$180,788	3.38%	$154,011	3.67%
Term loan(1)	100,000	4.49%	—	—
Broad Oak credit facility(2)	123,782	4.27%	27,657	4.65%

(1) The term loan was entered into on July 7, 2010 and was paid-in-full and terminated on January 20, 2011.

(2) The Broad Oak credit facility was paid-in-full and terminated on July 1, 2011 in connection with the Broad Oak acquisition.

During 2010 and 2009, we entered into certain variable-to-fixed interest rate derivatives that hedge our exposure to interest rate variations on our variable interest rate debt. At December 31, 2010, we had interest rate swaps and caps outstanding for a notional amount of $300.0 million with fixed pay rates ranging from 1.11% to 3.41% and terms expiring from June 2011 to September 2013 compared to outstanding swaps for a notional amount of $180.0 million with fixed pay rates ranging from 1.60% to 3.41% and terms expiring from June 2011 to June 2012 at December 31, 2009. During the year ended December 31, 2010, we realized a loss on interest rate derivatives of approximately $5.2 million compared to a realized loss of $3.8 million for the year ended December 31, 2009. Additionally, we recorded an unrealized loss on interest rate derivatives of approximately $0.1 million as of December 31, 2010 compared to an unrealized gain of $0.4 million at December 31, 2009. At December 31, 2010, the estimated fair value of our interest rate derivatives was in a net liability position of approximately $5.5 million compared to a net liability position of $5.6 million at December 31, 2009.

Income tax expense. We recorded a deferred income tax benefit of approximately $25.8 million for the year ended December 31, 2010, compared to a deferred income tax benefit of approximately $74.0 million for the year ended December 31, 2009. At December 31, 2009, we recognized a deferred income tax benefit for the impairment of our oil and gas properties of approximately $86.1 million.

Additionally, we recorded a valuation allowance of approximately $0.7 million against our Texas deferred tax asset at December 31, 2010, as we believe it is more likely than not that we will not realize a future benefit for the full amount of our Texas deferred tax asset. The estimated annual effective tax rate was 37% for the year ended December 31, 2010 and 35% for the year ended December 31, 2009. Our annual effective tax rate is based on our estimated annual permanent tax differences and estimated annual pre-tax book income. Our estimates involve assumptions we believe to be reasonable at the time of the estimation.

During the fourth quarter of 2010, we determined that it was more likely than not that the remaining federal net operating loss carry-forwards and net federal deferred assets would be realized. Consideration given included estimated future net cash flows from oil and gas reserves (including the timing of those cash flows) and the future tax effect of the deferred tax assets and liabilities recorded at December 31, 2010. As a result of this determination, the valuation allowance was released against the deferred tax assets, resulting in a decrease of the valuation allowance by approximately $47.9 million.

For the year ended December 31, 2009, we increased the valuation allowance against Broad Oak's net federal deferred tax asset by approximately $16.5 million and decreased the valuation allowance against Broad Oak's Louisiana deferred tax by approximately $0.1 million. We believed it was more likely than not that we would not realize a future benefit for the full amount of the federal and Louisiana net deferred tax asset as of December 31, 2009.

Liquidity and capital resources

Our primary sources of liquidity have been capital contributions from Warburg Pincus, certain members of our management and our board of directors, borrowings on our senior secured credit facility, proceeds from the 2019 senior unsecured notes and the 2022 senior unsecured notes, borrowings on the prior Broad Oak credit facility, borrowings on our prior term loan facility, proceeds from our IPO and cash flows from operations. Our primary use of capital has been for the exploration, development and acquisition of oil and gas properties. As we pursue reserves and production growth, we continually consider which capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future ability to grow proved reserves and production will be highly dependent on the capital resources available to us. We believe that we have significant liquidity available to us from cash flow from operations and on our senior secured credit facility for our planned exploration and development activities. In addition, our hedge positions currently provide relative certainty on a majority of our cash flows from operations through 2014 even with the general decline in the prices of natural gas.

At June 30, 2012, we had no debt outstanding and approximately $0.03 million of outstanding letters of credit on our senior secured credit facility. Additionally, we had $1.05 billion of outstanding senior unsecured notes, excluding the remaining premium of $1.9 million received on the October 2011 offering of our 2019 senior unsecured notes. We had approximately $785.0 million available for borrowings on our senior secured credit facility and $146.5 million in cash on hand for total available liquidity of approximately $931.5 million at June 30, 2012. We believe such availability as well as cash flows from operations provide us with the ability to implement our planned exploration and development activities.

As of September 30, 2012, we had approximately $50.0 million in outstanding borrowings on our senior secured credit facility and approximately $735.0 million available for borrowings.

We expect that, in the future, our commodity derivative positions will help us stabilize a portion of our expected cash flows from operations despite potential declines in the price of oil and gas. Please see "—Quantitative and qualitative disclosures about market risk" below.

Cash flows

Our cash flows for the six months ended June 30, 2012 and 2011 and the years ended December 31, 2011, 2010 and 2009 are as follows:

	Six months ended June 30,		Years ended December 31,		
(in thousands)	**2012**	**2011**	**2011**	**2010**	**2009**
Net cash provided by operating activities	$ 199,790	$ 162,058	$ 344,076	$ 157,043	$ 112,669
Net cash used in investing activities	(485,831)	(359,449)	(706,787)	(460,547)	(361,333)
Net cash provided by financing activities	404,524	188,208	359,478	319,752	250,139
Net increase (decrease) in cash	$ 118,483	$ (9,183)	$ (3,233)	$ 16,248	$ 1,475

Cash flows provided by operating activities

Net cash provided by operating activities was $199.8 million and $162.1 million for the six months ended June 30, 2012 and 2011, respectively. The increase of $37.7 million was largely due to increases in revenue due to increased production.

Net cash provided by operating activities was $344.1 million, $157.0 million and $112.7 million for the years ended December 31, 2011, 2010 and 2009, respectively. The increases of

$187.1 million from 2010 to 2011 and $44.3 million from 2009 to 2010 were largely due to significant increases in revenue due to our successful drilling program, as well as an increase in the market price for oil.

Our operating cash flows are sensitive to a number of variables, the most significant of which are production levels and the volatility of oil and gas prices. Regional and worldwide economic activity, weather, infrastructure, capacity to reach markets, costs of operations and other variable factors significantly impact the prices of these commodities. These factors are not within our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "—Quantitative and qualitative disclosures about market risk."

Cash flows used in investing activities

We used cash flows in investing activities of approximately $485.8 million and $359.4 million for the six months ended June 30, 2012 and 2011, respectively, which is an increase of $126.4 million. A portion of our capital expenditures for the six months ended June 30, 2012 reflects expenditures which were accrued for at December 31, 2011 as part of our 2011 capital budget, but due to the timing of when billings were received, were paid during the first quarter of 2012. Additionally, a significant portion of the increase was due to increasing our drilling efforts in our Permian Basin and Anadarko Granite Wash areas as we continue to explore and develop our identified potential drilling locations.

We used cash flows in investing activities of approximately $706.8 million, $460.5 million and $361.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. The increases of $246.3 million from 2010 to 2011 and $99.2 million from 2009 to 2010 are due to increasing our drilling efforts in our Permian Basin and Anadarko Granite Wash areas in order to take advantage of strategic vertical and horizontal drilling and improving commodity prices.

Our cash used in investing activities for capital expenditures for the six months ended June 30, 2012 and 2011 and the years ended December 31, 2011, 2010 and 2009 is summarized in the table below.

	Six months ended June 30,		Years ended December 31,		
(in thousands)	**2012**	**2011**	**2011**	**2010**	**2009**
Restricted cash	$ —	$ —	$ —	$ —	$ 2,201
Capital expenditures:					
Oil and gas properties	(473,846)	(348,523)	(687,062)	(454,161)	(340,636)
Pipeline and gathering assets	(7,031)	(6,344)	(13,368)	(4,277)	(19,995)
Other fixed assets	(4,988)	(4,602)	(6,413)	(2,198)	(3,071)
Proceeds from other asset disposals	34	20	56	89	168
Net cash used in investing activities	$ (485,831)	$ (359,449)	$ (706,787)	$ (460,547)	$ (361,333)

Capital expenditure budget

Our board of directors approved a budget of approximately $900 million for calendar year 2012, excluding acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

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

Cash flows provided by financing activities

We had cash flows provided by financing activities of $404.5 million and $188.2 million for the six months ended June 30, 2012 and 2011, respectively.

The increase in net cash provided by financing activities for the six months ended June 30, 2012 is the result of issuing our 2022 senior unsecured notes in an aggregate principal amount of $500 million in April 2012, which were offset by payments for loan costs totaling $10.5 million, as well as the net effect of payments and borrowings on our senior secured credit facility.

Net cash provided by financing activities for the six months ended June 30, 2011 was largely the result of our first issuance of 2019 senior unsecured notes in an aggregate principal amount of $350.0 million in January 2011 as well as net borrowings and payments on the former Broad Oak credit facility and our senior secured credit facility and the payment-in-full and termination of our $100.0 million term loan. Additionally, we incurred $10.6 million in loan costs for the six months ended June 30, 2011.

We had cash flows provided by financing activities of $359.5 million, $319.8 million and $250.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Net cash provided by financing activities for the year ended December 31, 2011 was primarily the result of $552.0 million in gross proceeds from the issuance of the 2019 senior unsecured notes of $350.0 million on January 20, 2011 and $202.0 million on October 11, 2011, net proceeds from our IPO of $319.4 million, net reductions of our senior secured credit facility and former Broad Oak credit facility totaling $306.6 million, the payment of $100.0 million to pay in full and terminate our term loan and payments of $23.2 million for loan costs. Additionally, we incurred approximately $82.0 million in debt to facilitate the Broad Oak acquisition.

For the year ended December 31, 2010, net cash from financing activities was the result of capital contributions from Warburg Pincus, certain members of our management and our independent directors totaling $85.0 million, net borrowings on our senior secured credit facility and former Broad Oak credit facility totaling $144.5 million and borrowings on our term loan of $100.0 million, all of which were offset by payments of $9.2 million for loan costs. Following the Corporate Reorganization, we no longer have any commitments from Warburg Pincus or others to contribute any capital to us.

For the year ended December 31, 2009, net cash from financing activities was primarily the result of capital contributions from Warburg Pincus, certain members of our management and our independent directors of approximately $154.6 million, borrowings on our senior secured credit facility of $75.0 million and net borrowings of approximately $23.5 million on the Broad Oak credit facility.

Debt

At June 30, 2012, we were a party only to our senior secured credit facility and the indentures governing our 2019 and 2022 senior unsecured notes. The Broad Oak credit facility was terminated on July 1, 2011 in connection with the Broad Oak acquisition. Our term loan facility was paid in full and retired in connection with the closing of the January 2011 offering of the 2019 senior unsecured notes.

Senior secured credit facility. Laredo Petroleum, Inc. is the borrower on our senior secured credit facility which has a capacity of up to $2.0 billion and a borrowing base of $785.0 million. Our senior secured credit facility will mature on July 1, 2016.

We have a choice of borrowing at an Adjusted Base Rate or in Eurodollars. Adjusted Base Rate loans bear interest at the Adjusted Base Rate plus an applicable margin between 0.75% and 1.75%, and Eurodollar loans bear interest at the adjusted London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.75% and 2.75%. At June 30, 2012, the applicable margin rates were 0.75% for the Adjusted Base Rate advances and 1.75% for the Eurodollar advances. We had no outstanding borrowings on our senior secured credit facility at June 30, 2012. We are also required to pay an annual commitment fee on the unused portion of the bank's commitment of 0.5%.

Our senior secured credit facility is secured by a first priority lien on our assets (including the stock of Laredo Petroleum Holdings, Inc.'s wholly-owned subsidiary, Laredo Petroleum, Inc.), including oil and natural gas properties constituting at least 80% of the present value of our proved reserves owned now or in the future. At June 30, 2012, we were subject to and in compliance with the following financial and non-financial ratios on a consolidated basis:

- a current ratio at the end of each fiscal quarter, as defined by the agreement, that is not permitted to be less than 1.00 to 1.00; and
- at the end of each fiscal quarter, the ratio of earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses and other non-cash charges ("EBITDAX") for the four fiscal quarters ending on the relevant date to the sum of net interest expense plus letter of credit fees, in each case for such period, is not permitted to be less than 2.50 to 1.00.

Our senior secured credit facility contains both financial and non-financial covenants. We were in compliance with these covenants at June 30, 2012 and December 31, 2011, 2010 and 2009. At September 30, 2009, we were in violation of our current ratio covenant. A covenant waiver was included in the fourth amended senior secured credit facility agreement dated November 5, 2009.

Our senior secured credit facility contains various covenants that limit our ability to:

- incur indebtedness;

- pay dividends and repay certain indebtedness;
- grant certain liens;
- merge or consolidate;
- engage in certain asset dispositions;
- use proceeds for any purpose other than to finance the acquisition, exploration and development of mineral interests and for working capital and general corporate purposes;
- make certain investments;
- enter into transactions with affiliates;
- engage in certain transactions that violate ERISA or the Internal Revenue Code or enter into certain employee benefit plans and transactions;
- enter into certain swap agreements or hedge transactions;
- incur, become or remain liable under any operating lease which would cause rentals payable to be greater than $10.0 million in a fiscal year;
- acquire all or substantially all of the assets or capital stock of any person, other than assets consisting of oil and natural gas properties and certain other oil and natural gas related acquisitions and investments; and
- repay or redeem our senior unsecured notes, or amend, modify or make any other change to any of the terms in our senior unsecured notes that would change the term, life, principal, rate or recurring fee, add call or pre-payment premiums, or shorten any interest periods.

As of June 30, 2012, we were in compliance with the terms of our senior secured credit facility. If an event of default exists under our senior secured credit facility, the lenders will be able to accelerate the maturity of our senior secured credit facility and exercise other rights and remedies. As of June 30, 2012, each of the following will be an event of default:

- failure to pay any principal of any note or any reimbursement obligation under any letter of credit when due or any interest, fees or other amount within certain grace periods;
- failure to perform or otherwise comply with the covenants in the senior secured credit facility and other loan documents, subject, in certain instances, to certain grace periods;
- a representation, warranty, certification or statement is proved to be incorrect in any material respect when made;
- failure to make any payment in respect of any other indebtedness in excess of $25.0 million, any event occurs that permits or causes the acceleration of any such indebtedness or any event of default or termination event under a hedge agreement occurs in which the net hedging obligation owed is greater than $25.0 million;
- voluntary or involuntary bankruptcy or insolvency events involving us or our subsidiaries and in the case of an involuntary proceeding, such proceeding remains undismissed and unstayed for the applicable grace period;

- one or more adverse judgments in excess of $25.0 million to the extent not covered by acceptable third party insurers, are rendered and are not satisfied, stayed or paid for the applicable grace period;
- incurring environmental liabilities which exceed $25.0 million to the extent not covered by acceptable third party insurers;
- the loan agreement or any other loan paper ceases to be in full force and effect, or is declared null and void, or is contested or challenged, or any lien ceases to be a valid, first priority, perfected lien;
- failure to cure any borrowing base deficiency in accordance with the senior secured credit facility;
- a change of control, as defined in our senior secured credit facility; and
- notification if an "event of default" shall occur under the indenture governing our senior unsecured notes.

Additionally, our senior secured credit facility provides for the issuance of letters of credit, limited in the aggregate to the lesser of $20.0 million and the total availability under the facility. At June 30, 2012, we had one letter of credit outstanding totaling approximately $0.03 million under our senior secured credit facility.

Subsequent to June 30, 2012, we borrowed $50.0 million on our senior secured credit facility on August 28, 2012. As of September 30, 2012, the outstanding balance on our senior secured credit facility was $50.0 million.

Refer to Note C of our audited consolidated financial statements included elsewhere in this prospectus and Note C of our unaudited consolidated financial statements included elsewhere in this prospectus for further discussion of our senior secured credit facility.

Termination of the Broad Oak credit facility. At June 30, 2011, Broad Oak had a $600.0 million revolving credit facility under its seventh amendment executed on February 1, 2011 between Broad Oak and certain financial institutions. Under the seventh amendment, the borrowing base was redetermined at $375.0 million. The borrowing base was subject to a semi-annual redetermination. The Broad Oak credit facility term extended to April 11, 2013, at which time the outstanding balance would have been due. As defined in the Broad Oak credit facility, the Adjusted Base Rate Advances and Eurodollar Advances on the facilities bore interest payable quarterly at an Adjusted Base Rate or Adjusted LIBOR plus an applicable margin based on the ratio of outstanding revolving credit to the conforming borrowing base. At June 30, 2011, the applicable margin rates were 1.50% for the Adjusted Base Rate advances and 2.50% for the Eurodollar advances. Additionally, Broad Oak was also required to pay a quarterly commitment fee of 0.5% on the unused portion of the bank's commitment.

The Broad Oak credit facility was secured by a first priority lien on Broad Oak's oil and gas properties.

Concurrently with the Broad Oak acquisition on July 1, 2011, the Broad Oak credit facility was paid in full and terminated. Refer to Note A of our audited consolidated financial statements included elsewhere in this prospectus for further discussion of the Broad Oak transaction.

As of December 31, 2010 and 2009, borrowings outstanding on the Broad Oak credit facility totaled approximately $214.1 million and $44.6 million, respectively.

Senior unsecured notes. On January 20, 2011 and October 19, 2011, Laredo Petroleum, Inc. completed the offerings of $350 million aggregate principal amount and $200 million aggregate principal amount, respectively, of $9^1/_2$% senior unsecured notes due 2019. The 2019 senior unsecured notes will mature on February 15, 2019 and bear an interest rate of $9^1/_2$% per annum, payable semi-annually, in cash in arrears on February 15 and August 15 of each year. The 2019 senior unsecured notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by Laredo Petroleum Holdings, Inc. and its subsidiaries (other than Laredo Petroleum, Inc.) (collectively, the "guarantors"). The 2019 senior unsecured notes were issued under and are governed by an indenture dated January 20, 2011, among Laredo Petroleum, Inc., Wells Fargo Bank, National Association, as trustee, and the guarantors (the "2011 indenture"). The 2011 indenture contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of dividends or similar restricted payments, entering into transactions with affiliates and limitations on asset sales. Indebtedness under the 2019 senior unsecured notes may be accelerated in certain circumstances upon an event of default as set forth in the 2011 indenture.

In connection with the issuance of the 2019 senior unsecured notes, Laredo Petroleum, Inc. and the guarantors party thereto entered into registration rights agreements with the initial purchasers of the 2019 senior unsecured notes and agreed to file with the SEC a registration statement with respect to an offer to exchange the 2019 senior unsecured notes for substantially identical notes (other than with respect to restrictions on transfer or to any increase in annual interest rate) that are registered under the Securities Act. The offer to exchange the 2019 senior unsecured notes for substantially identical notes registered under the Securities Act was consummated on January 13, 2012.

On April 27, 2012, Laredo Petroleum, Inc. completed an offering of $500 million aggregate principal amount of $7^3/_8$% senior unsecured notes due 2022. The 2022 senior unsecured notes will mature on May 1, 2022 and bear an interest rate of $7^3/_8$% per annum, payable semi-annually, in cash in arrears on May 1 and November 1 of each year, commencing November 1, 2012. The 2022 senior unsecured notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by Laredo Petroleum Holdings, Inc. and the guarantors. The 2022 senior unsecured notes were issued under and are governed by an indenture and supplement thereto, each dated April 27, 2012 (collectively, the "2012 indenture"), among Laredo Petroleum, Inc., Wells Fargo Bank, National Association, as trustee, and the guarantors. The 2012 indenture contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of dividends or similar restricted payments, entering into transactions with affiliates and limitations on asset sales. Indebtedness under our 2022 senior unsecured notes may be accelerated in certain circumstances upon an event of default as set forth in the 2012 indenture. The net proceeds from the 2022 senior unsecured notes were used (i) to pay in full the $280.0 million outstanding under our senior secured credit facility, and (ii) for general working capital purposes.

In connection with the issuance of the 2022 senior unsecured notes, Laredo Petroleum, Inc. and the guarantors party thereto entered into registration rights agreements with the initial purchasers of the 2022 senior unsecured notes and agreed to file with the SEC a registration statement with respect to an offer to exchange the 2022 senior unsecured notes for substantially identical notes (other than with respect to restrictions on transfer or to any increase in annual interest rate) that are registered under the Securities Act. The offer to exchange the 2022 senior unsecured notes for substantially identical notes registered under the Securities Act was consummated on August 1, 2012.

As of September 30, 2012, we had a total of $1.05 billion of senior unsecured notes outstanding. Refer to Note C of our audited consolidated financial statements and Note C of our unaudited consolidated financial statements included elsewhere in this prospectus for further discussion of the 2019 senior unsecured notes and the 2022 senior unsecured notes.

Obligations and commitments

At December 31, 2011, we had the following significant contractual obligations and commitments that will require capital resources:

					Payments due
(in thousands)	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**	**Total**
Senior secured credit facility(1)	$ —	$ —	$ 85,000	$ —	$ 85,000
Senior unsecured notes	52,250	104,500	104,500	680,625	941,875
Drilling rig commitments(2)	9,631	—	—	—	9,631
Derivative financial instruments(3)	6,218	13,215	240	—	19,673
Asset retirement obligations(4)	1,458	788	1,022	9,806	13,074
Office and equipment leases(5)	1,413	2,550	1,013	—	4,976
Total	$ 70,970	$ 121,053	$ 191,775	$ 690,431	$ 1,074,229

(1) Includes outstanding principal amount at December 31, 2011. This table does not include future commitment fees, interest expense or other fees on our senior secured credit facility because it is a floating rate instrument and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged. As of June 30, 2012, we had no outstanding borrowings on our senior secured credit facility due in 2016 as the balance was paid-in-full in April 2012 with the proceeds of the 2022 senior unsecured notes issuance.

(2) At December 31, 2011, we had several drilling rigs under term contracts which expire during 2012. Any other rig performing work for us is doing so on a well-by-well basis and therefore can be released without penalty at the conclusion of drilling on the current well. Therefore, drilling obligations on well-by-well rigs have not been included in the table above. The value in the table represents the gross amount that we are committed to pay. However, we will record our proportionate share based on our working interest in our audited consolidated financial statements as incurred. See Note J to our audited consolidated financial statements included elsewhere in this prospectus for additional discussion of our drilling contract commitments. As of June 30, 2012, our drilling rig commitments total approximately $35.8 million due to increased drilling activity in our Permian and Anadarko Granite Wash regions and are due within one year.

(3) Represents payments due for deferred premiums on our commodity hedging contracts. As of June 30, 2012, our deferred premiums total approximately $27.5 million. Refer to Note H to our audited consolidated financial statements and Note G to our unaudited consolidated financial statements included elsewhere in this prospectus for additional discussion of our deferred hedging premiums.

(4) Amounts represent our estimate of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. As of June 30, 2012, our asset retirement obligation totals approximately $15.9 million. See Note B to our audited consolidated financial statements and to our unaudited consolidated financial statements included elsewhere in this prospectus for further discussion of our asset retirement obligation.

(5) See Note J to our audited consolidated financial statements and Note I to our unaudited consolidated financial statements included elsewhere in this prospectus for a description of our lease obligations.

In addition to the obligations and commitments noted above, as of June 30, 2012, our contractual obligations included an addition of approximately $6.2 million for the estimated total liability payable for our performance unit awards as of June 30, 2012, which will be payable in December 2014.

Critical accounting policies and estimates

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

In management's opinion, the more significant reporting areas impacted by our judgments and estimates are the choice of accounting method for oil and natural gas activities, estimation of oil and natural gas reserve quantities and standardized measure of future net revenues, revenue recognition, impairment of oil and gas properties, asset retirement obligations, valuation of derivative financial instruments, valuation of stock-based compensation and performance unit compensation, and estimation of income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

Method of accounting for oil and natural gas properties

The accounting for our business is subject to special accounting rules that are unique to the oil and gas industry. There are two allowable methods of accounting for oil and gas business activities: the successful efforts method and the full cost method. We follow the full cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities.

Under the full cost method, capitalized costs are amortized on a composite unit of production method based on proved oil and gas reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly. Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and proved reserves, in which case a gain or loss is recognized. The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties, and otherwise if impairment has occurred.

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

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

Revenue recognition

Revenue from our interests in producing wells is recognized when the product is delivered, at which time the customer has taken title and assumed the risks and rewards of ownership and collectability is reasonably assured. The sales prices for oil and natural gas are adjusted for transportation and other related deductions. These deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these revenue deductions are adjusted to reflect actual charges based on third party documents. Since there is a ready market for oil and natural gas, we sell the majority of production soon after it is produced at various locations.

Impairment of oil and gas properties

We review the carrying value of our oil and gas properties under the full cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. For the year ended December 31, 2009, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues from our proved reserves, net of related income tax considerations, resulting in a write-down in the carrying value of oil and gas properties of $245.9 million. For the six months ended June 30, 2012 and the years ended December 31, 2011 and 2010, the result of the ceiling test concluded that the carrying amount of our oil and natural gas properties was significantly below the calculated ceiling test value and as such a write-down was not required. In calculating future net revenues, effective December 31, 2009, current prices are calculated as the average oil and gas prices during the preceding 12-month period prior to the end of the current reporting period, determined as the unweighted arithmetic average first-day-of- the-month prices for the prior 12-month period and costs used are those as of the end of the appropriate quarterly period.

Asset retirement obligations

In accordance with the Financial Accounting Standard Board's (the "FASB") authoritative guidance on asset retirement obligations ("ARO"), we record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and gas properties, this is the period in which the well is drilled or acquired. The ARO represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period and the capitalized cost is depreciated on the unit of production method. The accretion expense is recorded as a component of depreciation, depletion and amortization in our consolidated statement of operations.

We determine the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Included in the fair value calculation are assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Derivative financial instruments

We record all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. We have not designated any derivative instruments as hedges for accounting purposes and we do not enter into such instruments for speculative trading purposes. Realized gains and realized losses from the settlement of commodity derivative instruments and unrealized gains and unrealized losses from valuation changes in the remaining unsettled commodity derivative instruments are reported under "Non-operating income (expense)" in our consolidated statements of operations.

Stock-based compensation

Under the modified prospective accounting approach, we measure stock-based compensation expense at the grant date based on the fair value of an award and recognize the compensation expense on a straight-line basis over the service period, which is usually the vesting period. The fair value of the awards is based on the value of our common stock on the date of grant. The determination of the fair value of an award requires significant estimates and subjective judgments regarding, among other things, the appropriate option pricing model, the expected life of the award and forfeiture rate assumptions. Beginning in the first quarter of 2012, we utilized the Black-Scholes option pricing model to measure the fair value of stock options granted under our 2011 Omnibus Equity Incentive Plan. As there are inherent uncertainties related to these factors and our judgment in applying them to the fair value determinations, there is risk that the recorded stock compensation may not accurately reflect the amount ultimately earned by the employee. Refer to Note D to our audited consolidated financial statements and our unaudited consolidated financial statements included elsewhere in this prospectus for additional information regarding our equity and stock-based compensation.

Performance unit compensation

For performance unit awards issued to management in 2012, we utilized a Monte Carlo simulation prepared by an independent third party to determine the fair value of the awards at the date of grant and to re-measure the fair value at the end of each reporting period until settlement in accordance with GAAP. Due to the relatively short trading history for our stock, the volatility criteria utilized in the Monte Carlo simulation is based on the volatilities of a group of peer companies that have been determined to be most representative of our expected volatility. The performance unit awards are classified as liability awards as they have a combination of performance and service criteria and will be settled in cash at the end of the requisite service period based on the achievement of certain performance criteria. The liability and related compensation expense for each period for these awards is recognized by dividing the fair value of the total liability by the requisite service period and recording the pro rata share for the period for which service has already been provided. Compensation expense for the performance units is included in "General and administrative" expense in our consolidated statements of operations with the corresponding liability recorded in the "Other long-term liabilities" section of our consolidated balance sheet. As there are inherent uncertainties related to the factors and our judgment in applying them to the fair value determinations, there is risk that the recorded performance unit compensation may not accurately reflect the amount ultimately earned by the member of management.

Income taxes

At June 30, 2012 and December 31, 2011, 2010 and 2009, we had deferred tax assets of $64.9 million, $95.6 million, $155.0 million and $129.1 million, respectively. At December 31, 2009, our deferred tax asset included a valuation allowance of approximately $48.6 million, of which $47.9 million was subsequently reversed in the fourth quarter of 2010.

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

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

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

During the first six months of 2012 and in 2011, in evaluating whether it was more-likely-than-not that our deferred tax asset was recoverable from future net income, we considered that in both 2008 and 2009, we had net operating losses due to impairment expense recognized largely as a result of lower oil and natural gas prices experienced during the economic downturn, which led to a full cost ceiling impairment recognized in both 2008 and 2009. Additionally, we considered our strong earnings history exclusive of the loss that created the future temporary difference, and that while a full cost ceiling impairment is possible in the future, we do not believe the impairments recorded in 2008 and 2009 are indicative of future full cost impairments based on the following: (i) the book basis of our oil and gas assets at June 30, 2012 and December 31, 2011, (ii) the net basis differences in our oil and gas properties represented by a net deferred tax liability at June 30, 2012 and December 31, 2011, and (iii) our full cost ceiling cushion at June 30, 2012 and December 31, 2011. We believe it is proper and meaningful when analyzing the negative evidence of our historic three-year results to adjust for items that cannot be expected to occur on a similar basis during the future period allowed to recover the deferred tax asset, such as our full cost impairments noted above. We believe the adjusted three-year results provide less negative evidence than that presented by the unadjusted cumulative losses.

We also determined through our analysis that our net operating loss carryforward deferred tax asset was recoverable over future years and that we had no material net operating losses expiring prior to 2026. In performing our analysis, we used inputs from third party sources, which came primarily from our reserve reports that were independently estimated by a third party engineer as well as future market pricing as determined by the New York Mercantile Exchange. Based on our forecasted results from multiple analyses, at June 30, 2012, December 31, 2011 and 2010, future taxable income from our oil and gas reserves is expected to be sufficient to utilize the entire net operating loss carryforward in approximately six to eight years. We believe this analysis provides significant positive evidence that is objectively verifiable, as it uses three-year historical operating results to predict future taxable income. We considered all applicable tax deductions in our analysis which were substantially known and were not subject to significant estimates. Based on this, we determined in the fourth quarter of 2010 that given the proper weight of the positive evidence noted above as compared to the negative evidence of our cumulative net losses, it was more-likely-than-not that our deferred tax asset would be recovered.

We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. If our assumptions regarding forecasted production, pricing and margins are not achieved by amounts in excess of our sensitivity analysis, it may have a significant impact on the corresponding taxable income which may require a valuation allowance to be recorded against our deferred tax assets at that time.

See Note B to our audited consolidated financial statements and our unaudited consolidated financial statements included elsewhere in this prospectus for a discussion of additional accounting policies and estimates made by management.

Recent accounting pronouncements

In December 2011, the FASB issued Accounting Standards Update ("ASU") 2011-11, *Disclosures about Offsetting Assets and Liabilities,* which requires disclosure of both gross information and net information about derivative instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to master netting arrangements. This information will enable users of an entity's financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments within the scope of the update.

The update is effective for annual periods beginning on or after January 1, 2013, and interim periods within those annual periods and is to be applied retrospectively for all comparative periods presented. We do not expect the adoption of this ASU to have a material effect on our financial statements.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the period from December 31, 2009 through the six months ended June 30, 2012. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the United States economy, and we do experience inflationary pressure on the costs of oilfield services and equipment as drilling activity increases in the areas in which we operate.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements other than operating leases, which are included in "—Obligations and commitments."

Quantitative and qualitative disclosures about market risk

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

Commodity price exposure. For a discussion of how we use financial commodity put, collar, swap and basis swap contracts to mitigate some of the potential negative impact on our cash flow caused by changes in oil and gas prices, see "—Hedging."

Interest rate risk. As part of our senior secured credit facility, we have debt which bears interest at a floating rate. At June 30, 2012, we had no indebtedness outstanding on our senior secured credit facility.

Through interest rate derivative contracts, we have attempted to mitigate our exposure to changes in interest rates. We have entered into various fixed interest rate swap and cap agreements which hedge our exposure to interest rate variations on our senior secured credit facility. At June 30, 2012, we had one interest rate swap and one interest rate cap outstanding for a notional amount of $100.0 million with fixed pay rates ranging from 1.11% to 3.00% and terms expiring in September 2013.

Counterparty and customer credit risk. Our principal exposures to credit risk are through receivables resulting from derivatives contracts (approximately $33.4 million at June 30, 2012), joint interest receivables (approximately $31.1 million at June 30, 2012) and the receivables from the sale of our oil and natural gas production (approximately $38.9 million at June 30, 2012), which we market to energy marketing companies and refineries.

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control who participates in our wells. Refer to Note I of our audited consolidated financial statements included elsewhere in this prospectus for additional disclosures regarding credit risk.

Business

Overview

We are an independent energy company focused on the exploration, development and acquisition of oil and natural gas primarily in the Permian and Mid-Continent regions of the United States. The oil and liquids-rich Permian Basin in West Texas and the liquids-rich Anadarko Granite Wash in the Texas Panhandle and Western Oklahoma are characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. As of June 30, 2012, we have assembled 188,014 net acres in the Permian Basin and 37,924 net acres in the Anadarko Granite Wash.

Our primary exploration and production fairway in the Permian Basin is centered on the eastern side of the basin approximately 35 miles east of Midland, Texas and extends approximately 20 miles wide (east/west) and 80 miles long (north/south) in Glasscock, Howard, Reagan and Sterling Counties, and is referred to in this prospectus as the "Permian-Garden City" area. As of June 30, 2012, we held 142,274 net acres in more than 300 sections in the Permian-Garden City area, with an average working interest of approximately 94% in all 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 four identified shale zones targeted for horizontal drilling (Upper, Middle and Lower Wolfcamp and Cline shales). Through September 17, 2012, we have drilled and completed 49 horizontal wells in these four horizontal target zones. We have completed 33 horizontal Cline wells and 14 horizontal Upper Wolfcamp wells. Our recent horizontal activity has moved toward drilling longer laterals (up to 7,500 feet) and increased frac density (up to 28 stages) as we continue the optimization of our completion techniques. Through September 2012, we have completed nine horizontal Cline wells and ten horizontal Upper Wolfcamp wells which have at least 30 days of production history. The average 30-day IP per stage of fracture stimulation for the nine horizontal Cline wells is 31 BOE/D per stage. The average 30-day IP per stage of fracture stimulation for the ten horizontal Upper Wolfcamp wells is approximately 30 BOE/D per stage. Additionally, we have completed one horizontal well in each of the Middle and Lower Wolfcamp zones. The one Middle Wolfcamp well that we have completed has a 30-day IP per stage of fracture stimulation of 36 BOE/D. We are still drilling our second Middle Wolfcamp horizontal well. Our first horizontal Lower Wolfcamp well is producing oil but does not have 30 days of production. Based on our technical data and well performance, we believe we have to date confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 50% and 45%, respectively, of our Permian-Garden City acreage. Going forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage, as reflected in our 2012 capital drilling budget allocation. As a result, we expect our Permian-Garden City acreage will be the primary driver of our reserves, production and cash flow growth for the foreseeable future.

Our Anadarko Granite Wash play extends within a large area in the western part of the Anadarko Basin in Hemphill County, Texas and Roger Mills County, Oklahoma. Currently, we are drilling horizontal opportunities targeting the liquids-rich Granite Wash formation. The Granite

Wash is a conventional play requiring precise drilling techniques to ensure maximum production per well.

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, many of whom have worked together for a decade or more. Prior to founding Laredo, Mr. Foutch and members of our management team successfully formed, built and sold three private oil and gas companies, all of which were focused on the same general areas of the Permian and Mid-Continent regions in which Laredo currently operates. All of these companies executed the same fundamental business strategy employed by Laredo in the same general operating areas and created significant growth in reserves, production and cash flow.

Since our inception, we have rapidly grown our reserves, production and cash flow through both our drilling program and strategic acquisitions, as evidenced by our July 2011 acquisition of Broad Oak. Our net proved reserves were estimated at 156,453 MBOE as of December 31, 2011, of which 40% were classified as proved developed and 36% as oil. 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. Unless otherwise specifically identified in this prospectus, the information presented with respect to our estimated proved reserves 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 average daily production for the six months ended June 30, 2012 was 29,690 BOE/D, 41% of which was oil and 59% 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 and, to a lesser extent, liquids-rich opportunities in the Anadarko Granite Wash.

In 2012, more emphasis has been placed on our horizontal drilling program than in prior periods. Approximately 85% of our planned drilling capital for 2012 will be invested in the Permian Basin, and we are increasingly allocating it towards our horizontal drilling activity. As of September 17, 2012, we had completed 49 gross horizontal Wolfcamp and Cline shale wells in the Permian and 21 gross horizontal Granite Wash wells. The horizontal drilling program comprises an extensive, multi-year, multiple-zone inventory of exploratory and development opportunities.

We maintain a financial profile that enables operational flexibility. At June 30, 2012, we had approximately $785 million available for borrowings on our senior secured credit facility and total debt of approximately $1.05 billion. Our total debt, less available cash, was approximately $905 million, or approximately 2.0 times our annualized Adjusted EBITDA (a non-GAAP financial measure) for the first six months of 2012. We use derivative financial instruments 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 believe that our operating cash flow and the aforementioned liquidity sources provide us with the ability to implement our planned exploration and development activities. As of September 30, 2012, we had $50 million outstanding on our senior secured credit facility.

In December 2011, we completed a Corporate Reorganization and IPO. See "—Corporate history and structure."

The following table summarizes our net acreage and producing wells as of June 30, 2012, total estimated net proved reserves as of December 31, 2011, and average daily production for the six months ended June 30, 2012 in our principal operating regions. Based on estimates in the report prepared by Ryder Scott, we operate wells that represent approximately 97% of the value of our proved developed oil and natural gas reserves as of December 31, 2011. In addition, the table shows our gross identified potential drilling locations and our proved undeveloped locations as of December 31, 2011.

	At December 31, 2011					Six months ended June 30, 2012	At June 30, 2012		
	Estimated net proved reserves(1)(2)			Identified potential drilling locations(4)		average daily production(6)		Producing wells	
	MBOE(3)	% of total reserves	% Oil	Total	PUD locations(5)	(BOE/D)	Net acreage	Gross	Net
Permian Basin									
Permian—Garden City	101,441	65%	52%	5,669	872	19,316	142,274	759	713
Permian—Other	—			—	—	—	45,740	—	—
Anadarko Granite Wash	45,101	29%	8%	335	207	7,931	37,924	184	138
Other Areas(7)	9,911	6%	3%	—	—	2,443	71,550	347	174
New Ventures(8)	—	—		—	—	—	106,788	1	1
Total	156,453	100%	36%	6,004	1,079	29,690	404,276	1,291	1,026

(1) Our estimated net proved reserves were prepared by Ryder Scott as of December 31, 2011 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 twelve-month index prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the applicable twelve-month period), held constant throughout the life of the properties. The reference prices were $92.71/Bbl for oil and $3.99/MMBtu for natural gas for the twelve months ended December 31, 2011.

(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, 2011 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 prices were $7.48/Mcf in the Permian area and $4.88/Mcf in the Anadarko Granite Wash area.

(3) MBbl equivalents ("MBOE") are calculated using a conversion rate of six MMcf per one MBbl.

(4) See the Glossary of Oil and Natural Gas Terms for the definition of "identified potential drilling locations" and below for more information regarding the processes and criteria through which these potential drilling locations were identified.

(5) Represents the number of identified potential drilling locations to which proved undeveloped reserves are attributable.

(6) 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.

(7) Includes our acreage in the gas prone Eastern Anadarko (26,929 net acres) and Central Texas Panhandle (44,621 net acres).

(8) Includes 99,144 net acres in the Dalhart Basin, which is an exploration effort targeting liquids-rich formations that are less than 7,000 feet in depth, and 7,643 net acres in other New Ventures. See "—New ventures."

At September 17, 2012, we had a total of 14 operated drilling rigs working. Ten of these rigs were working on our properties in the Permian Basin, six drilling vertical wells and four drilling horizontal wells. Three rigs were working on our properties in the Anadarko Granite Wash, all drilling horizontal wells. One rig was drilling an exploratory well in our New Ventures.

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. Our drilling programs are focused primarily on horizontal drilling in the Permian Basin and, to a lesser extent, the Anadarko Granite Wash.

In the drilling and development of hydrocarbon reserves, there are three key factors that can have an effect on our objective of establishing commercial production. In addition to the data collected and the wells we have drilled, each of these factors must be addressed in order to reduce the risk and uncertainty associated with (or "de-risk") our exploration and development program:

- Does the prospective reservoir underlie our acreage position?
- Are the petrophysics of the reservoir rock such that it contains hydrocarbons that can be recovered?
- Can the hydrocarbons be produced on a commercial basis?

We carefully assess and monitor all three 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 Anadarko Basin may extend back approximately 50 years and in the Permian Basin 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 recovered. As more wells are completed in the targeted reservoir and additional data becomes available, the process is further refined (and further de-risked) at which time we can begin to implement a development plan for the area in order to minimize costs and maximize recoveries (as we are doing for our Permian-Garden City acreage).

In the Permian Basin, the vertical 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 will now be centered in bringing forward the upside potential in the Wolfcamp and Cline shales in the remainder of our Permian 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 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 has allowed us to define the 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.

In the Anadarko Basin, the Granite Wash horizontal potential locations have been identified through a series of detailed maps which we have internally generated based on an extensive geological and engineering database. Information incorporated into this process includes both our own proprietary information as well as industry data available in the public domain. Specifically, open-hole logging data, production statistics from operated and non-operated wells, and petrophysical data describing the reservoir rock as derived from cores we recovered during our drilling operations have been captured and worked.

In both the Permian and Anadarko drilling programs, the timing of drilling the identified potential drilling locations will be influenced by several factors, including commodity prices, capital requirements, RRC well-spacing requirements and the continuation of the positive results from our ongoing development drilling program.

Utilizing the factors noted above, as of December 31, 2011, we had identified approximately 6,000 gross potential drilling locations on our acreage, with more than 5,600 in the Permian-Garden City area. As we have continued to de-risk our acreage in 2012, we have begun implementing a drilling plan that focuses our drilling program on horizontal wells and is also concentrated on optimizing resource recoveries and production through the drilling of longer laterals where possible. As we continue to de-risk our acreage and implement this plan, the number of potential locations will change based on the economics of each horizontal play. This will be the case for both our development program in the Permian-Garden City area (considered a resource play) and in the Anadarko Basin for Granite Wash (a conventional play). We expect that the focus of the drilling programs in both the Permian-Garden City area and Anadarko Granite Wash will be on horizontal exploration and development.

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. We have an inventory of approximately 6,000 identified potential drilling locations as of December 31, 2011. As of June 30, 2012, such locations are on 142,274 net acres in the Permian-Garden City area and 37,924 net acres in the Anadarko Granite Wash. We believe this inventory will support consistent, predictable, annual growth in reserves, production and cash flow.

Implement a development plan for our Permian-Garden City acreage. We expect our Permian-Garden City acreage will be the primary driver of our reserves, production and cash flow growth for the foreseeable future. As a result of our technical data and the performance of our 33 horizontal Cline wells and 14 horizontal Upper Wolfcamp wells, we believe we have confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 50% and 45%, respectively, of our Permian-Garden City acreage. We further believe this de-risked acreage position (as described below) provides a multi-year development inventory to support consistent growth of reserves and production. This enables us to create a plan to systematically and efficiently develop this acreage position as a resource play. Our future implementation plan will provide flexibility to include potential development of the Middle and Lower Wolfcamp zones as we continue to further de-risk these zones and our remaining Permian-Garden City acreage. Going forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage position, as reflected in our 2012 capital budget allocation.

Capitalize on technical expertise. We intend to leverage our operating and technical expertise to further delineate our core acreage positions. Through the utilization of an extensive technical petrophysical database, a vertical drilling program covering a majority of our core acreage position, and a number of horizontal tests to date, primarily in the Upper Wolfcamp and Cline shales in the Permian-Garden City area, we believe we have de-risked a significant portion of such acreage.

We intend to continue to make substantial 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 emphasizing our horizontal program, we can increase the efficiency of our resource recovery in the multiple vertically stacked producing horizons on our acreage in both our Permian and Anadarko Granite Wash plays. We are drilling longer laterals with increased density of frac stages 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. 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. Operational control 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. Laredo is the operator of our joint ventures, having drilled 24 wells under the ExxonMobil joint venture and 130 wells under the Linn Energy joint venture as of September 17, 2012.

Evaluate and pursue value-enhancing acquisitions, mergers and joint ventures. While we believe our multi-year inventory of identified potential drilling locations provides us with significant growth opportunities, we will continue to evaluate strategically compelling asset acquisitions, mergers and joint ventures. Any transaction we pursue will either generally complement our asset base or provide an anticipated competitive economic proposition relative to our existing opportunities or market conditions. Our Laredo-operated joint ventures with ExxonMobil and Linn Energy, our 2008 acquisition of properties from Linn Energy and our 2011 acquisition of Broad Oak are examples of this strategy.

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 significant upfront investment in research and development as well as data acquisition, owning and operating our natural gas gathering systems with 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 formation in 2006 through September 17, 2012, we have completed more than 700 gross vertical and 51 gross horizontal wells with a success rate of approximately 99%. Based on this drilling success, coupled with our technical data, we have confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 70,000 and 60,000 acres, respectively, of our Permian Basin acreage and are working to de-risk the remaining acreage and zones. As of December 31, 2011, we had identified approximately 5,600 gross potential drilling locations in the Permian-Garden City area, in addition to the 335 gross potential locations in our Anadarko Granite Wash acreage which we believe have been significantly de-risked through our focus on data-rich, mature producing basins with well studied geology, past drilling activity, engineering practices and concentrated operations, combined with our use of new technologies. We believe these potential locations provide a multi-year drilling inventory supporting future growth in reserves, production and cash flow.

Extensive 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 exploration and development programs. We have a large library of data that is applicable to our acreage base that includes approximately 740 square miles of 3D seismic data, 130 proprietary petrophysical logs and more than 13,500 historical open-hole logs. On our Permian-Garden City acreage, we have 10 whole cores and more than 300 sidewall cores in our four horizontal target zones. We have correlated this data across our Permian-Garden City acreage with more than 700 gross vertical and 51 gross horizontal wells. Our management team has extensive industry experience. Each of Mr. Foutch's previous companies focused on the same general areas of the Permian and Anadarko Basins in which Laredo currently operates. Most members of our senior management team have more than twenty years of experience and knowledge directly associated with our current primary operating areas. As of September 17, 2012, approximately 50% of our full-time staff are experienced technical employees, including 24 engineers, 16 geoscientists, 17 landmen and 46 technical support staff.

Significant operational control. We operate wells that represent approximately 97% of the value of our proved developed reserves as of December 31, 2011, 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 identified potential drilling locations.

Owned gathering infrastructure. Our wholly-owned subsidiary, Laredo Gas Services, LLC, has invested approximately $64 million in more than 270 miles of pipeline in our natural gas gathering systems in the Permian and Anadarko Basins as of June 30, 2012. These systems and flow lines provide greater operational efficiency and lower differentials for our natural gas production in our liquids-rich Permian and Anadarko Granite Wash plays 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 interconnecting pipelines, potentially minimizing the risks both of shut-ins awaiting pipeline connection and curtailment by downstream pipelines.

Financial strength and flexibility. We maintain a financial profile that enables operational flexibility. At June 30, 2012, we had approximately $785 million available for borrowings on our senior secured credit facility and total debt of approximately $1.05 billion. Our total debt, less available cash, was approximately $905 million, or approximately 2.0 times our annualized Adjusted EBITDA (a non-GAAP financial measure) for the first six months of 2012. We also use derivative financial instruments 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 believe that our operating cash flow and the aforementioned liquidity sources provide us with the ability to implement our planned exploration and development activities. As of September 30, 2012, we had $50 million outstanding on our senior secured credit facility.

Strong institutional investor support and corporate governance. Our institutional investor, 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. Warburg Pincus did not sell shares of our common stock in the IPO and after this offering will retain a majority interest in Laredo. In addition to the support we receive from Warburg Pincus, we also believe that our board of directors is well qualified and represents a meaningful resource. Our board, which is comprised of Laredo management and representatives of Warburg Pincus as well as independent individuals, has extensive oil and 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.

Focus areas

We focus on developing a balanced inventory of quality drilling opportunities that provide us with the operational flexibility to economically develop and produce oil and natural gas reserves from conventional and unconventional formations. Our properties are currently located in the prolific Permian and Mid-Continent regions 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.

Permian Basin

The oil and liquids-rich Permian Basin, located in West Texas and Southeastern New Mexico, where we have assembled 188,014 net acres as of June 30, 2012, is one of the most prolific 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 exploration fairway (Permian-Garden City) is centered on the eastern side of the basin approximately 35 miles east of Midland, Texas and extends approximately 20 miles wide (east/west) and 80 miles long (north/south) in Howard, Glasscock, Reagan, and Sterling Counties. As of June 30, 2012, we held 142,274 net acres in more than 300 sections in the Permian-Garden City area with an average working interest of approximately 94% in all producing wells drilled to such date.

Through December 2011, our drilling efforts were primarily defined by a vertical Wolfberry program, supplemented with horizontal wells in select intervals. Our drilling focus has evolved into a horizontal exploitation/exploration program supported by vertical wells that help us define the horizontal targets. We believe that our acreage in the Permian-Garden City area is highly prospective in both the Wolfcamp and Cline shale formations. Within the Wolfcamp, we have defined three distinct zones; the Upper, Middle and Lower Wolfcamp shales, which together with the Cline shale provide four horizontal targets.

Our proprietary and industry data includes 740 square miles of 3D seismic, 10 whole and more than 300 sidewall cores, 23 single-zone tests, more than 130 proprietary petrophysical logs, greater than 13,500 open-hole logs, and 51 completed horizontal wells providing production and reservoir engineering data as of September 17, 2012. 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 shale plays.

The Cline shale

As of September 2012, we estimate that approximately 70,000 net acres of our Permian-Garden City area have been de-risked for horizontal Cline development.

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 2010. We are moving into the horizontal development phase of this identified acreage. We believe the petrophysical data indicates this is a repeatable economic resource play, and we continue to delineate and define the Cline potential on our Permian-Garden City acreage. Industry activity relative to the Cline shale has also been initiated with several horizontal wells having recently been drilled and/or permitted immediately north and east of our Permian-Garden City acreage position.

The Cline shale is encountered at a depth of approximately 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 over 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. In the Cline shale, we are able to divide our acreage into two north-south elongated areas (pods), the western pod and the eastern pod, representing approximately 76% and 24%, respectively, of our Permian-Garden City acreage. The western pod is basin-ward and where we have extensive petrophysical data and have drilled a majority of our 33 horizontal Cline wells. We are moving into the development stage in the northern portion of the western pod, representing approximately 70% of the western pod acreage, and gradually transitioning into pre-development as one moves south on the remaining approximate 30% of this acreage. We are continuing to delineate and define the southern portion of this acreage through additional horizontal wells anticipated to be drilled in 2012 and early 2013.

The eastern pod is located toward the basin's eastern shelf and requires additional data collection and analysis in order for us to further evaluate its potential.

The Wolfcamp shale

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, it appears that all three Wolfcamp zones share many similar petrophysical attributes that define a shale resource play.

Historically, our drilling efforts have been primarily focused on the Upper Wolfcamp (14 horizontal wells completed as of September 17, 2012) with one additional horizontal well having been successfully drilled, completed and tested in each of the Middle and Lower Wolfcamp zones. The early production results from both of these wells appear comparable to our Upper Wolfcamp completions.

Upper Wolfcamp. As of September 2012, we estimate that approximately 60,000 net acres of our Permian-Garden City area have 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. As a result of the facies change, our acreage can be divided into two areas (or pods); the western pod is in various stages of development or pre-development, while the eastern pod is still in an exploration stage. Approximately 76% of our Permian-Garden City acreage is located to the west of this facies change and exhibits petrophysical characteristics that appear suitable for a systematic, repeatable horizontal development program. The portion of our Upper Wolfcamp drilling program that is now entering the development stage (representing approximately 60% of our acreage in the western pod) starts in the southern end of our acreage position and grades northward into a pre-development status.

Approximately 24% of our net acreage position in the Permian-Garden City area is located east of this Upper Wolfcamp facies demarcation line. Additional vertical and horizontal drilling and petrophysical analysis will be required to further evaluate the effect of the Wolfcamp interval transitioning into a more carbonate zone relative to the development potential of these zones.

Middle and Lower Wolfcamp. In the Middle and Lower Wolfcamp, we are early in the evaluation of 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 facies change (predominantly from shale to increasingly carbonate) moving from west to east, which will require more data and analysis for us to evaluate the significance of this lithological change. We have completed one horizontal well in each of these zones, and while initial results from both wells are encouraging, additional production time and further drilling in both zones will be needed in order to confirm the commercial development potential.

Anadarko Granite Wash

Straddling the Texas/Oklahoma state line, our Granite Wash play extends across a large area in the western part of the Anadarko Basin. As of June 30, 2012, we held 37,924 net acres in Hemphill County, Texas and Roger Mills County, Oklahoma. Currently, we are drilling only horizontal opportunities targeting the liquids-rich Granite Wash formation. By utilizing the whole core data we obtained early in the exploration process, the subsurface information from our vertical wells (and others drilled by industry), and enhanced logging interpretation techniques, we have been able to develop a detailed regional geologic depositional and engineering understanding of the Granite Wash.

Several of the targeted intervals in the Granite Wash are now being developed in a repeatable economic drilling program. The Granite Wash is a conventional play that requires drilling to be done "surgically" to insure that each lateral penetrates the maximum amount of pay in each defined porosity fairway. We continue our exploration efforts by defining additional porosity trends in both deeper and shallower Granite Wash zones, utilizing our large open-hole log database and in-house petrophysical expertise. At December 31, 2011, we believe there are a total of 335 gross potential locations in Texas and Oklahoma, which constitutes several years of drilling utilizing three rigs. As of September 17, 2012, we have identified 14 distinct Granite Wash porosity trends of which six have been tested and de-risked.

Other areas

As of June 30, 2012, we held 44,621 net acres in the Central Texas Panhandle where our operations are currently conducted through our joint venture with ExxonMobil. The prospective zones in this area are relatively shallow (less than 9,500 feet), with a majority being predominately natural gas.

As of June 30, 2012, we held 26,929 net acres in the eastern end of the Anadarko Basin, in Caddo County, Oklahoma. There are multiple targets to drill in this area, varying in depth between 8,000 feet and 22,000 feet, which are predominantly dry natural gas. Although our economic metrics require higher natural gas prices to justify additional drilling, the area could play a meaningful role in our future if natural gas prices increase.

These areas, which we refer to as our "Other Areas" and represent 8% of our six months ended June 30, 2012 production and 6% of our estimated proved reserves as of December 31, 2011, may become more compelling in the future if natural gas prices increase.

New ventures

In addition to our Permian and Anadarko Granite Wash plays, 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. As of June 30, 2012, we held 99,144 net acres in the Dalhart Basin. Our current exploration activity in this area is concentrated around liquids-rich shale plays that may underlie a significant portion of the entire area. Targeted intervals are considered oil plays at depths of less than 7,000 feet. As of September 17, 2012, we have drilled three gross vertical wells in the Dalhart Basin.

In addition, as of June 30, 2012, we held 7,643 net acres in other New Venture areas within our core operating regions.

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. Unless otherwise specifically identified in this prospectus, 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 156,453 MBOE as of December 31, 2011, of which 40% were classified as proved developed and 36% as oil. The following table presents summary data for each of our core operating areas as of December 31, 2011. Our estimated proved reserves at December 31, 2011 assume our ability to fund the capital costs necessary for their development and are impacted 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 "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".

	At December 31, 2011 Proved Reserves (MBOE)(1)	% of Total
Area:		
Permian Basin	101,441	65%
Anadarko Granite Wash	45,101	29%
Other Areas(2)	9,911	6%
Total	156,453	100%

(1) MBbl equivalents ("MBOE") are calculated using a conversion rate of six MMcf per one MBbl.

(2) Includes Eastern Anadarko and Central Texas Panhandle.

The following table sets forth more information regarding our estimated proved reserves at December 31, 2011 and 2010. Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves at December 31, 2010 and December 31, 2011. The reserve estimates at December 31, 2011 and 2010 were prepared in accordance with the SEC's rules regarding oil and natural gas reserve reporting currently in effect. The information in the following table does not give any effect to our commodity hedges.

	At December 31,	
	2011	2010
Estimated proved reserves:		
Oil and condensate (MBbl)	56,267	44,847
Natural gas (MMCF)	601,117	550,278
Total estimated proved reserves (MBOE)(1)	156,453	136,560
Proved developed producing (MBOE)(1)	59,631	39,300
Proved developed non-producing (MBOE)(1)	3,564	5,533
Proved undeveloped (MBOE)(1)	93,258	91,727
Percent developed	40%	33%

(1) MBbl equivalents ("MBOE") are calculated using a conversion rate of six MMcf per one MBbl.

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, 2011 and 2010 included in this prospectus. 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.

John E. Minton, our Senior Vice President of Reservoir Engineering, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. He has more than 38 years of practical experience with 34 years of this experience being in the estimation and evaluation of reserves. He has been a registered Professional Engineer in the State of Oklahoma since 1982. He has a Bachelor of Science degree in Mechanical Engineering and is a life member in good standing of the Society of Petroleum Engineers. Mr. Minton reports directly to our President and Chief Operating Officer. Reserve 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' reserve estimates and related reports with our senior reservoir engineering staff and other members of our technical staff.

Proved undeveloped reserves

Our proved undeveloped reserves increased from 91,727 MBOE at December 31, 2010 to 93,258 MBOE at December 31, 2011. 22,844 MBOE of proved undeveloped reserves were added during the year, (i) 15,009 MBOE of which were added from 155 wells in the Permian Basin that were previously unproved locations, but were proved up by drilling offset locations during the year and (ii) 7,835 MBOE of which were added from 47 wells in the Anadarko Granite Wash that became economic based on updated mapping of expected reserves. During 2011, 10,704 MBOE of proved undeveloped reserves were converted to proved developed reserves as a result of drilling 147 locations at a total net cost of approximately $259 million. 142 of these locations were in the Permian Basin and five were in the Anadarko Basin. Negative revisions of 10,609 MBOE of proved undeveloped reserves during 2011 were primarily the result of removing potential Permian Basin and Anadarko Basin locations. Our anticipated capital costs for directionally drilling or obtaining additional surface locations increased for 33 vertical wells in our Anadarko Granite Wash play, making these locations uneconomic to drill at current gas prices. We also decided to drill 149 Permian Basin locations (with proved reserves through the upper Wolfcamp zone) deeper into the non-proved lower Wolfcamp through Atoka zones. The additional capital costs to drill these wells deeper, based on the shallow proved reserves only, made these locations uneconomic as proved locations. During 2011, we drilled 19 wells to test the deeper, unproved horizons, and such testing indicates these zones, combined with the shallower uphole zones, could result in economic completions.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2011 reserve report are $1.9 billion. Based on this report, the capital estimated to be spent in 2012, 2013, 2014, 2015 and 2016 to develop the proved undeveloped reserves is $202 million, $395 million, $529 million, $702 million and $35 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 six months ended June 30, 2012 and 2011 and for the years ended December 31, 2011, 2010 and 2009. 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 information set forth in "Management's discussion and analysis of financial condition and results of operations."

	For the six months ended June 30,		For the years ended December 31,		
	2012	**2011**	**2011**	**2010**	**2009**
Production data:					
Oil (MBbls)	2,231	1,517	3,368	1,648	513
Natural gas (MMcf)	19,034	14,866	31,711	21,381	18,302
Oil equivalents (MBOE)(1)(2)	5,404	3,995	8,654	5,212	3,563
Average daily production (BOE/D)	29,690	20,070	23,709	14,278	9,762
Revenues (in thousands):					
Oil	$ 203,529	$ 143,464	$ 306,481	$ 126,891	$ 29,946
Natural gas	85,031	93,068	199,774	112,892	64,401
Average sales prices without hedges:					
Benchmark oil ($/Bbl)(3)	$ 98.10	$ 98.08	$ 95.01	$ 79.53	$ 61.79
Realized oil ($/Bbl)(4)	91.23	94.57	91.00	77.00	58.37
Benchmark natural gas ($/MMBtu)(3)	2.36	4.35	4.02	4.39	3.98
Realized natural gas ($/Mcf)(4)	4.47	6.26	6.30	5.28	3.52
Average price ($/BOE)	53.40	59.21	58.50	46.01	26.48
Average sales prices with hedges(5):					
Oil ($/Bbl)	$ 90.20	$ 90.31	$ 88.62	$ 77.26	$ 65.42
Natural gas ($/Mcf)	5.31	6.63	6.67	6.32	6.17
Average price ($/BOE)	55.95	58.97	58.93	50.37	41.10
Average cost per BOE:					
Lease operating expenses	$ 5.67	$ 4.53	$ 5.00	$ 4.16	$ 3.52
Production and ad valorem taxes	3.00	3.75	3.70	3.01	1.72
Depreciation, depletion and amortization	20.77	19.00	20.38	18.69	16.28
General and administrative(6)	5.91	4.95	5.90	5.93	6.34

(1) MBbl equivalents ("MBOE") are calculated using a conversion rate of six MMcf per one MBbl.

(2) The volumes presented for the six months ended June 30, 2012 and 2011 and for the year ended December 31, 2011 are based on actual results and are not calculated using the rounded numbers in the table above.

(3) 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.

(4) 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.

(5) Hedged prices reflect the after effect of our commodity hedging transactions on our average sales prices. Our calculation of such after effects include realized gains and losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting.

(6) General and administrative includes non-cash stock-based compensation of $4.8 million and $0.9 million for the six months ended June 30, 2012 and 2011, respectively, and $6.1 million, $1.3 million and $1.4 million for the years ended December 31, 2011, 2010 and 2009, respectively. Excluding stock-based compensation from the above metric results in average general and administrative cost per BOE of $5.02 and $4.73 for the six months ended June 30, 2012 and 2011, respectively, and $5.19, $5.69 and $5.94 for the years ended December 31, 2011, 2010 and 2009, respectively.

Productive wells

The following table sets forth certain information regarding productive wells in each of our core areas at June 30, 2012. 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				
	Vertical	Horizontal	Gross Total(1)	Net	Average WI %
Permian Basin					
Permian-Garden City	718	41	759	713	94%
Permian-Other	0	0	0	0	0%
Anadarko Granite Wash	165	19	184	138	75%
Other(2)	336	11	347	174	50%
New Ventures(3)	1	0	1	1	95%
Total	1,220	71	1,291	1,026	79%

(1) 1,090 of the 1,291 total gross producing wells are Laredo operated.

(2) Includes Eastern Anadarko and Central Texas Panhandle.

(3) 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 June 30, 2012 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	Sections
Permian Basin								
Permian-Garden City	84,632	77,067	94,595	65,207	179,227	142,274	54%	334
Permian-Other	—	—	60,777	45,740	60,777	45,740	0%	196
Anadarko Granite Wash	35,045	26,733	20,032	11,191	55,077	37,924	70%	115
Other(1)	91,285	60,983	23,249	10,567	114,534	71,550	85%	250
New Ventures(2)	640	502	128,430	106,286	129,070	106,788	0%	233
Total	211,602	165,285	327,083	238,991	538,685	404,276	41%	1,128

(1) Includes Eastern Anadarko and Central Texas Panhandle.

(2) Includes Dalhart Basin and other New Ventures.

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Undeveloped acreage expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of June 30, 2012 that will expire over the next three 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.

	Remaining 2012		2013		2014		2015	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin								
Permian-Garden City	7,169	3,204	52,294	37,040	15,466	11,235	8,353	8,159
Permian-Other	4,669	4,084	0	0	13,829	10,615	36,467	27,428
Anadarko Granite Wash	3,316	1,684	6,398	3,163	5,450	2,755	1,264	432
Other(1)	11,892	4,050	9,762	5,476	1,313	989	280	51
New Ventures(2)	26,267	22,240	15,979	11,936	42,167	40,529	43,206	29,255
Total	53,313	35,262	84,433	57,615	78,225	66,123	89,570	65,325

(1) Includes Eastern Anadarko and Central Texas Panhandle.

(2) Includes Dalhart Basin and other New Ventures.

Drilling activity

The following table summarizes our drilling activity for the six months ended June 30, 2012 and for the years ended December 31, 2011, 2010 and 2009. 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.

	Six months ended June 30,		Years ended December 31,					
	2012		2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development wells:								
Productive	104	97.0	260	233.2	294	276.6	127	114.7
Dry	0	0.0	0	0.0	2	2.0	2	2.0
Total development wells	104	97.0	260	233.2	296	278.6	129	116.7
Exploratory wells:								
Productive	1	1.0	2	1.4	11	9.3	17	13.7
Dry	2	1.8	0	0.0	1	1.0	2	1.3
Total exploratory wells	3	2.8	2	1.4	12	10.3	19	15.0

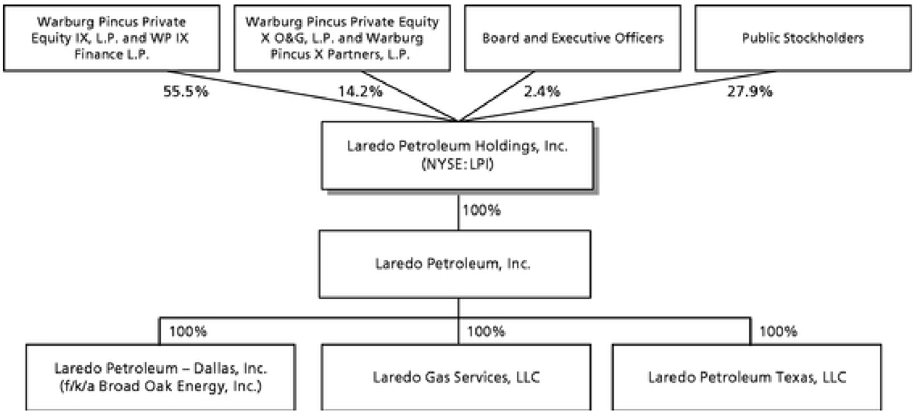
Corporate history and structure

Laredo Petroleum Holdings, Inc. was incorporated in August 2011 pursuant to the laws of the State of Delaware for purposes of the Corporate Reorganization and 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. Laredo Petroleum, LLC was formed in 2007 pursuant to the laws of the State of Delaware by 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 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. Our business continues to be conducted through Laredo Petroleum, Inc., a wholly-owned subsidiary of Laredo Petroleum Holdings, Inc., and through Laredo Petroleum Inc.'s subsidiaries. The Corporate Reorganization and IPO are discussed in Notes A and D to our audited consolidated financial statements included elsewhere in this prospectus.

Laredo Petroleum, Inc. is the borrower under our senior secured credit facility as well as the issuer of our $550 million 2019 senior unsecured notes issued in January and October 2011 and our $500 million 2022 senior unsecured notes issued in April 2012. Laredo Petroleum Holdings, Inc. and all of its subsidiaries (other than Laredo Petroleum, Inc.) are guarantors of the obligations under our senior secured credit facility and senior unsecured notes.

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.

The following diagram indicates our ownership structure following this offering assuming no exercise of the underwriters' option to acquire additional shares of common stock:



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 significant 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 more favorable Gulf Coast pricing. However, 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 prospectus. See "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." See also "Certain relationships and related party transactions."

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 June 30, 2012, 41% of our leasehold acreage was held by production.

Seasonality

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

Competition

The oil and natural gas industry is intensely competitive, and we compete with 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 natural gas 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 activities during periods of low natural gas 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 locations and producing natural gas 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 and Oklahoma 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 and the Anadarko Granite Wash. While hydraulic fracturing is not required to maintain 41% 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 non-producing and proved undeveloped reserves associated with future drilling, recompletion, and refracture stimulation projects, or approximately 62% of our total estimated proved reserves as of December 31, 2011, 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. 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. More than 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.

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 or injection wells, so as to minimize the potential for impact to nearby surface water. We currently do not discharge water to the surface.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read "Business—Regulation of environmental and occupational health and safety matters—Water and other waste discharges and spills." For related risks to our stockholders, please read "Risk factors—Risks related to our business—Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could prohibit projects or result in 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. All of the jurisdictions in which we own or operate producing oil and natural gas properties have 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 unitization or pooling of crude 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 EPA, 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. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, 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, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. We own interests in properties located onshore in different U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states 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, unitization and pooling of oil and natural gas properties and establishment of maximum rates of production from oil and natural gas wells. Some states have 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 crude 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 cleanup 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 cleanup 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 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. Some states also maintain 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, particularly 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. 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 May 4, 2012, the EPA published a draft UIC Program permitting guidance for oil and gas hydraulic fracturing activities using diesel fuel. The guidance document is designed for use by EPA UIC permit writers, and 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 and Oklahoma, where we maintain acreage, the EPA is encouraging state programs to review and consider use of this permit guidance. The draft guidance document underwent an extended public comment process, which concluded on August 23, 2012. The EPA is presently evaluating the public comments and will likely issue a final guidance document at a later date. 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 intends to release an interim report by late 2012 and a final report in 2014 synthesizing the longer-term research projects. 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, and such legislation could be introduced in the current session of Congress. 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. Proposed rules are expected in 2013 for coalbed methane and 2014 for shale gas. 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.

A committee of the House of Representatives also is conducting an investigation of hydraulic fracturing practices. Further, certain members of the Congress have called upon: (i) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; (ii) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and (iii) the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board released its final report on November 18, 2011, proposing strategies to implement the Subcommittee's August 11, 2011 recommendations to reduce the potential environmental impacts from shale gas production. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, pursuant to legislation adopted by the State of Texas in June 2011, the chemical components used in the hydraulic fracturing process, as well as the volume of water used, must be disclosed to the RRC and the public beginning February 1, 2012. 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 4, 2012, the DOI issued a draft 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. On April 17, 2012, the EPA issued a final rule that subjects 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 EPA's final rule includes NSPS standards for completions of hydraulically fractured 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 becomes effective October 15, 2012; however, a number of the requirements will not take immediate effect. The final rule establishes 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 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 wells will be required to use green completions. Controls for certain storage vessels and pneumatic controllers may phase-in over one year beginning on the date the final rule is published in the Federal Register, while certain compressors, dehydrators and other equipment must comply with the final rule immediately or up to three years and 60 days after 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. 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 may be required to incur certain 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 from sources within the U.S. between 2012 and 2050, but it was not approved by the U.S. Senate in the 2009-2010 legislative session. Congress is likely to continue to consider similar bills. Moreover, almost 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, 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 manufactured in model years 2012-2016; however, it does not require immediate reductions in GHG emissions. A recent rulemaking proposal by the EPA and the Department of Transportation's National Highway Traffic Safety Administration seeks to expand the motor vehicle rule to include vehicles manufactured in model years 2017-2025. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it also became effective January 2011, although it remains the subject of several pending lawsuits filed by industry groups. The tailoring rule establishes new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. The permitting requirements of the PSD program apply only to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Phase I of the tailoring rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the tailoring rule, which became effective on July 1, 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the tailoring rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. Finally, in October 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. On March 27, 2012, the EPA issued a proposed rule establishing carbon pollution standards for new fossil-fuel-fired electric utility generating units. The proposed rule underwent an extended public comment process, which concluded on June 25, 2012. The EPA is presently evaluating the public comments and is expected to issue a final rule at a later date. The EPA plans to implement GHG emissions standards for refineries in November 2012.

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 2011 and the first six months of 2012, nor do we anticipate that such expenditures will be material in the remainder of 2012.

Employees

As of September 17, 2012, we had 204 full-time employees. We also employed a total of 24 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 own or lease field offices in Midland and Dallas, Texas. For additional information regarding our business properties and financial condition, please refer to the documents referenced in the section entitled "Where you can find more information."

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 material legal proceedings which we currently believe will have a material adverse effect on our business, financial position, results of operations or liquidity.

Management

Executive officers and directors

The following table sets forth information regarding the individuals who are currently serving as our executive officers and directors. The respective age of each individual in the table is as of September 30, 2012. There are no family relationships among any of our directors or executive officers. Effective September 1, 2012, Rodney S. Myers, our former Senior Vice President—Permian, has transitioned into a new role as a Senior Business Advisor to Laredo.

Name	Age	Position
Randy A. Foutch	61	Chairman and Chief Executive Officer
Jerry R. Schuyler	57	Director, President and Chief Operating Officer
W. Mark Womble	61	Senior Vice President and Chief Financial Officer
Patrick J. Curth	60	Senior Vice President—Exploration and Land
John E. Minton	64	Senior Vice President—Reservoir Engineering
Kenneth E. Dornblaser	57	Senior Vice President and General Counsel
Richard C. Buterbaugh	57	Senior Vice President—Investor Relations
Peter R. Kagan	44	Director
James R. Levy	36	Director
B.Z. (Bill) Parker	65	Director
Pamela S. Pierce	57	Director
Ambassador Francis Rooney	58	Director
Dr. Myles W. Scoggins	64	Director
Edmund P. Segner, III	58	Director
Donald D. Wolf	69	Director

Randy A. Foutch is our founder and has served as our Chairman and Chief Executive Officer since that time. He also served as our President from October 2006 to July 2008. Mr. Foutch has over 30 years of experience in the oil and gas industry. Prior to our formation, Mr. Foutch founded Latigo Petroleum, Inc. ("Latigo") in 2001 and served as its President and Chief Executive Officer until it was sold to Pogo Producing Co. in May 2006. Previous to Latigo, Mr. Foutch founded Lariat Petroleum, Inc. ("Lariat") in 1996 and served as its President until January 2001 when it was sold to Newfield Exploration, Inc. He is currently serving on the board of directors of Helmerich & Payne, Inc. and is also a member of its audit, governance and nominating and corporate committees. Mr. Foutch is also a member of the National Petroleum Council, America's Natural Gas Alliance and the Advisory Council of the Energy Institute at the University of Texas, Austin. From 2006 to August 2011, he served on the board of directors of Bill Barrett Corporation and from 2006 to 2008, on the board of directors of MacroSolve, Inc. Mr. Foutch also serves on the University of Tulsa Board of Trustees and several nonprofit and private industry boards. He holds a Bachelor of Science in Geology from the University of Texas and a Master of Science in Petroleum Engineering from the University of Houston.

Mr. Foutch has been successful in founding other oil and gas companies and serves in director positions of various oil and gas companies. As a result, he provides a strong operational and strategic background and has valuable business, leadership and management experience and insights into many aspects of the operations of exploration and production companies. Mr. Foutch also brings financial expertise to the board, including his experience in obtaining financing for startup oil and gas companies. For these reasons, we believe Mr. Foutch is qualified to serve as a director.

Jerry R. Schuyler joined Laredo in June 2007 as Executive Vice President and Chief Operating Officer. In July 2008, he was promoted to President and Chief Operating Officer and has served in that capacity since that time. He is also one of our directors. Prior to joining Laredo, he held various executive positions with Atlantic Richfield Company ("ARCO"), Dominion Exploration and Production, Inc. and St. Mary Land & Exploration. While at St. Mary Land & Exploration from December 2003 to June 2007, he established their Houston and Midland offices and managed all exploration and production activities in the Gulf of Mexico, Gulf Coast and Permian areas. While at Dominion Exploration and Production, Inc. from March 2000 to July 2002, he managed all exploration and production activities in the Gulf Coast, Michigan and Appalachian areas. During his years with ARCO from 1977 to 1999, he held several key positions, such as Prudhoe Bay Field Manager, Manager of Worldwide Exploration and Production Planning and President of ARCO Middle East and Central Asia. Mr. Schuyler serves on several industry and college related boards of directors. He earned a Bachelor of Science degree in Petroleum Engineering from Montana Tech University and attended numerous graduate business courses at University of Houston.

Mr. Schuyler has significant experience managing oil and gas operations and serving in executive positions for various exploration and production companies and extensive knowledge of the energy industry. For these reasons, we believe Mr. Schuyler is qualified to serve as a director.

W. Mark Womble has served as our Chief Financial Officer and Senior Vice President since July 2007. Prior to joining Laredo, he was the Vice President and Chief Financial Officer of Latigo and served in this capacity from 2002 until the company was sold in May 2006. He then retired until joining Laredo in July 2007. Mr. Womble has more than 30 years of experience in the oil and natural gas industry and, throughout his career, has served as financial analyst, consultant and in several executive positions with multiple companies. He earned a Bachelor of Business Administration degree and a Master of Business Administration degree in finance and accounting from West Texas State University in Canyon, Texas. In June 2012, Mr. Womble informed Laredo of his intent to retire within a year.

Patrick J. Curth has served as our Senior Vice President—Exploration and Land since October 2006. He has been involved in exploration and development projects in the Mid-Continent area for over three decades. Prior to joining Laredo, Mr. Curth joined Latigo in 2000 as Exploration Manager and served as Vice President—Exploration when Latigo was sold in May 2006. From 1997 to 2001, he was the Vice President—Exploration at Lariat. Mr. Curth holds a Bachelor of Arts in Geology from Windham College, a Masters Degree in Geological Sciences from the University of Wisconsin—Milwaukee and a second Masters Degree in Environmental Sciences from Oklahoma State University.

John E. Minton joined Laredo in October 2007 as Vice President—Reservoir Engineering and became Senior Vice President—Reservoir Engineering in September 2009. Before joining

Laredo, Mr. Minton served as Senior Vice President of Reservoir Engineering at Rockford II Energy Partners from July 2006 to October 2007. In 2003, he joined Latigo as a Senior Reservoir Engineer and later became Manager of Corporate Reservoir Engineering. He served in this position until the company was sold in May 2006. He joined Lariat in 2000 as a Senior Reservoir Engineer and stayed with its successor Newfield Exploration until early 2003 as a Senior Reservoir Engineer. Mr. Minton is a member of the Society of Petroleum Engineers and has been a Registered Professional Engineer in the state of Oklahoma since 1982. He graduated from the University of Oklahoma with a Bachelor of Science degree in Mechanical Engineering.

Kenneth E. Dornblaser joined Laredo in June 2011 as Senior Vice President and General Counsel. Immediately prior to joining Laredo, Mr. Dornblaser was a shareholder in the Johnson & Jones law firm, which he co-founded in March 1994. Prior to co-founding Johnson & Jones, Mr. Dornblaser had been engaged in the private practice of law in Tulsa, Oklahoma, since 1980. Mr. Dornblaser graduated from Oklahoma State University with a Bachelor of Science degree in Accounting and the University of Oklahoma where he received his Juris Doctorate degree.

Richard C. Buterbaugh joined Laredo in June 2012 as Senior Vice President—Investor Relations. From March 2007 to June 2011, he was Vice President—Investor Relations and Corporate Planning at Quicksilver Resources Inc. From November 1989 to August 2006, he was with Kerr-McGee Corp., most recently as Vice President of Corporate Planning and previously as Vice President of Investor Relations and Communications. After leaving Quicksilver Resources, Inc. and prior to joining Laredo, as well as after leaving Kerr-McGee Corp. and prior to joining Quicksilver Resources, Inc., he was a consultant for oil and gas finance and management projects. Mr. Buterbaugh has 35 years of corporate finance, planning and investor relations experience in the oil and gas industry. He holds a Bachelor of Science degree in Accounting from the University of Colorado.

Peter R. Kagan has served as one of our directors since July 2007. He has been with Warburg Pincus since 1997 where he leads the firm's investment activities in energy and natural resources. He is a Partner of Warburg Pincus & Co. and a Managing Director of Warburg Pincus LLC. He is also a member of Warburg Pincus' Executive Management Group. Mr. Kagan is currently on the board of directors of Antero Resources LLC, Asian American Gas Limited (f/k/a China CBM Investment Holdings, Ltd.), Canbriam Energy, Inc., Fairfield Energy Limited, Hawkwood Energy LLC, MEG Energy Corp., Targa Resources, Inc., Targa Resources Partners L.P. and Venari Resources LLC. He previously served on the board of directors of Broad Oak, Lariat and Latigo. Mr. Kagan received a Bachelor of Arts degree cum laude from Harvard College and Juris Doctorate and Master of Business Administration degrees with honors from the University of Chicago.

Mr. Kagan has significant experience with energy companies and investments and broad familiarity with the industry and related transactions and capital markets activity, which enhance his contributions to the board of directors. For these reasons, we believe Mr. Kagan is qualified to serve as a director.

James R. Levy has served as one of our directors since May 2007. He joined Warburg Pincus in 2006 and focuses on investments in the energy industry. Prior to joining Warburg Pincus, he worked as an Associate at Kohlberg & Company, a middle market private equity investment firm, from 2002 to 2006, and as an Analyst and Associate at Wasserstein Perella & Co. from

1999 to 2002. Mr. Levy currently serves on the board of directors of Black Swan Energy Ltd., a privately held oil and gas exploration and production company, EnStorage, Inc., a privately held energy storage system development company, Hawkwood Energy LLC, a private start-up exploration and production company, and Suniva, Inc., a private company that manufactures solar cells for use in power generation. He is a former director of Broad Oak. Mr. Levy received a Bachelor of Arts in history from Yale University.

Mr. Levy has significant experience with investments in the energy industry and currently serves on the boards of various energy companies. For these reasons, we believe Mr. Levy is qualified to serve as a director.

B. Z. (Bill) Parker has served as one of our directors since May 2007. Mr. Parker joined Phillips Petroleum Company in 1970 where he held various engineering positions in exploration and production in the United States and abroad. He later served in numerous executive positions at Phillips Petroleum Company and in 2000, he was named Executive Vice President for Worldwide Production & Operations. He retired from Phillips Petroleum Company in this position in November 2002. Mr. Parker served on the board of Williams Partners GP from August 2005 to September 2010 where he also served as chairman of the conflicts and audit committees. He served on the board of directors of Latigo from January 2003 to May 2006 where he also served as chairman of the audit committee. Mr. Parker is a member of the Society of Petroleum Engineers. He received a Bachelor of Science degree in petroleum engineering from the University of Oklahoma.

Mr. Parker has over 40 years of experience in the oil and gas industry, having served in various engineering and executive positions for an exploration and production company and as a director and audit committee member for various energy companies. For these reasons, we believe Mr. Parker is qualified to serve as a director.

Pamela S. Pierce has served as one of our directors since May 2007. She has been a partner at Ztown Investments, Inc. since 2005, focused on investments in domestic oil and natural gas non-working interests. She also serves as Vice Chair of the Michael Baker, Inc. board of directors and is a member of the Scientific Drilling International, Inc. board of directors. From 2002 to 2004, she was the President of Huber Energy, an operating company of J.M. Huber Corporation. From 2000 to 2002, she was the President and Chief Executive Officer of Houston-based Mirant Americas Energy Capital and Production Company. She has also held a variety of managerial positions with ARCO Oil and Gas Company, ARCO Alaska and Vastar Resources. She received a Bachelor of Science Degree in Petroleum Engineering from the University of Oklahoma and a Master of Business Administration in Corporate Finance from the University of Dallas.

Ms. Pierce is a highly experienced business executive with extensive knowledge of the energy industry. Her business acumen enhances the board of directors' discussions on all issues affecting us and her leadership insights contribute significantly to the board of directors' decision making process. For these reasons, we believe Ms. Pierce is qualified to serve as a director.

Ambassador Francis Rooney has served as one of our directors since February 2010. He has been the Chief Executive Officer of Rooney Holdings, Inc. since 1984, and of Manhattan Construction Group, Tulsa, since 2008, which is engaged in road and bridge construction, civil works and building construction and construction management in the United States, Mexico and the Central America/Caribbean region. From 2005 through 2008, he served as the United States Ambassador to the Holy See, appointed by President George W. Bush. Ambassador Rooney currently serves on the boards of directors of Helmerich & Payne, Inc. and VETRA Energy Group, Bogota, Colombia. He is a member of the Board of Advisors of the Panama Canal Authority, Republic of Panama, the Board of the Florida Gulf Coast University Foundation, the INCAE Presidential Advisory Council and the Board of Visitors of the University of Oklahoma International Programs. Ambassador Rooney graduated from Georgetown University with a Bachelor of Arts and from Georgetown University Law Center with a Juris Doctorate. He is a member of the District of Columbia and Texas Bar Associations.

Ambassador Rooney has broad business and financial experience and has served as a director of public and private energy companies. For these reasons, we believe Ambassador Rooney is qualified to serve as a director.

Dr. Myles W. Scoggins has served as one of our directors since May 2012. In June 2006, Dr. Scoggins was appointed President of the Colorado School of Mines, an engineering and science research university with strong ties to the oil and gas industry. Dr. Scoggins retired in April 2004 after a 34-year career with Mobil Corporation and ExxonMobil Corporation, where he held senior executive positions in the upstream oil and gas business. From December 1999 to April 2004, he served as Executive Vice President of ExxonMobil Production Co. Prior to the merger of Mobil and Exxon in December 1999, he was President, International Exploration & Production and Global Exploration and an officer and member of the executive committee of Mobil Oil Corporation. He has been a member of the board of directors of Cobalt International Energy, an independent oil exploration and production company focusing on the deepwater U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa, since March 2010 and QEP Resources, Inc., an independent natural gas and oil exploration and production company with operations focused in the Rocky Mountain and Midcontinent regions of the United States, since July 2010. He also currently serves as a member of the National Advisory Council of the United States Department of Energy's National Renewable Energy Laboratory. From February 2005 until June 2010, Dr. Scoggins was a member of the board of directors of Questar Corporation, a Rockies-based integrated natural gas company; from March 2005 until August 2011, he was a member of the board of directors of Trico Marine Services, Inc., an integrated provider of subsea, trenching and marine support vessels and services; and from June 2007 until October 2012, he was a member of the Board of Directors of Venoco, Inc., an oil and gas production company. Dr. Scoggins has a Ph.D. in Petroleum Engineering from The University of Tulsa.

Dr. Scoggins has nearly 40 years of experience in the oil and gas exploration and production industry with extensive industry and management experience and expertise, and has served in senior executive and management positions in the upstream oil and gas business. For these reasons, we believe Dr. Scoggins is qualified to serve as a director.

Edmund P. Segner, III joined our board of directors in August 2011. Mr. Segner currently is a professor in the practice of engineering management in the Department of Civil and Environmental Engineering at Rice University in Houston, Texas, a position he has held since July 2006 and full time since July 2007. In 2008, Mr. Segner retired from EOG Resources, Inc. ("EOG"), a publicly traded independent oil and gas exploration and production company. Among the positions he held at EOG were President, Chief of Staff, and director from 1999 to

2007. From March 2003 through June 2007, he also served as the Principal Financial Officer of EOG. He has been a member of the board of directors of Bill Barrett Corporation, an oil and gas company primarily active in the Rocky Mountain region of the United States, since August 2009, and of Exterran Partners, L.P., a master limited partnership that provides natural gas contract operations services, since May 2009. From August 2009 until October 2011, Mr. Segner was a member of the board of directors of Seahawk Drilling, Inc., an offshore oil and natural gas drilling company. He also currently serves as a member of the board or as a trustee for several non-profit organizations. Mr. Segner graduated from Rice University with a Bachelor of Science degree in civil engineering and received an M.A. degree in economics from the University of Houston. He is a certified public accountant.

Mr. Segner's service as President, Principal Financial Officer and director of publicly traded oil and gas exploration and development companies provides our board of directors with a strong operational, financial, accounting and strategic background and provides valuable business, leadership and management experience and insights into many aspects of the operations of exploration and production companies. Mr. Segner also brings financial and accounting expertise to the board of directors, including through his experience in financing transactions for oil and gas companies, his background as a certified public accountant, his service as a Principal Financial Officer, his supervision of principal financial officers and principal accounting officers, and his service on the audit committees of other companies. For these reasons, we believe Mr. Segner is qualified to serve as a director.

Donald D. Wolf has served as one of our directors since February 2010. Mr. Wolf currently serves as the Chairman of the general partner of QR Energy, LP., which is a master limited partnership operated by Quantum Resources Management. He was the Chief Executive Officer of Quantum Resources Management from 2006 to 2009. He served as President and Chief Executive Officer of Aspect Energy, LLC from 2004 to 2006. Prior to joining Aspect, Mr. Wolf served as Chairman and Chief Executive Officer of Westport Resources Corporation from 1996 to 2004. He is currently a director of the general partner of MarkWest Energy Partners, L.P., Enduring Resources, LLC, Ute Energy, LLC, and Aspect Energy, LLC. Mr. Wolf graduated from Greenville College, Greenville, Illinois, with a Bachelor of Science in Business Administration.

Mr. Wolf has had a diversified career in the oil and natural gas industry and has served in executive positions for various exploration and production companies. His extensive experience in the energy industry brings substantial experience and leadership skill to the board of directors. For these reasons, we believe Mr. Wolf is qualified to serve as a director.

Board of directors

Our board of directors consists of ten members, including our Chief Executive Officer and our President and Chief Operating Officer. The board of directors reviewed the independence of our directors using the independence standards of the NYSE and, based on this review, determined that Messrs. Kagan, Levy, Parker, Rooney, Scoggins, Segner and Wolf and Ms. Pierce are independent within the meaning of the NYSE listing standards currently in effect.

As of September 28, 2012, Warburg Pincus owns approximately 79.4% of our outstanding common stock, and upon completion of this offering (assuming the underwriters exercise their option to acquire additional shares in full), Warburg Pincus will own approximately 68.3% of our outstanding common stock. Because Warburg Pincus owns a majority of our outstanding common stock, we are a "controlled company" as that term is set forth in Section 303A of the NYSE Listed Company Manual. Under the NYSE rules, a "controlled company" may elect not to comply with certain NYSE corporate governance requirements, including: (1) the requirement that a majority of our board of directors consist of independent directors, (2) the requirement that our nominating and corporate governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities, and (3) the requirement that our compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities. While these requirements will not apply to us as long as we remain a "controlled company," our board of directors nonetheless consists of a majority of independent directors and our nominating and corporate governance committee and compensation committee consist entirely of independent directors within the meaning of the NYSE listing standards currently in effect. Our nominating and corporate governance committee and compensation committee each have a written charter addressing such committee's purpose and responsibilities in accordance with NYSE listing standards.

Currently, our board of directors consists of a single class of directors, each serving a one year term. At such time as Warburg Pincus no longer beneficially owns more than 50% of our issued and outstanding common stock, our board of directors will be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms, and such directors being removable only for "cause."

Committees of the board of directors

Our board of directors has an audit committee, a compensation committee and a nominating and corporate governance committee, and may have such other committees as the board of directors shall determine from time to time. Each of the standing committees of the board of directors has the composition and responsibilities described below.

Audit committee

The members of our audit committee are Messrs. Parker, Segner, Levy and Wolf, each of whom our board of directors has determined is financially literate. Mr. Parker is the chairman of this committee. Our board of directors has determined that Messrs. Wolf and Segner are the audit committee financial experts. It has further determined that Messrs. Parker, Segner and Wolf are "independent" under the standards of the NYSE and SEC regulations. We have relied on one of the phase-in rules of the SEC and NYSE with respect to the independence of our audit committee, which permitted us to have an audit committee that had a majority of members that are independent for up to one year after the IPO. As approved by our board of directors, effective November 28, 2012, Mr. Scoggins, whom our board of directors has determined to be independent and financially literate, will replace Mr. Levy as a member of the audit committee and Mr. Segner will replace Mr. Parker as the chairman of this committee. Upon replacement of Mr. Levy with Mr. Scoggins, we will have a fully independent audit committee and no longer rely on the phase-in rules of the SEC and NYSE.

This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to our independent accountants, the performance of our independent accountants and our accounting practices. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements. We have adopted an audit committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Compensation committee

The members of the compensation committee are Messrs. Wolf, Rooney and Kagan and Ms. Pierce. Mr. Wolf is the chairman of this committee. This committee establishes salaries, incentives and other forms of compensation for officers and other employees. Our compensation committee also administers our incentive compensation and benefit plans. We have adopted a compensation committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Nominating and corporate governance committee

The members of our nominating and corporate governance committee are Messrs. Rooney, Parker, Segner and Wolf and Ms. Pierce. Mr. Rooney is the chairman of this committee. This committee identifies, evaluates and recommends qualified nominees to serve on our board of directors, develops and oversees our internal corporate governance processes and maintains a management succession plan. We have adopted a nominating and corporate governance committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Compensation committee interlocks and insider participation

No member of our compensation committee has been at any time an employee of ours. None of our executive officers serve on the board of directors or compensation committee of a company that has an executive officer that serves on our board or compensation committee. No member of our board is an executive officer of a company for which one of our executive officers serves as a member of the board of directors or compensation committee.

Code of business conduct and ethics

Our board of directors has adopted a code of business conduct and ethics applicable to our employees, directors and officers, in accordance with applicable U.S. federal securities laws and the corporate governance rules of the NYSE. Any waiver of this code may be made only by our board of directors and will be promptly disclosed as required by applicable U.S. federal securities laws and the corporate governance rules of the NYSE. A copy of the code of business conduct and ethics is available on our website at www.laredopetro.com. Information on our website or any other website is not incorporated by reference into, and does not constitute part of, this prospectus.

Corporate governance guidelines

Our board of directors has adopted corporate governance guidelines in accordance with the corporate governance rules of the NYSE, a copy of which is available on our website at www.laredopetro.com. Information on our website or any other website is not incorporated by reference into, and does not constitute part of, this prospectus.

Certain relationships and related party transactions

Corporate reorganization

On December 19, 2011, pursuant to the terms of the Corporate Reorganization completed prior to the closing of the IPO, Laredo Petroleum Holdings, Inc. merged with and into Laredo Petroleum, LLC, with Laredo Petroleum Holdings, Inc. being the surviving entity. All of Laredo Petroleum, LLC's outstanding preferred equity units were exchanged for shares of Laredo Petroleum Holdings, Inc.'s common stock in accordance with the limited liability company agreement of Laredo Petroleum, LLC (the "LLC Agreement"). In addition, under the LLC Agreement and the restricted unit agreements, certain series of Laredo Petroleum, LLC's incentive equity units were also exchanged into Laredo Petroleum Holdings, Inc.'s common stock. To the extent any of such incentive units were subject to vesting requirements, the common stock issued in exchange therefor is also subject to such requirements.

The number of shares of common stock that the former unitholders of Laredo Petroleum, LLC received in the Corporate Reorganization was determined by the value such holder would have received under the distribution provisions in the LLC Agreement upon a liquidation of Laredo Petroleum, LLC at a liquidation value determined by reference to the initial public offering price of Laredo Petroleum Holdings, Inc.'s common stock in the IPO. Laredo Petroleum Holdings, Inc. issued an aggregate of approximately 107,500,000 shares of common stock to the former unitholders of Laredo Petroleum, LLC in exchange for an aggregate of 215,236,554 equity units in Laredo Petroleum, LLC.

Acquisition of Broad Oak Energy, Inc.

On July 1, 2011, we completed an acquisition of Broad Oak, with Broad Oak becoming a wholly-owned subsidiary of Laredo Petroleum, Inc., for a combination of equity and cash. Warburg Pincus Private Equity IX, L.P., a Delaware limited partnership and the owner of the majority of Laredo Petroleum Holdings, Inc.'s stock, was a majority stockholder in Broad Oak and received approximately $611.2 million in the form of units in Laredo Petroleum, LLC in the transaction. We changed the name of Broad Oak to Laredo Petroleum-Dallas, Inc. on July 19, 2011. Messrs. Kagan and Levy, who are both members of Laredo Petroleum Holdings, Inc.'s board of directors, were also directors of Broad Oak.

Registration rights

On December 20, 2011, in connection with the closing of the IPO, Laredo Petroleum Holdings, Inc. entered into a registration rights agreement (the "Registration Rights Agreement") with affiliates of Warburg Pincus and the other former unitholders of Laredo Petroleum, LLC (together with Warburg Pincus, the "Holders"), which is currently only applicable to Warburg Pincus and Mr. Foutch. The Registration Rights Agreement requires Laredo Petroleum Holdings, Inc. to file, within 30 days of receipt of a demand notice issued by Warburg Pincus, a registration statement with the SEC permitting the public offering of registrable securities. In addition, the Registration Rights Agreement grants the Holders the right to join Laredo Petroleum Holdings, Inc., or "piggyback", in certain circumstances, if Laredo Petroleum Holdings, Inc. sells its common stock in a public offering. The Registration Rights Agreement also includes customary provisions dealing with indemnification, contribution and allocation of expenses.

Gas gathering and processing arrangement with Targa

Laredo has a gas gathering and processing arrangement with affiliates of Targa Resources, Inc. ("Targa"). Warburg Pincus Private Equity IX, L.P., a majority stockholder in Laredo Petroleum Holdings, Inc., and other Warburg Pincus affiliates hold investment interests in Targa. Mr. Kagan, one of our directors, is a member of the board of directors of Targa Resources, Inc. and Targa Resource Partners L.P. Our net oil and gas sales to Targa were approximately $37.7 million and $79.3 million during the six months ended June 30, 2012 and the year ended December 31, 2011, respectively.

Other related party transactions

Our board of directors has adopted an aircraft use policy for our Chairman and Chief Executive Officer Randy A. Foutch, whereby his personally owned aircraft can be used for Laredo business travel, subject to certain conditions. Mr. Foutch travels extensively for company business, often on short notice and to areas that have limited access to direct commercial flights, so our board of directors has determined that the use of Mr. Foutch's aircraft is an efficient and cost-effective option that is beneficial to us. On occasion, other Laredo employees fly with Mr. Foutch when convenient or necessary on these business trips at no extra cost to us. Mr. Foutch's aircraft is owned by a family limited partnership that he controls. Although Mr. Foutch is a fully qualified pilot with a single pilot rating and has flown his aircraft solo for business while working for other companies in the past, we believe it is in our best interest to require the presence of a fully-licensed and qualified co-pilot and certain specified safety and mechanical inspections to assure the airworthiness of the aircraft. The expenses covered by us consist of the salary of the co-pilot and his out-of-pocket expenses on business trips, the training and certification expenses of Mr. Foutch and the co-pilot, and the cost of aircraft safety and mechanical inspections. In addition, we reimburse Mr. Foutch for the use of this aircraft for company business in an amount equal to the cost of a first class commercial airline ticket to such destination or the cost of a charter flight if commercial flights are not available to such destination. During 2011, we incurred approximately $205,000 in expenses for business trips pursuant to this policy. These payments represent only a partial refund of the total costs and expenses of flying the aircraft, including the additional fixed costs required to be incurred under the policy, and as a result Mr. Foutch incurs a loss each year on the aircraft. All amounts reimbursed to Mr. Foutch are approved by our Chief Financial Officer in accordance with the board of directors approved policy.

Procedures for approval of related party transactions

Our board of directors has adopted a written related party transactions policy. Pursuant to this policy, the audit committee reviews all material facts of all related party transactions and either approves or disapproves entry into the related party transaction, subject to certain limited exceptions. In determining whether to approve or disapprove entry into a related party transaction, the audit committee shall take into account, among other factors, the following: (1) whether the related party transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances and (2) the extent of the related person's interest in the transaction. Further, the policy requires that all related party transactions required to be disclosed in our filings with the SEC be so disclosed in accordance with applicable laws, rules and regulations. A copy of the policy is available on our website at www.laredopetro.com. Information on our website or any other website is not incorporated by reference into, and does not constitute part of, this prospectus.

Principal and selling stockholders

The following table presents information as to the beneficial ownership of our common stock as of September 28, 2012, subject to certain assumptions set forth in the footnotes and as adjusted to reflect the sale of our common stock in this offering, for:

- each stockholder, or a group of affiliated stockholders, known by us to be the beneficial owner of more than 5% of the outstanding shares of our common stock;
- each of our directors;
- each of our named executive officers;
- all of our directors and executive officers as a group; and
- each selling stockholder.

Beneficial ownership is determined in accordance with the rules of the SEC and thus represents voting or investment power with respect to our securities. Unless otherwise indicated below, to our knowledge, the persons and entities named in the table have sole voting and sole investment power with respect to all shares beneficially owned. Shares of our common stock subject to options that are currently exercisable or exercisable within 60 days of September 28, 2012 are deemed to be outstanding and to be beneficially owned by the person holding the options for the purpose of computing the percentage ownership of that person but are not treated as outstanding for the purpose of computing the percentage ownership of any other person.

The number of shares and percentages of beneficial ownership prior to this offering set forth below are based on shares of common stock outstanding as of September 28, 2012.

The number of shares and percentages of beneficial ownership after this offering set forth below are based on the number of shares of our common stock outstanding immediately after the consummation of this offering, assuming no exercise of the underwriters' option to purchase up to an additional 1,875,000 shares of our common stock from the selling stockholders.

Name of beneficial owner	Shares beneficially owned prior to offering		Number of shares offered	Shares beneficially owned after offering	
	Number	Percentage		Number	Percentage
5% stockholders:					
Warburg Pincus Private Equity IX, L.P.(1)	81,193,140	63.3%	9,961,457	71,231,683	55.5%
Warburg Pincus Private Equity X O&G, L.P.(1)	20,690,977	16.1%	2,538,543	18,152,434	14.2%
Directors and named executive officers:					
Randy A. Foutch(2)	1,438,594(3)	1.1%	—	1,438,594(3)	1.1%
Jerry R. Schuyler	464,550	0.4%	—	464,550	0.4%
W. Mark Womble	65,569	0.1%	—	65,569	0.1%
Patrick J. Curth	234,493	0.2%	—	234,493	0.2%
John E. Minton	96,087	0.1%	—	96,087	0.1%
Peter R. Kagan(1)(4)	101,896,529	79.5%	—	89,396,529	69.7%
James R. Levy	12,412	0.0%	—	12,412	0.0%
B.Z. (Bill) Parker	76,210	0.1%	—	76,210	0.1%
Pamela S. Pierce	84,663	0.1%	—	84,663	0.1%
Francis Rooney	452,899(5)	0.4%	—	452,899(5)	0.4%
Myles W. Scoggins	13,450	0.0%	—	13,450	0.0%
Edmund P. Segner, III	14,405	0.0%	—	14,405	0.0%
Donald D. Wolf	35,202(6)	0.0%	—	35,202(6)	0.0%
Directors and executive officers as a group (15 persons)(7)	3,065,274	2.4%	—	3,065,274	2.4%

(1) The stockholders are Warburg Pincus Private Equity IX, L.P., a Delaware limited partnership, together with an affiliated partnership ("WP IX"), and Warburg Pincus Private Equity X O&G, L.P., a Delaware limited partnership, together with an affiliated partnership ("WP O&G"). Prior to the offering, the total number of shares owned by WP IX includes 3,064,551 shares of common stock owned by WP IX Finance L.P., an affiliated Delaware limited partnership, or 2.4% of the common stock outstanding, and the total number of shares owned by WP O&G includes 641,420 shares of common stock owned by Warburg Pincus X Partners, L.P., an affiliated Delaware limited partnership, or less than 1% of the common stock outstanding. After the offering, the total number of shares owned by WP IX includes 3,064,551 shares of common stock owned by WP IX Finance L.P., an affiliated Delaware limited partnership, or 2.4% of the common stock outstanding, and the total number of shares owned by WP O&G includes 562,725 shares of common stock owned by Warburg Pincus X Partners, L.P., an affiliated Delaware limited partnership, or less than 1% of the common stock outstanding. Warburg Pincus IX, LLC, a New York limited liability company ("WPIX LLC"), an indirect subsidiary of Warburg Pincus & Co., a New York general partnership ("WP"), is the general partner of WP IX. Warburg Pincus X, L.P., a Delaware limited partnership ("WP X GP") is the general partner of the WP O&G. Warburg Pincus X LLC, a Delaware limited liability company ("WP X LLC"), is the general partner of WP X GP. Warburg Pincus Partners LLC, a New York limited liability company ("WP Partners"), is the sole member of each of WPIX LLC and WP X LLC. WP is the managing member of WP Partners. Warburg Pincus LLC, a New York limited liability company ("WP LLC"), manages WP IX and WP O&G. Charles R. Kaye and Joseph P. Landy are each Managing General Partners of WP and Managing Members and Co-Presidents of WP LLC and may be deemed to control the Warburg Pincus entities. Messrs. Kaye, Landy and Kagan disclaim beneficial ownership of all shares of common stock held by the Warburg Pincus entities. The address of the Warburg Pincus entities is 450 Lexington Avenue, New York, New York 10017.

(2) Randy A. Foutch, our Chief Executive Officer and Chairman of the board of directors, is a limited partner of certain affiliates of Warburg Pincus.

(3) Includes (i) 400,148 shares held equally among four family trusts, (ii) 500 shares held by Mr. Foutch's daughter and (iii) 529,989 shares held by Lariat Ranch LLC, an entity of which Mr. Foutch owns approximately 80% and has shared voting power.

(4) Mr. Kagan, a director of Laredo Petroleum Holdings, Inc., is a Partner of Warburg Pincus & Co. and a Managing Director and Member of Warburg Pincus LLC. Mr. Kagan may be deemed to have an indirect pecuniary interest (within the meaning of Rule 16a-1 under the Exchange Act) in an indeterminate portion of the common stock owned by WP IX and WP O&G (as defined in footnote 1).

(5) Includes 434,265 shares held by Rooney Capital LLC.

(6) Includes 3,000 shares held by the Donald D. Wolf 2007 Irrevocable Trust.

(7) Does not include shares of common stock held by WP IX and WP O&G (as defined in footnote 1) in which Mr. Kagan may be deemed to have an indirect pecuniary interest (within the meaning of Rule 16a-1 under the Exchange Act).

The address for all officers and directors is c/o Laredo Petroleum Holdings, Inc., 15 W. Sixth Street, Suite 1800, Tulsa, Oklahoma 74119.

Description of capital stock

The authorized capital stock of Laredo Petroleum Holdings, Inc. consists of 450,000,000 shares of common stock, par value $0.01 per share, of which, as of September 28, 2012, 128,230,576 shares are issued and outstanding, and 50,000,000 shares of preferred stock, par value $0.01 per share, of which no shares are issued and outstanding.

The following summary of the capital stock and amended and restated certificate of incorporation and amended and restated bylaws of Laredo Petroleum Holdings, Inc. does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our amended and restated certificate of incorporation and amended and restated bylaws, which are exhibits to the registration statement of which this prospectus is a part.

Common stock

Except as provided by law or in a preferred stock designation, holders of common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, holders of common stock, as such, are not entitled to vote on any amendment to the amended and restated certificate of incorporation (including any certificate of designations relating to any series of preferred stock) that relates solely to the terms of any outstanding series of preferred stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to the amended and restated certificate of incorporation (including any certificate of designations relating to any series of preferred stock) or pursuant to the General Corporation Law of the State of Delaware, or DGCL. Subject to preferences that may be applicable to any outstanding shares or series of preferred stock, holders of common stock are entitled to receive ratably such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors out of funds legally available for dividend payments. All outstanding shares of common stock are fully paid and non-assessable. The holders of common stock have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to the common stock. In the event of any liquidation, dissolution or winding-up of our affairs, holders of common stock will be entitled to share ratably in our assets that are remaining after payment or provision for payment of all of our debts and obligations and after liquidation payments to holders of outstanding shares of preferred stock, if any.

Preferred stock

Our amended and restated certificate of incorporation authorizes our board of directors, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of preferred stock, par value $0.01 per share, covering up to an aggregate of 50,000,000 shares of preferred stock. Each class or series of preferred stock will cover the number of shares and will have the powers, preferences, rights, qualifications, limitations and restrictions determined by our board of directors, which may include, among others, dividend rights, liquidation preferences, voting rights, conversion rights, preemptive rights and redemption rights.

Registration rights

Certain of our stockholders have registration rights with respect to our common stock pursuant to the Registration Rights Agreement. For further information regarding the Registration Rights Agreement, see "Certain relationships and related party transactions—Registration rights."

Anti-takeover effects of provisions of our certificate of incorporation, our bylaws and Delaware law

Some provisions of Delaware law, and our amended and restated certificate of incorporation and our amended and restated bylaws described below, contain provisions that could make the following transactions more difficult: acquisitions of us by means of a tender offer, a proxy contest or otherwise and removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions, summarized below, are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware law

We are subject to the provisions of Section 203 of the DGCL, which regulates corporate takeovers. In general, those provisions prohibit a Delaware corporation, including those whose securities are listed for trading on the NYSE, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- the business combination or transaction in which the person became interested is approved by the board of directors before the date the interested stockholder attained that status;

- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced other than, for purposes of determining the voting stock outstanding (but not the outstanding stock owned by the interested stockholder), shares owned by persons who are directors and also officers of Laredo and by certain employee stock plans; or

- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

Section 203 defines "business combination" to include the following:

- certain mergers or consolidations involving the corporation and the interested stockholder;
- any sale, transfer, pledge or other disposition of 10% or more of the assets of the corporation to or with the interested stockholder;
- subject to certain exceptions, any transaction that results in the issuance or transfer by the corporation of any stock of the corporation to the interested stockholder;
- subject to certain exceptions, any transaction involving the corporation that has the effect of increasing the proportionate share of the stock of any class or series of the corporation beneficially owned by the interested stockholder; or
- the receipt by the interested stockholder of the benefit of loans, advances, guarantees, pledges or other financial benefits provided by or through the corporation.

In general, Section 203 defines an interested stockholder as any entity or person beneficially owning 15% or more of the outstanding voting stock of the corporation and any entity or person affiliated with or controlling or controlled by any of these entities or persons. Since Warburg Pincus owned their equity in us at the time we completed the Corporate Reorganization, Warburg Pincus is not subject to the restrictions of Section 203.

Certificate of incorporation and bylaws

Among other things, our amended and restated certificate of incorporation and amended and restated bylaws:

- provide advance notice procedures with regard to stockholder nomination of candidates for election as directors or proposals of business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder nominations or proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 45 days nor more than 75 days prior to the first anniversary date of the date on which we first mailed our proxy materials for the annual meeting for the preceding year. Our amended and restated bylaws specify the requirements as to form and content of all stockholders' notices. These requirements may make it more difficult for stockholders to bring matters before the stockholders at an annual or special meeting;
- provide our board of directors the ability to establish the terms of undesignated preferred stock. This ability makes it possible for our board of directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These and other provisions may have the effect of deterring hostile takeovers or delaying changes in control or management of Laredo;

- provide that at such time as Warburg Pincus no longer beneficially owns more than 50% of our outstanding common stock, our board of directors will be divided into three classes with each class serving staggered three year terms;
- provide that the authorized number of directors may be changed only by resolution of our board of directors;
- provide that all vacancies, including newly created directorships, shall, except as otherwise required by law or by resolution of the board of directors and subject to the rights of the holders of any series of preferred stock, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;
- provide that at such time as Warburg Pincus no longer beneficially owns more than 50% of our outstanding common stock, any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of preferred stock;
- provide that certain provisions of our amended and restated certificate of incorporation may be amended only with the affirmative vote of the holders of at least 75% of our then outstanding common stock;
- provide that our amended and restated bylaws may be amended by the affirmative vote of the holders of at least 75% of our then outstanding common stock;
- provide that special meetings of our stockholders may only be called by the board of directors; and
- provide that our amended and restated bylaws can be amended or repealed by our board of directors or our stockholders.

Limitation of liability and indemnification matters

Our amended and restated certificate of incorporation limits the liability of our directors for monetary damages for breach of their fiduciary duty as directors, except for the following liabilities that cannot be eliminated under the DGCL:

- for any breach of their duty of loyalty to us or our stockholders;
- for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;
- for an unlawful payment of dividends or an unlawful stock purchase or redemption, as provided under Section 174 of the DGCL; or
- for any transaction from which the director derived an improper personal benefit.

Any amendment or repeal of these provisions will be prospective only and would not affect any limitation on liability of a director for acts or omissions that occurred prior to any such amendment or repeal.

Our amended and restated bylaws also provide that we will indemnify our directors and officers to the fullest extent permitted by Delaware law; provided that we shall indemnify any such person seeking indemnification in connection with a proceeding (or part thereof) initiated by such person only if such proceeding (or part thereof) was authorized by the board of directors. Our amended and restated bylaws also explicitly authorize us to purchase insurance to protect any of our officers, directors, employees or agents or any person who is or was serving at our request as an officer, director, employee or agent of another enterprise for any expense, liability or loss, regardless of whether Delaware law would permit indemnification.

We have entered into indemnification agreements with each of our directors and officers. The agreements provide that we will indemnify and hold harmless each indemnitee for certain expenses to the fullest extent permitted or authorized by law, including the DGCL, in effect on the date of the agreement or as it may be amended to provide more advantageous rights to the indemnitee. If such indemnification is unavailable as a result of a court decision and if we and the indemnitee are jointly liable in the proceeding, we will contribute funds to the indemnitee for his expenses in proportion to relative benefit and fault of us and indemnitee in the transaction giving rise to the proceeding. The indemnification agreements also provide that we will indemnify the indemnitee for monetary damages for actions taken as our director or officer or for serving at our request as a director or officer or another position at another corporation or enterprise, as the case may be. The indemnification agreements also provide that we must advance payment of certain expenses to the indemnitee, including fees of counsel, subject to receipt of an undertaking from the indemnitee to return such advance if it is it is ultimately determined that the indemnitee is not entitled to indemnification.

We believe that the limitation of liability provision in our amended and restated certificate of incorporation and the indemnification agreements will facilitate our ability to continue to attract and retain qualified individuals to serve as directors and officers.

Corporate opportunity

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 entities or persons have an equity interest (other than us and our subsidiaries) (each a "specified party") participates or desires or seeks to participate in and that involves any aspect of the energy business or industry, unless any such business opportunity, transaction or matter 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 opportunity solely in his or her capacity as one of our directors, officers or employees.

Transfer agent and registrar

The transfer agent and registrar for our common stock is American Stock Transfer & Trust Company, LLC.

Listing

Our common stock is listed on the NYSE under the symbol "LPI."

Shares eligible for future sale

Future sales of our common stock in the public market, or the availability of such shares for sale in the public market, could adversely affect market prices prevailing from time to time. As described below, only a limited number of shares will be available for sale shortly after this offering due to contractual and legal restrictions on resale. Nevertheless, sales of a substantial number of shares of our common stock in the public market after such restrictions lapse, or the perception that those sales may occur, could adversely affect the prevailing market price at such time and our ability to raise equity-related capital at a time and price we deem appropriate.

Lock-up agreements

We, all of our directors and executive officers and our principal stockholders, including the selling stockholders, have agreed not to sell or otherwise transfer or dispose of any common stock for a period of 60 days from the date of this prospectus, subject to certain exceptions and extensions. There are no agreements or other intentions, either tacit or explicit, regarding the possible early release of any common stock subject to these lock-up provisions. See "Underwriting" for a description of these lock-up provisions.

Rule 144

In general, under Rule 144, a person who is not our affiliate and has not been our affiliate at any time during the preceding three months will be entitled to sell any shares of our common stock that such person has beneficially owned for at least six months, including the holding period of any prior owner other than one of our affiliates, without regard to volume limitations. Sales of our common stock by any such person would be subject to the availability of current public information about us if the shares to be sold were beneficially owned by such person for less than one year.

In addition, under Rule 144, a person may sell shares of our common stock acquired from us immediately upon the closing of this offering, without regard to volume limitations or the availability of public information about us, if:

- the person is not our affiliate and has not been our affiliate at any time during the preceding three months; and

- the person has beneficially owned the shares to be sold for at least one year, including the holding period of any prior owner other than one of our affiliates.

Our affiliates who have beneficially owned shares of our common stock for at least six months, including the holding period of any prior owner other than one of our affiliates, would be entitled to sell within any three-month period a number of shares that does not exceed the greater of:

- 1% of the number of shares of our common stock then-outstanding, which is approximately 1,282,306 shares; and

- the average weekly trading volume in our common stock on the NYSE during the four calendar weeks preceding the date of filing of a Notice of Proposed Sale of Securities Pursuant to Rule 144 with respect to the sale.

Sales under Rule 144 by our affiliates are also subject to manner of sale provisions and notice requirements and to the availability of current public information about us.

Stock issued under employee plans

We have an effective registration statement on Form S-8 under the Securities Act to register stock issuable under our long-term incentive plan. Shares covered by such registration statement are eligible for sale in the open market, subject to vesting restrictions with us, Rule 144 restrictions applicable to our affiliates or the lock-up restrictions described above.

Registration rights

Pursuant to the Registration Rights Agreement, Warburg Pincus and Mr. Foutch have certain registration rights. Pursuant to the lock-up agreements described herein, these stockholders have agreed not to exercise those rights during the lock-up period following this offering without the prior written consent of J.P. Morgan Securities LLC and Goldman, Sachs & Co. See "Certain relationships and related party transactions—Registration rights."

Certain U.S. federal income tax considerations for non-U.S. holders of shares of our common stock

Introduction

The following is a discussion of certain U.S. federal income tax considerations applicable to Non-U.S. Holders (as defined below) arising from the acquisition, ownership and disposition of shares of our common stock. This summary is for general information purposes only and does not purport to be a complete analysis or listing of all potential U.S. federal income tax considerations that may apply to a Non-U.S. Holder as a result of the acquisition, ownership and disposition of shares of our common stock. In addition, this summary does not take into account the individual facts and circumstances of any particular Non-U.S. Holder that may affect the U.S. federal income tax considerations applicable to such holder. Accordingly, this summary is not intended to be, and should not be construed as, legal or U.S. federal income tax advice with respect to any Non-U.S. Holder. Moreover, this summary is not binding on the Internal Revenue Service (the "IRS") or the U.S. courts, and no assurance can be provided that the conclusions reached in this summary will not be challenged by the IRS or will be sustained by a U.S. court if so challenged. We have not requested, and we do not intend to request, a ruling from the IRS or an opinion from U.S. legal counsel regarding any of the U.S. federal income or other tax considerations of the acquisition, ownership and disposition of shares of our common stock. Each Non-U.S. Holder should consult its own tax advisor regarding the acquisition, ownership and disposition of shares of our common stock.

Scope of this disclosure

Authorities

This summary is based on the Internal Revenue Code of 1986, as amended (the "Code"), Treasury Regulations (final, temporary, and proposed), U.S. court decisions, published IRS rulings and published administrative positions of the IRS, that are applicable and, in each case, as in effect and available, as of the date of this prospectus. Any of the authorities on which this summary is based could be changed in a material and adverse manner at any time, and any such change could be applied on a retroactive basis and could affect the U.S. federal income tax considerations described in this summary.

Non-U.S. holders

For purposes of this summary, a "Non-U.S. Holder" is a beneficial owner of shares of our common stock that is not a partnership or other entity classified as a partnership for U.S. federal income tax purposes and that is not: (a) an individual who is a citizen or resident of the U.S., (b) a corporation, or other entity classified as a corporation for U.S. federal income tax purposes, that is created or organized in or under the laws of the U.S. or any state in the U.S., including the District of Columbia, (c) an estate if the income of such estate is subject to U.S. federal income tax regardless of the source of such income, or (d) a trust if (i) such trust has validly elected to be treated as a U.S. person for U.S. federal income tax purposes or (ii) a U.S. court is able to exercise primary supervision over the administration of such trust and one or more U.S. persons have the authority to control all substantial decisions of such trust.

Non-U.S. holders subject to special U.S. federal income tax rules not addressed

This summary does not address the U.S. federal income tax considerations of the acquisition, ownership and disposition of shares of our common stock by Non-U.S. Holders that are subject to special provisions under the Code, including the following Non-U.S. Holders: (a) Non-U.S. Holders that are tax-exempt organizations, qualified retirement plans, individual retirement accounts, or other tax-deferred accounts; (b) Non-U.S. Holders that are financial institutions, insurance companies, real estate investment trusts, or regulated investment companies or that are broker-dealers, dealers, or traders in securities or currencies that elect to apply a mark-to-market accounting method; (c) Non-U.S. Holders that have a "functional currency" other than the U.S. dollar; (d) Non-U.S. Holders that own shares of our common stock as part of a straddle, hedging transaction, conversion transaction, constructive sale, or other arrangement involving more than one position; (e) Non-U.S. Holders that acquire shares of our common stock in connection with the exercise of employee stock options or otherwise as compensation for services; (f) Non-U.S. Holders that hold shares of our common stock other than as a capital asset within the meaning of Section 1221 of the Code; (g) Non-U.S. Holders who are U.S. expatriates or former long term residents of the United States; and (h) Non-U.S. Holders that own, directly, indirectly, or by attribution, 5% or more, by voting power or value, of the outstanding shares of our common stock. Non-U.S. Holders that are subject to special provisions under the Code, including but not limited to Non-U.S. Holders described immediately above, should consult their own tax advisors regarding the U.S. federal, U.S. state and local, and foreign tax and other tax considerations of the acquisition, ownership and disposition of shares of our common stock.

If a partnership or other entity that is classified as partnership for U.S. federal income tax purposes holds shares of our common stock, the U.S. federal income tax considerations to such partnership and the partners of such partnership generally will depend on the activities of the partnership and the status of such partners (or owners). Partnerships or other entities that are classified as partnerships for U.S. federal income tax purposes and their owners should consult their own tax advisors regarding the U.S. federal income tax considerations of the acquisition, ownership and disposition of shares of our common stock.

Tax considerations other than U.S. federal income tax considerations not addressed

This summary does not address any state, local, alternative minimum, estate and gift, foreign, or other tax considerations other than U.S. federal income tax considerations that may be relevant to Non-U.S. Holders in connection with the acquisition, ownership and disposition of shares of our common stock. Each Non-U.S. Holder should consult its own tax advisors regarding any state, local, estate and gift, foreign, and any other tax considerations that may be relevant to such holder in connection with the acquisition, ownership and disposition of shares of our common stock.

Dividends

In general, if distributions with respect to shares of our common stock are made, such distributions would be treated as dividends to the extent of our current or accumulated earnings and profits as determined under the Code. Any portion of a distribution that exceeds our current or accumulated earnings and profits will first be applied to reduce the Non-U.S. Holder's basis in shares of our common stock, and, to the extent such portion exceeds the

Non-U.S. Holder's basis, the excess will be treated as gain from the disposition of shares of our common stock, the tax treatment of which is discussed below under the heading "Gain on sale or other disposition of shares of our common stock."

Generally, dividends paid in respect of shares of our common stock to a Non-U.S. Holder will be subject to U.S. withholding tax at a 30% rate, subject to the two following exceptions:

- Dividends effectively connected with a trade or business of a Non-U.S. Holder within the U.S. generally will not be subject to withholding if the Non-U.S. Holder complies with applicable IRS certification and disclosure requirements and generally will be subject to U.S. federal income tax on a net income basis at regular U.S. federal income tax rates (in the same manner as a U.S. person) on its U.S. trade or business income. In the case of a Non-U.S. Holder that is a corporation, such effectively connected income also may be subject to the branch profits tax at a 30% rate (or such lower rate as may be prescribed by an applicable tax treaty).

- The withholding tax might not apply, or might apply at a reduced rate, under the terms of an applicable tax treaty. Under Treasury Regulations, to obtain a reduced rate of withholding under a tax treaty, a Non-U.S. Holder generally will be required to satisfy applicable certification and other requirements. A Non-U.S. Holder of shares of our common stock eligible for a reduced rate of U.S. withholding tax may obtain a refund or credit of any excess amounts withheld by filing an appropriate claim for refund with the IRS.

Gain on sale or other disposition of shares of our common stock

Except as described in the discussion below under the heading "Information Reporting; Backup Withholding Tax," a Non-U.S. Holder generally will not be subject to U.S. federal income tax, including withholding tax, in connection with the receipt of proceeds from the sale, exchange, or other taxable disposition of shares of our common stock, unless:

- the gain is effectively connected with the Non-U.S. Holder's conduct of a trade or business within the United States and, if subject to an applicable tax treaty, is attributable to a permanent establishment or fixed base maintained by the Non-U.S. Holder in the U.S.;

- in the case of an individual, the Non-U.S. Holder has been present in the U.S. for at least 183 days or more in the taxable year of disposition (and certain other conditions are satisfied); or

- we are or have been a "U.S. real property holding corporation" ("USRPHC"), for U.S. federal income tax purposes (that is, a domestic corporation whose trade or business and real property assets consist primarily of "U.S. real property interests") at any time during the shorter of the five-year period ending on the date of disposition and the Non-U.S. Holder's holding period for its shares of our common stock and, if shares of our common stock are "regularly traded on an established securities market," the Non-U .S. Holder held, directly or indirectly, at any time during such period, more than 5% of the issued and outstanding common stock.

Income that is effectively connected with the conduct of a U.S. trade or business by a Non-U.S. Holder generally will be subject to regular U.S. federal income tax in the same manner as if it were realized by a U.S. Holder. In addition, if such Non-U.S. Holder is a corporation, such gain may be subject to a branch profits tax at a rate of 30% (or such lower rate as is provided by an applicable income tax treaty).

If an individual Non-U.S. Holder is present in the U.S. for at least 183 days during the taxable year of disposition, the Non-U.S. Holder may be subject to a flat 30% tax on any U.S.-source gain derived from the sale, exchange, or other taxable disposition of shares of our common stock (other than gain effectively connected with a U.S. trade or business), which may be offset by U.S.-source capital losses.

It is likely that we are a USRPHC. As a result, any gain recognized by a Non-U.S. Holder on the sale, exchange, or other taxable disposition of our common stock may be subject to U.S. federal income tax in the same manner as gain recognized by a U.S. Holder ("FIRPTA Tax"). In addition, a Non-US. Holder may under certain circumstances be subject to withholding in an amount equal to 10% of the gross proceeds on the sale or disposition; if the Non-U.S. Holder files a U.S. federal income tax return, any amounts so withheld will generally be credited against, and refunded to the extent in excess of, any FIRPTA Tax such Non-U.S. Holder owes.

However, so long as our common stock is considered to be "regularly traded on an established securities market" ("regularly traded") at any time during the calendar year, a Non-U.S. Holder generally will not be subject to FIRPTA Tax on any gain recognized on the sale or other disposition of our common stock unless the Non-U.S. Holder owned (actually or constructively) shares of our common stock with a fair market value of more than 5% of the total fair market value of our common stock at any time during the applicable period described in the third bullet point above. No withholding is required under these rules upon a sale or other taxable disposition of our common stock if it is considered to be regularly traded. If, on the other hand, our common stock is not considered to be regularly traded, you would be subject to FIRPTA Tax on any gain recognized on your sale or other taxable disposition of our common stock, and withholding on the gross proceeds thereof, regardless of your percentage ownership of our common stock.

Recent law changes affecting U.S. federal income tax withholding

Recently enacted legislation and administrative guidance will require withholding at a rate of 30% on dividends paid on or after January 1, 2014 and gross proceeds from the sale of shares of our common stock paid on or after January 1, 2015 to certain foreign financial institutions (including investment funds), unless such institution enters into an agreement with the Secretary of the Treasury to, among other things, report, on an annual basis, information with respect to accounts with or shares in the institution held by certain U.S. persons and by certain non-U.S. entities that are wholly or partially owned by United States persons, and to withhold on payments made to certain account holders. Accordingly, the entity through which shares of our common stock is held will affect the determination of whether such withholding is required. Similarly, dividends in respect of, and gross proceeds from the sale of, shares of our common stock held by an investor that is a non-financial foreign entity will be subject to withholding at a rate of 30% if such entity or another non-financial foreign entity is the beneficial owner of the payment, unless, among other things, the beneficial owner or the payee either (i) certifies to us that such entity does not have any "substantial United States owners" or (ii) provides certain information regarding the entity's "substantial United States owners," which we will in turn provide to the Secretary of the Treasury. Non-U.S. Holders are encouraged to consult with their tax advisors regarding the possible implications of the legislation on their investment in shares of our common stock.

Information reporting and backup withholding tax

A Non-U.S. Holder generally will not be subject to information reporting or backup withholding with respect to payments of dividends on, or gross proceeds from the disposition of, shares of our common stock that are made within the United States or though certain U.S.-related financial intermediaries, provided that the Non-U.S. Holder certifies as to its foreign status or otherwise establishes an exemption.

Backup withholding is not an additional tax. Amounts withheld as backup withholding may be credited against a Non-U.S. Holder's U.S. federal income tax liability, and a Non-U.S. Holder may obtain a refund of any excess amounts withheld under the backup withholding rules by timely filing the appropriate claim for refund with the IRS and furnishing any required information. Non-U.S. Holders should consult their own tax advisors regarding the application of the information reporting and backup withholding rules to them in their particular circumstances.

Certain ERISA considerations

There are certain considerations to be made in connection with the purchase of the common stock by (1) employee benefit plans that are subject to Title I of the Employee Retirement Income Security Act of 1974, as amended, or ERISA, (2) plans, individual retirement accounts and other arrangements that are subject to Section 4975 of the Code or provisions under any federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of the Code or ERISA, which similar provisions are collectively referred to herein as Similar Laws, and (3) entities whose underlying assets are considered to include "plan assets" of any such plan, account or arrangement, each (1), (2), and (3), a Plan.

ERISA and the Code impose certain duties on persons who are fiduciaries of a Plan subject to Title I of ERISA or Section 4975 of the Code, which Plan is referred to herein as an ERISA Plan, and prohibit certain transactions involving the assets of an ERISA Plan with parties that are "parties in interest" under ERISA or "disqualified persons" under the Code. Under ERISA and the Code, any person who exercises any discretionary authority or control over the administration of such an ERISA Plan or the management or disposition of the assets of such an ERISA Plan, or who renders investment advice for a fee or other compensation to such an ERISA Plan, is generally considered to be a fiduciary of the ERISA Plan.

In considering an investment in the common stock of a portion of the assets of any Plan, a fiduciary should determine whether the investment is in accordance with the documents and instruments governing the Plan and the applicable provisions of ERISA, the Code or any Similar Law relating to a fiduciary's duties to the Plan including, without limitation, the prudence, diversification, delegation of control and prohibited transaction provisions of ERISA, the Code and any other applicable Similar Laws.

Underwriting

The selling stockholders are offering the shares of common stock described in this prospectus through a number of underwriters. J.P. Morgan Securities LLC, Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wells Fargo Securities, LLC are acting as book-running managers of the offering and as the representatives of the underwriters. We and the selling stockholders have entered into an underwriting agreement with the underwriters. Subject to the terms and conditions of the underwriting agreement, the selling stockholders have agreed to sell to the underwriters, and each underwriter has severally agreed to purchase, at the public offering price less the underwriting discount set forth on the cover page of this prospectus, the number of shares of common stock listed next to its name in the following table:

Name	Number of Shares
J.P. Morgan Securities LLC	
Goldman, Sachs & Co.	
Merrill Lynch, Pierce, Fenner & Smith Incorporated	
Wells Fargo Securities, LLC	
BMO Capital Markets Corp.	
Capital One Southcoast, Inc.	
Howard Weil Incorporated	
SG Americas Securities, LLC	
BB&T Capital Markets, a division of Scott & Stringfellow, LLC	
BOSC, Inc.	
Comerica Securities, Inc.	
Mitsubishi UFJ Securities (USA), Inc.	
Total	12,500,000

The underwriters are committed to purchase all the common stock offered hereby if they purchase any shares. The underwriting agreement also provides that if an underwriter defaults, the purchase commitments of non-defaulting underwriters may also be increased or the offering may be terminated.

The underwriters propose to offer the common stock directly to the public at the public offering price set forth on the cover page of this prospectus and to certain dealers at that price less a concession not in excess of $ per share. After the public offering of the shares, the offering price and other selling terms may be changed by the underwriters. Sales of shares made outside of the United States may be made by affiliates of the underwriters. The representatives have advised us that the underwriters do not intend to confirm discretionary sales in excess of 5% of the common stock offered in this offering. The offering of the shares by the underwriters is subject to receipt and acceptance and subject to the underwriters right to reject any order in whole or in part.

The underwriters have an option to buy up to 1,875,000 additional shares of common stock from the selling stockholders to cover sales of shares by the underwriters which exceed the number of shares specified in the table above. The underwriters have 30 days from the date of this prospectus to exercise the underwriters' option to purchase additional shares of common stock. If any shares are purchased with an option to acquire additional shares of common stock, the underwriters will purchase shares in approximately the same proportion as shown in the table above. If any additional shares of common stock are purchased, the underwriters will offer the additional shares on the same terms as those on which the shares are being offered.

The underwriting fee is equal to the public offering price per share of common stock less the amount paid by the underwriters to the selling stockholders per share of common stock. The underwriting fee is $ per share. The following table shows the per share and total underwriting discount to be paid to the underwriters assuming both no exercise and full exercise of the underwriters' option to purchase additional shares of common stock.

	Without exercise of option to purchase additional shares	**With full exercise of option to purchase additional shares**
Per share	$	$
Total	$	$

We estimate that the total expenses of this offering to us, including registration, filing and listing fees, printing fees, and legal and accounting expenses, but excluding the underwriting discount, will be approximately $.

A prospectus in electronic format may be made available on the web sites maintained by one or more underwriters, or selling group members, if any, participating in the offering. The underwriters may agree to allocate a number of shares to underwriters and selling group members for sale to their online brokerage account holders. Internet distributions will be allocated by the representatives to underwriters and selling group members that may make Internet distributions on the same basis as other allocations.

We have agreed that we will not (1) offer, pledge, announce the intention to sell, sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, or otherwise dispose of, directly or indirectly, or file with the SEC a registration statement under the Securities Act relating to, any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, or publicly disclose the intention to make any offer, sale, pledge, disposition, or filing, or (2) enter into any swap or other arrangement that transfers all or a portion of the economic consequences associated with the ownership of any shares of common stock or any such other securities (regardless of whether any of these transactions are to be settled by the delivery of shares of common stock or such other securities, in cash or otherwise), in each case without the prior written consent of J.P. Morgan Securities LLC and Goldman, Sachs & Co. for a period of 60 days after the date of this prospectus, other than any shares of our common stock issued upon the exercise of options granted under our management incentive plans. There are no agreements or other intentions, either tacit or explicit, regarding the possible early release of any common stock subject to the lock-up provisions.

Notwithstanding the foregoing, if (A) during the last 17 days of the 60-day restricted period, we issue an earnings release or material news or a material event relating to Laredo occurs; or

(B) prior to the expiration of the 60-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 16-day period, the restrictions described above shall continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the occurrence of the material news or material event.

Certain affiliates of Warburg Pincus and each of our directors and executive officers have entered into lock-up agreements with the underwriters prior to the commencement of this offering pursuant to which each of these persons or entities, with limited exceptions, for a period of 60 days after the date of this prospectus, may not, without the prior written consent of J.P. Morgan Securities LLC and Goldman, Sachs & Co. (1) offer, pledge, announce the intention to sell, sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, or otherwise transfer or dispose of, directly or indirectly, any shares of our common stock or any securities convertible into or exercisable or exchangeable for our common stock (including, without limitation, common stock or such other securities which may be deemed to be beneficially owned by such affiliates of Warburg Pincus, directors, executive officers, managers, and members in accordance with the rules and regulations of the SEC and securities which may be issued upon exercise of a stock option or warrant) or (2) enter into any swap or other agreement that transfers, in whole or in part, any of the economic consequences of ownership of the common stock or such other securities, whether any such transaction described in clause (1) or (2) above is to be settled by delivery of common stock or such other securities, in cash or otherwise, or (3) make any demand for or exercise any right with respect to the registration of any shares of our common stock or any security convertible into or exercisable or exchangeable for our common stock, except that Warburg Pincus will be permitted to spin-off our common stock that it owns to its shareholders 60 days after the date of this prospectus. In addition, the lock-up agreements will not restrict the transfer of common stock as bona fide gifts, transfer by will or the laws of intestacy, transfers to family members (including to vehicles of which they are beneficial owners), transfers pursuant to domestic relations or court orders, or (in the case of corporations or other entities) transfers to affiliates, in each case so long as the transferee agrees to be bound by the restrictions in the lock-up agreements. Notwithstanding the foregoing, if (A) during the last 17 days of the 60-day restricted period, we issue an earnings release or material news or a material event relating to our company occurs; or (B) prior to the expiration of the 60-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 60-day period, the restrictions described above shall continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the occurrence of the material news or material event.

We have agreed to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act. The selling stockholders have also agreed that they will indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute payments that the underwriters may be required to make for these liabilities, in each case as set forth in the underwriting agreement up to the gross proceeds received by the selling stockholders from this offering.

Our shares of common stock are listed for trading on the NYSE under the symbol "LPI."

In connection with this offering, the underwriters may engage in stabilizing transactions, which involves making bids for, purchasing and selling shares of common stock in the open market for the purpose of preventing or retarding a decline in the market price of the common stock while this offering is in progress. These stabilizing transactions may include making short sales of the common stock, which involves the sale by the underwriters of a greater number of shares of common stock than they are required to purchase in this offering, and purchasing shares of common stock on the open market to cover positions created by short sales. Short sales may be "covered" shorts, which are short positions in an amount not greater than the underwriters' option to acquire additional shares of common stock referred to above, or may be "naked" shorts, which are short positions in excess of that amount. The underwriters may close out any covered short position either by exercising their option to acquire additional shares of common stock, in whole or in part, or by purchasing shares in the open market. In making this determination, the underwriters will consider, among other things, the price of shares available for purchase in the open market compared to the price at which the underwriters may purchase shares through the option to acquire additional shares of common stock. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common stock in the open market that could adversely affect investors who purchase in this offering. To the extent that the underwriters create a naked short position, they will purchase shares in the open market to cover the position.

The underwriters have advised us that, pursuant to Regulation M of the Securities Act, they may also engage in other activities that stabilize, maintain or otherwise affect the price of the common stock, including the imposition of penalty bids. This means that if the representatives of the underwriters purchase common stock in the open market in stabilizing transactions or to cover short sales, the representative can require the underwriters that sold those shares as part of this offering to repay the underwriting discount received by them.

These activities may have the effect of raising or maintaining the market price of the common stock or preventing or retarding a decline in the market price of the common stock, and, as a result, the price of the common stock may be higher than the price that otherwise might exist in the open market. If the underwriters commence these activities, they may discontinue them at any time. The underwriters may carry out these transactions on the NYSE, in the over-the-counter market or otherwise.

Other than in the United States, no action has been taken by us or the underwriters that would permit a public offering of the securities offered by this prospectus in any jurisdiction where action for that purpose is required. The securities offered by this prospectus may not be offered or sold, directly or indirectly, nor may this prospectus or any other offering material or advertisements in connection with the offer and sale of any such securities be distributed or published in any jurisdiction, except under circumstances that will result in compliance with the applicable rules and regulations of that jurisdiction. Persons into whose possession this prospectus comes are advised to inform themselves about and to observe any restrictions relating to the offering and the distribution of this prospectus. This prospectus does not constitute an offer to sell or a solicitation of an offer to buy any securities offered by this prospectus in any jurisdiction in which such an offer or a solicitation is unlawful.

This document is only being distributed to and is only directed at (1) persons who are outside the United Kingdom or (2) to investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, which we refer to as the Order, or (3) high net worth entities, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order, all such persons together we refer to as relevant persons. The securities are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such securities will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents.

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive, which we refer to as a Relevant Member State, from and including the date on which the European Union Prospectus Directive, or the EU Prospectus Directive, is implemented in that Relevant Member State, which we refer to this date as the Relevant Implementation Date, an offer of securities described in this prospectus may not be made to the public in that Relevant Member State prior to the publication of a prospectus in relation to the shares which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the EU Prospectus Directive, except that it may, with effect from and including the Relevant Implementation Date, make an offer of shares to the public in that Relevant Member State at any time:

- to legal entities which are authorized or regulated to operate in the financial markets or, if not so authorized or regulated, whose corporate purpose is solely to invest in securities;

- to any legal entity which has two or more of (1) an average of at least 250 employees during the last financial year; (2) a total balance sheet of more than €43,000,000 and (3) an annual net turnover of more than €50,000,000, as shown in its last annual or consolidated accounts;

- to fewer than 100 natural or legal persons (other than qualified investors as defined in the EU Prospectus Directive) subject to obtaining the prior consent of the book-running managers for any such offer; or

- in any other circumstances which do not require the publication by the issuer of a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, the expression an "offer of securities to the public" in relation to any securities in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the securities to be offered so as to enable an investor to decide to purchase or subscribe for the securities, as the same may be varied in that Member State by any measure implementing the EU Prospectus Directive in that Member State and the expression EU Prospectus Directive means Directive 2003/71/EC and includes any relevant implementing measure in each Relevant Member State.

The shares may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (ii) to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a "prospectus" within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), and no advertisement, invitation or document relating to the shares may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to shares which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the shares may not be circulated or distributed, nor may the shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the "SFA"), (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the shares are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries' rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the shares under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

The securities have not been and will not be registered under the Financial Instruments and Exchange Law of Japan (the Financial Instruments and Exchange Law) and each underwriter has agreed that it will not offer or sell any securities, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Financial Instruments and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

The shares may not be publicly offered in Switzerland and will not be listed on the SIX Swiss Exchange ("SIX") or on any other stock exchange or regulated trading facility in Switzerland. This document has been prepared without regard to the disclosure standards for issuance prospectuses under art. 652a or art. 1156 of the Swiss Code of Obligations or the disclosure standards for listing prospectuses under art. 27 ff. of the SIX Listing Rules or the listing rules of any other stock exchange or regulated trading facility in Switzerland. Neither this document nor any other offering or marketing material relating to the shares or the offering may be publicly distributed or otherwise made publicly available in Switzerland.

Neither this document nor any other offering or marketing material relating to the offering, Laredo, the shares have been or will be filed with or approved by any Swiss regulatory authority. In particular, this document will not be filed with, and the offer of shares will not be supervised by, the Swiss Financial Market Supervisory Authority FINMA (FINMA), and the offer of shares has not been and will not be authorized under the Swiss Federal Act on Collective Investment Schemes ("CISA"). The investor protection afforded to acquirers of interests in collective investment schemes under the CISA does not extend to acquirers of shares.

This prospectus relates to an Exempt Offer in accordance with the Offered Securities Rules of the Dubai Financial Services Authority ("DFSA"). This prospectus is intended for distribution only to persons of a type specified in the Offered Securities Rules of the DFSA. It must not be delivered to, or relied on by, any other person. The DFSA has no responsibility for reviewing or verifying any documents in connection with Exempt Offers. The DFSA has not approved this prospectus nor taken steps to verify the information set forth herein and has no responsibility for the prospectus. The shares to which this prospectus relates may be illiquid and/or subject to restrictions on their resale. Prospective purchasers of the shares offered should conduct their own due diligence on the shares. If you do not understand the contents of this prospectus you should consult an authorized financial advisor.

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their affiliates have provided in the past to us and our affiliates and may provide from time to time in the future certain commercial banking, including as lenders under our senior credit facility, financial advisory, investment banking and other services for us and such affiliates for which they have received and may continue to receive customary fees and commissions. Merrill Lynch, Pierce, Fenner & Smith Incorporated acted as representative of the initial purchasers in connection with Laredo Petroleum, Inc.'s April 2012 offering of $500 million aggregate principal amount of 2022 senior unsecured notes. Each of the underwriters acted as an initial purchaser in the April 2012 offering of 2022 senior unsecured notes.

In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of the issuer. The underwriters and their respective affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

Legal matters

Certain legal matters in connection with this offering will be passed upon for us by Kenneth E. Dornblaser, our Senior Vice President and General Counsel. Mr. Dornblaser beneficially owns 26,918 shares of common stock, 13,617 of which are subject to forfeiture and vesting requirements. The validity of our common stock offered by this prospectus will be passed upon for us by Akin Gump Strauss Hauer & Feld LLP, Houston, Texas. Certain legal matters in connection with this offering will be passed upon for the underwriters by Andrews Kurth LLP, Houston, Texas.

Experts

The consolidated financial statements of Laredo Petroleum Holdings, Inc. as of December 31, 2011 and 2010 and for each of the years in the three year period ended December 31, 2011, included in this prospectus and elsewhere in the registration statement have been so included in reliance upon the report of Grant Thornton LLP, independent registered public accountants, upon the authority of said firm as experts in accounting and auditing in giving said report.

The estimates of our proved reserves as of December 31, 2011, 2010 and 2009 included in this prospectus are based on a reserve report prepared by Ryder Scott Company, L.P., independent petroleum engineers. These estimates are included in this prospectus in reliance upon the authority of the firm as experts in these matters.

Incorporation of certain information by reference

The SEC allows us to "incorporate by reference" information contained in documents that we file with the SEC into this prospectus. This means that we can disclose important information to you by referring you to those documents. The information that we incorporate by reference is an integral part of this prospectus, and references to "this prospectus" include the documents (or portions of documents) incorporated by reference into this prospectus. We incorporate by reference the documents listed below (other than information furnished rather than filed):

- Laredo Petroleum Holdings, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011;
- Laredo Petroleum Holdings, Inc.'s Definitive Proxy Statement on Schedule 14A, as filed on April 6, 2012 (only those sections incorporated by reference into our Annual Report on Form 10-K for the year ended December 31, 2011);
- Laredo Petroleum Holdings, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2012;
- Laredo Petroleum Holdings, Inc.'s Quarterly Report on Form 10-Q for the period ended June 30, 2012; and
- Laredo Petroleum Holdings, Inc.'s Current Reports on Form 8-K filed on January 19, 2012, February 9, 2012, April 16, 2012, April 25, 2012, April 30, 2012, May 22, 2012 and June 14, 2012.

Any statement contained in a document incorporated by reference into this prospectus shall be deemed to be modified or superseded for purposes of this prospectus to the extent that a statement contained in this prospectus modifies or supersedes the statement. Any statement so modified or superseded shall not be deemed to constitute a part of this prospectus except as so modified or superseded. The information contained in this prospectus should be read together with the information in the documents incorporated in this prospectus by reference.

We will provide to each person, including any beneficial owner, to whom this prospectus is delivered these incorporated documents without charge, excluding any exhibits to these documents unless the exhibit is specifically incorporated by reference in such document, upon request received in writing or by telephone at the following address: Laredo Petroleum Holdings, Inc., Attention: Investor Relations, 15 W. Sixth Street, Suite 1800, Tulsa, Oklahoma 74119, (918) 513-4570. These incorporated documents may also be available on our website at www.laredopetro.com. Except for incorporated documents, information contained on our website is not a prospectus and does not constitute part of this prospectus.

Where you can find more information

We have filed with the SEC a registration statement on Form S-1 under the Securities Act with respect to the shares of common stock offered hereby. This prospectus, which constitutes a part of the registration statement, does not contain all of the information set forth in the registration statement or the exhibits and schedules filed therewith. For further information about us and the common stock offered hereby, we refer you to the registration statement and the exhibits and schedules filed thereto. Statements contained in this prospectus regarding the contents of any contract or any other document that is filed as an exhibit to the registration statement are not necessarily complete, and each such statement is qualified in all respects by reference to the full text of such contract or other document filed as an exhibit to the registration statement.

We are subject to the information and reporting requirements of the Exchange Act and, in accordance with this law, are required to file periodic reports, proxy statements and other information with the SEC. You may read and copy this information at the Public Reference Room of the SEC, 100 F Street, N.E., Room 1580, Washington D.C. 20549. You may obtain information on the operation of the public reference rooms by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet website that contains reports, proxy statements and other information about issuers, like us, that file electronically with the SEC. The address of that site is www.sec.gov. You may also access our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act with the SEC free of charge at our website, www.laredopetro.com, as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. The information contained in, or that can be accessed through, our website is not part of this prospectus.

Index to financial statements

Laredo Petroleum Holdings, Inc.
Consolidated balance sheets

(in thousands, except share data) (Unaudited)	June 30, 2012	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 146,485	$ 28,002
Accounts receivable, net	71,832	74,135
Derivative financial instruments	20,513	13,281
Deferred income taxes	—	5,202
Other current assets	5,816	2,318
Total current assets	244,646	122,938
Property and equipment:		
Oil and natural gas properties, full cost method:		
Proved properties	2,551,524	2,083,015
Unproved properties not being amortized	127,971	117,195
Pipeline and gas gathering assets	63,667	58,136
Other fixed assets	21,840	16,948
	2,765,002	2,275,294
Less accumulated depreciation, depletion, amortization and impairment	1,008,597	896,785
Net property and equipment	1,756,405	1,378,509
Deferred income taxes	64,903	90,376
Derivative financial instruments	12,888	6,510
Deferred loan costs, net	31,666	23,457
Other assets, net	5,430	5,862
Total assets	$ 2,115,938	$ 1,627,652
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$ 49,311	$ 46,007
Undistributed revenue and royalties	31,565	26,844
Accrued capital expenditures	92,646	91,022
Accrued compensation and benefits	8,210	11,270
Derivative financial instruments	603	4,187
Accrued interest payable	26,193	20,112
Other current liabilities	15,498	14,919
Total current liabilities	224,026	214,361
Long-term debt	1,051,863	636,961
Derivative financial instruments	72	2,415
Asset retirement obligations	15,483	12,568
Other noncurrent liabilities	2,436	1,334
Total liabilities	1,293,880	867,639
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued at June 30, 2012 and December 31, 2011	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized, and 128,296,239 and 127,617,391 issued, net of treasury, at June 30, 2012 and December 31, 2011, respectively	1,283	1,276
Additional paid-in capital	956,203	951,375
Accumulated deficit	(135,424)	(192,634)
Treasury stock, at cost, 7,609 common shares at June 30, 2012 and December 31, 2011	(4)	(4)
Total stockholders' equity	822,058	760,013
Total liabilities and stockholders' equity	$ 2,115,938	$ 1,627,652

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

Laredo Petroleum Holdings, Inc.
Consolidated statements of operations

(in thousands, except per share data) (Unaudited)	Six months ended June 30, 2012	2011
Revenues:		
Oil and natural gas sales	$ 288,560	$ 236,532
Natural gas transportation and treating	2,412	2,306
Total revenues	290,972	238,838
Costs and expenses:		
Lease operating expenses	30,644	18,112
Production and ad valorem taxes	16,237	14,999
Natural gas transportation and treating	691	1,167
Drilling and production	1,771	693
General and administrative (including non-cash stock-based compensation of $4,835 and $876 for the six months ended June 30, 2012 and 2011, respectively)	31,941	19,770
Accretion of asset retirement obligations	556	304
Depreciation, depletion and amortization	112,220	75,917
Impairment expense	—	243
Total costs and expenses	194,060	131,205
Operating income	96,912	107,633
Non-operating income (expense):		
Realized and unrealized gain (loss):		
Commodity derivative financial instruments, net	29,137	(9,585)
Interest rate derivatives, net	(323)	(1,094)
Interest expense	(36,358)	(22,252)
Interest and other income	31	58
Write-off of deferred loan costs	—	(3,246)
Loss on disposal of assets	(8)	(35)
Non-operating expense, net	(7,521)	(36,154)
Income before income taxes	89,391	71,479
Income tax expense:		
Deferred	(32,181)	(25,737)
Total income tax expense	(32,181)	(25,737)
Net income	$ 57,210	$ 45,742
Net income per common share:		
Basic	$ 0.45	
Diluted	$ 0.45	
Weighted average common shares outstanding:		
Basic	126,862	
Diluted	128,101	

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

Laredo Petroleum Holdings, Inc.
Consolidated statement of stockholders' equity

(in thousands) (Unaudited)	Common Stock Shares	Common Stock Amount	Additional paid-in capital	Treasury Stock (at cost) Shares	Treasury Stock (at cost) Amount	Accumulated deficit	Total
Balance, December 31, 2011	127,617	$ 1,276	$ 951,375	8	$ (4)	$ (192,634)	$ 760,013
Restricted stock awards	777	8	(8)	—	—	—	—
Restricted stock forfeitures	(98)	(1)	1	—	—	—	—
Stock-based compensation	—	—	4,835	—	—	—	4,835
Net income	—	—	—	—	—	57,210	57,210
Balance, June 30, 2012	128,296	$ 1,283	$ 956,203	8	$ (4)	$ (135,424)	$ 822,058

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

Laredo Petroleum Holdings, Inc.
Consolidated statements of cash flows

(in thousands) (Unaudited)	Six months ended June 30, 2012	2011
Cash flows from operating activities:		
Net income	$ 57,210	$ 45,742
Adjustments to reconcile net income to net cash provided by operating activities:		
Deferred income tax expense	32,181	25,737
Depreciation, depletion and amortization	112,220	75,917
Impairment expense	—	243
Non-cash stock-based compensation	4,835	876
Accretion of asset retirement obligations	556	304
Unrealized (gain) loss on derivative financial instruments, net	(16,929)	7,192
Premiums paid for derivative financial instruments	(2,927)	(512)
Amortization of premiums paid for derivative financial instruments	319	216
Amortization of deferred loan costs	2,268	1,909
Write-off of deferred loan costs	—	3,246
Amortization of October 2011 Notes premium	(99)	—
Amortization of other assets	10	9
Loss on disposal of assets	8	35
(Increase) decrease in accounts receivable	2,303	(12,142)
(Increase) decrease in other current assets	(3,075)	(768)
Increase (decrease) in accounts payable	3,304	(6,513)
Increase (decrease) in undistributed revenues and royalties	4,721	8,019
Increase (decrease) in accrued compensation and benefits	(3,060)	(3,970)
Increase (decrease) in other accrued liabilities	4,828	16,572
Increase (decrease) in other noncurrent liabilities	1,117	(54)
Net cash provided by operating activities	199,790	162,058
Cash flows from investing activities:		
Capital expenditures:		
Oil and natural gas properties	(473,846)	(348,523)
Pipeline and gas gathering assets	(7,031)	(6,344)
Other fixed assets	(4,988)	(4,602)
Proceeds from other fixed asset disposals	34	20
Net cash used in investing activities	(485,831)	(359,449)
Cash flows from financing activities:		
Borrowings on revolving credit facilities	195,000	180,100
Payments on revolving credit facilities	(280,000)	(231,300)
Payments on term loan	—	(100,000)
Issuance of 2019 Notes	—	350,000
Issuance of 2022 Notes	500,000	—
Payments for loan costs	(10,476)	(10,592)
Net cash provided by financing activities	404,524	188,208
Net increase (decrease) in cash and cash equivalents	118,483	(9,183)
Cash and cash equivalents, beginning of period	28,002	31,235
Cash and cash equivalents, end of period	$ 146,485	$ 22,052
Supplemental disclosure of cash flow information:		
Cash paid during the period:		
Interest, net of $505 and zero, respectively, of capitalized interest for the six months ended June 30, 2012 and 2011, respectively	$ 27,956	$ 6,626

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

Laredo Petroleum Holdings, Inc.
Condensed notes to the consolidated financial statements
(Unaudited)

A—Organization

Laredo Petroleum Holdings, Inc. ("Laredo Holdings") together with its subsidiaries, is an independent energy company focused on the exploration, development and acquisition of oil and natural gas properties in the Permian and Mid-Continent regions of the United States. Laredo Holdings was incorporated pursuant to the laws of the State of Delaware on August 12, 2011 for the purposes of a Corporate Reorganization (as defined below) and the initial public offering of its common stock (the "IPO") on December 20, 2011. As a holding company, Laredo Holdings' management operations are conducted through its wholly-owned subsidiary, Laredo Petroleum, Inc. ("Laredo"), a Delaware corporation, and Laredo's subsidiaries, Laredo Petroleum Texas, LLC ("Laredo Texas"), a Texas limited liability company, Laredo Gas Services, LLC ("Laredo Gas"), a Delaware limited liability company, and Laredo Petroleum—Dallas, Inc. ("Laredo Dallas"), a Delaware corporation.

On July 1, 2011, Laredo Petroleum, LLC ("Laredo LLC"), a Delaware limited liability company, and Laredo completed the acquisition of Broad Oak Energy, Inc., a Delaware corporation ("Broad Oak"), for a combination of equity and cash. Prior to the acquisition, Broad Oak was owned by its management and Warburg Pincus Private Equity, L.P. ("Warburg Pincus IX"). On July 19, 2011, Broad Oak's name was changed to Laredo Petroleum—Dallas, Inc.

On December 19, 2011, immediately prior to the IPO, Laredo LLC merged with and into Laredo Holdings, with Laredo Holdings being the surviving entity. Warburg Pincus IX and other affiliates of Warburg Pincus LLC were majority owners of Laredo LLC and are of Laredo Holdings. The preferred units and certain series of restricted units of Laredo LLC were exchanged into shares of common stock of Laredo Holdings based on the pre-offering equity value of such units (the "Corporate Reorganization"). The common stock has one vote per share and a par value of $0.01 per share.

In these notes, the "Company," when used in the present tense, prospectively or for historical periods since December 19, 2011, refers to Laredo Holdings, Laredo and its subsidiaries collectively, and for historical periods prior to December 19, 2011 refers to Laredo LLC, Laredo and its subsidiaries collectively, unless the context indicates otherwise.

B—Basis of presentation and significant accounting policies

1. Basis of presentation

The accompanying unaudited consolidated financial statements were derived from the historical accounting records of the Company and reflect the historical financial position, results of operations and cash flows for the periods described herein. The Broad Oak acquisition discussed in Note A was accounted for in a manner similar to a pooling of interests. The historical financial statements present the assets and liabilities of Laredo Holdings and its subsidiaries and Broad Oak at historical carrying values and their operations as if they were consolidated for all periods presented. All material intercompany transactions and account balances have been eliminated in the consolidation of accounts. The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The Company operates oil and natural gas properties as one business segment, which explores for, develops and produces oil and natural gas.

The accompanying consolidated financial statements have not been audited by the Company's independent registered public accounting firm, except that the consolidated balance sheet at December 31, 2011 is derived from audited consolidated financial statements. In the opinion of management, the accompanying unaudited consolidated financial statements reflect all necessary adjustments to present fairly the Company's financial position at June 30, 2012 and the results of operations and cash flows for the six months ended June 30, 2012 and 2011. All such adjustments are of a normal recurring nature.

Certain disclosures have been condensed or omitted from these unaudited consolidated financial statements. Accordingly, these unaudited consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in Laredo Holdings' Annual Report on Form 10-K for the year ended December 31, 2011 (the "2011 Annual Report").

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

The preparation of the accompanying unaudited consolidated financial statements in conformity with GAAP requires management of the Company to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ from these estimates. The interim results reflected in the unaudited consolidated financial statements are not necessarily indicative of the results that may be expected for other interim periods or for the full year.

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

3. Accounts receivable

The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Joint interest and oil and natural gas sales receivables related to these operations are generally unsecured. Accounts receivable for joint interest billings are recorded as amounts billed to customers less an allowance for doubtful accounts. Amounts are considered past due after 30 days. The Company determines joint interest operations accounts receivable allowances based on management's assessment of the creditworthiness of the joint interest owners and as the operator in the majority of its wells the ability to realize the receivables through netting of anticipated future production revenues. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging, and existing industry and economic data. The Company reviews its allowance for doubtful accounts quarterly. Past due balances over 90 days and over a specified amount are reviewed individually for collectability. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is remote.

Accounts receivable consist of the following components as of June 30, 2012 and December 31, 2011:

(in thousands)	June 30, 2012	December 31, 2011
Oil and natural gas sales	$ 38,945	$ 49,434
Joint operations(1)	31,104	24,190
Other	1,783	511
Total, net	$ 71,832	$ 74,135

(1) Accounts receivable for joint operations are presented net of an allowance for doubtful accounts of approximately $0.1 million at each of June 30, 2012 and December 31, 2011.

4. Derivative financial instruments

The Company uses derivative financial instruments 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, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices. These transactions are primarily in the form of collars, swaps, puts and basis swaps. In addition, the Company enters into derivative contracts in the form of interest rate derivatives to minimize the effects of fluctuations in interest rates.

Derivative instruments are recorded at fair value and are included on the unaudited consolidated balance sheets as assets or liabilities. The Company netted the fair value of derivative instruments by counterparty in the accompanying unaudited consolidated balance sheets where the right of offset exists. The Company determines the fair value of its derivative financial instruments utilizing pricing models for significantly similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties.

The Company's derivatives were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the unaudited consolidated statements of operations in the period of change. Realized and unrealized gains and losses on derivatives are included in cash flows from operating activities (see Note F).

5. *Other current liabilities*

Other current liabilities consist of the following components as of June 30, 2012 and December 31, 2011:

(in thousands)	June 30, 2012	December 31, 2011
Lease operating expense payable	$ 6,663	$ 5,297
Prepaid drilling liability	1,995	2,378
Production taxes payable	1,591	1,493
Deferred income taxes payable	1,506	—
Current portion of asset retirement obligations	393	506
Other accrued liabilities	3,350	5,245
Total other current liabilities	$ 15,498	$ 14,919

6. *Property and equipment*

The following table sets forth the Company's property and equipment as of June 30, 2012 and December 31, 2011:

(in thousands)	June 30, 2012	December 31, 2011
Proved oil and natural gas properties	$ 2,551,524	$ 2,083,015
Less accumulated depletion and impairment	993,312	884,533
Proved oil and natural gas properties, net	1,558,212	1,198,482
Unproved properties not being amortized	127,971	117,195
Pipeline and gas gathering assets	63,667	58,136
Less accumulated depreciation	7,900	6,394
Pipeline and gas gathering assets, net	55,767	51,742
Other fixed assets	21,840	16,948
Less accumulated depreciation and amortization	7,385	5,858
Other fixed assets, net	14,455	11,090
Total property and equipment, net	$ 1,756,405	$ 1,378,509

For the six months ended June 30, 2012 and 2011, depletion expense was $20.20 per barrel of oil equivalent ("BOE") and $18.44 per BOE, respectively.

7. *Deferred loan costs*

Loan origination fees are stated at cost, net of amortization, which are amortized over the life of the respective debt agreements utilizing the effective interest and straight-line methods. The Company capitalized $10.5 million and $10.6 million in the six months ended June 30, 2012 and 2011, respectively. The Company had total deferred loan costs of $31.7 million and $23.5 million, net of accumulated amortization of $6.7 million and $4.4 million, as of June 30, 2012 and December 31, 2011, respectively.

During the six months ended June 30, 2011, the Company wrote off approximately $3.2 million in deferred loan costs as a result of the retirement of debt and changes in the borrowing base of the Senior Secured Credit Facility (as defined in Note C). No deferred loan costs were written off in the six months ended June 30, 2012.

Future amortization expense of deferred loan costs at June 30, 2012 is as follows:

(in thousands)	
Remaining 2012	$ 2,534
2013	5,107
2014	5,164
2015	5,225
2016	3,969
Thereafter	9,667
Total	$ 31,666

8. *Asset retirement obligations*

Asset retirement obligations associated with the retirement of tangible long-lived assets are recognized as a liability in the period in which they are incurred and become determinable. The associated asset retirement costs are part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related long-lived asset is charged to expense through the depletion of the asset. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and as corresponding accretion expense. See Note G for fair value disclosures related to the Company's asset retirement obligations.

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

The following reconciles the Company's asset retirement obligations liability as of June 30, 2012 and December 31, 2011:

(in thousands)	Six months ended June 30, 2012	Year ended December 31, 2011
Liability at beginning of period	$ 13,074	$ 8,278
Liabilities added due to acquisitions, drilling and other	2,270	1,519
Accretion expense	556	616
Liabilities settled upon plugging and abandonment	(24)	(340)
Revision of estimates	—	3,001
Liability at end of period	$ 15,876	$ 13,074

9. Fair value measurements

The carrying amounts reported in the unaudited consolidated balance sheets for cash and cash equivalents, accounts receivable, prepaid expenses, accounts payable, undistributed revenue and royalties, and other accrued liabilities approximate their fair values. See Note C for fair value disclosures related to the Company's debt obligations. The Company carries its derivative financial instruments at fair value. See Note F and Note G for details regarding the fair value of the Company's derivative financial instruments.

10. Compensation awards

For stock-based compensation awards, compensation expense is recognized in "General and administrative" in the Company's unaudited consolidated statements of operations over the awards' vesting periods based on their grant date fair value. The Company utilizes the closing stock price on the date of grant to determine the fair value of service vesting restricted stock awards and a Black-Scholes pricing model to determine the fair values of service vesting restricted stock option awards. See Note D for further discussion of the restricted stock awards and restricted stock option awards.

For performance unit awards issued to management with a combination of market and service vesting criteria, a Monte Carlo simulation prepared by an independent third party is utilized in order to determine the fair value of the awards at the date of grant and to re-measure the fair value at the end of each reporting period until settlement in accordance with GAAP. Due to the relatively short trading history for the Company's stock, the volatility criteria utilized in the Monte Carlo simulation is based on the volatilities of a group of peer companies that have been determined to be most representative of the Company's expected volatility. These awards are accounted for as liability awards as they will be settled in cash at the end of the requisite service period based on the achievement of certain performance criteria. The liability and related compensation expense for each period for these awards is recognized by dividing the fair value of the total liability by the requisite service period and recording the pro rata share for the period for which service has already been provided. Compensation expense for these awards amounted to $1.0 million in the six months ended June 30, 2012, and is recognized in "General and administrative" in the Company's unaudited consolidated statements of operations and the corresponding liability is included in "Other noncurrent liabilities" in the June 30, 2012 unaudited consolidated balance sheet. As there are inherent uncertainties related to the factors and the Company's judgment in applying them to the fair value determinations, there is risk that the recorded performance unit compensation may not accurately reflect the amount ultimately earned by the member of management.

11. Impairment of long-lived assets

Impairment losses are recorded on property and equipment used in operations and other long-lived assets when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. During the six months ended June 30, 2011, the Company recorded a $0.2 million write-down of materials and supplies. Other than the aforementioned write-down, for the six months ended June 30, 2012 and 2011, the Company did not record any additional impairment to property and equipment used in operations or other long-lived assets.

12. Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Management believes no materially significant liabilities of this nature existed at June 30, 2012 or December 31, 2011.

13. Business combinations

Acquisitions are accounted for under the acquisition method of accounting. Accordingly, the Company conducts assessments of net assets acquired and recognizes amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction and integration costs associated with the acquisitions are expensed as incurred.

14. Related party transactions

The following table summarizes the net oil and natural gas sales (oil and natural gas sales less production taxes) received from the Company's related party and is included in the unaudited consolidated statements of operations for the periods presented:

	Six months ended June 30,	
(in thousands)	**2012**	**2011**
Net oil and natural gas sales(1)	$ 37,740	$ 33,533

The following table summarizes the amounts included in oil and natural gas sales receivable in the unaudited consolidated balance sheets for the periods presented:

(in thousands)	**June 30, 2012**	**December 31, 2011**
Oil and natural gas sales receivable(1)	$ 5,504	$ 6,845

(1) The Company has a gas gathering and processing arrangement with affiliates of Targa Resources, Inc. ("Targa"). Warburg Pincus IX, a majority stockholder of Laredo Holdings, and other affiliates of Warburg Pincus LLC hold investment interests in Targa. One of Laredo Holdings' directors is on the board of directors of affiliates of Targa.

C—Debt

1. Interest expense

The following amounts have been incurred and charged to interest expense for the six months ended June 30, 2012 and 2011:

(in thousands)	Six months ended June 30, 2012	2011
Cash payments for interest	$ 28,461	$ 6,626
Amortization and write-off of deferred loan costs and other adjustments	2,321	5,155
Change in accrued interest	6,081	10,471
Interest costs incurred	36,863	22,252
Less capitalized interest	(505)	—
Total interest expense	$ 36,358	$ 22,252

The following table presents the weighted average interest rates and the weighted average outstanding debt balances for the six months ended June 30, 2012 and 2011:

	Six months ended June 30,			
	2012		2011	
(in thousands except for percentages)	Weighted average principal	Weighted average interest rate(3)	Weighted average principal	Weighted average interest rate(3)
Senior Secured Credit Facility	$ 190,085	0.72%	$ 68,056	0.75%
2019 Notes	550,000	4.73%	350,000	4.19%
2022 Notes	500,000	1.29%	—	—
Term Loan(1)	—	—	100,000	0.31%
Broad Oak Credit Facility(2)	—	—	122,904	3.07%

(1) Laredo's Second Lien Term Loan Agreement was entered into on July 7, 2010 and was paid-in-full and terminated on January 20, 2011.

(2) The Broad Oak revolving credit facility was paid-in-full and terminated on July 1, 2011.

(3) Interest rates presented are annual rates which have been prorated to reflect the portion of the year for which they have been incurred.

2. 2022 Notes

On April 27, 2012, Laredo completed an offering of $500 million in aggregate principal amount of $7^3/_8$% senior unsecured notes due 2022 (the "2022 Notes"). The 2022 Notes will mature on May 1, 2022 and bear an interest rate of $7^3/_8$% per annum, payable semi-annually, in cash in arrears on May 1 and November 1 of each year, commencing November 1, 2012. The 2022 Notes are fully and unconditionally guaranteed, jointly and severally on a senior unsecured basis by Laredo Holdings and its subsidiaries, with the exception of Laredo (collectively, the "Guarantors"). The net proceeds from the 2022 Notes (i) were used to pay in full $280.0 million outstanding under Laredo's revolving Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility"), and (ii) will be used for general working capital purposes.

The 2022 Notes were issued under and are governed by an indenture and supplement thereto, each dated April 27, 2012 (collectively, the "2012 Indenture"), among Laredo, Wells Fargo Bank, National Association, as trustee, and the Guarantors. The 2012 Indenture contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of dividends or similar restricted payments, entering into transactions with affiliates and limitations on asset sales. Indebtedness under the 2022 Notes may be accelerated in certain circumstances upon an event of default as set forth in the 2012 Indenture.

Laredo will have the option to redeem the 2022 Notes, in whole or in part, at any time on or after May 1, 2017, at the redemption prices (expressed as percentages of principal amount) of 103.688% for the twelve-month period beginning on May 1, 2017, 102.458% for the twelve-month period beginning on May 1, 2018, 101.229% for the twelve-month period beginning on May 1, 2019 and 100.000% for the twelve-month period beginning on May 1, 2020 and at any time thereafter, together with any accrued and unpaid interest to, but not including, the date of redemption. In addition, before May 1, 2017, Laredo may redeem all or any part of the 2022 Notes at a redemption price equal to the sum of the principal amount thereof, plus a make whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. Furthermore, before May 1, 2015, Laredo may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the 2022 Notes with the net proceeds of a public or private equity offering at a redemption price of 107.375% of the principal amount of the 2022 Notes, plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the 2022 Notes issued under the 2012 Indenture remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. Laredo may also be required to make an offer to purchase the 2022 Notes upon a change of control triggering event. In addition, if a change of control occurs prior to May 1, 2013, Laredo may redeem all, but not less than all, of the notes at a redemption price equal to 110% of the principal amount of the 2022 Notes redeemed, plus any accrued and unpaid interest, if any, to the date of redemption.

In connection with the issuance of the 2022 Notes, Laredo and the Guarantors entered into a registration rights agreement with the initial purchasers of the 2022 Notes on April 27, 2012, pursuant to which Laredo and the Guarantors filed with the Securities and Exchange Commission ("SEC") a registration statement that became effective with respect to an offer to exchange the 2022 Notes for substantially identical notes (other than with respect to restrictions on transfer or to any increase in annual interest rate) that are registered under the Securities Act of 1933, as amended (the "Securities Act"). The offer to exchange the 2022 Notes for substantially identical notes registered under the Securities Act commenced on July 2, 2012 and was consummated on August 1, 2012 with all notes exchanged.

3. 2019 Notes

On January 20, 2011, Laredo completed an offering of $350 million $9^{1}/_{2}$% Senior Notes due 2019 (the "January Notes") and on October 19, 2011, Laredo completed an offering of an additional $200 million $9^{1}/_{2}$% Senior Notes due 2019 (the "October 2011 Notes" and together with the January Notes, the "2019 Notes"). The 2019 Notes will mature on February 15, 2019 and bear an interest rate of 9.5% per annum payable semi-annually, in cash, in arrears on February 15 and August 15 of each year. The 2019 Notes are fully and unconditionally guaranteed, jointly and severally on a senior unsecured basis by the Guarantors.

In connection with the issuance of the 2019 Notes, Laredo and the Guarantors entered into registration rights agreements with the initial purchasers of the 2019 Notes, pursuant to which Laredo and the Guarantors filed with the SEC a registration statement that became effective with respect to an offer to exchange the 2019 Notes for substantially identical notes (other than with respect to restrictions on transfer or to any increase in annual interest rate) registered under the Securities Act. The offer to exchange the 2019 Notes for substantially identical notes registered under the Securities Act was consummated on January 13, 2012 with all notes exchanged.

4. Senior secured credit facility

The Senior Secured Credit Facility, which matures July 1, 2016, had a borrowing base of $785.0 million with no amounts outstanding at June 30, 2012. It contains both financial and non-financial covenants that the Company was in compliance with at June 30, 2012.

Additionally, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $20.0 million. At June 30, 2012, Laredo had one letter of credit outstanding totaling $0.03 million under the Senior Secured Credit Facility.

5. Fair value of debt

The Company has not elected to account for its debt instruments at fair value. The following table presents the carrying amount and fair value of the Company's debt instruments at June 30, 2012 and December 31, 2011:

	June 30, 2012		December 31, 2011	
(in thousands)	**Carrying value**	**Fair value**	**Carrying value**	**Fair value**
2019 Notes(1)	$ 551,863	$ 616,000	$ 551,961	$ 585,750
2022 Notes	500,000	521,875	—	—
Senior Secured Credit Facility(2)	—	—	85,000	84,893
Total value of debt	$ 1,051,863	$ 1,137,875	$ 636,961	$ 670,643

(1) The carrying value of the 2019 Notes includes the October 2011 Notes unamortized bond premium of approximately $1.9 million and $2.0 million as of June 30, 2012 and December 31, 2011, respectively.

(2) No amounts were outstanding under the Senior Secured Credit Facility at June 30, 2012.

At June 30, 2012 and December 31, 2011, the fair value of the debt outstanding on the 2019 Notes and the 2022 Notes was determined using the June 30, 2012 and December 31, 2011 quoted market price (Level 1), respectively, and the fair value of the outstanding debt at December 31, 2011 on the Senior Secured Credit Facility was estimated utilizing pricing models for similar instruments (Level 2). See Note G for information about fair value hierarchy levels.

D—Stock-based compensation

In November 2011, the Board of Directors of Laredo Holdings and its stockholders approved a Long-Term Incentive Plan (the "LTIP"), which provides for the granting of incentive awards in the form of stock options, restricted stock awards and other awards. The LTIP provides for the issuance of 10.0 million shares.

The Company recognizes the fair value of stock-based payments to employees and directors as a charge against earnings. The Company recognizes stock-based payment expense over the requisite service period. Laredo Holdings' stock-based payment awards are accounted for as equity instruments. Stock-based compensation is included in "General and administrative" in the unaudited consolidated statements of operations.

Restricted stock awards

All restricted stock awards are treated as issued and outstanding in the accompanying unaudited consolidated financial statements. If an employee terminates employment prior to the restriction lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. Restricted stock awards converted in the Corporate Reorganization vested 20% at the grant date and then vest 20% annually thereafter. The restricted stock awards granted under the LTIP vest 33%, 33% and 34% per year beginning on the first anniversary date of the grant. The following table reflects the outstanding restricted stock awards for the six months ended June 30, 2012:

(in thousands, except for weighted average grant date fair values)	Restricted stock awards	Weighted average grant date fair value
Outstanding at December 31, 2011	911	$ 1.14
Granted	777	$ 23.50
Forfeited	(98)	$ 14.93
Vested	(233)	$ 0.44
Outstanding at June 30, 2012	1,357	$ 13.02

Restricted stock option awards

Restricted stock options granted under the LTIP vest and are exercisable in four equal installments on each of the first four anniversaries of the date of the grant. The following table reflects the stock option award activity for the six months ended June 30, 2012:

(in thousands, except for weighted average exercise price and contractual term)	Restricted stock option awards	Weighted average exercise price (per option)	Weighted average contractual term (years)
Outstanding at December 31, 2011	—	$ —	—
Granted	603	$ 24.11	10
Forfeited	(54)	$ 24.11	10
Outstanding at June 30, 2012	549	$ 24.11	10
Vested and exercisable at end of period	—		

The Company used the Black-Scholes option pricing model to determine the fair value of restricted stock options and is recognizing the associated expense on a straight-line basis over the four year requisite service period of the awards. Determining the fair value of equity-based awards requires judgment, including estimating the expected term that stock options will be outstanding prior to exercise, and the associated volatility.

The assumptions used to estimate the fair value of restricted stock options granted on February 3, 2012 are as follows:

Risk-free interest rate(1)	1.07%
Expected option life(2)	6.01
Expected volatility(3)	60.18%
Fair value per option	$ 13.36

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

(2) As the Company has no historical exercise history, expected option life assumptions were developed using the simplified method in accordance with GAAP.

(3) The Company utilized a peer historical look-back, weighted with the Company's own volatility since the IPO, to develop the expected volatility.

E—Income taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

The Company is subject to corporate income taxes and the Texas margin tax. Income tax expense for the six months ended June 30, 2012 and 2011 consisted of the following:

	Six months ended June 30,	
(in thousands)	**2012**	**2011**
Current taxes		
Federal	$ —	$ —
State	—	—
Deferred taxes		
Federal	30,847	24,528
State	1,334	1,209
Income tax expense	$ 32,181	$ 25,737

Income tax expense differed from amounts computed by applying the federal income tax rate of 34% to pre-tax income from operations as a result of the following:

	Six months ended June 30,	
(in thousands)	**2012**	**2011**
Income tax expense computed by applying the statutory rate	$ 30,393	$ 24,303
State income tax, net of federal tax benefit and increase in valuation allowance	1,900	1,189
Income from non-taxable entity	—	(16)
Non-deductible compensation	655	287
Change in valuation allowance	2	2
Other items	(769)	(28)
Income tax expense	$ 32,181	$ 25,737

Significant components of the Company's deferred tax assets as of June 30, 2012 and December 31, 2011 are as follows:

(in thousands)	June 30, 2012	December 31, 2011
Derivative financial instruments	$ (3,526)	$ 3,551
Oil and natural gas properties and equipment	(119,354)	(87,138)
Net operating loss carry-forward	186,222	180,740
Other	705	(926)
	64,047	96,227
Valuation allowance	(650)	(649)
Net deferred tax asset	$ 63,397	$ 95,578

Net deferred tax assets and liabilities were classified in the unaudited consolidated balance sheets as follows as of June 30, 2012 and December 31, 2011:

(in thousands)	June 30, 2012	December 31, 2011
Deferred tax asset	$ 64,903	$ 95,578
Deferred tax liability	1,506	—
Net deferred tax assets	$ 63,397	$ 95,578

The Company had federal net operating loss carry-forwards totaling approximately $527.3 million and state net operating loss carry-forwards totaling approximately $180.9 million at June 30, 2012. These carry- forwards begin expiring in 2026. The Company maintains a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized. At June 30, 2012, a $0.6 million valuation allowance was recorded against the state of Louisiana deferred tax asset and a $0.03 million valuation allowance was recorded against the Company's charitable contribution carry-forward. The Company believes the federal and state of Oklahoma net operating loss carry-forwards are fully realizable. The Company considered all available evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance was needed. 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 at June 30, 2012 and the Company's ability to capitalize intangible drilling costs, rather than expensing these costs, in order to prevent an operating loss carry-forward from expiring unused.

The Company's income tax returns for the years 2008 through 2011 remain open and subject to examination by federal tax authorities and/or the tax authorities in Oklahoma, Texas and Louisiana which are the jurisdictions where the Company has or had operations. Additionally, the statute of limitations for examination of federal net operating loss carryovers typically does not begin to run until the year the attribute is utilized in a tax return. In evaluating its current tax positions in order to identify any material uncertain tax positions, the Company developed a policy in identifying uncertain tax positions that considers support for each tax position, industry standards, tax return disclosures and schedules, and the significance of each position. The Company had no material adjustments to its unrecognized tax benefits during the six months ended June 30, 2012.

F—Derivative financial instruments

1. Commodity derivatives

The Company engages in derivative transactions such as collars, swaps, puts and basis swaps to hedge price risks due to unfavorable changes in oil and natural gas prices related to its oil and natural gas production. As of June 30, 2012, the Company had 54 open derivative contracts with financial institutions, none of which were designated as hedges for accounting purposes, which extend from July 2012 to December 2015. The contracts are recorded at fair value on the balance sheet and any realized and unrealized gains and losses are recognized in current year earnings.

Each collar transaction has an established price floor and ceiling. When the settlement price is below the price floor established by these collars, the Company receives an amount from its counterparty equal to the difference between the settlement price and the price floor multiplied by the hedged contract volume. When the settlement price is above the price ceiling established by these collars, the Company pays its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the hedged contract volume.

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

Each put transaction has an established floor price. The Company pays the counterparty a premium in order to enter into the put transaction. When the settlement price is below the floor price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires.

Each basis swap transaction has an established fixed differential between the NYMEX gas futures and West Texas WAHA ("WAHA") index gas price. When the NYMEX futures settlement price less the fixed WAHA differential is greater than the actual WAHA price, the difference multiplied by the hedged contract volume is paid to the Company by the counterparty. When the difference between the NYMEX futures settlement price less the fixed WAHA differential is less than the actual WAHA price, the Company pays the counterparty an amount equal to the difference multiplied by the hedged contract volume.

During the six months ended June 30, 2012, the Company entered into additional commodity contracts to hedge a portion of its estimated future production. The following table summarizes information about these additional commodity derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Aggregate volumes	Swap price	Floor price	Ceiling price	Contract period
Oil (volumes in Bbls):					
Price collar	270,000	—	$ 90.00	$ 126.50	April 2012—December 2012
Price collar	240,000	—	$ 90.00	$ 118.35	January 2013—December 2013
Price collar	198,000	—	$ 70.00	$ 140.00	January 2014—December 2014
Put	360,000	—	$ 75.00	—	January 2014—December 2014
Price collar	252,000	—	$ 75.00	$ 135.00	January 2015—December 2015
Put	360,000	—	$ 75.00	—	January 2015—December 2015
Put	180,000	—	$ 75.00	—	January 2014—December 2014
Put	96,000	—	$ 75.00	—	January 2015—December 2015
Natural gas (volumes in MMBtu):					
Swap	700,000	$ 2.72	—	—	April 2012—October 2012
Price collar	700,000	—	$ 3.25	$ 3.90	April 2013—October 2013

The following table summarizes open positions as of June 30, 2012, and represents, as of such date, derivatives in place through December 31, 2015, on annual production volumes:

	Remaining year 2012	Year 2013	Year 2014	Year 2015
Oil Positions:				
Puts:				
Hedged volume (Bbls)	336,000	1,080,000	540,000	456,000
Weighted average price ($/Bbl)	$ 65.79	$ 65.00	$ 75.00	$ 75.00
Swaps:				
Hedged volume (Bbls)	366,000	600,000	—	—
Weighted average price ($/Bbl)	$ 93.52	$ 96.32	$ —	$ —
Collars:				
Hedged volume (Bbls)	603,000	768,000	726,000	252,000
Weighted average floor price ($/Bbl)	$ 79.50	$ 79.38	$ 75.45	$ 75.00
Weighted average ceiling price ($/Bbl)	$ 118.09	$ 121.67	$ 129.09	$ 135.00
Natural Gas Positions:				
Puts:				
Hedged volume (MMBtu)	2,160,000	6,600,000	—	—
Weighted average price ($/MMBtu)	$ 5.38	$ 4.00	$ —	$ —
Swaps:				
Hedged volume (MMBtu)	1,240,000	—	—	—
Weighted average price ($/MMBtu)	$ 5.04	$ —	$ —	$ —
Collars:				
Hedged volume (MMBtu)	3,900,000	7,300,000	6,960,000	—
Weighted average floor price ($/MMBtu)	$ 4.12	$ 3.93	$ 4.00	$ —
Weighted average ceiling price ($/MMBtu)	$ 5.79	$ 6.75	$ 7.03	$ —
Basis swaps(1):				
Hedged volume (MMBtu)	1,440,000	1,200,000	—	—
Weighted average price ($/MMBtu)	$ 0.31	$ 0.33	$ —	$ —

(1) The cash settlement price of the Company's basis swaps is calculated on the difference between the Company's natural gas futures contracts that settle on the NYMEX index and the NYMEX index price at the time of settlement. At June 30, 2012, the Company had 200,000 MMBtu for the remainder of 2012 and 500,000 MMBtu for 2013 in basis swaps that did not have corresponding volumes hedged with a NYMEX index price.

2. Interest rate derivatives

The Company is exposed to market risk for changes in interest rates related to its Senior Secured Credit Facility. Interest rate derivative agreements are used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. If LIBOR is lower than the fixed rate in the contract, the Company is required to pay the counterparties the difference, and conversely, the counterparties are required to pay the Company if LIBOR is higher than the fixed rate in the contract. The Company did not designate the interest rate derivatives as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings.

The following presents the settlement terms of the interest rate derivatives at June 30, 2012:

(in thousands except rate data)	Year 2012	Year 2013	Expiration date
Notional amount	$ 50,000	$ 50,000	
Fixed rate	1.11%	1.11%	September 13, 2013
Notional amount	$ 50,000	$ 50,000	
Cap rate	3.00%	3.00%	September 13, 2013
Total	$ 100,000	$ 100,000	

3. Balance sheet presentation

The Company's oil and natural gas commodity derivatives and interest rate derivatives are presented on a net basis in "Derivative financial instruments" in the unaudited consolidated balance sheets.

The following summarizes the fair value of derivatives outstanding on a gross basis as of:

(in thousands)	June 30, 2012	December 31, 2011
Assets:		
Commodity derivatives:		
Oil derivatives	$ 33,033	$ 16,026
Natural gas derivatives	28,980	34,019
Interest rate derivatives	—	11
	$ 62,013	$ 50,056
Liabilities:		
Commodity derivatives:		
Oil derivatives(1)	$ 23,691	$ 28,044
Natural gas derivatives(2)	5,231	6,832
Interest rate derivatives	365	1,991
	$ 29,287	$ 36,867

(1) The oil derivatives fair value includes a deferred premium liability of $19.7 million and $13.4 million at June 30, 2012 and December 31, 2011, respectively.

(2) The natural gas derivatives fair value includes a deferred premium liability of $3.9 million and $5.4 million at June 30, 2012 and December 31, 2011, respectively.

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company's counterparties are participants in the Senior Secured Credit Facility which is secured by the Company's oil and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not require collateral from its counterparties. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that are also lenders in the Senior Secured Credit Facility and meet the Company's minimum credit quality standard, or have a guarantee from an affiliate that meets the Company's minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis. In accordance with the Company's standard practice, its commodity and interest rate derivatives are subject to counterparty netting under agreements governing such derivatives and, therefore, the risk of such loss is somewhat mitigated at June 30, 2012.

4. Gain (loss) on derivatives

Gains and losses on derivatives are reported on the unaudited consolidated statements of operations in the respective "Realized and unrealized gain (loss)" amounts. Realized gains (losses) represent amounts related to the settlement of derivative instruments, and for commodity derivatives, are aligned with the underlying production. Unrealized gains (losses) represent the change in fair value of the derivative instruments and are non-cash items.

The following represents the Company's reported gains and losses on derivative instruments for the six months ended June 30, 2012 and 2011:

	Six months ended June 30,	
(in thousands)	**2012**	**2011**
Realized gains (losses):		
Commodity derivatives	$ 13,823	$ (931)
Interest rate derivatives	(1,938)	(2,556)
	11,885	(3,487)
Unrealized gains (losses):		
Commodity derivatives	15,314	(8,654)
Interest rate derivatives	1,615	1,462
	16,929	(7,192)
Total gains (losses):		
Commodity derivatives	29,137	(9,585)
Interest rate derivatives	(323)	(1,094)
	$ 28,814	$ (10,679)

G—Fair value measurements

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

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

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

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

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

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

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. The Company conducts a review of fair value hierarchy classifications on an annual basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities. Transfers between fair value hierarchy levels are recognized and reported in the period in which the transfer occurred. No transfers between fair value hierarchy levels occurred during the six months ended June 30, 2012 and 2011.

Fair value measurement on a recurring basis

The following presents the Company's fair value hierarchy for assets and liabilities measured at fair value on a recurring basis at June 30, 2012 and December 31, 2011.

(in thousands)	Level 1	Level 2	Level 3	Total fair value
As of June 30, 2012:				
Commodity derivatives	$ —	$ 56,643	$ —	$ 56,643
Deferred premiums	—	—	(23,552)	(23,552)
Interest rate derivatives	—	(365)	—	(365)
Total	$ —	$ 56,278	$ (23,552)	$ 32,726

(in thousands)	Level 1	Level 2	Level 3	Total fair value
As of December 31, 2011:				
Commodity derivatives	$ —	$ 34,037	$ —	$ 34,037
Deferred premiums	—	—	(18,868)	(18,868)
Interest rate derivatives	—	(1,980)	—	(1,980)
Total	$ —	$ 32,057	$ (18,868)	$ 13,189

These items are included in "Derivative financial instruments" on the unaudited consolidated balance sheets. Significant Level 2 assumptions associated with the calculation of discounted cash flows used in the "mark-to-market" analysis of commodity derivatives include the NYMEX natural gas and crude oil prices, appropriate risk adjusted discount rates and other relevant data. Significant Level 2 assumptions associated with the calculation of discounted cash flows used in the "mark-to-market" analysis of interest rate swaps include the interest rate curves, appropriate risk adjusted discount rates and other relevant data.

The Company's deferred premiums associated with its commodity derivative contracts are categorized in Level 3, as the Company utilizes a net present value calculation to determine the valuation. They are considered to be measured on a recurring basis as the derivative contracts they derive from are measured on a recurring basis. As commodity derivative contracts containing deferred premiums are entered into, the Company discounts the associated deferred premium to its net present value at the contract trade date, using the Senior Secured Credit Facility rate at the trade date (historical input rates range from 2.06% to 3.56%) and then amortizing the change in net present value into interest expense over the period from trade until the final settlement date at the end of the contract. After this initial valuation the net present value of each deferred premium is not adjusted, therefore significant increases (decreases) in the Senior Secured Credit Facility rate would result in a significantly lower (higher) fair value measurement for each new deal containing a deferred premium entered into; however the valuation for the deals already recorded would remain unaffected. While the Company believes the sources utilized to arrive at the fair value estimates are reliable, different sources or methods could have yielded different fair value estimates; therefore on a quarterly basis, the valuation is compared to counterparty valuations and third party valuation of the deferred premiums for reasonableness. A summary of the changes in assets classified as Level 3 measurements for the six months ended June 30, 2012 and 2011 are as follows:

(in thousands)	Six months ended June 30, 2012 Derivative option contracts	Six months ended June 30, 2012 Deferred premiums
Balance of Level 3 at beginning of period(1)	$ —	$ (18,868)
Realized and unrealized gains included in earnings	—	—
Amortization of deferred premiums	—	(319)
Total purchases and settlements:		
Purchases	—	(7,292)
Settlements	—	2,927
Balance of Level 3 at end of period	$ —	$ (23,552)
Change in unrealized losses attributed to earnings relating to derivatives still held at end of period	$ —	$ —

(in thousands)	Six months ended June 30, 2011 Derivative option contracts	Six months ended June 30, 2011 Deferred premiums
Balance of Level 3 at beginning of period	$ 20,026	$ (12,495)
Realized and unrealized losses included in earnings	(6,588)	—
Amortization of deferred premiums	—	(216)
Total purchases and settlements:		
Purchases	500	—
Settlements	—	41
Balance of Level 3 at end of period	$ 13,938	$ (12,670)
Change in unrealized gains attributed to earnings relating to derivatives still held at end of period	$ 1,970	$ —

(1) The Company transferred the commodity derivative option contracts out of Level 3 during the year ended December 31, 2011 due to the Company's ability to utilize transparent forward price curves and volatilities published and available through independent third party vendors. As a result, the Company transferred positions from Level 3 to Level 2 as the significant inputs used to calculate the fair value are all observable.

Fair value measurement on a nonrecurring basis

The Company accounts for additions to its asset retirement obligation (see Note B.8) and the impairment of long-lived assets (see Note B.11), if any, at fair value on a nonrecurring basis in accordance with GAAP. For purposes of fair value measurement, it was determined that the impairment of long-lived assets and the additions to the asset retirement obligation are classified as Level 3 based on the use of internally developed cash flow models. No impairments of long-lived assets were recorded in the six months ended June 30, 2012.

Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including, in addition to those noted above, the ultimate settlement of these amounts, the ultimate timing of such settlement, and changes in legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment will be made to the asset balance.

Asset retirement obligations. The accounting policies for asset retirement obligations are discussed in Note B.8, including a reconciliation of the Company's asset retirement obligation. The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, which converts future cash flows to a single discounted amount. Significant inputs to the valuation include: (i) estimated plug and abandonment cost per well based on Company experience; (ii) estimated remaining life per well based on the reserve life per well; (iii) future inflation factors; and (iv) the Company's average credit adjusted risk free rate.

Impairment of oil and natural gas properties. The accounting policies for impairment of oil and natural gas properties are discussed in the audited consolidated financial statements and notes thereto included in the 2011 Annual Report. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of operating and development costs, anticipated production of proved reserves and other relevant data.

H—Credit risk

The Company's oil and natural gas sales are to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. The Company's joint operations accounts receivable are from a number of oil and natural gas companies, partnerships, individuals and others who own interests in the properties operated by the Company. Management believes that any credit risk imposed by a concentration in the oil and natural gas industry is offset by the creditworthiness of the Company's customer base and industry partners. The Company routinely assesses the recoverability of all material trade and other receivables to determine collectability.

The Company uses derivative instruments to hedge its exposure to oil and natural gas price volatility and its exposure to interest rate risk associated with the Senior Secured Credit Facility. These transactions expose the Company to potential credit risk from its counterparties. In accordance with the Company's standard practice, its derivative instruments are subject to counterparty netting under agreements governing such derivatives and therefore, the credit risk associated with its derivative counterparties is somewhat mitigated. See Note F for additional information regarding the Company's derivative instruments.

I—Commitments and contingencies

1. Lease commitments

The Company leases equipment and office space under operating leases expiring on various dates through 2016. Minimum annual lease commitments at June 30, 2012 and for the calendar years following are as follows:

(in thousands)	
Remaining 2012	$ 720
2013	1,448
2014	1,102
2015	731
2016	282
Total	$ 4,283

The following table presents rent expense for the six months ended June 30, 2012 and 2011.

	Six months ended June 30,	
(in thousands)	2012	2011
Rent expense	$ 602	$ 590

The Company's office space lease agreements contain scheduled escalation in lease payments during the term of the lease. In accordance with GAAP, the Company records rent expense on a straight-line basis and a deferred lease liability for the difference between the straight-line amount and the actual amounts of the lease payments.

2. Litigation

The Company may be involved in legal proceedings or is subject to industry rulings that could bring rise to claims in the ordinary course of business. The Company has concluded that the likelihood is remote that the ultimate resolution of any pending litigation or pending claims will be material or have a material adverse effect on the Company's business, financial position, results of operations or liquidity.

3. Drilling contracts

The Company has committed to several short-term drilling contracts with various third parties in order to complete its various drilling projects. The contracts contain an early termination clause that requires the Company to pay significant penalties to the third party should the Company cease drilling efforts. These penalties could significantly impact the Company's financial statements upon contract termination. These commitments are not recorded in the accompanying unaudited consolidated balance sheets. Future commitments as of June 30, 2012 are $35.8 million. Management does not anticipate canceling any drilling contracts or discontinuing drilling efforts in 2012.

4. Federal and state regulations

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

J—Defined contribution plans

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

The following table presents total contributions to the plans for the six months ended June 30, 2012 and 2011.

	Six months ended June 30,	
(in thousands)	**2012**	**2011**
Contributions	$ 642	$ 855

K—Net income per share

Basic net income per share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted net income per share reflects the potential dilution of non-vested restricted stock awards. The effect of the Company's outstanding options to purchase 549,446 shares of common stock at $24.11 per share were excluded from the calculation of diluted earnings per share for the six months ended June 30, 2012 because the exercise price of those options was greater than the average market price during the period, and therefore the inclusion of these outstanding options would have been anti-dilutive. The following is the calculation of basic and diluted weighted average shares outstanding and net income per share for the six months ended June 30, 2012:

(in thousands, except for per share data)	Six months ended June 30, 2012
Income (numerator):	
Net income—basic and diluted	$ 57,210
Weighted average shares (denominator):	
Weighted average shares—basic	126,862
Non-vested restricted stock	1,239
Weighted average shares—diluted	128,101
Net income per share:	
Basic	$ 0.45
Diluted	$ 0.45

L—Recently issued accounting standards

In December 2011, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") 2011-11, *Disclosures about Offsetting Assets and Liabilities*, to improve reporting and transparency of offsetting (netting) assets and liabilities and the related effects on the financial statements. This ASU is effective for fiscal years and interim periods within those years beginning on or after January 1, 2013. The Company does not expect the adoption of this ASU to have a material effect on its consolidated financial statements.

M—Subsidiary guarantees

Laredo Holdings and all of Laredo's wholly-owned subsidiaries (Laredo Gas, Laredo Texas and Laredo Dallas, collectively, the "Subsidiary Guarantors") have fully and unconditionally guaranteed the 2019 Notes, the 2022 Notes and the Senior Secured Credit Facility. In accordance with practices accepted by the SEC, Laredo has prepared condensed consolidating financial statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. The following unaudited condensed consolidating balance sheet as of June 30, 2012 and audited condensed consolidating balance sheet as of December 31, 2011, unaudited condensed consolidating statements of operations and unaudited condensed consolidating statements of cash flows for the six months ended June 30, 2012 and 2011, present financial information for Laredo Holdings as the parent of Laredo on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for Laredo on a stand-alone basis (carrying any investment in subsidiaries under the equity method), financial information for the Subsidiary Guarantors on a stand-alone basis (carrying any investment in subsidiaries under the equity method), and the consolidation and elimination entries necessary to arrive at the information for the Company on a condensed consolidated basis. All deferred income taxes are recorded on Laredo's statements of financial position, as Laredo's subsidiaries are flow-through entities for income tax purposes. Prior to the Broad Oak acquisition on July 1, 2011, both Laredo and Laredo Dallas were separate taxable entities and deferred income taxes for the Company are recorded separately. The Subsidiary Guarantors are not restricted from making distributions to Laredo.

Condensed consolidating balance sheet
June 30, 2012
(unaudited)

(in thousands)	Laredo Holdings	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Accounts receivable	$ —	$ 54,616	$ 17,216	$ —	$ 71,832
Other current assets	—	172,615	199	—	172,814
Total oil and natural gas properties, net	—	999,604	686,579	—	1,686,183
Total pipeline and gas gathering assets, net	—	—	55,767	—	55,767
Total other fixed assets, net	—	11,686	2,769	—	14,455
Investment in subsidiaries	942,804	619,841	—	(1,562,645)	—
Total other long-term assets	—	114,887	—	—	114,887
Total assets	$ 942,804	$ 1,973,249	$ 762,530	$ (1,562,645)	$ 2,115,938
Accounts payable	$ 1	$ 29,730	$ 19,580	$ —	$ 49,311
Other current liabilities	—	126,691	48,024	—	174,715
Other long-term liabilities	—	9,443	8,548	—	17,991
Long-term debt	—	1,051,863	—	—	1,051,863
Stockholders' equity	942,803	755,522	686,378	(1,562,645)	822,058
Total liabilities and stockholders' equity	$ 942,804	$ 1,973,249	$ 762,530	$ (1,562,645)	$ 2,115,938

Condensed consolidating balance sheet
December 31, 2011
(audited)

(in thousands)	Laredo Holdings	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Accounts receivable	$ —	$ 53,006	$ 21,129	$ —	$ 74,135
Other current assets	54,921	20,599	204	(26,921)	48,803
Total oil and natural gas properties, net	—	780,152	535,525	—	1,315,677
Total pipeline and gas gathering assets, net	—	—	51,742	—	51,742
Total other fixed assets, net	—	10,321	769	—	11,090
Investment in subsidiaries	888,043	554,901	—	(1,442,944)	—
Total other long-term assets	—	126,205	—	—	126,205
Total assets	$ 942,964	$ 1,545,184	$ 609,369	$ (1,469,865)	$ 1,627,652
Accounts payable	$ 1	$ 58,729	$ 14,198	$ (26,921)	$ 46,007
Other current liabilities	—	130,990	37,364	—	168,354
Other long-term liabilities	—	8,779	7,538	—	16,317
Long-term debt	—	636,961	—	—	636,961
Stockholders' equity	942,963	709,725	550,269	(1,442,944)	760,013
Total liabilities and stockholders' equity	$ 942,964	$ 1,545,184	$ 609,369	$ (1,469,865)	$ 1,627,652

Condensed consolidating statement of operations
for the six months ended June 30, 2012
(unaudited)

(in thousands)	Laredo Holdings	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$ —	$ 152,458	$ 143,403	$ (4,889)	$ 290,972
Total operating costs and expenses	159	126,564	72,226	(4,889)	194,060
Income (loss) from operations	(159)	25,894	71,177	—	96,912
Interest income (expense), net	—	(36,327)	—	—	(36,327)
Other, net	—	28,814	(8)	—	28,806
Income (loss) from operations before income tax	(159)	18,381	71,169	—	89,391
Income tax expense	—	(32,181)	—	—	(32,181)
Net income (loss)	$ (159)	$ (13,800)	$ 71,169	$ —	$ 57,210

Condensed consolidating statement of operations for the six months ended June 30, 2011 (unaudited)

(in thousands)	Laredo Holdings	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$ —	$ 102,482	$ 139,650	$ (3,294)	$ 238,838
Total operating costs and expenses	7	71,859	62,633	(3,294)	131,205
Income (loss) from operations	(7)	30,623	77,017	—	107,633
Interest income (expense), net	55	(17,152)	(5,097)	—	(22,194)
Other, net	—	(5,696)	(8,264)	—	(13,960)
Income from operations before income tax	48	7,775	63,656	—	71,479
Income tax expense	—	(4,336)	(21,401)	—	(25,737)
Net income	$ 48	$ 3,439	$ 42,255	$ —	$ 45,742

Condensed consolidating statement of cash flows for the six months ended June 30, 2012 (unaudited)

(in thousands)	Laredo Holdings	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by (used in) operating activities	$ (160)	$ 49,843	$ 123,186	$ 26,921	$ 199,790
Net cash flows provided by used in investing activities	(54,761)	(307,882)	(123,188)	—	(485,831)
Net cash flows provided by financing activities	—	404,524	—	—	404,524
Net increase (decrease) in cash and cash equivalents	(54,921)	146,485	(2)	26,921	118,483
Cash and cash equivalents at beginning of period	54,921	—	2	(26,921)	28,002
Cash and cash equivalents at end of period	$ —	$ 146,485	$ —	$ —	$ 146,485

Condensed consolidating statement of cash flows for the six months ended June 30, 2011 (unaudited)

(in thousands)	Laredo Holdings	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$ 47	$ 65,580	$ 102,583	$ (6,152)	$ 162,058
Net cash flows used in investing activities	(7,318)	(203,452)	(148,679)	—	(359,449)
Net cash flows provided by financing activities	—	137,872	50,336	—	188,208
Net increase (decrease) in cash and cash equivalents	(7,271)	—	4,240	(6,152)	(9,183)
Cash and cash equivalents at beginning of period	38,652	—	6,489	(13,906)	31,235
Cash and cash equivalents at end of period	$ 31,381	$ —	$ 10,729	$ (20,058)	$ 22,052

N—Subsequent events

1. Acquisition

On July 12, 2012, the Company completed the acquisition of additional working interest in certain oil and natural gas properties located in Glasscock County, TX for a contract price of $20.5 million from a private company, subject to certain purchase price adjustments. The initial accounting for the business combination is not complete pending detailed analyses of the facts and circumstances that existed as of the acquisition date.

2. New derivative contracts

Subsequent to June 30, 2012, the Company entered into additional commodity contracts, with approximately $4.2 million in deferred premiums associated. The following table summarizes information about these new commodity derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Aggregate volumes	Floor price	Ceiling price	Contract period
Natural gas (volumes in MMBtu):				
Price collar	8,760,000	$ 3.00	$ 5.00	January 2013—December 2013
Price collar	11,160,000	$ 3.00	$ 5.50	January 2014—December 2014
Price collar	15,480,000	$ 3.00	$ 6.00	January 2015—December 2015

3. Additional borrowing

On August 28, 2012, the Company borrowed $50.0 million under the Senior Secured Credit Facility. The outstanding balance under the Senior Secured Credit Facility was approximately $50.0 million at September 30, 2012.

O—Supplementary information

Costs incurred in oil and natural gas property acquisition, exploration and development activities(1)

Costs incurred in the acquisition and development of oil and natural gas assets are presented below for the six months ended June 30, 2012 and 2011:

(in thousands)	Six months ended June 30, 2012	Six months ended June 30, 2011
Property acquisition costs:		
Proved	$ —	$ —
Unproved	—	—
Exploration	51,686	21,868
Development costs	427,599	312,390
Total costs incurred	$ 479,285	$ 334,258

(1) The costs incurred for oil and natural gas development activities include $2.3 million and $0.5 million for the six months ended June 30, 2012 and 2011, respectively.

Report of independent registered public accounting firm

Board of Directors and Stockholders
Laredo Petroleum Holdings, Inc.

We have audited the accompanying consolidated balance sheets of Laredo Petroleum Holdings, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, stockholders' equity/unit holders' equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Laredo Petroleum Holdings, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
March 20, 2012

Laredo Petroleum Holdings, Inc.
Consolidated balance sheets
December 31, 2011 and 2010

(in thousands, except units and share data)	2011	2010
Assets		
Current assets:		
Cash and cash equivalents	$ 28,002	$ 31,235
Accounts receivable, net	74,135	43,939
Derivative financial instruments	13,281	8,376
Deferred income taxes	5,202	11,229
Other current assets	2,318	5,637
Total current assets	122,938	100,416
Property and equipment:		
Oil and natural gas properties, full cost method:		
Proved properties	2,083,015	1,379,885
Unproved properties not being amortized	117,195	96,515
Pipeline and gas gathering assets	58,136	43,271
Other fixed assets	16,948	10,869
	2,275,294	1,530,540
Less accumulated depreciation, depletion, amortization and impairment	896,785	720,647
Net property and equipment	1,378,509	809,893
Deferred income taxes	90,376	143,723
Derivative financial instruments	6,510	1,804
Deferred loan costs, net	23,457	10,353
Other assets, net	5,862	1,971
Total assets	$ 1,627,652	$ 1,068,160
Liabilities and stockholders' equity/unit holders' equity		
Current liabilities:		
Accounts payable	$ 46,007	$ 41,338
Undistributed revenue and royalties	26,844	10,664
Accrued capital expenditures	91,022	65,900
Accrued compensation and benefits	11,270	8,778
Derivative financial instruments	4,187	11,978
Accrued interest payable	20,112	1,542
Other current liabilities	14,919	10,043
Total current liabilities	214,361	150,243
Long-term debt	636,961	491,600
Derivative financial instruments	2,415	5,987
Asset retirement obligations	12,568	7,547
Other noncurrent liabilities	1,334	1,684
Total liabilities	867,639	657,061
Unit holders' equity:		
Preferred units, zero and 99,870,000 units issued at December 31, 2011 and 2010, respectively	—	549,187
Restricted units, zero and 31,432,000 units issued at December 31, 2011 and 2010, respectively	—	4,504
Other equity interests	—	155,596
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero outstanding at December 31, 2011 and 2010	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized, and 127,617,391 and zero outstanding at December 31, 2011 and 2010, respectively	1,276	—
Additional paid-in capital	951,375	—
Accumulated deficit	(192,634)	(298,188)
Less treasury stock, at cost, 7,609 and zero common shares at December 31, 2011 and 2010, respectively	(4)	—
Total stockholders' equity/unit holders' equity	760,013	411,099
Total liabilities and stockholders' equity/unit holders' equity	$ 1,627,652	$ 1,068,160

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

Laredo Petroleum Holdings, Inc.
Consolidated statements of operations
for the years ended December 31, 2011, 2010 and 2009

(in thousands, except for per share data)	2011	2010	2009
Revenues:			
Oil and natural gas sales	$ 506,255	$ 239,783	$ 94,347
Natural gas transportation and treating	4,015	2,217	2,227
Total revenues	510,270	242,000	96,574
Costs and expenses:			
Lease operating expenses	43,306	21,684	12,531
Production and ad valorem taxes	31,982	15,699	6,129
Natural gas transportation and treating	977	2,501	1,416
Drilling rig fees	—	—	1,606
Drilling and production	3,817	340	758
General and administrative	44,953	29,651	21,164
Equity and stock-based compensation	6,111	1,257	1,419
Accretion of asset retirement obligations	616	475	406
Depreciation, depletion and amortization	176,366	97,411	58,005
Impairment expense	243	—	246,669
Total costs and expenses	308,371	169,018	350,103
Operating income (loss)	201,899	72,982	(253,529)
Non-operating income (expense):			
Realized and unrealized gain (loss):			
Commodity derivative financial instruments, net	21,047	11,190	5,744
Interest rate derivatives, net	(1,311)	(5,375)	(3,394)
Interest expense	(50,580)	(18,482)	(7,464)
Interest and other income	108	151	227
Write-off of deferred loan costs	(6,195)	—	—
Loss on disposal of assets	(40)	(30)	(85)
Non-operating expense, net	(36,971)	(12,546)	(4,972)
Income (loss) before income taxes	164,928	60,436	(258,501)
Income tax (expense) benefit:			
Deferred	(59,374)	25,812	74,006
Total income tax (expense) benefit, net	(59,374)	25,812	74,006
Net income (loss)	$ 105,554	$ 86,248	$ (184,495)
Pro forma net income per common share:			
Basic	$ 0.98		
Diluted	$ 0.98		
Pro forma weighted average common shares outstanding:			
Basic	107,187		
Diluted	108,099		

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

Laredo Petroleum Holdings, Inc.
Consolidated statements of stockholders' equity/unit holders' equity
for the years ended December 31, 2011, 2010 and 2009

	Series A		BOE Preferred		Restricted Units			Common Stock			Treasury Stock (at cost)				
(in thousands)	Units	Amount	Units	Amount	Units	Amount	Treasury units	Shares	Amount	Additional paid-in capital	Shares	Amount	Other equity interests	Accumulated deficit	Tota
Balance, December 31, 2008	76,000	$ 399,820	—	$ —	16,537	$ 1,864	$ —	—	$ —	$ —	—	$ —	$ 116,621	$ (199,941)	$ 318,36
Issuance of equity interests	20,000	125,000	—	—	—	—	—	—	—	—	—	—	29,581	—	154,58
Purchase of equity interests	—	—	—	—	—	—	(300)	—	—	—	—	—	(632)	—	(93
Cancellation of Series A Units	(48)	(120)	—	—	—	—	300	—	—	—	—	—	—	—	18
Equity-based compensation	—	—	—	—	10,694	1,419	—	—	—	—	—	—	—	—	1,41
Purchase of restricted units	—	—	—	—	—	—	(10)	—	—	—	—	—	—	—	(1
Cancellation of restricted units	—	—	—	—	(272)	(10)	10	—	—	—	—	—	—	—	—
Net loss	—	—	—	—	—	—	—	—	—	—	—	—	—	(184,495)	(184,49
Balance, December 31, 2009	95,952	524,700	—	—	26,959	3,273	—	—	—	—	—	—	145,570	(384,436)	289,10
Issuance of equity interests	4,000	25,000	—	—	—	—	—	—	—	—	—	—	10,000	—	35,00
Purchase of equity interests	—	—	—	—	—	—	(513)	—	—	—	—	—	—	—	(51
Cancellation of Series A Units	(82)	(513)	—	—	—	—	513	—	—	—	—	—	—	—	—
Equity-based compensation	—	—	—	—	6,286	1,231	—	—	—	—	—	—	26	—	1,25
Cancellation of restricted units	—	—	—	—	(1,813)	—	—	—	—	—	—	—	—	—	—
Net income	—	—	—	—	—	—	—	—	—	—	—	—	—	86,248	86,24
Balance, December 31, 2010	99,870	549,187	—	—	31,432	4,504	—	—	—	—	—	—	155,596	(298,188)	411,09
Purchase of equity interests	—	—	—	—	—	—	(125)	—	—	—	—	—	—	—	(12
Cancellation of Series A Units	(20)	(125)	—	—	—	—	125	—	—	—	—	—	—	—	—
Equity-based compensation	—	—	—	—	9,859	5,829	—	—	—	—	—	—	132	—	5,96
Purchase of restricted units	—	—	—	—	—	—	(38)	—	—	—	—	—	—	—	(3
Cancellation of restricted units	—	—	—	—	(1,389)	(37)	38	—	—	—	—	—	—	—	
Broad Oak Transaction	—	—	88,986	73,765	—	—	—	—	—	—	—	—	(155,728)	—	(81,96
Common shares issued upon Corporate Reorganization	(99,850)	(549,062)	(88,986)	(73,765)	(39,902)	(10,296)	—	107,500	1,075	632,048	—	—	—	—	—
Common shares issued at initial public offering, net of offering costs	—	—	—	—	—	—	—	20,125	201	319,177	—	—	—	—	319,37
Stock-based compensation	—	—	—	—	—	—	—	—	—	150	—	—	—	—	15
Shares repurchased	—	—	—	—	—	—	—	(8)	—	—	8	(4)	—	—	(
Net income	—	—	—	—	—	—	—	—	—	—	—	—	—	105,554	105,55
Balance, December 31, 2011	—	$ —	—	$ —	—	$ —	$ —	127,617	$1,276	$ 951,375	8	$ (4)	$ —	$ (192,634)	$ 760,01

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

Laredo Petroleum Holdings, Inc.
Consolidated statements of cash flows
for the years ended December 31, 2011, 2010 and 2009

(in thousands)	2011	2010	2009
Cash flows from operating activities:			
Net income (loss)	$ 105,554	$ 86,248	$ (184,495)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred income tax expense (benefit)	59,374	(25,812)	(74,006)
Depreciation, depletion and amortization	176,366	97,411	58,005
Impairment expense	243	—	246,669
Non-cash equity and stock-based compensation	6,111	1,257	1,419
Accretion of asset retirement obligations	616	475	406
Unrealized (gain) loss on derivative financial instruments, net	(20,890)	11,648	46,003
Premiums paid for derivative financial instruments	(555)	(5,397)	(6,283)
Amortization of premiums paid for derivative financial instruments	471	155	—
Bad debt expense	—	—	91
Amortization of deferred loan costs	3,871	2,132	546
Write-off of deferred loan costs	6,195	—	—
Amortization of October Notes premium	(39)	—	—
Amortization of other assets	19	19	9
Loss on disposal of assets	40	30	85
(Increase) decrease in accounts receivable	(30,196)	(23,299)	22,062
(Increase) decrease in other assets	(833)	(2,331)	6,092
Increase (decrease) in accounts payable	(3,825)	5,711	(6,753)
Increase (decrease) in undistributed revenues and royalties	16,180	735	1,905
Increase (decrease) in accrued compensation and benefits	2,492	5,621	(3,188)
Increase (decrease) in other accrued liabilities	23,031	2,457	3,781
Increase (decrease) in deferred lease liabilities	(149)	(17)	321
Net cash provided by operating activities	344,076	157,043	112,669
Cash flows from investing activities:			
Restricted cash	—	—	2,201
Capital expenditures:			
Oil and natural gas properties	(687,062)	(454,161)	(340,636)
Pipeline and gas gathering assets	(13,368)	(4,277)	(19,995)
Other fixed assets	(6,413)	(2,198)	(3,071)
Proceeds from other fixed asset disposals	56	89	168
Net cash used in investing activities	(706,787)	(460,547)	(361,333)
Cash flows from financing activities:			
Broad Oak Transaction	(81,963)	—	—
Borrowings on revolving credit facilities	790,100	250,300	114,400
Payments on revolving credit facilities	(1,096,700)	(105,800)	(15,900)
Borrowings on term loan	—	100,000	—
Payments on term loan	(100,000)	—	—
Issuance of 2019 Notes	552,000	—	—
Proceeds from initial public offering, net	319,378	—	—
Proceeds from issuance of equity interests, net	—	10,000	29,580
Purchase of equity interests and units, net	(164)	(513)	(762)
Purchase of treasury stock	(3)	—	—
Capital contributions	—	75,000	125,000
Payments for loan costs	(23,170)	(9,235)	(2,179)
Net cash provided by financing activities	359,478	319,752	250,139
Net increase (decrease) increase in cash and cash equivalents	(3,233)	16,248	1,475
Cash and cash equivalents, beginning of year	31,235	14,987	13,512
Cash and cash equivalents, end of year	$ 28,002	$ 31,235	$ 14,987
Non-cash financing activities:			
Capital contributions receivable	$ —	$ —	$ 50,000
Supplemental disclosure of cash flow information:			
Cash paid during the period:			
Interest	$ 31,157	$ 15,223	$ 7,096

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

A—Organization

Laredo Petroleum Holdings, Inc. ("Laredo Holdings") was incorporated pursuant to the laws of the State of Delaware on August 12, 2011 for the purposes of a Corporate Reorganization (as defined below) and the initial public offering of its common stock (the "IPO"). As a holding company, Laredo Holdings' management operations are conducted through its wholly-owned subsidiary, Laredo Petroleum, Inc. ("Laredo"), a Delaware corporation, and Laredo's subsidiaries, Laredo Petroleum Texas, LLC ("Laredo Texas"), a Texas limited liability company, Laredo Gas Services, LLC ("Laredo Gas"), a Delaware limited liability company, and Laredo Petroleum—Dallas, Inc. ("Laredo Dallas"), a Delaware corporation.

Laredo was incorporated on October 10, 2006, for the purpose of acquiring, developing and operating oil and natural gas producing properties on its behalf and on the behalf of others. On October 20, 2006, Laredo entered into a consulting agreement with Warburg Pincus Private Equity IX, L.P. ("Warburg Pincus IX") under which Laredo, as an independent contractor, agreed to pursue and develop acquisition and investment opportunities in the oil and natural gas industry for the benefit of Warburg Pincus IX and certain of its affiliates (collectively, the "Warburg Pincus Partnerships").

In May 2007, Warburg Pincus IX and certain members of Laredo's management contributed their common stock in Laredo to Laredo Petroleum, LLC ("Laredo LLC"), a Delaware limited liability company, and Laredo became a wholly-owned subsidiary of Laredo LLC. The consulting agreement between Laredo and Warburg Pincus IX was consequently terminated. Laredo LLC was focused on the exploration, development and acquisition of oil and natural gas in the Mid-Continent and Permian regions of the United States.

Broad Oak Energy, Inc. ("Broad Oak"), a Delaware corporation, was formed on May 11, 2006, and was engaged in the acquisition, exploration, development and production of oil and natural gas in the southwestern United States. Immediately upon formation, Broad Oak entered into a stock purchase agreement with Warburg Pincus IX and Broad Oak management.

On July 1, 2011, Laredo LLC and Laredo completed the acquisition of Broad Oak, which became a wholly-owned subsidiary of Laredo. In connection with the transaction, Laredo LLC issued: (i) approximately 86.5 million preferred equity units to Warburg Pincus IX and its affiliate in exchange for the convertible preferred stock previously held in Broad Oak; and (ii) approximately 2.4 million preferred equity units to Broad Oak's management and directors in exchange for certain of the vested common stock and convertible preferred stock previously held in Broad Oak. In addition, Laredo paid approximately $82 million in cash for certain Broad Oak vested common stock, convertible preferred stock and all outstanding and vested Broad Oak options that certain Broad Oak directors, management and employees elected to sell. All unvested shares of Broad Oak common stock and unvested Broad Oak options were cancelled. Immediately following the consummation of this transaction, Laredo LLC assigned 100% of its ownership interest in Broad Oak to Laredo as a contribution to capital (the transactions described in this paragraph are collectively, the "Broad Oak Transaction"). On July 19, 2011, Broad Oak's name was changed to Laredo Petroleum—Dallas, Inc.

Laredo LLC and Broad Oak were commonly controlled by Warburg Pincus Partnerships, and as such the Broad Oak Transaction was accounted for in a manner similar to a pooling of interests. As a result, the accompanying historical financial statements give retrospective effect to the Broad Oak Transaction, whereby the assets and liabilities of Laredo LLC and its subsidiaries and Broad Oak are reflected at the historical carrying values and their operations are presented as if they were consolidated for all periods. The consolidated equity statement presents Broad Oak's historical equity as "Other equity interests," all of which was exchanged for either (i) equity in Laredo LLC through BOE Preferred Units or (ii) cash in the Broad Oak Transaction.

Prior to the IPO, Laredo LLC merged with and into Laredo Holdings on December 19, 2011, with Laredo Holdings being the surviving entity, and the three classes of preferred units of Laredo LLC, namely the (i) Series A-1, (ii) Series A-2 and (iii) BOE Preferred Units (collectively, the "Preferred Units") and certain series of restricted units of Laredo LLC were exchanged into shares of common stock of Laredo Holdings based on the pre-offering equity value of such units in a corporate reorganization (the "Corporate Reorganization"). This resulted in the Preferred Units and the restricted units being exchanged into 104,079,546 and 3,420,454 shares of common stock of Laredo Holdings, respectively, or 107,500,000 shares of common stock in the aggregate. The 107,500,000 shares of common stock included 912,137 restricted shares issued to management and employees in exchange for unvested units in the Corporate Reorganization and 7,405 treasury shares held by Laredo Holdings. The conversion of the Preferred Units and the restricted units resulted in fractional shares of Laredo Holdings issued to each respective unit holder, which aggregated to 204 shares of common stock. Laredo Holdings then purchased all fractional shares based on the offering price of $17.00 per share, these shares are held as treasury stock. After the fractional share purchase and treasury stock transaction, 106,580,353 vested shares and 912,038 unvested shares were outstanding at the completion of the Corporate Reorganization. The common stock has one vote per share and a par value of $0.01 per share.

Laredo Holdings completed the IPO of 20,125,000 of its shares of common stock on December 20, 2011, which included 2,625,000 shares of common stock issued pursuant to the over-allotment option exercised by the underwriters of the IPO. The net proceeds from the sale of 20,125,000 shares of common stock, after underwriting discounts and commissions and offering expenses, was $319.4 million.

In these notes, the "Company," when used in the present tense, prospectively or for historical periods since December 19, 2011, refers to Laredo Holdings, Laredo and its subsidiaries collectively, and for historical periods prior to December 19, 2011 refers to Laredo LLC, Laredo and its subsidiaries collectively, unless the context indicates otherwise.

B—Basis of presentation and significant accounting policies

1. Basis of presentation

The accompanying consolidated financial statements were derived from the historical accounting records of the Company and reflect the historical financial position, results of operations and cash flows for the periods described herein. As discussed in Note A, the Broad Oak Transaction was accounted for in a manner similar to a pooling of interests and the historical financial statements present the assets and liabilities of Laredo Holdings and subsidiaries and Broad Oak at historical carrying values and their operations as if they were consolidated for all periods presented. All material intercompany transactions and account balances have been eliminated in the consolidation of accounts. The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The Company operates oil and natural gas properties as one business segment, which explores, develops and produces oil and natural gas.

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

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

Significant estimates include, but are not limited to, estimates of the Company's reserves of oil and natural gas, future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, equity and stock-based compensation, deferred income taxes and fair values of commodity and interest rate derivatives. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management's best judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment. Such estimates and assumptions are adjusted when facts and circumstances dictate. Illiquid credit markets and volatile equity and energy markets have consolidated to increase the uncertainty inherent in such estimates and assumptions. Management believes its estimates and assumptions to be reasonable under the circumstances. As future events and their effects cannot be determined with precision, actual results could differ from these estimates. Any changes in estimates resulting from future changes in the economic environment will be reflected in the financial statements in future periods.

3. Reclassifications

Certain immaterial amounts in the accompanying consolidated financial statements have been reclassified to conform to the 2011 presentation. These reclassifications had no impact to previously reported net income or losses, total stockholders'/unit holders' equity or cash flows.

4. Cash and cash equivalents

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

5. *Accounts receivable*

The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Joint interest and oil and natural gas sales receivables related to these operations are generally unsecured. Accounts receivable for joint interest billings are recorded as amounts billed to customers less an allowance for doubtful accounts. Amounts are considered past due after 30 days. The Company determines joint interest operations accounts receivable allowances based on management's assessment of the creditworthiness of the joint interest owners and the Company's ability to realize the receivables through netting of anticipated future production revenues. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging, and existing industry and national economic data. The Company reviews its allowance for doubtful accounts quarterly. Past due balances over 90 days and over a specified amount are reviewed individually for collectability. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is remote.

Accounts receivable consist of the following components as of December 31:

(in thousands)	2011	2010
Oil and natural gas sales	$ 49,434	$ 31,773
Joint operations(1)	24,190	12,031
Other	511	135
Total, net	$ 74,135	$ 43,939

(1) Accounts receivable for joint operations are presented net of an allowance for doubtful accounts of approximately $0.1 million at December 31, 2011 and 2010, respectively.

6. *Derivative financial instruments*

The Company uses derivative financial instruments 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, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices. These transactions are primarily in the form of swaps, basis swaps, puts and collars. In addition, the Company enters into derivative contracts in the form of interest rate derivatives to minimize the effects of fluctuations in interest rates.

Derivative instruments are recorded at fair value and are included on the consolidated balance sheets as assets or liabilities. The Company netted the fair value of derivative instruments by counterparty in the accompanying consolidated balance sheets where the right of offset exists. The Company determines the fair value of its derivative financial instruments utilizing pricing models for significantly similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties.

The Company's derivatives at December 31, 2011, 2010 or 2009 were not designated as hedges for financial statement purposes. Accordingly, the changes in fair value are recognized in the consolidated statement of operations in the period of change. Realized and unrealized gains and losses on derivatives are included in cash flows from operating activities (see Note G).

7. *Other current assets and liabilities*

Other current assets consist of the following components as of December 31:

(in thousands)	2011	2010
Prepaid expenses	$ 2,131	$ 1,483
Materials and supplies	187	4,154
Total other current assets	$ 2,318	$ 5,637

Other current liabilities at consist of the following components as of December 31:

(in thousands)	2011	2010
Lease operating expense accrual	$ 5,297	$ 2,913
Prepaid drilling liability	2,378	1,896
Production taxes payable	1,493	1,378
Current portion of asset retirement obligations	506	731
Other accrued liabilities	5,245	3,125
Total other current liabilities	$ 14,919	$ 10,043

8. *Materials and supplies*

Materials and supplies, which are included in current assets and other assets, are comprised of equipment used in developing oil and natural gas properties. They are carried at the lower of cost or market using the average cost method. On a regular basis, the Company reviews quantities of materials and supplies on hand and records a provision for excess or obsolete materials and supplies, if necessary.

During the year ended December 31, 2011, the Company reduced materials and supplies by approximately $0.2 million in order to reflect the balance at the lower of cost or market. Although management believes it has established adequate allowances, it is possible that additional losses on materials and supplies could occur in future periods. The Company determined a lower of cost or market adjustment was not necessary for materials and supplies at December 31, 2010.

9. *Oil and natural gas properties*

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

The Company computes the provision for depletion of oil and natural gas properties using the units of production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. Approximately $117.2 million and $96.5 million of such costs were excluded from the amortization base at December 31, 2011 and 2010, respectively. The amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. Total accumulated depletion for oil and natural gas properties was $884.5 million and $713.1 million for the years ended December 31, 2011 and 2010, respectively. Depletion expense for oil and natural gas properties was $171.5 million, $93.8 million and $55.4 million for the years ended December 31, 2011, 2010 and 2009, respectively. Impairment expense was $245.9 million for the year ended December 31, 2009. There were no impairments recorded for years ended December 31, 2011 and 2010. Depletion per barrel of oil equivalent for the Company's oil and natural gas properties was $19.82, $18.00 and $15.54 for the years ended December 31, 2011, 2010 and 2009, respectively.

The Company excludes the costs directly associated with acquisition and evaluation of unproved properties from the depletion calculation until it is determined whether or not proved reserves can be assigned to the properties. These properties are assessed at least quarterly to ascertain whether impairment has occurred. Such costs are transferred into the amortization base on an ongoing basis as projects are evaluated and proved reserves established or impairment is determined.

The Company assesses all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

The full cost ceiling is based principally on the estimated future net cash flows from oil and natural gas properties discounted at 10%. Full cost companies are required to use the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices were defined by contractual arrangements, to calculate the discounted future revenues. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the Securities and Exchange Commission ("SEC"), the excess is charged to expense in the period during which such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

At December 31, 2011, the full cost ceiling value of the Company's reserves was calculated based on the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2011 of $3.99 per MMBtu for natural gas, adjusted by area for energy content, transportation fees, and regional price differentials by area, and the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2011 of $92.71 per barrel for oil, adjusted by area for energy content, transportation fees, and regional price differentials by area. Using these prices, the Company's net book value of oil and natural gas properties did not exceed the full cost ceiling amount at December 31, 2011. Changes in production rates, levels of reserves, future development costs, and other factors will determine the Company's actual full cost ceiling test calculation and impairment analyses in future periods.

At December 31, 2010, the full cost ceiling value of the Company's reserves was calculated based on the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2010 of $4.15 per MMBtu for natural gas, adjusted by area for energy content, transportation fees, and regional price differentials by area, and the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2010 of $75.96 per barrel for oil, adjusted by area for energy content, transportation fees, and regional price differentials by area. Using these prices, the Company's net book value of oil and natural gas properties did not exceed the full cost ceiling amount at December 31, 2010.

At December 31, 2009, the full cost ceiling value of the Company's reserves was calculated based on the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period ended December 31, 2009 price of $3.15 per MMBtu for natural gas, adjusted by lease for energy content, transportation fees, and regional price differentials, on the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period ended December 31, 2009 price of $57.04 per barrel for oil, adjusted by lease for quality, transportation fees, and regional price differentials. Using these prices, the Company's net book value of oil and natural gas properties at December 31, 2009, exceeded the full cost ceiling amount. As a result, the Company recorded a non-cash full cost ceiling impairment of $245.9 million before income taxes and $159.8 million after taxes.

10. Pipeline and gas gathering assets

Pipeline and gas gathering assets are recorded at cost, net of accumulated depletion, depreciation and amortization ("DD&A"), and consist of gathering assets and related equipment. Depreciation of assets is provided using the shorter of the lease term or the straight-line method based on estimated useful lives of twenty years, as applicable. Expenditures for major renewals or betterments, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation and amortization are removed from the accounts and any gain or loss is recognized in "Non-operating income (expense)" in the consolidated statements of operations. DD&A expense for pipeline and gathering assets was $2.5 million, $2.0 million and $1.5 million for the years ended December 31, 2011, 2010 and 2009, respectively. Pipeline and gathering assets consist of the following as of December 31:

(in thousands)	2011	2010
Pipeline and gas gathering assets	$ 58,136	$ 43,271
Less accumulated depreciation and amortization	6,394	3,928
Total, net	$ 51,742	$ 39,343

11. Other fixed assets

Other fixed assets are recorded at cost net of accumulated depreciation and amortization and consist of furniture and fixtures, vehicles, leasehold improvements and computer hardware and software. Depreciation of other fixed assets is provided using the shorter of the lease term or the straight-line method based on estimated useful lives of three to ten years, as applicable. Leasehold improvements are capitalized and amortized over the shorter of the estimated useful lives of the assets or the terms of the related leases. Expenditures for major renewals or betterments, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation and amortization are removed from the accounts and any gain or loss is recognized in "Non-operating income (expense)" in the consolidated statements of operations. DD&A expense for other fixed assets was $2.4 million, $1.6 million and $1.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Other property and equipment fixed assets consist of the following as of December 31:

(in thousands)	**2011**	**2010**
Computer hardware and software	$ 6,206	$ 4,677
Leasehold improvements	1,847	1,781
Drilling service assets	5,742	1,985
Vehicles	1,279	1,022
Furniture and fixtures	1,021	673
Production equipment	255	219
Other	598	512
	16,948	10,869
Less accumulated depreciation and amortization	5,858	3,601
Total, net	$ 11,090	$ 7,268

12. Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Management believes no materially significant liabilities of this nature existed at December 31, 2011 or 2010.

13. Deferred loan costs

Loan origination fees are stated at cost, net of amortization, which are amortized over the life of the respective debt agreements on a basis that represents the effective interest method. The Company capitalized $23.2 million and $10.1 million of deferred loan costs in 2011 and 2010, respectively. The Company had total deferred loan costs of $23.5 million and $10.4 million, net of accumulated amortization of $4.4 million and $2.8 million, as of December 31, 2011 and 2010, respectively.

During the year ended December 31, 2011, the Company wrote-off $6.2 million in deferred loan costs as a result of the early retirement of the Term Loan (as defined below), the early retirement of the Broad Oak Credit Facility (as defined below) and changes in the borrowing base under the $1.0 billion revolving Senior Secured Credit Facility (as defined below).

Future amortization expense of deferred loan costs at December 31, 2011 is as follows:

(in thousands)	
2012	$ 4,240
2013	4,240
2014	4,240
2015	4,240
2016	2,993
Thereafter	3,504
Total	$ 23,457

14. Other assets and other noncurrent liabilities

Other assets consist of the following components as of December 31:

(in thousands)	**2011**	**2010**
Materials and supplies	$ 5,797	$ 1,886
Other assets, net	65	85
Total other assets	$ 5,862	$ 1,971

Other noncurrent liabilities consist of the following components as of December 31:

(in thousands)	**2011**	**2010**
Gas imbalances	$ 935	$ 1,093
Deferred lease liability	399	591
Total other noncurrent liabilities	$ 1,334	$ 1,684

15. Asset retirement obligations

Asset retirement obligations associated with the retirement of tangible long-lived assets, are recognized as a liability in the period in which they are incurred and become determinable. The associated asset retirement costs are part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related long-lived asset is charged to expense through the depletion of the asset. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and as corresponding accretion expense. See Note H for fair value disclosures related to the Company's asset retirement obligations.

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

The following reconciles the Company's asset retirement obligations liability as of December 31:

(in thousands)	**2011**	**2010**
Liability at beginning of year	$ 8,278	$ 5,845
Liabilities added due to acquisitions, drilling, and other	1,519	1,291
Liabilities removed due to sale of wells	—	(34)
Accretion expense	616	475
Liabilities settled upon plugging and abandonment	(340)	(1,250)
Revision of estimates	3,001	1,951
Liability at end of year	$ 13,074	$ 8,278

16. Fair value measurements

The carrying amounts reported in the consolidated balance sheets for cash and cash equivalents, accounts receivable, prepaid expenses, accounts payable, undistributed revenue and royalties, and other accrued liabilities approximate their fair values. See Note C for fair value disclosures related to the Company's debt obligations. The Company carries its derivative financial instruments at fair value. See Note G and Note H for details about the fair value of the Company's derivative financial instruments.

17. Treasury stock

The Company accounts for treasury stock at cost. See Note A for discussion of the Company's treasury stock transactions.

18. Revenue recognition

Oil and natural gas revenues are recorded using the sales method. Under this method, the Company recognizes revenues based on actual volumes of oil and natural gas sold to purchasers. The Company and other joint interest owners may sell more or less than their entitlement share of the volumes produced. Under the sales method, when a working interest owner has overproduced in excess of its share of remaining estimated reserves, the overproduced party recognizes the excessive gas imbalance as a liability. If the underproduced working interest owner determines that an overproduced partner's share of remaining net reserves is insufficient to settle the imbalance, the underproduced owner recognizes a receivable, net of any allowance from the overproduced working interest owner.

The following tables reflect the Company's natural gas imbalance positions as of December 31:

(dollars in thousands)	2011	2010
Natural gas imbalance current receivable (included in "Accounts receivable—Oil and natural gas sales")	$ 22	$ 174
Underproduced positions (Mcf)	6,312	43,720
Natural gas imbalance current liability (included in "Other current liabilities")	$ 32	$ 15
Overproduced positions (Mcf)	9,049	3,839
Natural gas imbalance long-term liability (included in "Other noncurrent liabilities")	$ 935	$ 1,093
Overproduced positions (Mcf)	264,808	275,201

	For the years ended December 31,		
(dollars in thousands)	2011	2010	2009
Value of net (overproduced) underproduced positions arising during the period increasing oil and natural gas sales	$ (10)	$ 25	$ (311)
Net overproduced (underproduced) positions arising during the period (Mcf)	32,353	(12,772)	63,229

19. General and administrative expense

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

The following amounts have been recorded for the years ended December 31, 2011, 2010 and 2009:

	For the years ended December 31,		
(in thousands)	2011	2010	2009
Fees received for the operation of jointly-owned oil and natural gas properties	$ 2,241	$ 1,497	$ 1,273

20. Equity and stock-based awards

Prior to the Corporate Reorganization on December 19, 2011, the Company recognized equity-based awards as a charge against earnings over the requisite service period, in an amount equal to the fair value of equity-based awards granted to employees and directors. The fair value of the equity-based awards was computed at the date of grant. Refer to Note E and Note O for further information regarding the Company's equity-based awards/stock-based awards.

For stock-based compensation equity awards, compensation expense is recognized in the Company's financial statements over the awards' vesting periods based on their grant date fair value. The Company utilizes the closing stock price on the date of grant to determine the fair value of service vesting restricted stock awards.

21. Income taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating losses and tax credit carry-forwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income 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 realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. Additionally, the Company has not recorded any reserves for uncertain tax positions. See Note F for detail of amounts recorded in the consolidated financial statements.

22. Impairment of long-lived assets

Impairment losses are recorded on property and equipment used in operations and other long-lived assets when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. See Note B.8 for disclosure of the 2011 write-down of materials and supplies and Note B.9 for disclosure of the 2009 non-cash full cost ceiling impairment. Other than the aforementioned write-downs, for the years ended December 31, 2011, 2010 and 2009, the Company did not record any additional impairment to property and equipment used in operations or other long-lived assets.

23. Related party transactions

The following table summarizes the net oil and natural gas sales (oil and natural gas sales less production taxes) received from the Company's related party and included in the consolidated statements of operation for the periods presented:

	For the years ended December 31,		
(in thousands)	**2011**	**2010**	**2009**
Net oil and natural gas sales(1)	$ 79,300	$ 35,000	$ 7,288

The following table summarizes the amounts included all in oil and natural gas sales receivable in the consolidated balance sheets for the periods presented:

	At December 31,	
(in thousands)	**2011**	**2010**
Oil and natural gas sales receivable(1)	$ 6,845	$ 4,435

(1) The Company has a gas gathering and processing arrangement with affiliates of Targa Resources, Inc, ("Targa"). Warburg Pincus IX, a majority equityholder in the Company, and other Warburg Pincus affiliates hold investment interests in Targa. One of Laredo Holdings' directors is on the board of directors of affiliates of Targa.

C—Debt

1. Interest expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2011, 2010 and 2009:

(in thousands)	For the years ended December 31, 2011	2010	2009
Cash payments for interest	$ 31,157	$ 15,223	$ 7,096
Amortization of deferred loan costs and other adjustments	4,231	2,256	493
Accrued interest related to the October Notes(1)	(3,378)	—	—
Change in accrued interest	18,570	1,003	(125)
Total interest expense	$ 50,580	$ 18,482	$ 7,464

(1) As part of the October 19, 2011 offering of $200 million additional senior unsecured notes (further explained below), Laredo received $3.4 million in interest from the initial notes purchasers, which represents the interest on such notes that accrued from August 15, 2011 to October 19, 2011, the date of the issuance of the notes. This accrued interest was paid to the holders of such notes by Laredo on February 15, 2012.

The following table presents the weighted average interest rates and the weighted average outstanding debt balances for the years ended December 31, 2011, 2010 and 2009:

	Years ended December 31,					
	2011		2010		2009	
(in thousands except for percentages)	Weighted average principal	Weighted average interest rate	Weighted average principal	Weighted average interest rate	Weighted average principal	Weighted average interest rate
Senior Secured Credit Facility	$ 299,502	2.07%	$ 180,788	3.38%	$ 154,011	3.67%
2019 Notes	392,319	8.98%	—	—	—	—
Term Loan(1)	100,000	0.51%	100,000	4.49%	—	—
Broad Oak Credit Facility(2)	122,904	3.07%	123,782	4.27%	27,657	4.65%

(1) The Term Loan was entered into on July 7, 2010 and was paid-in-full and terminated on January 20, 2011.

(2) The Broad Oak Credit Facility was paid-in-full and terminated on July 1, 2011 in conjunction with the Broad Oak Transaction.

2. 2019 Notes

On January 20, 2011, Laredo completed an offering of $350 million 9$^1/_2$% Senior Notes due 2019 (the "January Notes"). The January Notes will mature on February 15, 2019 and bear an interest rate of 9.5% per annum payable semi-annually, in cash, in arrears on February 15 and August 15 of each year, commencing August 15, 2011. The January Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by Laredo Holdings and (other than Laredo) its subsidiaries (collectively, the "Guarantors"). The net proceeds from the January Notes were used (i) to repay and retire $100 million outstanding under Laredo's Second Lien Term Loan Agreement (the "Term Loan"), (ii) to pay in full $177.5 million outstanding under Laredo's revolving Second Amended and Restated Senior

Secured Credit Facility Agreement (the "Senior Secured Credit Facility"), and (iii) for general working capital purposes.

On October 19, 2011 Laredo completed an offering of an additional $200 million 9$^{1}/_{2}$% Senior Notes due 2019 (the "October Notes" and together with the January Notes, the "2019 Notes"), at a price of 101% of par. The October Notes were issued under the same Indenture (defined below) as the January Notes and are part of the same series as the January Notes. As such, the October Notes will mature on February 15, 2019 and bear an interest rate of 9.5% per annum payable semi-annually, in cash, in arrears on February 15 and August 15 of each year, commencing February 15, 2012. Interest accrued on the October Notes beginning August 15, 2011. The October Notes are fully and unconditionally guaranteed, jointly and severally on a senior unsecured basis by the Guarantors. The net proceeds from the October Notes were used to pay down $200 million of the loan amounts outstanding under the Senior Secured Credit Facility. At December 31, 2011, the carrying amount of the October Notes was approximately $202.0 million which includes a bond premium of approximately $2.0 million. The bond premium is being amortized into interest expense over the life of the 2019 Notes on a basis that represents the effective interest method.

The 2019 Notes were issued under and are governed by an indenture dated January 20, 2011 (as supplemented, the "Indenture") among Laredo, Wells Fargo Bank, National Association, as trustee, and the Guarantors. The Indenture contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of dividends or similar restricted payments, the undertaking of transactions with Laredo's unrestricted affiliates and limitations on asset sales. Indebtedness under the 2019 Notes may be accelerated in certain circumstances upon an event of default as set forth in the Indenture.

Laredo will have the option to redeem the 2019 Notes, in whole or in part, at any time on or after February 15, 2015, at the redemption prices (expressed as percentages of principal amount) of 104.750% for the twelve-month period beginning on February 15, 2015, 102.375% for the twelve-month period beginning on February 15, 2016 and 100.000% for the twelve-month period beginning on February 15, 2017 and at any time thereafter, together with accrued and unpaid interest, if any, to the date of redemption. In addition, before February 15, 2015, Laredo may redeem all or any part of the 2019 Notes at a redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. Furthermore, before February 15, 2014, Laredo may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the 2019 Notes with the net proceeds of a public or private equity offering at a redemption price of 109.500% of the principal amount of 2019 Notes, plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the 2019 Notes issued under the Indenture remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. Laredo may also be required to make an offer to purchase the 2019 Notes upon a change of control triggering event.

In connection with the issuance of the 2019 Notes, (i) Laredo and the Guarantors party thereto entered into a registration rights agreement with the initial purchasers of the January Notes on January 20, 2011 and (ii) Laredo and the Guarantors party thereto entered into a registration rights agreement with the initial purchasers of the October Notes on October 19, 2011 pursuant to which, in each case, Laredo and the Guarantors agreed to file with the SEC and use commercially reasonable efforts to cause to become effective a registration statement with respect to an offer to exchange the 2019 Notes for substantially identical notes (other than with respect to restrictions on transfer or to any increase in annual interest rate) registered under the Securities Act of 1933, as amended (the "Securities Act"), so as to permit the exchange offer to be consummated by the 365th day after January 20, 2011. The offer to exchange the 2019 Notes for substantially identical notes registered under the Securities Act was consummated on January 13, 2012.

3. Senior secured credit facility

As previously described in Note A, on July 1, 2011, Laredo LLC and Laredo consummated a transaction by which Broad Oak became a wholly-owned subsidiary of Laredo. The cash portion of the transaction was funded under an amendment and restatement to the Senior Secured Credit Facility. Under this third amendment and restatement, the Senior Secured Credit Facility's capacity increased to $1.0 billion, with a borrowing base of $712.5 million, at December 31, 2011. At December 31, 2011, $85.0 million was outstanding. The borrowing base is subject to a semi-annual redetermination based on the financial institutions' evaluation of the Company's oil and natural gas reserves. The amendment lengthened the term of the Senior Secured Credit Facility, making it available to July 1, 2016, at which time the outstanding balance will be due. As defined in the Senior Secured Credit Facility, (i) the Adjusted Base Rate advances under the facility bear interest payable quarterly at an Adjusted Base Rate plus applicable margin and (ii) the Eurodollar advances under the facility bear interest, at our election, at the end of one-month, two-month, three-month, six-month or, to the extent available, twelve-month interest periods (and in the case of six-month and twelve-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate plus an applicable margin, based on the ratio of outstanding revolving credit to the conforming base rate. Laredo is also required to pay an annual commitment fee on the unused portion of the bank's commitment of 0.375% to 0.5%.

The Senior Secured Credit Facility is secured by a first priority lien on Laredo and the Guarantor's assets and stock, including oil and natural gas properties, constituting at least 80% of the present value of the Company's proved reserves. Further, the Company is subject to various financial and non-financial ratios on a consolidated basis, including a current ratio at the end of each calendar quarter, of not less than 1.00 to 1.00. As defined by the Senior Secured Credit Facility, the current ratio represents the ratio of current assets to current liabilities, inclusive of available capacity and exclusive of current balances associated with derivative positions. Additionally, at the end of each calendar quarter, the Company must maintain a ratio of its consolidated net income (a) plus each of the following; (i) any provision for (or less any benefit from) income or franchise taxes; (ii) consolidated net interest expense; (iii) depreciation, depletion and amortization expense; (iv) exploration expenses; and (v) other noncash charges, and (b) minus all non-cash income ("EBITDAX"), as defined in the Senior Secured Credit Facility, to the sum of net interest expense plus letter of credit fees of not less than 2.50 to 1.00, in each case for the four quarters then ending. The Senior Secured Credit Facility contains both financial and non-financial covenants and the Company was in compliance with these covenants at December 31, 2011 and 2010.

Additionally, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $20.0 million. At December 31, 2011, Laredo had one letter of credit outstanding totaling $0.03 million under the Senior Secured Credit Facility.

4. Retirement of term loan

In January 2011, Laredo paid in full its $100.0 million outstanding balance under the Term Loan, dated July 7, 2010, between Laredo and certain financial institutions, using a portion of the proceeds from its January Notes and retired the loan. The Term Loan was subject to an interest rate of 9.25% prior to its pay-off and subsequent retirement.

5. Retirement of Broad Oak credit facility

At July 1, 2011, Broad Oak had a $600.0 million revolving credit facility under its Seventh Amendment to the Credit Agreement (the "Broad Oak Credit Facility"), dated April 11, 2008, between Broad Oak and certain financial institutions. As of June 30, 2011, the Broad Oak Credit Facility had a borrowing base of $375 million with $265.4 million outstanding. As of December 31, 2010, the borrowing was $250 million with $214.1 million outstanding. The borrowing base was subject to a semi-annual redetermination based on the financial institutions' evaluation of Broad Oak's oil and natural gas reserves. The Broad Oak Credit Facility was available to Broad Oak until April 2013, at which time the outstanding balance would have been due. As defined in the Broad Oak Credit Facility, the Adjusted Base Rate Advances and Eurodollar Advances bore interest payable quarterly at an Adjusted Base Rate or Adjusted LIBOR plus an applicable margin based on the ratio of outstanding revolving credit to the conforming borrowing base. Broad Oak was also required to pay a quarterly commitment fee of 0.5% on the unused portion of the bank's commitment.

The Broad Oak Credit Facility was secured by a first priority lien on Broad Oak's oil and natural gas properties. Further, Broad Oak was subject to various financial and non-financial ratios, including a current ratio at the end of each calendar quarter, of not less than 1.00 to 1.00. As defined by the Broad Oak Credit Facility, the current ratio represented the ratio of current assets to current liabilities, inclusive of available capacity and exclusive of current balances associated with non-cash derivative positions. Additionally, at the end of each calendar quarter, Broad Oak had to maintain a ratio of debt to "Consolidated EBITDAX" of not more than 3.50 to 1.00, based on the quarter then ended annualized. "Consolidated EBITDAX" is defined as consolidated net income plus the sum of (i) income or franchise taxes; (ii) consolidated net interest expense; (iii) depreciation, depletion and amortization expense; (iv) any non-cash losses or charges on any derivative positions; (v) other noncash charges; and (vi) costs associated with oil and natural gas capital expenditures that are expensed rather than capitalized, less, to the extent included in the calculation of Consolidated Net Income (as defined in the Broad Oak Credit Facility), the sum of (A) the income of any person (other than wholly owned subsidiaries of such person) unless such income is received by such person in a cash distribution; (B) gains for losses from sales or other dispositions of assets (other than hydrocarbons produced in the normal course of business); (C) any non-cash gains on any hedge agreement resulting from the requirements of Accounting Standards Codification 815, *Derivatives and Hedging,* for that period; (D) extraordinary or non-recurring gains, but not net of extraordinary or non-recurring "cash" losses; and (E) costs and expenses associated with, and attributable to, oil and natural gas capital expenditures that are expensed rather than capitalized. The Broad Oak Credit Facility contained both financial and non-financial covenants and Broad Oak was in compliance with these covenants at December 31, 2010.

Additionally, the Broad Oak Credit Facility provided for the issuance of letters of credit, limited to the total capacity. At December 31, 2010, Broad Oak had no letters of credit outstanding.

On July 1, 2011, Laredo paid the Broad Oak Credit Facility in full and the facility was terminated. Upon consummation of the acquisition of Broad Oak, Broad Oak was added as a guarantor under the Senior Secured Credit Facility and the 2019 Notes and its name was changed to Laredo Petroleum—Dallas, Inc. on July 19, 2011.

6. Fair value of debt

The following table presents the carrying amount and fair value of the Company's debt instruments at December 31, 2011 and 2010:

	December 31, 2011		December 31, 2010	
(in thousands)	**Carrying value**	**Fair value**	**Carrying value**	**Fair value**
2019 Notes(1)	$ 551,961	$ 585,750	$ —	$ —
Credit Facilities(2)	85,000	84,893	391,600	392,097
Term Loan	—	—	100,000	100,707
Total value of debt	$ 636,961	$ 670,643	$ 491,600	$ 492,804

(1) The carrying value of the 2019 Notes includes the October Notes unamortized bond premium of approximately $2.0 million as of December 31, 2011.

(2) December 31, 2010 values include the Broad Oak Credit Facility.

At December 31, 2011 the fair value of the debt outstanding on the 2019 Notes was determined using the December 31, 2011 quoted market price. For December 31, 2011, the fair value of the outstanding debt on the Laredo Senior Secured Credit Facility and for December 31, 2010, the fair value of the outstanding debt on the Laredo Senior Secured Credit Facility, the Broad Oak Credit Facility and the Term Loan was estimated utilizing pricing models for similar instruments.

D—Owners' equity

In the Corporate Reorganization, the Series A-1 Units, Series A-2 Units, BOE Preferred Units, Series B-1 Units, Series B-2 Units, Series D Units, Series F Units, Series G Units and BOE Incentive Units of Laredo LLC were exchanged into shares of common stock of Laredo Holdings based on the pre-offering equity value of such units. This resulted in the Series A-1 Units, Series A-2 Units and BOE Preferred Units being exchanged for 32,469,452; 21,011,572; and 50,598,522 shares of Laredo Holdings common stock, respectively, and the Series B Units, Series B-2 Units, Series D Units, Series F Units, Series G Units and BOE Incentive Units being exchanged for 2,029,425; 300,269; 666,857; 303,673; 66,333; and 53,897 shares of Laredo Holdings common stock, respectively, or 107,500,000 shares of common stock in the aggregate. The shares of common stock have one vote per share and a par value of $0.01 per share. The exchange of the units had no effect on the book value of stockholders' equity/unit holders' equity.

Preferred units

Prior to the Corporate Reorganization, the Laredo LLC Second Amended and Restated Limited Liability Company Agreement (the "LLC Agreement") provided for the issuance of three classes of preferred units, (i) Series A-1, (ii) Series A-2 and (iii) BOE Preferred Units. First, the LLC Agreement authorized a total of 60.0 million Series A-1 Units of Laredo LLC for total consideration of $300 million, consisting of approximately $294.9 million from Warburg Pincus IX and $5.1 million from certain members of Laredo LLC's management team and Board of Managers. This portion was fully funded as of December 31, 2009. Second, the LLC Agreement provided for a total of 48.0 million Series A-2 Units of Laredo LLC for total consideration of $300 million, initially consisting of approximately $288.5 million from Warburg Pincus Private Equity X O&G, L.P. ("Warburg Pincus X"), $9.2 million from Warburg Pincus X Partners, L.P. ("Warburg Pincus X Partners") and $2.3 million from certain members of Laredo LLC's management team and Board of Managers. Third, the LLC Agreement authorized a total of 89.0 million BOE Preferred Units, all of which were issued and outstanding at September 30, 2011, for total consideration of $670.1 million, consisting of approximately $611.2 million from Warburg Pincus IX, $40.6 million from WP IX Finance LP and $18.4 million from Broad Oak's management team.

The Series A-1 and A-2 Units, (collectively the "Series A Units") and the BOE Preferred Units, had a liquidation preference amount equal to the total capital then invested, plus a 7% cumulative return, compounded quarterly. The holders of the Series A Units and BOE Preferred Units received the accumulated preferred return upon the consummation of the qualified public offering, as defined in the LLC Agreement. Prior to the IPO, approximately $1,219.2 million had been contributed to Laredo LLC, net of Series A Unit repurchases by Laredo LLC. Of this total, approximately $906.0 million was contributed by Warburg Pincus IX, $238.4 million by Warburg Pincus X, $40.6 million by WP IX Finance LP, $7.6 million by Warburg Pincus X Partners, $18.4 million by the former Broad Oak management team and former directors and $8.2 million by certain members of Laredo LLC's management and Board of Managers.

Restricted units

Prior to the Corporate Reorganization, Laredo LLC was authorized to issue up to 16,923,077 Series B Units, up to 8,791,209 Series C Units, up to 13,538,462 Series D Units up to 7,032,967 Series E Units, up to 5,538,542 Series F Units, up to 4,299,635 Series G Units and up to 1,245,195 BOE Incentive Units under restricted unit agreements (collectively, the "Restricted Units"). The Series B Units were divided into two unit series, B-1 Units and B-2 Units. The Series B-1 Units had an initial threshold value of $0 and the Series B-2 Units had an initial threshold value of $1.25. The Series C Units had an initial threshold value of $10.00, the Series D Units, Series F Units, and Series G Units had an initial threshold value of $1.25, the Series E Units had an initial threshold value of $13.75, and the BOE Incentive Units have an initial threshold value of $0.

The table below summarizes the activity relating to the Restricted Units by series prior to the Corporate Reorganization on December 19, 2011:

(in thousands)	Series B units	Series C units	Series D units	Series E units	Series F units	Series G units	Series BOE Incentive units	Total units
BALANCE, December 31, 2008	8,757	7,780	—	—	—	—	—	16,537
Issuance of restricted units	54	—	4,644	5,996	—	—	—	10,694
Cancellation of restricted units	(113)	(100)	(49)	(10)	—	—	—	(272)
BALANCE, December 31, 2009	8,698	7,680	4,595	5,986	—	—	—	26,959
Issuance of restricted units	—	—	5,530	756	—	—	—	6,286
Cancellation of restricted units	(700)	(420)	(513)	(180)	—	—	—	(1,813)
BALANCE, December 31, 2010	7,998	7,260	9,612	6,562	—	—	—	31,432
Issuance of restricted units	—	—	2,356	170	5,370	1,197	766	9,859
Cancellation of restricted units	(376)	(370)	(275)	(120)	(18)	(140)	(90)	(1,389)
BALANCE, December 19, 2011	7,622	6,890	11,693	6,612	5,352	1,057	676	39,902

E—Equity and stock-based compensation

Restricted Stock Awards

As part of the Corporate Reorganization, vested Restricted Units were exchanged for 2,500,807 shares of common stock of Laredo Holdings and unvested Restricted Units were exchanged for 912,038 restricted stock awards of Laredo Holdings. In accordance with GAAP, it was determined that the fair value of the unit awards immediately prior to the conversion was equal to the fair value of the shares of common stock immediately after the conversion and as such, the basis in the former unvested Restricted Units was carried over to the unvested shares of common stock of Laredo Holdings. Therefore, the exchange of Restricted Units for common stock of Laredo Holdings resulted in no incremental compensation costs. The restricted stock awards are subject to the same vesting and forfeiture as the unvested Restricted Units they exchanged for.

The following table reflects the outstanding restricted stock awards following the Corporate Reorganization as of December 31, 2011:

(in thousands, except for grant date fair values)	Restricted stock awards	Weighted-average grant date fair value
Outstanding at December 19, 2011	—	$ —
Exchanged	912	1.14
Vested	(1)	1.11
Outstanding at December 31, 2011	911	$ 1.14

In November 2011, the Board of Directors of Laredo Holdings and its stockholder approved a Long-Term Incentive Plan (the "LTIP"), which provides for the granting of incentive awards in the form of stock options, restricted stock awards and other awards. The LTIP provides for the issuance of 10.0 million shares. No awards or shares were outstanding under the LTIP as of December 31, 2011. See Note O for discussion of the February 2012 issuance of restricted stock, stock option awards and other awards.

The term "equity-based" refers to awards in the form of Restricted Units of Laredo LLC prior to December 19, 2011. The term "stock-based" refers to the unvested Restricted Units exchanged for restricted stock awards of Laredo Holdings. The Company recognizes the fair value of equity and stock-based payments to employees and directors as a charge against earnings. The Company recognizes equity and stock-based payment expense over the requisite service period. Laredo LLC's equity-based awards were and Laredo Holdings' stock-based payment awards are accounted for as equity instruments. Equity and stock-based compensation are included in "Equity and stock-based compensation" in the consolidated statements of operations.

The following table presents equity-based compensation for the year ended December 31, 2011, 2010 and 2009, respectively.

	For the years ended December 31,		
(in thousands)	**2011**	**2010**	**2009**
Equity-based compensation until December 19, 2011	$ 5,961	$ 1,257	$ 1,419
Stock-based compensation from December 19, 2011 to December 31, 2011	150	—	—
Total equity and stock-based compensation	$ 6,111	$ 1,257	$ 1,419

For the year ended December 31, 2011, the estimated market value of equity-based compensation for Restricted Units and stock-based compensation for the restricted stock awards the Restricted Units were exchanged for were estimated based on a valuation prepared by the Company's third-party valuation firm. The estimated market value was calculated at the end of each calendar quarter and the estimated market value of the Company was applied to each Series B-1, B-2, C, D, E, F, G and BOE Incentive Units granted during the current calendar quarter. The method of allocation was based on first determining the enterprise value using the market approach and the income approach and then weighting the indicated value to arrive at the fair value of the unit grants. The allocation of total equity remaining after giving effect to the preference amounts based upon the Preferred Units of the Company and the issued units' initial threshold value, as defined in the LLC Agreement was then determined by a valuation model taking into account the facts and circumstances that exist at the preceding quarter end and was allocated to each series of Restricted Units. Although the fair value of the unit grants were determined in accordance with GAAP, that value may not be indicative of the fair value observed in a market transaction between a willing buyer and a willing seller.

For the year ended December 31, 2010, the fair value of equity-based compensation for Restricted Units was estimated based on the Company's estimated market value. The Company calculated the estimated market value at the end of each calendar quarter and then applied the calculated value to each Series B-1, B-2, C, D and E Units granted during the current calendar quarter. The Company's determination of the fair value for Series B-1, B-2, C, D and E Units was calculated based on the value of the Company's proved reserves using published market prices held flat after year five and then applying the following present value factors to the cash flows for proved reserves: 8% to proved developed properties, 15% to proved developed nonproducing properties and 20% to proved undeveloped properties. The aggregate calculated values were then adjusted by the net value of the Company's other non-oil and natural gas assets and liabilities to arrive at a net asset value. The net asset value was then adjusted for equity capital invested and the corresponding 7% preference amount to arrive at our net equity value. The net value was then allocated to each class of outstanding units, based upon unit sharing ratios and unit threshold values to arrive at the fair market value for each respective award. Although the fair value of the unit grants was determined in accordance with GAAP, that value may not be indicative of the fair value observed in a market transaction between a willing buyer and a willing seller.

Prior to the Corporate Reorganization, Laredo LLC was authorized to issue equity incentive awards in the form of Restricted Units. Unvested Restricted Units could not be sold, transferred or assigned. The fair value of the Restricted Units was measured based upon the estimated market price of the underlying member units as of the date of grant. The Restricted Units were subject to the following vesting terms: 20% at the grant date and 20% annually thereafter. The fair value of the Restricted Units in excess of the amounts paid by the employee, which is zero, was amortized to expense over its applicable requisite service period using the straight-line method. In the event of a termination of employment for cause, all Restricted Units, including unvested Restricted Units and vested Restricted Units, and all rights arising from such Restricted Units and from being a holder thereof, were forfeited. In the event of a termination of employment without cause or a resignation, all unvested Restricted Units and all rights arising from such Restricted Units and from being a holder thereof, were forfeited. For a period of one year from the date of termination of employment, in the event of a termination of employment for cause, the Company could elect to redeem the Series A Units and BOE Preferred Units at a price per unit equal to the lesser of the fair market value or original purchase price. In the event of a termination without cause or a resignation, the Company could elect to redeem the Series A Units and BOE Preferred Units and vested Restricted Units at a price equal to the fair market value.

The tables below summarize activity relating to the unvested Restricted Units prior to the Corporate Reorganization on December 19, 2011:

(in thousands, except grant date fair values)	Series B-1	Weighted average fair value	Series B-2	Weighted average fair value	Series C	Weighted average fair value	Series D	Weighted average fair value
Outstanding at December 31, 2008	4,221	$ 0.34	1,975	$ 2.16	5,581	$ —	—	$ —
Granted	—	$ —	54	$ —	—	$ —	4,644	$ —
Vested	(1,242)	$ 0.26	(502)	$ 2.12	(1,536)	$ —	(930)	$ —
Forfeited	(80)	$ 1.75	(14)	$ 2.23	(80)	$ —	(43)	$ —
Outstanding at December 31, 2009	2,899	$ 0.33	1,513	$ 2.10	3,965	$ —	3,671	$ —
Granted	—	$ —	—	$ —	—	$ —	5,530	$ —
Vested	(1,055)	$ 0.27	(483)	$ 2.12	(1,416)	$ —	(1,983)	$ —
Forfeited	(425)	$ 0.64	(88)	$ 2.17	(420)	$ —	(473)	$ —
Outstanding at December 31, 2010	1,419	$ 0.36	942	$ 2.10	2,129	$ —	6,745	$ —
Granted	—	$ —	—	$ —	—	$ —	2,256	$ 0.67
Vested	(1,043)	$ 0.24	(453)	$ 2.13	(1,346)	$ —	(2,345)	$ 0.13
Forfeited	(10)	$ 0.35	(17)	$ —	—	$ —	(78)	$ 0.05
Outstanding at December 19, 2011	366	$ 0.68	472	$ 2.08	783	$ —	6,578	$ 0.18

(in thousands, except grant date fair values)	Series E	Weighted average fair value	Series F	Weighted average fair value	Series G	Weighted average fair value	BOE Incentive	Weighted average fair value
Outstanding at December 31, 2008	—	$ —	—	$ —	—	$ —	—	$ —
Granted	5,996	$ —	—	$ —	—	$ —	—	$ —
Vested	(1,199)	$ —	—	$ —	—	$ —	—	$ —
Forfeited	(8)	$ —	—	$ —	—	$ —	—	$ —
Outstanding at December 31, 2009	4,789	$ —	—	$ —	—	$ —	—	$ —
Granted	756	$ —	—	$ —	—	$ —	—	$ —
Vested	(1,349)	$ —	—	$ —	—	$ —	—	$ —
Forfeited	(180)	$ —	—	$ —	—	$ —	—	$ —
Outstanding at December 31, 2010	4,016	$ —	—	$ —	—	$ —	—	$ —
Granted	170	$ 0.05	5,340	$ 1.46	1,197	$ 5.12	766	$ 3.36
Vested	(1,322)	$ —	(1,068)	$ 1.34	(219)	$ 5.12	(140)	$ 3.37
Forfeited	(2)	$ —	(14)	$ 1.46	(140)	$ 5.12	(90)	$ 3.36
Outstanding at December 19, 2011	2,862	$ —	4,258	$ 1.46	838	$ 5.12	536	$ 3.37

For the years ended December 31, 2011, 2010 and 2009, respectively, unrecognized equity and stock-based compensation expense related to restricted stock awards/unvested Restricted Units was $13.0 million, $2.1 million and $3.7 million. That cost is expected to be recognized over a weighted average period of 1.5 years.

A summary of weighted average grant date fair values and intrinsic values of Restricted Units that vested during the period ended December 19, 2011 (prior to the Corporate Reorganization) and the year ended December 31, 2010 are as follows:

(in thousands, except weighted average grant date fair values)	December 19, 2011	December 31, 2010
B-1 Units:		
Weighted average grant date fair value	$ 0.24	$ 0.27
Total intrinsic value of units vested	$ 2,736	$ 431
B-2 Units:		
Weighted average grant date fair value	$ 2.13	$ 2.12
Total intrinsic value of units vested	$ 965	$ —
C Units:		
Weighted average grant date fair value	$ —	$ —
Total intrinsic value of units vested	$ 236	$ —
D Units:		
Weighted average grant date fair value	$ 0.13	$ —
Total intrinsic value of units vested	$ 1,038	$ —
E Units:		
Weighted average grant date fair value	$ —	$ —
Total intrinsic value of units vested	$ 14	$ —
F Units:		
Weighted average grant date fair value	$ 1.34	$ —
Total intrinsic value of units vested	$ 1,558	$ —
G Units:		
Weighted average grant date fair value	$ 5.12	$ —
Total intrinsic value of units vested	$ 1,123	$ —
BOE Incentive Units:		
Weighted average grant date fair value	$ 3.37	$ —
Total intrinsic value of units vested	$ 472	$ —

F—Income taxes

Income taxes in these financial statements are generally presented on a "consolidated" basis. However, in light of the historic ownership structure of the Company, U.S. tax laws do not allow tax losses of one entity to offset income and losses of another entity until after the consummation of the Broad Oak Transaction 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.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

As previously discussed in Note A, Laredo LLC merged into Laredo Holdings on December 19, 2011, and accordingly Laredo Holdings will file a consolidated return for the period December 19, 2011 through December 31, 2011. Prior to the Corporate Reorganization, Laredo LLC's subsidiaries were subject to corporate income taxes. Laredo Holdings and its subsidiaries are subject to corporate income taxes. In addition, the Company is subject to the Texas margin tax. Income tax (expense) benefit for the years ended December 31, 2011, 2010 and 2009 consisted of the following:

(in thousands)	2011	2010	2009
Current taxes			
Federal	$ —	$ —	$ —
State	—	—	—
Deferred taxes			
Federal	(58,727)	27,345	69,046
State	(647)	(1,533)	4,960
Income tax (expense) benefit	$ (59,374)	$ 25,812	$ 74,006

Income tax (expense) benefit differed from amounts computed by applying the federal income tax rate of 34% to pre-tax loss from operations as a result of the following:

(in thousands)	2011	2010	2009
Income tax (expense) benefit computed by applying the statutory rate	$ (56,076)	$ (20,548)	$ 87,891
State income tax, net of federal tax benefit and increase in valuation allowance	(2,530)	(1,118)	3,110
Income from non-taxable entity	30	48	61
Non-deductible compensation	(2,078)	(418)	(482)
Valuation allowance	660	47,888	(16,476)
Other items	620	(40)	(98)
Income tax (expense) benefit	$ (59,374)	$ 25,812	$ 74,006

Significant components of the Company's deferred tax assets as of December 31 are as follows:

(in thousands)	2011	2010
Derivative financial instruments	$ 3,551	$ 10,862
Oil and natural gas properties and equipment	(87,138)	(59,854)
Net operating loss carry-forward	180,740	207,427
Other	(926)	(2,174)
	96,227	156,261
Valuation allowance	(649)	(1,309)
Net deferred tax asset	$ 95,578	$ 154,952

Net deferred tax assets and liabilities were classified in the consolidated balance sheets as follows:

(in thousands)	2011	2010
Deferred tax asset	$ 95,578	$ 154,952
Deferred tax liability	—	—
Net deferred tax assets	$ 95,578	$ 154,952

The Company had federal net operating loss carry-forwards totaling approximately $511.5 million and state net operating loss carry-forwards totaling approximately $167.6 million at December 31, 2011. These carry-forwards begin expiring in 2026. The Company maintains a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized. At December 31, 2011, a $0.6 million valuation allowance has been recorded against the state of Louisiana deferred tax asset and a $0.02 million valuation allowance has been recorded against the Company's charitable contribution carry-forward. The Company believes the federal and state of Oklahoma net operating loss carry-forwards are fully realizable. The Company considered all available evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance was needed. 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 at December 31, 2011 and the Company's ability to capitalize intangible drilling costs, rather than expensing these costs, in order to prevent an operating loss carry-forward from expiring unused.

The Company's income tax returns for the years 2008 through 2010 remain open and subject to examination by federal tax authorities and/or the tax authorities in Oklahoma, Texas and Louisiana which are the jurisdictions where the Company has or had operations. Additionally, the statute of limitations for examination of federal net operating loss carryovers typically does not begin to run until the year the attribute is utilized in a tax return. In evaluating its current tax positions in order to identify any material uncertain tax positions, the Company developed a policy in identifying uncertain tax positions that considers support for each tax position, industry standards, tax return disclosures and schedules, and the significance of each position. The Company had no material adjustments to its unrecognized tax benefits during the year ended December 31, 2011.

G—Derivative financial instruments

1. Commodity derivatives

The Company engages in derivative transactions such as collars, swaps, puts and basis swaps to hedge price risks due to unfavorable changes in oil and natural gas prices related to its oil and natural gas production. As of December 31, 2011, the Company had 44 open derivative contracts with financial institutions, none of which were designated as hedges, which extend from January 2012 to December 2014. The contracts are recorded at fair value on the balance sheet and any realized and unrealized gains and losses are recognized in current year earnings.

Each collar transaction has an established price floor and ceiling. When the settlement price is below the price floor established by these collars, the Company receives an amount from its counterparty equal to the difference between the settlement price and the price floor multiplied by the hedged contract volume. When the settlement price is above the price ceiling established by these collars, the Company pays its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the hedged contract volume.

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

Each basis swap transaction has an established fixed differential between the NYMEX gas futures and West Texas WAHA ("WAHA") index gas price. When the NYMEX futures settlement price less the fixed WAHA differential is greater than the actual WAHA price, the difference multiplied by the hedged contract volume is paid to the Company by the counterparty. When the difference between the NYMEX futures settlement price less the fixed WAHA differential is less than the actual WAHA price, the Company pays the counterparty an amount equal to the difference multiplied by the hedged contract volume.

During the year ended December 31, 2011, the Company entered into additional commodity contracts to hedge a portion of its estimated future production. The following table summarizes information about these additional commodity derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Aggregate volumes	Swap price	Floor price	Ceiling price	Contract period
Oil (volumes in Bbls):					
Swap	100,000	$ 101.00	$ —	$ —	March 2011—December 2011
Price collar	160,000	$ —	$ 85.00	$ 125.00	March 2011—December 2011
Swap	90,000	$ 100.10	$ —	$ —	April 2011—December 2011
Price collar	80,000	$ —	$ 95.00	$ 125.70	May 2011—December 2011
Price collar	120,000	$ —	$ 85.00	$ 125.00	January 2012—December 2012
Price collar	348,000	$ —	$ 75.00	$ 125.00	January 2012—December 2012
Swap	120,000	$ 99.75	$ —	$ —	January 2012—December 2012
Swap	120,000	$ 101.10	$ —	$ —	January 2012—December 2012
Swap	120,000	$ 100.06	$ —	$ —	January 2012—December 2012
Price collar	312,000	$ —	$ 75.00	$ 125.00	January 2013—December 2013
Swap	120,000	$ 99.10	$ —	$ —	January 2013—December 2013
Swap	120,000	$ 100.02	$ —	$ —	January 2013—December 2013
Swap	120,000	$ 102.50	$ —	$ —	January 2013—December 2013
Price collar	96,000	$ —	$ 85.00	$ 125.00	January 2013—December 2013
Price collar	264,000	$ —	$ 80.00	$ 125.00	January 2014—December 2014
Price collar	264,000	$ —	$ 75.00	$ 125.00	January 2014—December 2014
Natural gas (volumes in MMBtu):					
Basis swap	500,000	$ 0.26	$ —	$ —	March 2011—December 2011
Swap	350,000	$ 4.75	$ —	$ —	June 2011—December 2011
Price collar	3,480,000	$ —	$ 4.00	$ 7.05	January 2014—December 2014
Price collar	3,480,000	$ —	$ 4.00	$ 7.00	January 2014—December 2014

The following table summarizes open positions as of December 31, 2011, and represents, as of such date, derivatives in place through December 31, 2014, on annual production volumes:

	Year 2012	Year 2013	Year 2014
Oil Positions:			
Puts:			
Hedged volume (Bbls)	672,000	1,080,000	—
Weighted average price ($/Bbl)	$ 65.79	$ 65.00	$ —
Swaps:			
Hedged volume (Bbls)	732,000	600,000	—
Weighted average price ($/Bbl)	$ 93.52	$ 96.32	$ —
Collars:			
Hedged volume (Bbls)	846,000	528,000	528,000
Weighted average floor price ($/Bbl)	$ 75.04	$ 74.55	$ 77.50
Weighted average ceiling price ($/Bbl)	$ 114.50	$ 123.18	$ 125.00
Natural Gas Positions:			
Puts:			
Hedged volume (MMBtu)	4,320,000	6,600,000	—
Weighted average price ($/MMBtu)	$ 5.38	$ 4.00	$ —
Swaps:			
Hedged volume (MMBtu)	1,680,000	—	—
Weighted average price ($/MMBtu)	$ 6.14	$ —	$ —
Collars:			
Hedged volume (MMBtu)	7,800,000	6,600,000	6,960,000
Weighted average floor price ($/MMBtu)	$ 4.12	$ 4.00	$ 4.00
Weighted average ceiling price ($/MMBtu)	$ 5.79	$ 7.05	$ 7.03
Basis swaps:			
Hedged volume (MMBtu)	2,880,000	1,200,000	—
Weighted average price ($/MMBtu)	$ 0.31	$ 0.33	$ —

The natural gas derivatives are settled based on NYMEX gas futures, the Northern Natural Gas Co. Demarcation price or the Panhandle Eastern Pipe Line spot price of natural gas for the calculation period. The oil derivatives are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude Oil. Each basis swap transaction is settled based on the differential between the NYMEX gas futures and WAHA index gas price.

2. Interest rate derivatives

The Company is exposed to market risk for changes in interest rates related to its Senior Secured Credit Facility. Interest rate derivative agreements are used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. If LIBOR is lower than the fixed rate in the contract, the Company is required to pay the counterparties the difference, and conversely, the counterparties are required to pay the Company if LIBOR is higher than the fixed rate in the contract. For the interest rate cap below, the Company paid a premium of $0.2 million in 2010 upon entering into the agreement. The Company did not designate the interest rate derivatives as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings.

The following presents the settlement terms of the interest rate derivatives at December 31, 2011:

(in thousands except rate data)	Year 2012	Year 2013
Notional amount	$ 110,000	—
Fixed rate	3.41%	—
Notional amount	$ 30,000	—
Fixed rate	1.60%	—
Notional amount	$ 20,000	—
Fixed rate	1.35%	—
Notional amount	$ 50,000	$ 50,000
Fixed rate	1.11%	1.11%
Notional amount	$ 50,000	$ 50,000
Cap rate	3.00%	3.00%
Total	$ 260,000	$ 100,000

3. Balance sheet presentation

The Company's oil and natural gas commodity derivatives and interest rate derivatives are presented on a net basis in "Derivative financial instruments" in the consolidated balance sheets.

The following summarizes the fair value of derivatives outstanding on a gross basis as of:

	December 31,	
(in thousands)	2011	2010
Assets:		
Commodity derivatives:		
Oil derivatives	$ 16,026	$ 8,398
Natural gas derivatives	34,019	22,035
Interest rate derivatives	11	248
	$ 50,056	$ 30,681
Liabilities:		
Commodity derivatives:		
Oil derivatives(1)	$ 28,044	$ 23,405
Natural gas derivatives(2)	6,832	9,271
Interest rate derivatives	1,991	5,790
	$ 36,867	$ 38,466

(1) The oil derivatives fair value is presented net of deferred premium liability of $13.4 million and $7.6 million at December 31, 2011 and 2010, respectively.

(2) The natural gas derivatives fair value is presented net of deferred premium liability of $5.4 million and $4.9 million at December 31, 2011 and 2010, respectively.

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company's counterparties are participants in its Senior Secured Credit Facility (as described in Note C) which is secured by the Company's oil and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not require collateral from its counterparties. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that are also lenders in the Company's Senior Secured Credit Facility and meet the Company's minimum credit quality standard, or have a guarantee from an affiliate that meets the Company's minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis. In accordance with the Company's standard practice, its commodity and interest rate derivatives are subject to counterparty netting under agreements governing such derivatives and, therefore, the risk of such loss is somewhat mitigated at December 31, 2011.

4. Gain (loss) on derivatives

Gains and losses on derivatives are reported on the consolidated statements of operations in the respective "Realized and unrealized gain (loss)" amounts. Realized gains (losses), represent amounts related to the settlement of derivative instruments, and for commodity derivatives, are aligned with the underlying production. Unrealized gains (losses) represent the change in fair value of the derivative instruments and are non-cash items.

The following represents the Company's reported gains and losses on derivative instruments for the years ended December 31, 2011, 2010 and 2009:

	Years ended December 31,		
(in thousands)	**2011**	**2010**	**2009**
Realized gains (losses):			
Commodity derivatives	$ 3,719	$ 22,701	$ 52,117
Interest rate derivatives	(4,873)	(5,238)	(3,764)
	(1,154)	17,463	48,353
Unrealized gains (losses):			
Commodity derivatives	17,328	(11,511)	(46,373)
Interest rate derivatives	3,562	(137)	370
	20,890	(11,648)	(46,003)
Total gains (losses):			
Commodity derivatives	21,047	11,190	5,744
Interest rate derivatives	(1,311)	(5,375)	(3,394)
	$ 19,736	$ 5,815	$ 2,350

H—Fair value measurements

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

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

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

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

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

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

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. The Company conducts a review of fair value hierarchy classifications on an annual basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities.

Fair value measurement on a recurring basis

The following presents the Company's fair value hierarchy for assets and liabilities measured at fair value on a recurring basis at December 31, 2011 and 2010. These items are included in "Derivative financial instruments" on the consolidated balance sheets. Significant Level 2 assumptions associated with the calculation of discounted cash flows used in the "mark-to-market" analysis include the NYMEX natural gas and crude oil prices, appropriate risk adjusted discount rates and other relevant data.

(in thousands)	Level 1	Level 2	Level 3	Total fair value
As of December 31, 2011:				
Commodity derivatives	$ —	$ 34,037	$ —	$ 34,037
Deferred premiums	—	—	(18,868)	(18,868)
Interest rate derivatives	—	(1,980)	—	(1,980)
Total	$ —	$ 32,057	$ (18,868)	$ 13,189

(in thousands)	Level 1	Level 2	Level 3	Total fair value
As of December 31, 2010:				
Commodity derivatives	$ —	$ (9,774)	$ 20,026	$ 10,252
Deferred premiums	—	—	(12,495)	(12,495)
Interest rate derivatives	—	(5,542)	—	(5,542)
Total	$ —	$ (15,316)	$ 7,531	$ (7,785)

A summary of the changes in assets classified as Level 3 measurements for the years ended December 31, 2011 and 2010 are as follows:

(in thousands)	Derivative option contracts	Deferred premiums
Balance of Level 3 at December 31, 2010	$ 20,026	$ (12,495)
Realized and unrealized gains included in earnings	5,323	—
Amortization of deferred premiums	—	(471)
Total purchases and settlements:		
Purchases	—	(5,988)
Settlements	—	86
Transfers out of Level 3(1)(2)	(25,349)	—
Balance of Level 3 at December 31, 2011	$ —	$ (18,868)
Change in unrealized losses attributed to earnings relating to derivatives still held at December 31, 2010	$ —	$ —

(in thousands)		Derivative option contracts		Deferred premiums
Balance of Level 3 at December 31, 2009	$	14,610	$	(3,524)
Realized and unrealized losses included in earnings		(1,965)		—
Amortization of deferred premiums		—		(116)
Total purchases and settlements:				
Purchases		7,381		(8,855)
Settlements		—		—
Balance of Level 3 at December 31, 2010	$	20,026	$	(12,495)
Change in unrealized gains attributed to earnings relating to derivatives still held at December 31, 2010	$	2,392	$	—

(1) Transfers out of Level 3 during the year ended December 31, 2011, were attributable to the Company's ability to utilize transparent forward price curves and volatilities published and available through independent third party vendors. As a result, the Company transferred positions from Level 3 to Level 2 as the significant inputs used to calculate the fair value are all observable.

(2) The Company's policy is to recognize transfers in and out as of the actual date of the event or change in circumstances that caused the transfer.

Fair value measurement on a nonrecurring basis

The Company accounts for additions to its asset retirement obligation (see Note B.15) and impairment of long-lived assets (see Note B.22), if any, at fair value on a nonrecurring basis in accordance with GAAP. For purposes of fair value measurement, it was determined that the impairment of long-lived assets and the additions to the asset retirement obligation are classified as Level 3 based on the use of internally developed cash flow models. No impairments of long-lived assets were recorded in 2011.

Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including, in addition to those noted above, the ultimate settlement of these amounts, the ultimate timing of such settlement, and changes in legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment will be made to the asset balance.

Asset retirement obligations. The accounting policies for asset retirement obligations are discussed in Note B.15, including a reconciliation of the Company's asset retirement obligation. The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, which converts future cash flows to a single discounted amount. Significant inputs to the valuation include: (i) estimated plug and abandonment cost per well based on Company experience; (ii) estimated remaining life per well based on the reserve life per well; (iii) future inflation factors; and (iv) the Company's average credit adjusted risk free rate.

Impairment of oil and natural gas properties. The accounting policies for impairment of oil and natural gas properties are discussed in Note B.9. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of operating and development costs, anticipated production of proved reserves and other relevant data.

I—Credit risk

The Company's oil and natural gas sales are to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. The Company's joint operations accounts receivable are from a number of oil and natural gas companies, partnerships, individuals and others who own interests in the properties operated by the Company. Management believes that any credit risk imposed by a concentration in the oil and natural gas industry is offset by the creditworthiness of the Company's customer base and industry partners. The Company routinely assesses the recoverability of all material trade and other receivables to determine collectability.

The Company uses derivative instruments to hedge its exposure to oil and natural gas price volatility and its exposure to interest rate risk associated with the credit facilities (as described in Note C). These transactions expose the Company to potential credit risk from its counterparties. In accordance with the Company's standard practice, its derivative instruments are subject to counterparty netting under agreements governing such derivatives and therefore, the credit risk associated with its derivative counterparties is somewhat mitigated. See Note G for additional information regarding the Company's derivative instruments.

For the year ended December 31, 2011, the Company had three customers that accounted for 36.1%, 16.2% and 12.9% of total revenues, with the same three customers accounting for 31.6%, 13.9% and 15.9% and another customer accounting for 11.0% of oil and natural gas sales accounts receivable as of December 31, 2011. For the year ended December 31, 2010, the Company had three customers that accounted for 33.1%, 19.0%, and 14.5% of total revenues, with the same three customers accounting for 41.3%, 16.2%, and 14.0% of oil and natural gas sales accounts receivable as of December 31, 2010. For the year ended December 31, 2009, the Company had three customers that accounted for 35.8%, 13.7% and 11.7% of total revenues, with two of these customers accounting for 42.7% and 16.9% of oil and natural gas sales accounts receivable as of December 31, 2009.

For the year ended December 31, 2011, three partners' joint operations accounts receivable accounted for 30.4%, 17.4% and 16.1% of the Company's total joint operations accounts receivable. For the year ended December 31, 2010, two partners' joint operations accounts receivable accounted for 76.5% and 11.4% of the Company's total joint operations accounts receivable.

The Company's cash balances are insured by the FDIC up to $250,000 per bank. The Company had a cash balance on deposit with a certain bank in the credit facilities bank group at December 31, 2011, which exceeded the balance insured by the FDIC in the amount of $54.7 million. Management believes that the risk of loss is mitigated by the bank's reputation and financial position.

J—Commitments and contingencies

1. Lease commitments

The Company leases equipment and office space under operating leases expiring on various dates through 2016. Minimum annual lease commitments at December 31, 2011, and for the calendar years following are:

(in thousands)	
2012	$ 1,413
2013	1,448
2014	1,102
2015	731
2016	282
Total	$ 4,976

The following table presents rent expense for the years ended December 31, 2011, 2010 and 2009, respectively.

	For the years ended December 31,		
(in thousands)	**2011**	**2010**	**2009**
Rent expense	$ 1,175	$ 946	$ 822

The Company's office space lease agreements contain scheduled escalation in lease payments during the term of the lease. In accordance with GAAP, the Company records rent expense on a straight-line basis and a deferred lease liability for the difference between the straight-line amount and the actual amounts of the lease payments.

2. Litigation

The Company may be involved in legal proceedings or is subject to industry rulings that could bring rise to claims in the ordinary course of business. The Company has concluded that the likelihood is remote that the ultimate resolution of any pending litigation or pending claims will be material or have a material adverse effect on the Company's business, financial position, results of operations or liquidity.

3. Drilling contracts

The Company has committed to several short-term drilling contracts with various third parties in order to complete its various drilling projects. The contracts contain an early termination clause that requires the Company to pay significant penalties to the third party should the Company cease drilling efforts. These penalties could significantly impact the Company's financial statements upon contract termination. These commitments are not recorded in the accompanying consolidated balance sheets. Future commitments as of December 31, 2011 are $9.6 million. As a result of these commitments $1.6 million in stacked rig fees were incurred in 2009. No stacked rig fees were incurred in 2011 or 2010. Management does not anticipate canceling any drilling contracts or discontinuing drilling efforts in 2012.

4. Federal and state regulations

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

K—Defined contribution plans

Laredo sponsors a 401(k) defined contribution plan for the benefit of substantially all employees at the date of hire. As part of the Broad Oak Transaction, Laredo began funding the former Broad Oak sponsored plan on July, 1, 2011. The former Broad Oak plan is substantially identical to the Laredo sponsored plan. The plans allow eligible employees to make tax-deferred contributions up to 100% of their annual compensation, not to exceed annual limits established by the federal government. Laredo makes matching contributions of up to 6% of an employee's compensation and may make additional discretionary contributions for eligible employees. Employees are 100% vested in the employer contributions upon receipt. The two plans merged on January 1, 2012.

The following table presents total contributions to the plans for the years ended December 31, 2011, 2010 and 2009.

(in thousands)	2011	2010	2009
Contributions	$ 1,651	$ 1,201	$ 1,099

L—Pro forma income per share

Pro forma weighted average shares outstanding used in the computation of pro forma basic and diluted income per share attributable to shareholders has been computed taking into account (1) the conversion ratio at the time of the Corporate Reorganization of all Preferred Units and certain Restricted Units into shares of Laredo Holdings common stock as if the conversion occurred as of the beginning of the year and (2) the 20,125,000 shares of common stock issued by the Company in the IPO.

Basic net income per share is computed by dividing net income by the pro forma weighted-average number of shares outstanding for the period. Diluted net income per share reflects the potential dilution of non-vested restricted stock awards. The following is the calculation of basic and diluted weighted average shares outstanding and net income per share for the year ended December 31, 2011:

(in thousands, except for per share data)	Year ended December 31, 2011
Income (numerator):	
Net income—basic and diluted	$ 105,554
Pro forma weighted average shares (denominator):	
Pro forma weighted average shares—basic	107,187
Non-vested restricted stock	912
Pro forma weighted average shares—diluted	108,099
Pro forma net income per share:	
Basic	$ 0.98
Diluted	$ 0.98

M—Recently issued accounting standards

In May 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS,* which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and International Financial Reporting Standards. This new guidance changes some fair value measurement principles and disclosure requirements, but does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. The update is effective for annual periods beginning after December 15, 2011 and the Company does not expect the adoption of this ASU to have a material effect on the consolidated financial statements.

In December 2011, the FASB issued ASU 2011-11, *Disclosures about Offsetting Assets and Liabilities*, to improve reporting and transparency of offsetting (netting) assets and liabilities and the related effects on the financial statements. This ASU is effective for fiscal years and interim periods within those years beginning on or after January 1, 2013. The Company does not expect the adoption of this ASU to have a material effect on the consolidated financial statements.

N—Subsidiary guarantees

Pursuant to the terms of the Corporate Reorganization that was completed on December 19, 2011, immediately prior to the closing of the IPO, Laredo LLC was merged with and into Laredo Holdings, with Laredo Holdings surviving the merger. Laredo Holdings and all of Laredo's wholly-owned subsidiaries (Laredo Gas, Laredo Texas and Laredo Dallas, collectively, the "Subsidiary Guarantors") have fully and unconditionally guaranteed the 2019 Notes and the Senior Secured Credit Facility (see Note C). In accordance with practices accepted by the SEC, Laredo has prepared condensed consolidating financial statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. The following condensed consolidating balance sheets as of December 31, 2011 and 2010, and condensed consolidating statements of operations and condensed consolidating statements of cash flows each for the years ended December 31, 2011, 2010 and 2009, present financial information for Laredo Holdings or Laredo LLC, as applicable, as the parent of Laredo on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for Laredo on a stand-alone basis (carrying any investment in subsidiaries under the equity method), financial information for the Subsidiary Guarantors on a stand-alone basis (carrying any investment in subsidiaries under the equity method), and the consolidation and elimination entries necessary to arrive at the information for the Company on a condensed consolidated basis. All deferred income taxes are recorded on Laredo's statements of financial position, as Laredo's subsidiaries are flow-through entities for income tax purposes. Prior to the Broad Oak Transaction on July 1, 2011, both Laredo and Laredo Dallas were separate taxable entities and deferred income taxes for the Company are recorded separately. The Subsidiary Guarantors are not restricted from making distributions to Laredo.

Condensed consolidating balance sheet
December 31, 2011

(in thousands)	Laredo Holdings	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Accounts receivable	$ —	$ 53,006	$ 21,129	$ —	$ 74,135
Other current assets	54,921	20,599	204	(26,921)	48,803
Total oil and natural gas properties, net	—	780,152	535,525	—	1,315,677
Total pipeline and gas gathering assets, net	—	—	51,742	—	51,742
Total other fixed assets, net	—	10,321	769	—	11,090
Investment in subsidiaries	888,043	554,901	—	(1,442,944)	—
Total other long-term assets	—	126,205	—	—	126,205
Total assets	$ 942,964	$ 1,545,184	$ 609,369	$ (1,469,865)	$ 1,627,652
Accounts payable	$ 1	$ 58,729	$ 14,198	$ (26,921)	$ 46,007
Other current liabilities	—	130,990	37,364	—	168,354
Other long-term liabilities	—	8,779	7,538	—	16,317
Long-term debt	—	636,961	—	—	636,961
Owners' equity	942,963	709,725	550,269	(1,442,944)	760,013
Total liabilities and owners' equity	$ 942,964	$ 1,545,184	$ 609,369	$ (1,469,865)	$ 1,627,652

Condensed consolidating balance sheet
December 31, 2010

(in thousands)	Laredo LLC	Laredo	Subsidiary guarantors	Intercompany eliminations	Total
Accounts receivable, net	$ —	$ 24,168	$ 19,771	$ —	$ 43,939
Other current assets	38,652	21,391	10,340	(13,906)	56,477
Total oil and natural gas properties, net	—	430,242	333,040	—	763,282
Total pipeline and gas gathering assets, net	—	—	39,343	—	39,343
Total other fixed assets, net	—	6,915	353	—	7,268
Investment in subsidiaries	511,208	114,881	—	(626,089)	—
Total other long-term assets	—	129,799	28,052	—	157,851
Total assets	$ 549,860	$ 727,396	$ 430,899	$ (639,995)	$ 1,068,160
Accounts payable	$ 1	$ 42,311	$ 12,932	$ (13,906)	$ 41,338
Other current liabilities	—	64,675	44,230	—	108,905
Other long-term liabilities	—	6,602	8,616	—	15,218
Long-term debt	—	277,500	214,100	—	491,600
Owner's equity	549,859	336,308	151,021	(626,089)	411,099
Total liabilities and owners' equity	$ 549,860	$ 727,396	$ 430,899	$ (639,995)	$ 1,068,160

Condensed consolidating statement of operations
for the year ended December 31, 2011

(in thousands)	Laredo Holdings	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$ —	$ 237,194	$ 280,349	$ (7,273)	$ 510,270
Total operating costs and expenses	8	173,638	141,998	(7,273)	308,371
Income (loss) from operations	(8)	63,556	138,351	—	201,899
Interest income (expense), net	96	(45,470)	(5,098)	—	(50,472)
Other, net	—	10,492	3,009	—	13,501
Income from operations before income tax	88	28,578	136,262	—	164,928
Income tax expense	—	(37,974)	(21,400)	—	(59,374)
Net income (loss)	$ 88	$ (9,396)	$ 114,862	$ —	$ 105,554

Condensed consolidating statement of operations for the year ended December 31, 2010

(in thousands)	Laredo LLC	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$ —	$ 93,580	$ 152,373	$ (3,953)	$ 242,000
Total operating costs and expenses	7	91,620	81,344	(3,953)	169,018
Income (loss) from operations	(7)	1,960	71,029	—	72,982
Interest income (expense), net	150	(11,911)	(6,570)	—	(18,331)
Other, net	—	13,808	(8,023)	—	5,785
Income from operations before income tax	143	3,857	56,436	—	60,436
Income tax (expense) benefit	—	(2,234)	28,046	—	25,812
Net income	$ 143	$ 1,623	$ 84,482	$ —	$ 86,248

Condensed consolidating statement of operations for the year ended December 31, 2009

(in thousands)	Laredo LLC	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$ —	$ 60,684	$ 38,956	$ (3,066)	$ 96,574
Total operating costs and expenses	7	244,252	108,910	(3,066)	350,103
Loss from operations	(7)	(183,568)	(69,954)	—	(253,529)
Interest income (expense), net	185	(6,032)	(1,394)	—	(7,241)
Other, net	—	8,316	(6,047)	—	2,269
Income (loss) from operations before income tax	178	(181,284)	(77,395)	—	(258,501)
Income tax benefit	—	74,006	—	—	74,006
Net income (loss)	$ 178	$ (107,278)	$ (77,395)	$ —	$ (184,495)

Condensed consolidating statement of cash flows for the year ended December 31, 2011

(in thousands)	Laredo Holdings	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$ 89	$ 150,002	$ 207,000	$ (13,015)	$ 344,076
Net cash flows provided by (used in) investing activities	(303,194)	(408,412)	4,819	—	(706,787)
Net cash flows provided by (used in) financing activities	319,374	258,410	(218,306)	—	359,478
Net increase (decrease) in cash and cash equivalents	16,269	—	(6,487)	(13,015)	(3,233)
Cash and cash equivalents at beginning of period	38,652	—	6,489	(13,906)	31,235
Cash and cash equivalents at end of period	$ 54,921	$ —	$ 2	$ (26,921)	$ 28,002

Condensed consolidating statement of cash flows for the year ended December 31, 2010

(in thousands)	Laredo LLC	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$ 143	$ 63,887	$ 103,218	$ (10,205)	$ 157,043
Net cash flows used in investing activities	(52,900)	(132,564)	(275,083)	—	(460,547)
Net cash flows provided by financing activities	74,487	68,677	176,588	—	319,752
Net increase in cash and cash equivalents	21,730	—	4,723	(10,205)	16,248
Cash and cash equivalents at beginning of period	16,922	—	1,766	(3,701)	14,987
Cash and cash equivalents at end of period	$ 38,652	$ —	$ 6,489	$ (13,906)	$ 31,235

Condensed consolidating statement of cash flows for the year ended December 31, 2009

(in thousands)	Laredo LLC	Laredo	Subsidiary guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$ 178	$ 88,896	$ 22,094	$ 1,501	$ 112,669
Net cash flows used in investing activities	(122,701)	(162,704)	(75,928)	—	(361,333)
Net cash flows provided by financing activities	124,700	73,808	51,631	—	250,139
Net increase (decrease) in cash and cash equivalents	2,177	—	(2,203)	1,501	1,475
Cash and cash equivalents at beginning of period	14,745	—	3,969	(5,202)	13,512
Cash and cash equivalents at end of period	$ 16,922	$ —	$ 1,766	$ (3,701)	$ 14,987

O—Subsequent events

1. Additional borrowing

On January 9, February 9 and March 5, 2012, the Company borrowed $40.0 million, $55.0 million and $50.0 million, respectively, under the Senior Secured Credit Facility. The outstanding balance under the Senior Secured Credit Facility was approximately $230.0 million at March 19, 2012.

2. New derivative contracts

Subsequent to December 31, 2011, the Company entered into the following new commodity contracts, with approximately $1.3 million in deferred premiums associated:

	Aggregate volumes	Swap price	Floor price	Ceiling price	Contract period
Oil (volumes in Bbls):					
Price collar	270,000	—	$ 90.00	$ 126.50	April 2012—December 2012
Price collar	240,000	—	$ 90.00	$ 118.35	January 2013—December 2013
Price collar	198,000	—	$ 70.00	$ 140.00	January 2014—December 2014
Price collar	252,000	—	$ 75.00	$ 135.00	January 2015—December 2015
Natural gas (volumes in MMBtu):					
Swap	700,000	$ 2.72	—	—	April 2012—October 2012
Price collar	700,000	—	$ 3.25	$ 3.90	April 2013—October 2013

3. Restricted stock awards and other compensation

On February 3, 2012, the Company granted 593,939 restricted stock awards with service vesting criteria, 602,948 stock options with service vesting criteria and 49,244 performance awards with a combination of market and service vesting criteria under the LTIP and related award agreements. For stock-based compensation equity awards, compensation expense will be recognized in the Company's financial statements over the awards' vesting periods based on their grant date fair value. The Company will utilize (i) the closing stock price on the date of grant of $24.11 to determine the fair value of service vesting restricted stock awards and options and (ii) a probability analysis to determine the fair value of performance awards with a combination of market and service vesting criteria.

In accordance with the LTIP and restricted stock agreement, the restricted stock awards are subject to a three year vesting schedule, with one third vesting each year. Upon termination with or without cause all unvested shares granted and all rights arising from such shares are forfeited. In the event of the death or disability of the holder, all unvested awards shall automatically become vested.

In accordance with the LTIP and stock option agreement, the options granted will become exercisable in accordance with the following schedule based upon the number of full years of the optionee's continuous employment or service with the Company, following February 3, 2012:

Full years of continuous employment	**Incremental percentage of option exercisable**	**Cumulative percentage of option exercisable**
Less than one	0%	0%
One	25%	25%
Two	25%	50%
Three	25%	75%
Four	25%	100%

No shares of common stock may be purchased unless the optionee has remained in the continuous employment of the Company through February 2, 2013. Unless sooner terminated, the option will expire if and to the extent it is not exercised within ten years from the grant date. The unvested portion of an option will expire upon termination of employment of the optionee, and the vested portion of such option will remain exercisable for (A) one year following termination of employment by death, but not later than the option expiration or (B) 90 days following termination of employment or service with cause, but not later than the expiration of the option period. The unvested and the unexercised vested portion of the option will expire upon termination of employment for cause.

In accordance with the LTIP and the performance compensation award agreement, the performance awards have a value of $100.00. The performance units will be payable, if at all, in cash, based upon the achievement by the Company of certain performance goals, over a three year period. In the event of termination with or without cause, the performance awards are forfeited. In the event of the grantee's death or disability, the grantee is eligible for a pro-rated award.

P—Supplemental oil and natural gas disclosures

1. Costs incurred in oil and natural gas property acquisition, exploration and development activities

Costs incurred in the acquisition and development of oil and natural gas assets are presented below for the years ended December 31:

(in thousands)	2011	2010	2009
Property acquisition costs:			
Proved	$ —	$ —	$ —
Unproved	—	—	—
Exploration	62,888	87,576	53,708
Development costs	660,922	414,870	273,856
Total costs incurred	$ 723,810	$ 502,446	$ 327,564

2. Capitalized oil and natural gas costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, amortization and impairment are presented below as of December 31:

(in thousands)	2011	2010	2009
Capitalized costs:			
Proved properties	$ 2,083,015	$ 1,379,885	$ 881,106
Unproved properties	117,195	96,515	92,847
	2,200,210	1,476,400	973,953
Less accumulated depreciation, depletion, amortization and impairment	884,533	713,118	620,537
Net capitalized costs	$ 1,315,677	$ 763,282	$ 353,416

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2011, by year in which such costs were incurred:

(in thousands)	2011	2010	2009	2008 and prior	Total
Unproved properties	$ 67,641	$ 24,099	$ 5,772	$ 19,683	$ 117,195

Unproved properties, which are not subject to amortization, are not individually significant and consist primarily of lease acquisition costs. The evaluation process associated with these properties has not been completed and therefore, the Company is unable to estimate when these costs will be included in the amortization calculation.

3. *Results of oil and natural gas producing activities*

The results of operations of oil and natural gas producing activities (excluding corporate overhead and interest costs) are presented below as of December 31:

(in thousands)	2011	2010	2009
Revenues:			
Oil and natural gas sales	$ 506,255	$ 239,783	$ 94,347
Production costs:			
Lease operating expenses	43,306	21,684	12,531
Production and ad valorem taxes	31,982	15,699	6,129
	75,288	37,383	18,660
Other costs:			
Depreciation, depletion, amortization and impairment	171,517	93,815	301,279
Accretion of asset retirement obligation	616	475	406
Income tax expense (benefit)	93,180	39,223	(67,637)
Results of operations	$ 165,654	$ 68,887	$ (158,361)

4. *Net proved oil and natural gas reserves—(unaudited)*

Ryder Scott Company, L.P., our independent reserve engineers ("Ryder Scott"), estimated 100% of our proved reserves at December 31, 2011 and 2010. Ryder Scott also estimated the proved reserves for the legacy Laredo properties as of December 31, 2009. Ryder Scott did not perform evaluations of the Broad Oak properties as of December 31, 2009. Our estimates of the combined proved reserves at December 31, 2009 are a combination of the Ryder Scott reports on the legacy Laredo properties and Laredo's internal proved reserve estimates of the Broad Oak properties. Based upon such reserve estimates we calculated for Broad Oak, we believe the legacy Laredo properties represented 92% of such combined proved reserves at year end 2009. In accordance with SEC regulations, reserves at December 31, 2011, 2010 and 2009 were estimated using the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Our reserves are reported in two streams; crude oil and natural gas. The economic value of the natural gas liquids in our natural gas is included in the wellhead natural gas price. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and natural gas properties. Accordingly, the estimates may change as future information becomes available.

An analysis of the change in estimated quantities of oil and natural gas reserves, all of which are located within the United States, for the years ended December 31, is as follows:

	Year ended December 31, 2011		
	Gas (MMcf)	Oil (MBbls)	MBOE
Proved developed and undeveloped reserves:			
Beginning of year	550,278	44,847	136,560
Revisions of previous estimates	(47,296)	(1,124)	(9,006)
Extensions, discoveries and other additions	129,846	15,912	37,553
Purchases of minerals in place	—	—	—
Production	(31,711)	(3,368)	(8,654)
End of year	601,117	56,267	156,453
Proved developed reserves:			
Beginning of year	194,481	12,420	44,833
End of year	248,598	21,762	63,195
Proved undeveloped reserves:			
Beginning of year	355,797	32,427	91,727
End of year	352,519	34,505	93,258

	Year ended December 31, 2010		
	Gas (MMcf)	Oil (MBbls)	MBOE
Proved developed and undeveloped reserves:			
Beginning of year	279,549	5,928	52,519
Revisions of previous estimates	(14,619)	326	(2,110)
Extensions, discoveries and other additions	306,729	40,241	91,363
Purchases of minerals in place	—	—	—
Production	(21,381)	(1,648)	(5,212)
End of year	550,278	44,847	136,560
Proved developed reserves:			
Beginning of year	135,204	2,905	25,439
End of year	194,481	12,420	44,833
Proved undeveloped reserves:			
Beginning of year	144,345	3,023	27,080
End of year	355,797	32,427	91,727

	Year ended December 31, 2009		
	Gas (MMcf)	Oil (MBbls)	MBOE
Proved developed and undeveloped reserves:			
Beginning of year	244,051	3,508	44,183
Revisions of previous estimates	(51,823)	(785)	(9,423)
Extensions, discoveries and other additions	105,623	3,718	21,322
Purchases of minerals in place	—	—	—
Production	(18,302)	(513)	(3,563)
End of year	279,549	5,928	52,519
Proved developed reserves:			
Beginning of year	107,175	1,506	19,368
End of year	135,204	2,905	25,439
Proved undeveloped reserves:			
Beginning of year	136,876	2,002	24,815
End of year	144,345	3,023	27,080

The tables above include changes in estimated quantities of oil and natural gas reserves shown in MBbl equivalents ("MBOE") calculated using a conversion rate of six MMcf per one MBbl.

For the year ended December 31, 2011, the Company's negative revision of 9,006 MBOE of previous estimated quantities is primarily due to the removing of uneconomic proved undeveloped locations, due to increased capital cost. Extensions, discoveries and other additions of 37,553 MBOE during the year ended December 31, 2011, consist of 14,709 MBOE primarily from the drilling of new wells during the year and 22,844 MBOE from new proved undeveloped locations added during the year, which increased the Company's proved reserves. The latter consists of 15,009 MBOE attributable to 155 locations in our Permian Basin play and 7,835 MBOE attributable to 47 locations in our Anadarko Granite Wash play. The oil and natural gas reference prices used in computing our reserves as of December 31, 2011 were $92.71 per barrel and $3.99 per MMBtu before price differentials.

For the year ended December 31, 2010, the Company's negative revision of 2,110 MBOE of previous estimated quantities is primarily due to uneconomic proved undeveloped locations. Extensions, discoveries and other additions of 91,363 MBOE during the year ended December 31, 2010, consist of 20,533 MBOE primarily from the drilling of new wells during the year and 70,830 MBOE from new proved undeveloped locations added during the year, which increased the Company's proved reserves, the latter of which consists of 63,444 MBOE attributable to 957 vertical locations in our Permian Basin play, 7,002 MBOE attributable to 53 vertical locations in our Anadarko Granite Wash play and 384 MBOE attributable to 8 locations in other areas. The oil and natural gas reference prices used in computing our reserves as of December 31, 2010 were $75.96 per barrel and $4.15 per MMBtu before price differentials.

For the year ended December 31, 2009, the Company's negative revision of previous estimated quantities is composed of a 7,708 MBOE revision due to the decrease in oil and natural gas prices at December 31, 2009 and a decrease of 1,715 MBOE for performance revisions. Extensions, discoveries and other additions of 21,322 MBOE during the year ended December 31, 2009, consist of 8,866 MBOE primarily from the drilling of new wells during the year and 12,456 MBOE from new proved undeveloped locations added during the year, which increased the Company's proved reserves. The oil and natural gas reference prices used in computing our reserves as of December 31, 2009 were $57.04 per barrel and $3.15 per MMBtu before price differentials.

5. Standardized measure of discounted future net cash flows—(unaudited)

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties, and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2011, 2010 and 2009 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. Future income tax expenses are computed using the appropriate year-end statutory tax rates applied to the future pretax net cash flows from proved oil and natural gas reserves, less the tax basis of the Company's and Broad Oak's oil and natural gas properties. Reference prices used, before differentials were applied were $3.99, $4.15, and $3.15 per MMBtu and $92.71, $75.96 and $57.04 per Bbl of oil for December 31, 2011, 2010 and 2009, respectively. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows at December 31:

(in thousands)	2011	2010	2009
Future cash inflows	$ 8,856,906	$ 6,597,739	$ 1,369,593
Future production costs	(2,562,237)	(2,057,681)	(431,240)
Future development costs	(1,959,818)	(1,715,836)	(318,074)
Future income tax expenses	(999,185)	(602,551)	—
Future net cash flows	3,335,666	2,221,671	620,279
10% discount for estimated timing of cash flows	(1,934,807)	(1,351,689)	(352,664)
Standardized measure of discounted future net cash flows	$ 1,400,859	$ 869,982	$ 267,615

In the foregoing determination of future cash inflows, sales prices used for gas and oil for December 31, 2011, 2010 and 2009 were estimated using the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month price for each month. Prices were adjusted by lease for quality, transportation fees and regional price differentials. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year-end, assuming the continuation of existing economic conditions.

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

Changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows:

(in thousands)	2011	2010	2009
Standardized measure of discounted future net cash flows, beginning of year	$ 869,982	$ 267,615	$ 222,371
Changes in the year resulting from:			
Sales, less production costs	(430,967)	(202,400)	(75,687)
Revisions of previous quantity estimates	(70,021)	(15,080)	(48,209)
Extensions, discoveries and other additions	529,041	788,090	127,704
Net change in prices and production costs	566,034	214,308	(40,062)
Changes in estimated future development costs	(163,399)	(62,386)	12,062
Previously estimated development costs incurred during the period	207,818	20,082	41,620
Purchases of minerals in place	—	—	—
Accretion of discount	106,170	26,762	24,302
Net change in income taxes	(176,165)	(191,714)	20,648
Timing differences and other	(37,634)	24,705	(17,134)
Standardized measure of discounted future net cash flows, end of year	$ 1,400,859	$ 869,982	$ 267,615

Estimates of economically recoverable oil and natural gas reserves and of future net revenues are based upon a number of variable factors and assumptions, all of which are to some degree subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of oil and natural gas may differ materially from the amounts estimated.

Q—Supplemental quarterly financial data (unaudited)

The Company's results of operations by quarter for the years ended December 31, 2011 and 2010 are as follows:

	Year ended December 31, 2011			
(in thousands)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 107,111	$ 131,727	$ 132,460	$ 138,972
Operating income	49,162	58,471	54,603	39,663
Net income	4,670	41,072	58,246	1,566
Pro forma net income per common share:				
Basic				$ 0.01
Diluted				$ 0.01

	Year ended December 31, 2010			
(in thousands)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 46,993	$ 49,930	$ 60,135	$ 84,942
Operating income	17,390	9,640	19,379	26,573
Net income	23,923	10,602	16,633	35,090

Annex A: Glossary of oil and natural gas terms

The terms defined in this section are used throughout this prospectus:

"*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.

"*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.

"*DD&A*"—Depreciation, depletion, amortization and accretion.

"*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.

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

"*HBP*"—Held by production.

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

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

"*Identified potential drilling locations*"—Locations specifically identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves data on contiguous acreage and geologic formations. The availability of local infrastructure, drilling support assets and other factors as management may deem relevant, such as spacing requirements, easement restrictions and state and local regulations, are considered in determining such locations. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results and other factors.

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

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

"*MBOE*"—One thousand BOE.

"*MBOE/D*"—MBOE per day.

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

"*MMBOE*"—One million barrels of oil equivalent.

"*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.

"*Residue natural gas*"—Natural gas remaining after natural gas liquids extraction.

"*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.

"*Unit*"—The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"*Wellbore*"—The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

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

"*Working interest*"—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.

Annex B: Ryder Scott Company, L.P. summary of December 31, 2011 reserves

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5218 TELEPHONE (713) 651-9191
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January 20, 2012

Laredo Petroleum, Inc.
15 West 6th Street, Suite 1800
Tulsa, Oklahoma 74119

Gentlemen:

At your request, Ryder Scott Company (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Laredo Petroleum, Inc. (Laredo) as of December 31, 2011. The subject properties are located in the states of Oklahoma and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 18, 2012 and presented herein, was prepared for public disclosure by Laredo in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Laredo as of December 31, 2011.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2011, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
Laredo Petroleum, Inc.
As of December 31, 2011

	Proved			
	Developed			
	Producing	Non-producing	Undeveloped	Total proved
Net remaining reserves				
Oil/condensate—barrels	20,882,328	880,183	34,504,895	56,267,406
Gas—MMCF	232,495	16,103	352,519	601,117
BOE	59,631,495	3,564,016	93,258,062	156,453,573
Income data (m$)				
Future gross revenue	$ 3,105,095	$ 151,460	$ 5,124,854	$ 8,381,409
Deductions	941,865	63,390	3,041,307	4,046,562
Future net income (FNI)	$ 2,163,230	$ 88,070	$ 2,083,547	$ 4,334,847
Discounted FNI @ 10%	$ 1,246,110	$ 33,179	$ 490,675	$ 1,769,964

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Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net remaining reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. In this report, the revenues, deductions, and income data are expressed in thousands of U.S. dollars (M$).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package AriesTM System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. The program was used at the request of Laredo. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 59 percent and gas reserves account for the remaining 41 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted future net income (M$) as of December 31, 2011	
Discount rate percent		**Total proved**
5	$	2,622,842
9	$	1,902,089
15	$	1,284,230
20	$	981,434

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves included in this report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Definitions" in this report. The proved developed non-producing reserves included herein consist of the behind-pipe category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes included herein do not attribute gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Laredo's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Laredo's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Laredo owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, and/or a combination of methods. Approximately 79 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include decline curve analysis and material balance which utilized extrapolations of historical production and pressure data available through December 2011, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Laredo or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 21 percent of the proved producing reserves was estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

Approximately 99 percent of the proved developed non-producing and undeveloped reserves included herein were estimated by analogy to the historical performance of offset wells producing from the same reservoir. The remaining one percent of proved developed non-producing and undeveloped reserves included herein was estimated by the volumetric method. The volumetric analysis utilized pertinent well data furnished to Ryder Scott by Laredo or which we have obtained from public data sources that were available through December, 2011. The data utilized from the analogues as well as well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Laredo has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Laredo with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Laredo. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future production rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were projected to decline similarly to historical offset wells producing from the same reservoir. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Laredo. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

Laredo furnished us with the above mentioned average prices in effect on December 31, 2011. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic areas included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, fuel and shrinkage and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Laredo. The differentials furnished by Laredo were reviewed by us for their reasonableness using information furnished by Laredo for this purpose.

All gas reserves included in this evaluation are sold on a wet basis, before natural gas liquids (NGL) plant processing. Because of the high liquid content of the gas attributable to Laredo's properties located in the Permian Basin area, Laredo's realized price is a premium to the posted reference price in those geographic areas.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

			Average realized prices by geographic area			
Product	Price reference	Average benchmark price	Anadarko Basin	Central Texas Panhandle	Eastern Anadarko Basin	Permian Basin
Oil / condensate	WTI Plains Pipeline	$ 92.71 /Bbl	$ 91.15 /Bbl	$ 92.66 /Bbl	$ 92.92 /Bbl	$ 92.88 /Bbl
Gas	PEPL(1)	$ 3.99 /MMBTU	$ 4.88 /MCF	$ 4.13 /MCF	$ 3.76 /MCF	$ 7.48 /MCF

(1) Panhandle Eastern Pipeline TX/OK (Main Line)

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report are based on the operating expense reports of Laredo and include only those costs directly applicable to the leases or wells. When applicable for operated properties, an appropriate level of costs associated with regional administration and overhead was included in the operating costs assigned to leases and wells. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Laredo. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Laredo and are based on authorizations for expenditure for the proposed work and actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were significant. The estimates of the net abandonment costs furnished by Laredo were accepted without independent verification.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Laredo's plans to develop these reserves as of December 31, 2011. The implementation of Laredo's development plans as presented to us and incorporated herein is subject to the approval process adopted by Laredo's management. As the result of our inquiries during the course of preparing this report, Laredo has informed us that the development activities included herein have been subjected to and received the internal approvals required by Laredo's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Laredo. Additionally, Laredo has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

A portion of the proved undeveloped reserves included herein are attributable to increased density locations in the Anadardo Basin area of Oklahoma and Texas, and the Permian Basin area of Texas. Certain of these increased density wells have yet to receive approval by the respective state's governing oil and gas regulatory commission. Laredo's management has a reasonable expectation that approval will be granted based on the company's experience with each commission. To date all applications for increased density locations made by Laredo with each of the state regulatory commissions have been approved. Furthermore, Laredo has informed us that should any of the working interest partners elect to non-consent, Laredo will assume the cost liability in these locations. Ryder Scott Company has included these locations based upon the foregoing facts.

Current costs used by Laredo were held constant throughout the life of the properties.

Standards of independence and professional qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Laredo. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing, and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Laredo.

For filings made with the SEC under the 1933 Securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by Laredo. Our consent for such use is included as a separate exhibit to the filings made with the SEC by Laredo.

Laredo makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Laredo has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-8 of Laredo of the references to our name as well as to the references to our third party report for Laredo, which appears in the December 31, 2011 annual report on Form 10-K of Laredo. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Laredo.

We have provided Laredo with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Laredo and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Val Rick Robinson

Val Rick Robinson, P.E.
TBPE License No. 105137 [SEAL]
Vice President

VRR/pl

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Professional qualifications of primary technical engineer

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Val Rick Robinson was the primary technical person responsible for the estimate of the reserves, future production and income presented herein.

Mr. Robinson, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2006, is a Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Robinson served in a number of engineering positions with ExxonMobil Corporation. For more information regarding Mr. Robinson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Robinson earned a Bachelor of Science degree in Chemical Engineering from Brigham Young University in 2003 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Robinson fulfills. As part of his 2011 continuing education hours, Mr. Robinson attended 44.25 hours of formalized training including the 2011 RSC Reserves Conference and various professional society presentations covering such topics as the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, overviews of the various productive basins of North America, computer software, and professional ethics.

Based on his educational background, professional training and more than 9 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Robinson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

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12,500,000 shares

LAREDO PETROLEUM

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Prospectus

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