Diamondback Energy, Inc.
Form 424B4
October 15, 2012
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SEC File No. 333-179502

PROSPECTUS

12,500,000 Shares

Diamondback Energy, Inc.

Common Stock

This is the initial public offering of our common stock. Prior to this offering, there has been no public market for our common stock. The initial public offering price of the common stock is $17.50 per share. We have been approved to list our common stock on The NASDAQ Global Select Market under the symbol FANG.

We have granted the underwriters an option to purchase up to 1,875,000 additional shares of our common stock to cover the underwriters option to purchase additional shares.

Wexford Capital LP, or Wexford, our equity sponsor, or one or more of its affiliates are purchasing in this offering 1,717,126 shares of our common stock at the same price as the price to the public. The underwriters will not receive any underwriting discounts or commissions on any shares sold to Wexford or its affiliates. The number of shares available for sale to the general public has been reduced by the number of shares purchased by Wexford or its affiliates. See Underwriting (Conflicts of Interest) beginning on page 151.

We are an emerging growth company under applicable Securities and Exchange Commission rules and will be subject to reduced public company reporting requirements. Investing in our common stock involves risks. See Risk Factors beginning on page 18.

	Price to Public	Underwriting Discounts and Commissions	Proceeds to Diamondback
Per Share	$17.50	$1.1375	$16.3625
Total(1)	$218,750,000	$12,265,519	$206,484,481

(1) Reflects the purchase by Wexford or its affiliates of 1,717,126 shares of our common stock in this offering, for which the underwriters will not receive any underwriting discounts or commissions.

Delivery of the shares of common stock will be made on or about October 17, 2012.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

Credit Suisse

Raymond James **Tudor, Pickering, Holt & Co.** **Wells Fargo Securities**

Capital One Southcoast
Scotiabank / Howard Weil
Simmons & Company

International
Sterne Agee
SunTrust Robinson Humphrey
Wunderlich Securities

The date of this prospectus is October 11, 2012.

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ABOUT THIS PROSPECTUS

You should rely only on the information contained in this prospectus. We have not, and the underwriters have not, authorized any other person to provide you with information different from that contained in this prospectus. If anyone provides you with different or inconsistent information, you should not rely on it. We and the underwriters are only offering to sell, and only seeking offers to buy, our common stock in jurisdictions where offers and sales are permitted.

The information contained in this prospectus is accurate and complete only as of the date of this prospectus, regardless of the time of delivery of this prospectus or of any sale of our common stock by us or the underwriters. Our business, financial condition, results of operations and prospects may have changed since that date.

Dealer Prospectus Delivery Obligation

Until November 5, 2012 (25 days after the commencement of the offering), all dealers that effect transactions in these securities, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealer s obligation to deliver a prospectus when acting as an underwriter and with respect to unsold allotments or subscriptions.

Industry and Market Data

This prospectus includes industry data and forecasts that we obtained from internal company surveys, publicly available information and industry publications and surveys. Our internal research and forecasts are based on management s understanding of industry conditions, and such information has not been verified by independent sources. Industry publications and surveys generally state that the information contained therein has been obtained from sources believed to be reliable.

Unless the context otherwise requires, the information in this prospectus (other than in the historical financial statements) assumes that the underwriters will not exercise their option to purchase additional shares.

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PROSPECTUS SUMMARY

This summary contains basic information about us and the offering. Because it is a summary, it does not contain all the information that you should consider before investing in our common stock. Except as expressly noted otherwise, the historical assets, operations and results described in this prospectus are those of Windsor Permian LLC, or Windsor Permian. Windsor Permian was a wholly-owned subsidiary of Diamondback Energy LLC, an entity controlled by Wexford Capital LP, or Wexford. Prior to the effectiveness of the registration statement relating to this prospectus, Diamondback Energy LLC merged with and into Diamondback Energy, Inc. and Diamondback Energy, Inc. continued as the surviving entity. As a result of this merger, Windsor Permian became our wholly-owned subsidiary. In addition, Wexford caused all of the outstanding equity interests in Windsor UT LLC, or Windsor UT, to be contributed to Windsor Permian prior to the merger in a transaction we refer to as the Windsor UT contribution. Windsor UT owns oil and natural gas interests in the Permian Basin. On May 7, 2012, we entered into an agreement with Gulfport Energy Corporation, or Gulfport, in which Gulfport agreed to sell to us, subject to certain conditions, all of its oil and natural gas interests in the Permian Basin in exchange for shares of our common stock and a promissory note in a transaction we refer to as the Gulfport transaction. The Gulfport transaction was completed prior to the effectiveness of the registration statement relating to this prospectus and immediately after the merger described above. In this prospectus, we refer to the Gulfport transaction and the Windsor UT contribution together as the Transactions. See Prospectus Summary The Transactions beginning on page 7 of this prospectus for more information regarding the Transactions. Except as expressly noted otherwise, references to our operations and assets as of June 30, 2012 and thereafter give effect to the Transactions. You should read and carefully consider this entire prospectus before making an investment decision, especially the information presented under the heading Risk Factors and our financial statements and the accompanying notes included elsewhere in this prospectus, as well as the other documents to which we refer you. We have provided definitions for some of the oil and natural gas industry terms used in this prospectus in the Glossary of Oil and Natural Gas Terms.

DIAMONDBACK ENERGY, INC.

Overview

We are an independent oil and natural gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. This basin, which is one of the major producing basins in the United States, is characterized by an extensive production history, a favorable operating environment, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators.

We began operations in December 2007 with our acquisition of 4,174 net acres with production at the time of acquisition of approximately 800 net barrels of oil equivalent, or BOE, per day from 34 gross (16.8 net) wells in the Permian Basin. Subsequently, we acquired approximately 26,878 additional net acres, which brought our total net acreage position in the Permian Basin to 31,052 net acres at August 31, 2012 and, after giving effect to the Transactions, we had 51,709 net acres. We are the operator of approximately 99% of this acreage. As of August 31, 2012, after giving effect to the Transactions, we had drilled 167 gross (155 net) wells, and participated in an additional 16 gross (seven net) non-operated wells, in the Permian Basin. Of these 183 gross wells, 171 were completed as producing wells and 12 are in various stages of completion. In the aggregate, as of August 31, 2012, we held interests in 205 gross (185 net) producing wells in the Permian Basin.

Our activities are primarily focused on the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations, which we refer to collectively as the Wolfberry play. The Wolfberry play is characterized by high oil and liquids rich natural gas, multiple vertical and horizontal target horizons, extensive production history, long-

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lived reserves and high drilling success rates. The Wolfberry play is a modification and extension of the Spraberry play, the majority of which is designated in the Spraberry trend area field. According to the U.S. Energy Information Administration, the Spraberry trend area ranks as the second largest oilfield in the United States, based on 2009 reserves.

As of December 31, 2011, our estimated proved oil and natural gas reserves, pro forma for the Transactions, were 39,460 MBOE based on reserve reports prepared by Ryder Scott Company L.P., or Ryder Scott, our independent reserve engineers. Of these reserves, approximately 21.7% are classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate are from 329 gross well locations on 40-acre spacing. As of December 31, 2011, these proved reserves were approximately 66% oil, 20% natural gas liquids and 14% natural gas.

We have 916 identified potential vertical drilling locations on 40-acre spacing based on our evaluation of applicable geologic and engineering data as of August 31, 2012 and we have an additional 1,122 identified potential vertical drilling locations based on 20-acre downspacing. These identified potential drilling locations do not include any potential horizontal drilling locations. We intend to grow our reserves and production through development drilling, exploitation and exploration activities on this multi-year project inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves. Our estimated ultimate recoveries, or EURs, from future PUD wells on 40-acre spacing, as estimated by Ryder Scott, range from 102 MBOE per well, consisting of 46 MBbls of oil, 143 MMcf of natural gas and 32 MBbls of natural gas liquids, to 158 MBOE per well, consisting of 112 MBbls of oil, 113 MMcf of natural gas and 27 MBbls of natural gas liquids, with an average EUR per well of 135 MBOE, consisting of 93 MBbls of oil, 102 MMcf of natural gas and 25 MBbls of natural gas liquids. We also intend to continue to refine our drilling pattern and completion techniques in an effort to increase our average EUR per well from vertical wells drilled on 40-acre spacing. We currently anticipate a reduction of approximately 20% in our EURs from vertical wells drilled on 20-acre spacing. Our 2012 drilling plan currently contemplates drilling 48 gross (43 net) vertical wells on 40-acre spacing and two gross (two net) horizontal wells in the Wolfberry play. As of August 31, 2012, we were using two drilling rigs and, upon completion of this offering, intend to increase our drilling program to six rigs.

We believe the experience gained from our historical drilling programs and the information obtained from the results of extensive industry drilling activity in the Permian Basin have helped us reduce the risk and uncertainity associated with drilling vertical wells on our Permian Basin acreage. We intend to supplement our vertical development drilling activity with horizontal wells targeting various intervals in the Wolfberry play. Our horizontal drilling program is intended to further capture the upside potential that may exist on our properties and increase our well performance and recoveries as compared to drilling vertical wells alone.

During 2011, we assembled a new executive team and, beginning with the fourth quarter of 2011, this team assumed management control of our operations and development activities in the Permian Basin. With an average of approximately 24 years of industry experience per person, this team has extensive experience in the Permian Basin as well as other resource plays in North America, including significant experience in drilling and completing horizontal wells. Under the direction of our new executive team, the average drilling time required to reach total depth, or TD, was shortened by 25% to 14 days during the period from April 2012 through August 2012 from 20 days during the second quarter of 2011. We also reduced the time from spud to production from an average of 68 days during the fourth quarter of 2011 to an average of 56 days during the second quarter of 2012. During the quarter ended June 30, 2012, our average daily production, pro forma for the Transactions, was 3,637 BOE/d, consisting of 2,579 Bbls/d of oil, 2,757 Mcf/d of natural gas and 599 Bbls/d of natural gas liquids, an increase of 13%, or 408 BOE/d, from 3,229 BOE/d, consisting of 2,365 Bbls/d of oil, 2,267 Mcf/d of natural gas and 486 Bbls/d of natural gas liquids, for the quarter ended March 31, 2012. This increase was due primarily to improved strategies and procedures introduced by our new executive team relating to wellbore configuration,

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completion, execution, fluid recovery and well pumping practices that significantly reduced the level of required well remediation and the associated loss of production. We anticipate further increases in efficiencies as our new executive team executes on our development strategies across our acreage base.

The following table provides a summary of selected operating information of our properties, pro forma for the Transactions. The information is as of August 31, 2012 except as otherwise noted.

			Identified Potential Drilling Locations[1]		2012 Budget			Estimated Net Proved Reserves at December 31, 2011		Average Daily
Basin	Net Acreage	Average Working Interest	Gross	Net	Gross Wells[2]	Net Wells[2]	Capex (In millions)	MBOE	% Developed	Production (BOE/d)[3]
Permian	51,709	87%	916	849	59	48	$ 150.0-$160.0	39,460	23.9	3,712

(1) Reflects identified potential vertical drilling locations on 40-acre spacing based on our evaluation of applicable geologic and engineering data. We have an additional 1,122 gross (1,027 net) identified potential vertical drilling locations based on 20-acre downspacing. These identified potential drilling locations do not include any potential horizontal drilling locations. The drilling locations on which we actually drill wells will ultimately depend on the availability of capital, regulatory approvals, oil and natural gas prices, costs, actual drilling results and other factors.

(2) Includes 50 gross (45 net) wells, of which two gross (two net) wells are horizontal, for which we are the operator and nine gross (three net) non-operated wells, of which three gross (one net) wells are horizontal wells.

(3) During August 2012.

We currently anticipate our 2012 capital budget for drilling and infrastructure will be approximately $150.0 million to $160.0 million after giving effect to the Transactions. Of this amount, we plan to spend approximately $126.0 million on the drilling and completion of 48 gross (43 net) operated vertical wells and two gross (two net) horizontal wells, $11.0 million for the drilling and completion of nine gross (three net) non-operated wells, $6.0 million for leasehold acquisitions and $12.0 million for the construction of infrastructure to support production, including investments in water disposal infrastructure and gathering line projects. During the six months ended June 30, 2012, our aggregate capital expenditures for drilling and infrastructure after giving effect to the Transactions were $70.7 million.

Our Business Strategy

Our business strategy is to increase stockholder value through the following:

- ***Grow production and reserves by developing our oil-rich resource base***. We intend to actively drill and develop our acreage base in an effort to maximize its value and resource potential. Through the conversion of our undeveloped reserves to developed reserves, we will seek to increase our production, reserves and cash flow while generating favorable returns on invested capital. As of August 31, 2012, after giving effect to the Transactions, we had 916 identified potential vertical drilling locations on our acreage in the Permian Basin based on 40-acre spacing and an additional 1,122 such locations based on 20-acre downspacing. We believe the drilling of these locations will provide us with the critical subsurface data necessary to target potential horizontal horizons. Our 2012 drilling plan currently contemplates drilling 48 gross (43 net) vertical wells and two gross (two net) horizontal wells in the Wolfberry play. We ended 2011 with a two rig drilling program which we increased to four drilling rigs in 2012. As of August 31, 2012, we were using two drilling rigs. Upon completion of this offering, we intend to increase our drilling program to six rigs. Subject to market conditions and rig availability, we expect to operate six rigs throughout 2013, which we expect will allow us to significantly increase our drilling program in 2013.

Focus on increasing hydrocarbon recovery through horizontal drilling and increased well density. We believe there are opportunities to target various intervals in the Wolfberry play with horizontal wells. In June 2012, we completed our first horizontal operated well, in which we have a 100% interest, in the Wolfcamp B interval in Upton County and currently plan to drill one additional gross (one net) horizontal operated well in 2012, also targeting the Wolfcamp B interval. Our first horizontal operated well had a 3,842 foot lateral, a 24-hour initial production rate of 618 BOE/d and a 30-day average initial production rate of 486 BOE/d, of which 86% was oil. Based on the decline curve analysis of the current production, we anticipate that the EUR for this well will be in the range of 400 to 500 MBOE, of which 67% is expected to be oil. Additionally, since June 2012, we have participated in three gross (one net) horizontal non-operated wells in Midland and Ector Counties. See *Prospectus Summary Recent Developments* on page 6. Our horizontal drilling program is designed to further capture the upside potential that may exist on our properties. We also believe our horizontal drilling program may significantly increase our recoveries per section as compared to drilling vertical wells alone. Horizontal drilling may also be economical in areas where vertical drilling is currently not economical or logistically viable. In addition, we believe increased well density opportunities may exist across our acreage base. We closely monitor industry trends with respect to higher well density, which could increase the recovery factor per section and enhance returns since infrastructure is typically in place.

Leverage our experience operating in the Permian Basin. Our executive team, which has an average of approximately 24 years of industry experience per person and significant experience in the Permian Basin, intends to continue to seek ways to maximize hydrocarbon recovery by refining and enhancing our drilling and completion techniques. The time to reach TD for our vertical Wolfberry wells decreased from an average of 20 days during the second quarter of 2011 to an average of 14 days during the period from April 2012 through August 2012, resulting in a lower total well cost. Our focus on efficient drilling and completion techniques, and the resulting reduction in time to reach TD, is an important part of the continuous drilling program we have planned for our significant inventory of identified potential drilling locations. In addition, we believe that the experience of our new executive team in deviated and horizontal drilling and completions should help reduce the execution risk normally associated with these complex well paths. Additionally, our completion techniques are continually evolving as we evaluate hydraulic fracturing practices that may potentially increase recovery and reduce completion costs. Our executive team regularly evaluates our operating results against those of other operators in the area in an effort to benchmark our performance against the best performing operators and evaluate and adopt best practices.

Enhance returns through our low cost development strategy of resource conversion, capital allocation and continued improvements in operational and cost efficiencies. In the current commodity price environment, our oil and liquids rich asset base provides attractive returns. Our acreage position in the Wolfberry play is generally in contiguous blocks which allows us to develop this acreage efficiently with a manufacturing strategy that takes advantage of economies of scale and uses centralized production and fluid handling facilities. We are the operator of approximately 99% of our acreage. This operational control allows us to more efficiently manage the pace of development activities and the gathering and marketing of our production and control operating costs and technical applications, including horizontal development. Our average 87% working interest in our acreage pro forma for the Transactions allows us to realize the majority of the benefits of these expected improvements and cost efficiencies.

Pursue strategic acquisitions with exceptional resource potential. We have a proven history of acquiring leasehold positions in the Permian Basin that have substantial oil-weighted resource potential and can achieve attractive returns on invested capital. Our executive team, with its extensive experience in the Permian Basin, has what we believe is a competitive advantage in identifying acquisition targets and a proven ability to evaluate resource potential. We intend to continue to pursue acquisitions that meet our strategic and financial targets.

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Maintain financial flexibility. We seek to maintain a conservative financial position. After giving effect to this offering and the use of proceeds from this offering to repay the outstanding borrowings under our revolving credit facility, we will have $90.0 million of available borrowing capacity under such facility.

Our Strengths

We believe that the following strengths will help us achieve our business goals:

Oil rich resource base in one of North America s leading resource plays. All of our leasehold acreage is located in one of the most prolific oil plays in North America, the Permian Basin in West Texas. As of September 21, 2012, the Baker Hughes Rig Count survey reported that there were 501 rigs drilling in the Permian Basin. The majority of our current properties are well positioned in the core of the Wolfberry play. We believe that our historical vertical development success will be complemented with horizontal drilling locations that could ultimately translate into an increased recovery factor on a per section basis. Our production was approximately 74% oil, 15% natural gas liquids and 11% natural gas for both the six months ended June 30, 2012 and the year ended December 31, 2011. As of December 31, 2011, after giving effect to the Transactions, our estimated net proved reserves were comprised of approximately 66% oil and 20% natural gas liquids. This oil and liquids exposure allows us to benefit from their currently more favorable prices as compared to natural gas.

Multi-year drilling inventory in one of North America s leading oil resource plays. We have identified a multi-year inventory of potential drilling locations for our oil-weighted reserves that we believe provides attractive growth and return opportunities. As of August 31, 2012, after giving effect to the Transactions, we had 916 identified potential vertical drilling locations based on 40-acre spacing and an additional 1,122 identified potential vertical drilling locations based on 20-acre downspacing. In 2012, after giving effect to the Transactions, we anticipate drilling 48 gross (43 net) vertical operated wells, which represent only approximately 5.1% of our identified potential vertical drilling locations on 40-acre spacing at August 31, 2012. We also believe that there are a significant number of horizontal locations that could be drilled on our acreage. In June 2012, we completed our first horizontal operated well, in which we have a 100% interest, in the Wolfcamp B interval in Upton County and currently expect to drill one additional gross (one net) horizontal operated well during 2012, also targeting the Wolfcamp B interval. Additionally, since June 2012, we have participated in three gross (one net) non-operated horizontal wells. Management currently estimates that EURs for our horizontal wells will be approximately 500 to 600 MBOE for lateral lengths averaging 7,500 feet. In addition, the liquids rich natural gas component of our inventory adds value with Btu content ranging from 1,225 MMBtu to 1,528 MMBtu and our June 2012 natural gas liquids yield was 118 Bbls/MMcf. In addition, we have approximately 117 square miles of proprietary 3-D seismic data covering our acreage. This data facilitates the evaluation of our existing drilling inventory and provides insight into future development activity, including horizontal drilling opportunities and strategic leasehold acquisitions.

Experienced, incentivized and proven management team. Our new executive team has an average of approximately 24 years of industry experience per person, most of which is focused on resource play development. This team has a proven track record of executing on multi-rig development drilling programs and extensive experience in the Permian Basin. In addition, our executive team has significant experience with both drilling and completing horizontal wells as well as horizontal well reservoir and geologic expertise, which will be of strategic importance as we expand our future development plans to include horizontal drilling. Prior to joining us, our Chief Executive Officer held management positions at Apache Corporation, Laredo Petroleum Holdings, Inc. and Burlington Resources.

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Favorable and stable operating environment. We have focused our drilling and development operations in the Permian Basin, one of the oldest hydrocarbon basins in the United States, with a long and well-established production history and developed infrastructure. With approximately 380,000 wells drilled in the Permian Basin since the 1940s, we believe that the geological and regulatory environment is more stable and predictable, and that we are faced with less operational risks, in the Permian Basin as compared to emerging hydrocarbon basins.

High degree of operational control. We are the operator of approximately 99% of our Permian Basin acreage. This operating control allows us to better execute on our strategies of enhancing returns through operational and cost efficiencies and increasing ultimate hydrocarbon recovery by seeking to continually improve our drilling techniques, completion methodologies and reservoir evaluation processes. Additionally, as the operator of substantially all of our acreage, we retain the ability to adjust our capital expenditure program based on commodity price outlooks. This operating control also enables us to obtain data needed for efficient exploration of horizontal prospects.

Financial flexibility to fund expansion. Upon the completion of this offering, we will have a conservative balance sheet. We will seek to maintain financial flexibility to allow us to actively develop our drilling, exploitation and exploration activities in the Wolfberry play and maximize the present value of our oil-weighted resource potential. After giving effect to this offering and the use of proceeds from this offering to repay the outstanding borrowings under our revolving credit facility, we will have $90.0 million of available borrowing capacity under our revolving credit facility. We expect that our borrowing base will be increased as a result of the Transactions.

Recent Developments

In June 2012, we completed our first horizontal operated well, in which we have a 100% interest, in the Wolfcamp B interval in Upton County and currently plan to drill one additional gross (one net) horizontal well in 2012, also targeting the Wolfcamp B interval. Our first horizontal operated well had a 3,842 foot lateral, a 24-hour initial production rate of 618 BOE/d and a 30-day average initial production rate of 486 BOE/d, of which 86% was oil. Based on the decline curve analysis of the current production, we anticipate that the EUR for this well will be in the range of 400 to 500 MBOE, of which 67% is expected to be oil. Additionally, since June 2012, we have participated in three gross (one net) horizontal non-operated wells. One of these is in Midland County and was completed in the Wolfcamp B interval with a 3,733 foot lateral and a 7-day average initial production rate as reported to us by the operator of 477 BOE/d, of which 89% was oil. During its initial production period, the well showed a production rate and pressures similar to those of our first horizontal operated well. We also participated in a horizontal non-operated well in Ector County targeting the Cline interval, which was completed in September 2012 with a 3,968 foot lateral and an average production rate as reported to us by the operator of 240 BOE/d measured on artificial lift over the last nine days of its initial 19 producing dates, of which 86% was oil. Finally, we participated in a horizontal non-operated well in Ector County, which was completed in August 2012 in the Clearfork interval with a 4,635 foot lateral and a 30-day initial production rate as reported to us by the operator of 58 BOE/d, of which 79% was oil.

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. You should read carefully the section of this prospectus entitled *Risk Factors* beginning on page 18 for an explanation of these risks before investing in our common stock. In particular, the following considerations may offset our competitive strengths or have a negative effect on our strategy or operating activities, which could cause a decrease in the price of our common stock and a loss of all or part of your investment:

Our business is difficult to evaluate because of our limited operating history.

Difficulties managing the growth of our business may adversely affect our financial condition and results of operations.

Failure to develop our undeveloped acreage could adversely affect our future cash flow and income.

Our exploration and development operations require substantial capital that we may be unable to obtain, which could lead to a loss of properties and a decline in our reserves.

Our future success depends on our ability to find, develop or acquire additional oil and natural gas reserves.

The volatility of oil and natural gas prices due to factors beyond our control greatly affects our profitability.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with a concentration of operations in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could limit our access to suitable markets for the oil and natural gas we produce.

Our operations are subject to various governmental regulations which require compliance that can be burdensome and expensive.

Any failure by us to comply with applicable environmental laws and regulations, including those relating to hydraulic fracturing, could result in governmental authorities taking actions that adversely affect our operations and financial condition.

Our operations are subject to operational hazards for which we may not be adequately insured.

Our failure to successfully identify, complete and integrate future acquisitions of properties or businesses could reduce our earnings and slow our growth.

Our largest stockholder controls a significant percentage of our common stock and its interests may conflict with yours.

For a discussion of other considerations that could negatively affect us, see *Risk Factors* beginning on page 18 and *Cautionary Note Regarding Forward-Looking Statements* on page 45 of this prospectus.

The Transactions

On May 7, 2012, we entered into an agreement with Gulfport in which Gulfport agreed to sell to us all of its oil and natural gas properties in the Permian Basin in exchange for (i) 7,914,036 shares of our common stock, which will represent 35% of our outstanding common stock immediately prior to the closing of this offering and (ii) approximately $63.6 million in the form of a non-interest bearing promissory note, which we refer to as the Gulfport transaction note, that will be repaid in full upon the closing of this offering with a portion of the net proceeds from this offering. The Gulfport transaction was completed on October 11, 2012. We are the operator of the acreage acquired by us from Gulfport. The aggregate consideration payable to Gulfport is subject to a post-closing cash adjustment and will be increased or decreased by an amount equal to the difference between $118.1 million and the final capital amount, divided by 65% and then multiplied by 35%. For purposes of our agreement with Gulfport, final capital amount means Windsor Permian s (a) total current assets, consisting of cash, trade accounts receivable (net of an allowance for doubtful accounts), inventory, prepaid expenses, other current assets and other assets, less (b) total current liabilities, consisting of trade accounts payable, accounts payable to related parties, accrued capital and other expenses, long-term debt and asset retirement obligations, in each case as of the closing date of the transaction. If the closing date for the transaction had been September 30, 2012, based on preliminary estimates we believe that we would have owed Gulfport approximately $16.0 million for this post-closing adjustment. Gulfport s obligation to complete this transaction was contingent upon, among other things, the contribution to us of all the outstanding equity interests in Windsor Permian and Gulfport s satisfaction with the terms of this offering. In connection with this transaction, we granted Gulfport the right, for so long as Gulfport beneficially owns more than 10% of our outstanding common stock, to designate one individual as a nominee to serve on our board of directors. We also granted Gulfport certain demand and piggyback registration rights obligating us to register with the SEC the shares of our common stock owned by Gulfport. For more information regarding the Gulfport transaction, see *Management Our Board of Directors and Committees*, *Related Party Transactions Gulfport Transaction and Investor Rights Agreement* and *Shares Eligible for Future Sale Registration Rights* beginning on pages 118, 134 and 146, respectively, of this prospectus.

In addition, our equity sponsor, Wexford, caused all of the outstanding equity interests in Windsor UT LLC, or Windsor UT, to be contributed to Windsor Permian before the completion of the Gulfport transaction described above. Windsor UT was formed in April 2010 and acquired 4,978 gross (2,489 net) acres in the Permian Basin, of which we are the operator. The other 2,489 net acres were owned by Gulfport and transferred to us in the Gulfport transaction. Six wells had been drilled on this acreage as of August 31, 2012, which acreage contains 118 of our identified potential vertical drilling locations based on 40-acre spacing.

We refer to Gulfport s sale of properties to us as the Gulfport transaction and we refer to the Gulfport transaction together with the contribution to Windsor Permian of all the equity interests in Windsor UT as the Transactions.

Our Equity Sponsor

We were formed by our equity sponsor, Wexford Capital LP, or Wexford, which is a Greenwich, Connecticut-based SEC-registered investment advisor with over $5.5 billion under management as of December 31, 2011. Wexford has made public and private equity investments in many different sectors and has particular expertise in the energy and natural resources sector. Wexford or one or more of its affiliates is purchasing in this offering 1,717,126 shares of our common stock at the same price as the price to the public, and Wexford will beneficially own, upon completion of the offering, approximately 46.7% of our common stock (or approximately 44.4% if the underwriters option to purchase additional shares is exercised in full). The underwriters will not receive any underwriting discounts or commissions on any shares sold to Wexford or its affiliates. As a result, Wexford will continue to be able to exercise significant control over all matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. Prior to the closing of this offering, we will enter into an advisory services agreement with Wexford under which Wexford will provide us with financial and strategic advisory services related to our business. We are also party to certain other agreements with Wexford and its affiliates. For a description of the advisory services agreement and other agreements with Wexford and its affiliates, see *Related Party Transactions* beginning on page 134. Although our management believes that the terms of these related party agreements are reasonable, it is possible that we could have negotiated more favorable terms for such transactions with unrelated third parties. The existence of these related party agreements may give Wexford the ability to further influence and maintain control over many matters affecting us.

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Our History

Diamondback Energy, Inc. was incorporated on December 30, 2011 in Delaware as a holding company and did not conduct any material business operations prior to the transaction described below. All of our historical assets, operations and results described in this prospectus are those of Windsor Permian LLC, or Windsor Permian. Windsor Permian was a wholly-owned subsidiary of Diamondback Energy LLC, which was an entity controlled by our equity sponsor, Wexford. Prior to the effectiveness of the registration statement relating to this prospectus, Wexford caused Diamondback Energy LLC to be merged with and into Diamondback Energy, Inc. and Diamondback Energy, Inc. continued as the surviving entity. Immediately after the merger and prior to the effectiveness of the registration statement relating to this prospectus, Gulfport completed the Gulfport transaction. Upon completion of these Transactions, Wexford and Gulfport beneficially owned 65% and 35%, respectively, of our outstanding common stock. Upon completion of the offering (including the purchase by Wexford or its affiliates of 1,717,126 shares of our common stock), Wexford and Gulfport will beneficially own approximately 46.7% and 22.5%, respectively, of our common stock (approximately 44.4% and 21.4%, respectively, if the underwriters option to purchase additional shares is exercised in full).

As of April 30, 2012, Windsor Permian held a 22% interest in Bison Drilling and Field Services LLC, or Bison, and a 33% interest in Muskie Holdings LLC, or Muskie. Bison owns drilling rigs and various oil and natural gas well servicing equipment and performs drilling and field services for us. Muskie owns certain assets, real estate and rights in a lease for land that is prospective for oil and natural gas fracture grade sand. Windsor Permian s interests in Bison and Muskie were distributed to Windsor Permian s sole member in June 2012 so we may focus our activities on our oil and natural gas exploration and development activities. We recorded revenues of $0.8 million and $1.5 million attributable to Bison in our consolidated statements of operations during 2010 and the first quarter of 2011, respectively. Muskie was formed in 2011, and we recorded a loss from equity method investments of $7,017 for 2011. The interests in Bison and Muskie are reflected in Investments-equity method on our consolidated balance sheets. For additional information regarding Bison and Muskie, see *Unaudited Pro Forma Condensed Consolidated Financial Statements* and *Related Party Transactions* beginning on pages 54 and 134, respectively, of this prospectus and Note 5 to our consolidated financial statements appearing elsewhere in this prospectus.

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The following organizational charts illustrate (a) our pre-offering organizational structure and (b) our organizational structure after giving effect to the Transactions and the offering:

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Emerging Growth Company

We are an emerging growth company within the meaning of the federal securities laws. For as long as we are an emerging growth company, we will not be required to comply with the requirements that are applicable to other public companies that are not emerging growth companies including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, the reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements and the exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved. We intend to take advantage of these reporting exemptions until we are no longer an emerging growth company. For a description of the qualifications and other requirements applicable to emerging growth companies and certain elections that we have made due to our status as an emerging growth company, see *Risk Factors Risks Related to this Offering and our Common Stock We are an emerging growth company and we cannot be certain if the reduced disclosure requirements applicable to emerging growth companies will make our common stock less attractive to investors* on page 41 of this prospectus.

Our Offices

Our principal executive offices are located at 500 West Texas, Suite 1225, Midland, Texas, and our telephone number at that address is (432) 221-7400. We also lease additional office space in Midland and in Oklahoma City, Oklahoma. Our website address is www.diamondbackenergy.com. Information contained on our website does not constitute part of this prospectus. Except as otherwise indicated or required by the context, all references in this prospectus to Diamondback, the Company, we, us or our relate to Diamondback Energy, Inc Windsor Permian LLC and its consolidated subsidiaries.

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The Offering

Common stock offered by us	12,500,000 shares (14,375,000 shares if the underwriters option to purchase additional shares is exercised in full)
Common stock to be outstanding immediately after completion of this offering	35,111,532 shares (36,986,532 shares if the underwriters option to purchase additional shares is exercised in full)
Option to purchase additional shares	We have granted the underwriters a 30-day option to purchase up to an aggregate of 1,875,000 additional shares of our common stock.
Use of proceeds	We expect to receive approximately $204.6 million of net proceeds from the sale of the common stock offered by us after deducting underwriting discounts and estimated offering expenses (or approximately $235.3 million if the underwriters option to purchase additional shares is exercised in full). Following the closing of this offering, we will use $100.0 million of the net proceeds to repay the outstanding borrowings under our revolving credit facility, approximately $63.6 million to repay the Gulfport transaction note, $30.0 million to repay outstanding borrowings under our subordinated note with an affiliate of Wexford and approximately $8.4 million to settle the existing crude oil swaps. The remaining net proceeds of approximately $2.5 million (or approximately $33.2 million if the underwriters option to purchase additional shares is exercised in full), will be used to fund a portion of our exploration and development activities and for general corporate purposes, which may include leasehold interest and property acquisitions, working capital and the settlement of the post-closing cash adjustment payable to Gulfport under the terms of the Gulfport transaction. See *Use of Proceeds* on page 46 of this prospectus.
Conflicts of interest	Affiliates of Wells Fargo Securities, LLC are lenders under our revolving credit facility and, accordingly, will receive a substantial portion of the net proceeds from this offering as a result of the repayment of the outstanding borrowings under our revolving credit facility.
	Because affiliates of Wells Fargo Securities, LLC are lenders under our revolving credit facility and will receive more than 5% of the net proceeds of this offering due to the repayment of a portion of the revolving credit facility, this offering will be conducted in accordance with Rule 5121 of the Financial Industry Regulatory Authority, Inc., which requires, among other things, that a qualified independent underwriter has participated in the preparation of, and has exercised the usual standards of due diligence with respect to, the registration statement and this prospectus. Credit Suisse Securities (USA) LLC has agreed to act as qualified independent underwriter for this offering. Please read *Use of Proceeds* and *Underwriting (Conflicts of Interest)* beginning on pages 46 and 151, respectively.

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Dividend policy	We currently anticipate that we will retain all future earnings, if any, to finance the growth and development of our business. We do not intend to pay cash dividends in the foreseeable future.
Directed Share Program	The underwriters have reserved for sale at the initial public offering price up to 5% of the common stock being offered by this prospectus for sale to our employees, executive officers, directors, business associates and related persons who have expressed an interest in purchasing common stock in the offering. We do not know if these persons will choose to purchase all or any portion of these reserved shares, but any purchases they do make will reduce the number of shares available to the general public. Please read *Underwriting (Conflicts of Interest)* beginning on page 151.
NASDAQ Global Select Market symbol	FANG
Risk Factors	You should carefully read and consider the information beginning on page 18 of this prospectus set forth under the heading *Risk Factors* and all other information set forth in this prospectus before deciding to invest in our common stock.

Except as otherwise indicated, all information contained in this prospectus:

- assumes the underwriters do not exercise their over-allotment option; and
- excludes 2,500,000 shares of common stock reserved for issuance under our equity incentive plan, including, based on the initial public offering price of $17.50 per share:
  - 245,716 restricted stock units to be issued to certain employees following the closing of this offering under the terms of their employment agreements, of which 57,143 will be vested on the closing date of this offering;
  - 33,330 restricted stock units to be issued to our non-employee directors following the closing of this offering as part of their director compensation, of which 11,110 will be vested on the closing date of this offering; and
  - options to purchase 850,000 shares of our common stock to be granted to certain employees following the closing of this offering under the terms of their employment agreements, of which options to purchase 200,000 shares will be vested on the closing date of this offering.

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Summary Consolidated Historical and Pro Forma Financial Data

The following table sets forth our summary historical consolidated financial data as of and for each of the periods indicated. The summary historical consolidated financial data as of December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009 are derived from our historical audited consolidated financial statements included elsewhere in this prospectus. The summary historical consolidated balance sheet data as of December 31, 2009 are derived from our audited consolidated balance sheet as of that date, which is not included in this prospectus. The summary historical consolidated financial data as of June 30, 2012 and for the six months ended June 30, 2012 and 2011 are derived from our historical unaudited consolidated financial statements included elsewhere in this prospectus. The summary historical consolidated balance sheet data as of June 30, 2011 are derived from our unaudited consolidated balance sheet as of such date, which is not included in this prospectus. The unaudited pro forma financial data give effect to (a) the Transactions and (b) the distribution by Windsor Permian to its equity holder of its minority equity interests in Bison and Muskie. The unaudited pro forma statement of operations data for the year ended December 31, 2011 and the six months ended June 30, 2012 assume that these transactions occurred on January 1, 2011. The unaudited pro forma balance sheet data assume that the Transactions occurred on June 30, 2012. The unaudited pro forma C Corporation financial data presented give effect to income taxes assuming we operated as a taxable corporation since inception for historical columns and since January 1, 2011 for pro forma columns. Operating results for the years ended December 31, 2011, 2010 and 2009 and the six months ended June 30, 2012 and 2011 are not necessarily indicative of results that may be expected for any future periods. You should review this information together with *Management s Discussion and Analysis of Financial Condition and Results of Operations,* *Selected Historical Consolidated Financial Data* and *Unaudited Pro Forma Condensed Consolidated Financial Statements* beginning on pages 61, 51 and 54, respectively, of this prospectus as well as our consolidated historical financial statements, the historical financial statements of Windsor UT and the statements of revenues and direct operating expenses of certain property interests of Gulfport and their respective related notes included elsewhere in this prospectus.

	Pro Forma		Historical				
	Six Months Ended June 30, 2012	Year Ended December 31, 2011	Six Months Ended June 30, 2012	2011	Year Ended December 31, 2011	2010	2009
Statement of Operations Data:							
Oil and natural gas revenues	$ 46,572,620	$ 70,927,468	$ 31,757,923	$ 22,038,729	$ 47,180,802	$ 26,441,927	$ 12,716,011
Other revenues				1,490,910	1,490,910	811,247	
Expenses:							
Lease operating expense	10,232,157	16,081,179	6,134,714	4,283,671	10,345,355	4,588,559	2,366,623
Production taxes	2,313,853	3,641,869	1,550,154	1,093,899	2,333,853	1,346,879	663,068
Gathering and transportation	146,320	201,828	146,320	85,944	201,828	105,870	42,091
Oil and natural gas services				1,732,892	1,732,892	811,247	
Depreciation, depletion and amortization	15,287,686	23,661,538	10,235,730	7,441,366	15,402,826	8,145,143	3,215,891
General and administrative	2,884,277	3,522,231	2,815,051	1,421,313	3,603,479	3,051,627	5,062,618
Asset retirement obligation accretion expense	65,269	103,407	40,195	28,736	63,259	37,856	27,934
Total expenses	30,929,562	47,212,052	20,922,164	16,087,821	33,683,492	18,087,181	11,378,225
Income from operations	15,643,058	23,715,416	10,835,759	7,441,818	14,988,220	9,165,993	1,337,786
Other income (expense):							
Interest income	2,004	11,197	2,004	6,988	11,197	34,474	35,075
Interest expense	(2,053,706)	(2,528,058)	(2,053,706)	(1,097,053)	(2,528,058)	(836,265)	(10,938)
Other income	1,058,043		1,058,043				
Gain (loss) on derivative contracts	5,164,987	(13,009,393)	5,164,987	(28,181)	(13,009,393)	(147,983)	(4,068,005)
Loss from equity investment			(66,654)		(7,017)		
Total other income (expense), net	4,171,328	(15,526,254)	4,104,674	(1,118,246)	(15,533,271)	(949,774)	(4,043,868)
Net income (loss)	$ 19,814,386	$ 8,189,162	$ 14,940,433	$ 6,323,572	$ (545,051)	$ 8,216,219	$ (2,706,082)

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	Pro Forma Six Months Ended June 30, 2012	Pro Forma Year Ended December 31, 2011	Historical Six Months Ended June 30, 2012	Historical Six Months Ended June 30, 2011	Historical Year Ended December 31, 2011	Historical Year Ended December 31, 2010	Historical Year Ended December 31, 2009
Pro Forma C Corporation Data:[1]							
Net income (loss) before income taxes	$ 19,814,386	$ 8,189,162	$ 14,940,433	$ 6,323,572	$ (545,051)	$ 8,216,219	$ (2,706,082)
Pro forma for income taxes	7,063,829	2,919,436					
Pro forma net income (loss)	$ 12,750,557	$ 5,269,726	$ 14,940,433	$ 6,323,572	$ (545,051)	$ 8,216,219	$ (2,706,082)
Pro forma income (loss) per common share basic and diluted[2]	$ 0.56	$ 0.23	$ 1.07		$ (0.04)		
Weighted average pro forma shares outstanding basic and diluted[2]	22,611,532	22,611,532	14,000,000		14,000,000		
Selected Cash Flow and Other Financial Data:							
Net income (loss)			$ 14,940,433	$ 6,323,572	$ (545,051)	$ 8,216,219	$ (2,706,082)
Depreciation, depletion and amortization			10,235,730	7,943,855	15,905,315	8,145,143	3,215,891
Other non-cash items			(4,273,541)	177,309	13,844,010	344,461	4,108,464
Change in operating assets and liabilities			1,406,699	(925,350)	1,179,920	(11,529,999)	(1,916,707)
Net cash provided by operating activities			$ 22,309,321	$ 13,519,386	$ 30,384,194	$ 5,175,824	$ 2,701,566
Net cash used in investing activities			$ (59,382,142)	$ (38,363,561)	$ (76,314,042)	$ (53,134,641)	$ (32,149,617)
Net cash provided by financing activities			$ 32,337,149	$ 23,292,499	$ 48,642,492	$ 49,618,254	$ 23,849,250

	Pro Forma As of June 30, 2012	Historical As of June 30, 2012	Historical As of June 30, 2011	Historical As of December 31, 2011	Historical As of December 31, 2010	Historical As of December 31, 2009
Balance sheet data:						
Cash and cash equivalents	$ 2,341,466	$ 2,066,717	$ 2,538,068	$ 6,802,389	$ 4,089,745	$ 2,430,308
Other current assets	23,267,333	23,197,048	23,855,341	24,130,450	20,947,659	2,263,097
Oil and gas properties, net using full cost method of accounting	494,138,149	254,189,321	164,635,560	206,342,604	135,782,510	89,777,517
Well equipment to be used in development of oil and gas properties						5,413,310
Other property and equipment, net	1,540,452	1,540,452	3,435,130	684,015	11,059,220	105,564
Other assets	1,997,772	1,997,772	12,286,037	11,524,427	637,562	82,813
Total assets	$ 523,285,172	$ 282,991,310	$ 206,750,136	$ 249,483,885	$ 172,516,696	$ 100,072,609
Current liabilities	$ 124,014,934	$ 51,806,938	$ 23,996,533	$ 42,418,305	$ 20,010,276	$ 13,972,080
Note payable-long term	338,560	338,560				
Note payable-credit facility-long term	90,000,000	90,000,000	68,400,000	85,000,000	44,766,687	
Note payable-related party-long term	14,109,782	14,109,782				
Derivative contracts-long term	1,666,639	1,666,639	1,498,517	6,138,573	1,373,864	1,416,431
Asset retirement obligations	1,899,835	1,195,662	893,471	1,079,725	727,826	481,887
Deferred income taxes	54,077,259					
Member s/stockholders equity	237,178,163	123,873,729	111,961,615	114,847,282	105,638,043	84,202,211
Total liabilities and member s/stockholders equity	$ 523,285,172	$ 282,991,310	$ 206,750,136	$ 249,483,885	$ 172,516,696	$ 100,072,609

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	Pro Forma		Historical				
	Six Months Ended June 30, 2012	Year Ended December 31, 2011	Six Months Ended June 30,		Year Ended December 31,		
			2012	2011	2011	2010	2009
Other financial data:							
Adjusted EBITDA(3)	$ 32,638,281	$ 48,538,337	$ 22,687,298	$ 15,421,397	$ 31,505,264	$ 17,383,466	$ 4,616,686

(1) Diamondback Energy, Inc. was incorporated on December 30, 2011 in Delaware as a holding company and will not conduct any material business operations prior to the transaction described below. Our historical consolidated financial statements and other financial information included in this prospectus pertain to assets, liabilities, revenues and expenses of Windsor Permian LLC, which is an entity controlled by our equity sponsor, Wexford. Windsor Permian LLC was treated as a partnership for federal income tax purposes. As a result, essentially all of Windsor Permian LLC s taxable earnings and losses were passed through to Wexford, and Windsor Permian LLC did not pay federal income taxes at the entity level. Prior to the effectiveness of the registration statement relating to this prospectus, Windsor Permian LLC became our wholly-owned subsidiary and, because we are a subchapter C corporation under the Internal Revenue Code, the earnings at Windsor Permian LLC will prospectively become subject to federal income tax. For comparative purposes, we have included pro forma financial data for the historical periods to give effect to income taxes assuming the earnings at Windsor Permian LLC had been subject to federal income tax as a subchapter C corporation since inception. If the earnings at Windsor Permian LLC had been subject to federal income tax as a subchapter C corporation since inception, we would have incurred net operating losses for income tax purposes in each period. We would have been in a net deferred tax asset, or DTA, position as a result of such tax losses and would have recorded a valuation allowance to reduce each period s DTA balance to zero. A valuation allowance to reduce each period s DTA would have resulted in an equal and offsetting credit for the respective expenses or an equal and offsetting debit for the respective benefits for income taxes, with the resulting tax expenses for each of the above periods of zero. The unaudited pro forma data is presented for informational purposes only, and does not purport to project our results of operations for any future period or our financial position as of any future date.

(2) Unaudited historical pro forma basic and diluted income (loss) per share has been presented for the latest fiscal year and interim period on the basis of the aggregate number of shares attributable to Windsor Permian LLC issued to DB Holdings in connection with the merger of Diamondback Energy LLC with and into Diamondback Energy, Inc.

(3) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss), see *Selected Historical Consolidated Financial Data* beginning on page 51 of this prospectus.

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Summary Historical and Pro Forma Reserve Data

The following table sets forth estimates of our net proved oil and natural gas reserves as of December 31, 2011 on a historical basis and on a pro forma basis after giving effect to the Transactions as if they had occurred as of December 31, 2011. Our historical reserves and the historical reserves attributable to the Windsor UT properties and the properties subject to the Gulfport transaction have been prepared in each case as of December 31, 2011 by Ryder Scott, an independent petroleum engineering firm, in accordance with SEC rules and regulations. Copies of these reserve reports are attached to this prospectus as Appendices B, C and D. You should also refer to *Risk Factors,* *Management s Discussion and Analysis of Financial Condition and Results of Operations,* *Business Oil and Gas Data Proved Reserves,* *Business Oil and Gas Production Prices and Production Costs Production and Price History* beginning on pages 18, 61, 98 and 102, respectively, of this prospectus, our audited consolidated financial statements and notes thereto and our unaudited pro forma financial statements and notes thereto included in this prospectus in evaluating the material presented below.

	Pro Forma December 31, 2011	Historical December 31, 2011
Estimated proved developed reserves:		
Oil (Bbls)	6,046,099	3,805,291
Natural gas (Mcf)	8,335,945	5,186,941
Natural gas liquids (Bbls)	1,969,710	1,233,318
Total (BOE)	9,405,133	5,903,099
Estimated proved undeveloped reserves:		
Oil (Bbls)	20,140,377	12,911,578
Natural gas (Mcf)	24,261,522	14,431,926
Natural gas liquids (Bbls)	5,870,849	3,529,955
Total (BOE)	30,054,813	18,846,854
Estimated Net Proved Reserves:		
Oil (Bbls)	26,186,476	16,716,869
Natural gas (Mcf)	32,597,467	19,618,867
Natural gas liquids (Bbls)	7,840,559	4,763,273
Total (BOE)[1]	39,459,946	24,749,953
Percent proved developed	23.8%	23.9%

(1) Estimates of reserves as of December 31, 2011 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2011, in accordance with revised SEC guidelines applicable to reserves estimates as of the end of 2011. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for unproved undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

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RISK FACTORS

An investment in our common stock involves a high degree of risk. You should carefully consider the following risks and all of the other information contained in this prospectus before deciding to invest in our common stock. Our business, financial condition and results of operations could be materially and adversely affected by any of these risks. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks Related to the Oil and Natural Gas Industry and Our Business

Our business is difficult to evaluate because we have a limited operating history.

We were incorporated in Delaware on December 30, 2011. All of our historical oil and natural gas assets, operations and results described in this prospectus were those of Windsor Permian which, prior to this offering, was an entity controlled by our equity sponsor, Wexford. Immediately prior to the effectiveness of the registration statement relating to this prospectus, Windsor Permian became our wholly-owned subsidiary and we acquired the oil and gas assets of Gulfport located in the Permian Basin in the Gulfport transaction. The oil and natural gas properties of Windsor Permian, Gulfport and Windsor UT described in this prospectus have been acquired by Windsor Permian, Gulfport and Windsor UT since December 2007. As a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.

As a recently-formed company, growth in accordance with our business plan, if achieved, could place a significant strain on our financial, technical, operational and management resources. As we expand our activities and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geologists, engineers and other professionals in the oil and natural gas industry, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

Approximately 86% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

Approximately 86% of our net leasehold acreage is undeveloped, or 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. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Our development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. In 2011, our total capital expenditures, including expenditures for

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leasehold interest and property acquisitions, drilling, seismic and infrastructure, were approximately $75.4 million. Our 2012 capital budget for drilling, completion and infrastructure, including investments in water disposal infrastructure and gathering line projects, is estimated to be approximately $150.0 million to $160.0 million after giving effect to the Transactions. To date, we have financed capital expenditures primarily with funding from Wexford, our equity sponsor, borrowings under our revolving credit facility and cash generated by operations. However, neither Wexford nor any of its affiliates has made any commitment to provide us additional funding. Notwithstanding prior contributions and loans to us by Wexford or its affiliates, you should not assume that any of them will provide any debt or equity funding to us in the future.

In the near term, we intend to finance our capital expenditures with cash flow from operations, proceeds from this offering and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the volume of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

We cannot assure you that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures in 2012 could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include traditional reserve base borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. We cannot assure you that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

If we are unable to fund our capital requirements, we may be required to curtail our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves, or may be otherwise unable to implement our development plan, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. In addition, a delay in or the failure to complete proposed or future infrastructure projects could delay or eliminate potential efficiencies and related cost savings.

Our success depends on finding, developing or acquiring additional reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we undertake development, exploration and other replacement activities or use third parties to accomplish these activities. We have made and expect to make in the future substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves. We may not have sufficient resources to undertake our exploration, development and production activities or the acquisition of oil and natural gas reserves, our exploratory projects or other replacement activities may not result in significant additional reserves and we may not have success drilling productive wells at low finding and development costs. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

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Our project areas, which are in various stages of development, may not yield oil or natural gas in commercially viable quantities.

Our project areas are in various stages of development, ranging from project areas with current drilling or production activity to project areas that consist of recently acquired leasehold acreage or that have limited drilling or production history. From inception through August 31, 2012, after giving effect to the Transactions, we drilled a total of 167 gross wells and participated in an additional 16 gross non-operated wells, of which 171 wells were completed as producing wells and 12 wells were in various stages of completion. If the wells in the process of being completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected.

Our identified potential drilling locations, which are part of our anticipated future drilling plans, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

As of August 31, 2012, after giving effect to the Transactions, we had 916 identified potential vertical drilling locations on our existing acreage based on 40-acre spacing and an additional 1,122 identified potential vertical drilling locations based on 20-acre downspacing. Only 303 of these identified potential vertical drilling locations were attributed to proved reserves. These drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, construction of infrastructure, inclement weather, regulatory changes and approvals, oil and natural gas prices, costs and drilling results. Further, our identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation. We cannot 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 or whether wells drilled on 20-acre downspacing will produce at the same rates as those on 40-acre spacing. The use of 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 sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Permian Basin may not be indicative of future or long-term production rates. Because of these uncertainties, we do not know if the 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. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. As of June 30, 2012 after giving effect to the Transactions, we had leases representing 201 net acres expiring in 2012, 222 net acres expiring in 2013, 2,065 net acres expiring in 2014, 17,766 net acres expiring in 2015 and 6,893 net acres expiring in 2016. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in

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the loss of acreage through lease expirations. In addition, in order to hold our current leases expiring in 2014 and 2015, we will need to operate at least a four-rig program. We cannot assure you that we will have the liquidity to deploy these rigs in this time frame, or that commodity prices will warrant operating such a drilling program. Any such losses of leases could materially and adversely affect the growth of our asset basis, cash flows and results of operations.

The volatility of oil and natural gas prices due to factors beyond our control greatly affects our profitability.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including:

- the domestic and foreign supply of oil and natural gas;
- the level of prices and expectations about future prices of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the price of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;

- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of alternative fuels; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the posted price for West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, has ranged from a low of $30.28 per barrel, or Bbl, in December 2008 to a high of $145.31 per Bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.82 per million British thermal units, or MMBtu, in April 2012 to a high of $13.31 per MMBtu in July 2008. During 2011, West Texas Intermediate prices ranged from $75.40 to $113.39 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.84 to $4.92 per MMBtu. On August 31, 2012, the West Texas Intermediate posted price for crude oil was $96.47 per Bbl and the Henry Hub spot market price of natural gas was $2.72 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development results deteriorate, full cost accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties.

We have entered into price swap derivatives and may in the future enter into forward sale contracts or additional price swap derivatives for a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas.

We use price swap derivatives to reduce price volatility associated with certain of our oil sales. Under these swap contracts, we receive a fixed price per barrel of oil and pay a floating market price per barrel of oil to the counterparty based on New York Mercantile Exchange Light Sweet Crude Oil pricing. The fixed-price payment and the floating-price payment are offset, resulting in a net amount due to or from the counterparty. For the purpose of locking-in the value of a swap, we enter into counter-swaps from time to time. Under the counter-swap, we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. The counter-swap is effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap.

In December 2007, we placed a swap contract covering 1,680,000 Bbls of crude oil for the period from January 2008 to December 2012 at various fixed prices. In April 2008, we entered into a series of counter-swaps to lock-in the value of certain of these swaps settling 1,188,000 Bbls of crude oil swaps. In June 2009, we entered into an additional series of counter-swaps to lock-in the value of the remaining swaps settling 324,000 Bbls of crude oil swaps. Locking in the value of our swaps with counter-swaps, without entering into new swaps, exposes us to commodity price risks on the originally swapped position. As of December 31, 2010 and 2009, all of our swap contracts were locked-in with counter swaps. In October 2011, we placed a swap contract covering 1,000 Bbls per day of crude oil for the period from January 1, 2012 through December 31, 2013 at a fixed price of $78.50 per barrel for 2012 and $80.55 per barrel for 2013. Such contracts and any future hedging arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. In addition, these arrangements may limit the benefit to us of increases in the price of oil. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty s liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

The inability of one or more of our customers to meet their obligations may 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 receivables from joint interest owners on properties we operate (approximately $10.4 million at June 30, 2012) and receivables from purchasers of our oil and natural gas production (approximately $4.8 million at June 30, 2012). Joint interest receivables arise from billing 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 wish to drill. We are generally unable to control which co-owners participate in our wells.

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We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. For the six months ended June 30, 2012, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (63%); Andrews Oil Buyers, Inc. (13%); and Occidental Energy Marketing, Inc. (12%). For the years ended December 31, 2011 and 2010, one purchaser, Windsor Midstream LLC, an entity controlled by Wexford, our equity sponsor, accounted for approximately 78% and 81% of our revenue, respectively. For the year ended December 31, 2009, two purchasers accounted for more than 10% of our revenue: Windsor Midstream LLC (68%) and DCP Midstream, LP (15%). No other customer accounted for more than 10% of our revenue during these periods. This concentration of customers may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Current economic circumstances may further increase these risks. 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.

Our method of accounting for investments in oil and natural gas properties may result in impairment of asset value.

We account for our oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. We also capitalize direct operating costs for services performed with internally owned drilling and well servicing equipment. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Income from services provided to working interest owners of properties in which we also own an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The average depletion rate per barrel equivalent unit of production was $24.22 and $26.72 for the six months ended June 30, 2012 and 2011, respectively, and $25.40, $17.78 and $11.21 for the years ended December 31, 2011, 2010 and 2009, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties for the six months ended June 30, 2012 and 2011 was $10.0 million and $7.3 million, respectively, and for the years ended December 31, 2011, 2010 and 2009 was $15.2 million, $7.4 million and $3.2 million, respectively.

The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment exceed the discounted future net revenues of proved oil and natural gas reserves, the excess capitalized costs are charged to expense. Beginning December 31, 2009, we have used the unweighted arithmetic average first day of the month price for oil and natural gas for the 12-month period preceding the calculation date in estimating discounted future net revenues.

No impairment on proved oil and natural gas properties was recorded for the years ended December 31, 2011, 2010 and 2009 or for the six months ended June 30, 2012 and 2011. We may experience additional ceiling test write downs in the future. See *Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Method of accounting for oil and natural gas properties* beginning of page 83 of this prospectus for a more detailed description of our method of accounting.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Oil and natural gas reserve engineering is not an exact science and requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, ultimate recoveries and operating and development costs. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may be incorrect. Our historical estimates of proved reserves and related valuations are based on reports prepared by Ryder Scott as of December 31, 2011 and by Pinnacle as of December 31, 2010 and 2009, each an independent petroleum engineering firm. The estimates of proved reserves and related valuations attributable to the Windsor UT properties and the properties subject to the Gulfport transaction are based, in each case, on reports prepared by Ryder Scott as of December 31, 2011. Ryder Scott and Pinnacle, as applicable, conducted a well-by-well review of all our properties for the periods covered by their respective reserve reports using information provided by us. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling, testing and production. Also, certain assumptions regarding future oil and natural gas prices, production levels and operating and development costs may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. A substantial portion of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil and natural gas we ultimately recover being different from our reserve estimates.

The estimates of reserves as of December 31, 2011, 2010 and 2009 included in this prospectus were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods ended December 31, 2011, 2010 and 2009, respectively, in accordance with the revised SEC guidelines applicable to reserves estimates for such periods. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for unproved undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

The timing of both our production and our incurrence of costs in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves.

SEC rules that went into effect for fiscal years ending on or after December 31, 2009 could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules that went into effect for fiscal years ending on or after December 31, 2009 require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 76% of our total estimated proved reserves at December 31, 2011 were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

All of our producing properties are geographically concentrated in the Permian Basin of West Texas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of crude oil, natural gas or natural gas liquids. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

In addition to the geographic concentration of our producing properties described above, at December 31, 2011, all of our proved reserves were attributable to the Wolfberry play. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of gas sold in interstate commerce. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. For the six months ended June 30, 2012, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (63%); Andrews Oil Buyers, Inc. (13%); and Occidental Energy Marketing, Inc. (12%). For the years ended December 31, 2011 and 2010, one purchaser, Windsor Midstream LLC, an entity controlled by Wexford, our equity sponsor, accounted for approximately 78% and 81% of our revenue, respectively. For the year ended December 31, 2009, two purchasers accounted for more than 10% of our revenue: Windsor Midstream LLC (68%) and DCP Midstream, LP (15%). No other customer accounted for more than 10% of our revenue during these periods. We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in demand. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. In addition, we do not have long-term contracts securing the use of our existing rigs, and the operator of those rigs may choose to cease providing services to us. In addition, we intend to increase the number of rigs we have operating in 2012 and 2013. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. According to the Lower Colorado River Authority, during 2011, Texas experienced the lowest inflows of water of any year in recorded history. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European debt crisis, the United States mortgage market and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad continues to deteriorate, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our oil, natural gas and natural gas liquids, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

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

We incurred a net loss of $0.5 million for the year ended December 31, 2011. Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures. The uncertainty and risks described in this prospectus may impede our ability to economically find, develop and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows provided by operating activities in the future.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned exploratory drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and consequently we are less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, and/or natural gas and oil prices decline, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and gas properties and the value of our undeveloped acreage could decline in the future.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Our oil production is transported from the wellhead to our tank batteries by our gathering system. Our purchasers then transport the oil by truck to a pipeline for transportation. Our gas production is generally transported by our gathering lines from the wellhead to an interconnection point with the purchaser. We do not control these trucks and other third party transportation facilities and our access to them may be limited or denied. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced, would adversely affect our financial condition and results of operations.

Our operations are subject to various governmental regulations which require compliance that can be burdensome and expensive.

Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, permit revocations, requirements for additional pollution controls and injunctions limiting or prohibiting some or all of our operations. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue. See *Business Regulation Environmental Matters and Regulation* and *Business Regulation Other Regulation of the Oil and Natural Gas Industry* beginning on pages 106 and 110, respectively, of this prospectus for a description of the laws and regulations that affect us.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act, or SDWA, regulates the underground injection of substances through the Underground Injection Control, or UIC, program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions. The EPA, however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as Class II UIC wells. At the same time, the Environmental Protection Agency, or EPA, has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. As part of these studies, both the EPA and the House committee have requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of underground injection and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. The U.S. Congress continues to consider legislation to amend the Safe Drinking Water Act.

On April 17, 2012, EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, EPA s rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule includes a 95 percent reduction in VOCs emitted by requiring the use of reduced emission completions or green completions on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules will require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The federal government is currently undertaking several studies of hydraulic fracturing s potential impacts, the results of which are expected between later in 2012 and 2014.

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 authorities.

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Several states, including Texas, and the Department of the Interior, in a May 4, 2012 proposed rule covering federal lands, have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Railroad Commission recently adopted rules and regulations requiring that the well operator disclose the list of chemical ingredients subject to the requirements of federal Occupational Safety and Health Act (OSHA) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. We plan to use hydraulic fracturing extensively in connection with the development and production of certain of our oil and natural gas properties and any increased federal, state, local, foreign or international regulation of hydraulic fracturing could reduce the volumes of oil and gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

There has been increasing public controversy regarding hydraulic fracturing with regard to use of fracturing fluids, impacts on drinking water supplies, use of waters and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing, such as the FRAC Act, are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our 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. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any 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 impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

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, producing and 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, the risk of 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.

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

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

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The U.S. Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the new legislation, the CFTC has proposed regulations to set 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 would be exempt from these position limits. Although the CFTC has promulgated numerous final rules based on its proposals, it is not possible at this time to predict when the CFTC will finalize its proposed regulations or the effect of such regulations on our business. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our derivative contracts in existence at that time, and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments 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. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas

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prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

The U.S. President s Fiscal Year 2013 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws. These changes include, but are not limited to, (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, (iii) the repeal of the of the percentage depletion allowance for oil and gas properties, (iv) an extension of the amortization period for certain geological and geophysical expenditures and (iv) implementing certain international tax reforms. These proposed changes in the U.S. tax laws, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and natural gas exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

Many nations have agreed to limit emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are greenhouse gases, or GHGs, regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol at this time, several states or geographic regions have adopted legislation and regulations to reduce emissions of greenhouse gases. Additionally, on April 2, 2007, the U.S. Supreme Court ruled, in *Massachusetts, et al. v. EPA*, that the EPA has the authority to regulate carbon dioxide emissions from automobiles as air pollutant under the federal Clean Air Act. Thereafter, in December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth s atmosphere and other climatic changes. These findings by the EPA allowed 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. Subsequently, the EPA adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in April 2010 and it became effective January 2011, although it does not require immediate reductions in GHG emissions. The EPA adopted the stationary source rule, also known as the Tailoring Rule, in May 2010, and it also became effective January 2011, although it remains subject of several pending lawsuits filed by industry groups. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In addition, the EPA has continued to adopt GHG regulations of other industries, such as the March 2012 proposed GHG rule restricting future development of coal-fired power plants. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or

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regional greenhouse gas cap and trade programs. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas emissions. Most of these 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.

Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry. Currently, while we are subject to certain federal GHG monitoring and reporting requirements, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

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

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, or the NGA, exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission, or 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 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.

We rely on a few key employees whose absence or loss could adversely affect our business.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services could adversely affect our business. In particular, the loss of the services of one or more members of our new executive team, including our Chief Executive Officer, Travis D. Stice, could disrupt our operations. We have employment agreements with these executives which contain restrictions on competition with us in the event they cease to be employed by us. However, as a practical matter, such employment agreements may not assure the retention of our employees. Further, we do not maintain key person life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

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

Prior to the Gulfport transaction, Wexford beneficially owned 100% of our equity interests. Upon completion of this offering (including the purchase by Wexford or its affiliates of 1,717,126 shares of our common stock), Wexford will beneficially own approximately 46.7% of our common stock, or approximately 44.4% if the underwriters exercise in full their option to purchase additional shares. See *Principal Stockholders* beginning on page 140 of this prospectus. Further, we anticipate that several individuals who will serve as our directors upon completion of this offering will be affiliates of Wexford. We believe that Wexford s substantial ownership interest in us provides Wexford with an economic incentive to assist us to be successful. Upon the expiration of the lock-up restrictions on transfers or sales of our securities by or on behalf of DB Holdings following the completion of this offering, Wexford will not be subject to any obligation to maintain its ownership interest in us and may elect at any time thereafter to sell all or a substantial portion of or otherwise reduce its ownership interest in us. If Wexford sells all or a substantial portion of its ownership interest in us, Wexford may have less incentive to assist in our success and its affiliate(s) that are expected to serve as 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 also receive certain services, including drilling services from entities controlled by Wexford. These service contracts may generally be terminated on 30-days notice. In the event Wexford ceases to own a significant ownership interest in us, such services may not be available to us on terms acceptable to us, if at all.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment and adversely affect our business, financial condition or results of operations.

Our drilling activities are subject to many risks. For example, we cannot assure you that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond our control, and increases in those costs can adversely affect the economics of a project. Further, our drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

Historically, we have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, gas leaks, ruptures or discharges of toxic gases. In addition, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of operations and repairs to resume operations.

We endeavor to contractually allocate potential liabilities and risks between us and the parties that provide us with services and goods, which include pressure pumping and hydraulic fracturing, drilling and cementing services and tubular goods for surface, intermediate and production casing. Under our agreements with our vendors, to the extent responsibility for environmental liability is allocated between the parties, (i) our vendors generally assume all responsibility for control and removal of pollution or contamination which originates above the surface of the land and is directly associated with such vendors equipment while in their control and (ii) we generally assume the responsibility for control and removal of all other pollution or contamination which may occur during our operations, including pre-existing pollution and pollution which may result from fire, blowout, cratering, seepage or any other uncontrolled flow of oil, gas or other substances, as well as the use or disposition of all drilling fluids. In addition, we generally agree to indemnify our vendors for loss or destruction of vendor-owned property that occurs in the well hole (except for damage that occurs when a vendor is performing work on a footage, rather than day work, basis) or as a result of the use of equipment, certain corrosive fluids, additives, chemicals or proppants. However, despite this general allocation of risk, we might not succeed in enforcing such contractual allocation, might incur an unforeseen liability falling outside the scope of such allocation or may be required to enter into contractual arrangements with the terms that vary from the above allocations of risk. As a result, we may incur substantial losses which could materially and adversely affect our financial condition and results of operation.

In accordance with what we believe to be customary industry practice, we historically have maintained insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flow. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

Since hydraulic fracturing activities are part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if we are unaware of the pollution event and unable to report the occurrence to our insurance company within the time frame required under our insurance policy. We have no coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Our failure to successfully identify, complete and integrate future acquisitions of properties or businesses could reduce our earnings and slow our growth.

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently operate, which could result in unforeseen operating difficulties and difficulties in coordinating geographically dispersed operations, personnel and facilities. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Completed acquisitions could require us to invest further in operational, financial and management information systems and to attract, retain, motivate and effectively manage additional employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest.

Prior to the drilling of an oil or gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to succeed.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and 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 oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other 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 prospects and producing oil and natural gas properties.

Our use of 2-D and 3-D 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, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

We will be subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we are unable to timely comply with Section 404 or if the costs related to compliance are significant, our profitability, stock price and results of operations and financial condition could be materially adversely affected.

We will be required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act of 2002 as early as December 31, 2013. Section 404 requires that we document and test our internal control over financial reporting and issue management s assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm opine on those internal controls upon becoming a large accelerated filer, as defined in the SEC rules, or otherwise ceasing to qualify for an exemption from the requirement to provide auditors attestation on internal controls afforded to emerging growth companies under the Jumpstart Our Business Startups Act enacted by the U.S. Congress in April 2012. We are currently evaluating our existing controls against the standards adopted by the Committee of Sponsoring Organizations of the Treadway Commission. During the course of our ongoing evaluation and integration of the internal control over financial reporting, we may identify areas requiring improvement, and we may have to design enhanced processes and controls to address issues identified through this review. For example, we anticipate the need to hire additional administrative and accounting personnel to conduct our financial reporting.

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We believe that the out-of-pocket costs, the diversion of management s attention from running the day-to-day operations and operational changes caused by the need to comply with the requirements of Section 404 of the Sarbanes-Oxley Act could be significant. If the time and costs associated with such compliance exceed our current expectations, our results of operations could be adversely affected.

We cannot be certain at this time that we will be able to successfully complete the procedures, certification and attestation requirements of Section 404 or that we or our auditors will not identify material weaknesses in internal control over financial reporting. If we fail to comply with the requirements of Section 404 or if we or our auditors identify and report such material weaknesses, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We recorded compensation expense in 2011 and we may incur substantial additional compensation expense related to our future grants of stock compensation which may have a material negative impact on our operating results for the foreseeable future.

As a result of outstanding stock-based compensation awards, we recorded $0.5 million of compensation expense in 2011. In addition, our compensation expenses may increase in the future as compared to our historical expenses because of the costs associated with our existing and anticipated stock-based incentive plans. These additional expenses will adversely affect our net income. We cannot determine the actual amount of these new stock-related compensation and benefit expenses at this time because applicable accounting practices generally require that they be based on the fair market value of the options or shares of common stock at the date of the grant; however, they may be significant. We will recognize expenses for restricted stock awards and stock options generally over the vesting period of awards made to recipients.

Our level of indebtedness may increase and reduce our financial flexibility.

In the future, we may incur significant indebtedness in order to make future acquisitions or to develop our properties.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flows could be used to service our indebtedness;

- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;

- the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;

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- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt, and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

Our revolving credit facility contains restrictive covenants that may limit our ability to respond to changes in market conditions or pursue business opportunities.

Our revolving credit facility contains restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness;
- create additional liens;
- sell assets;
- merge or consolidate with another entity;
- pay dividends or make other distributions;
- engage in transactions with affiliates; and
- enter into certain swap agreements.

In addition, our revolving credit facility requires us to maintain certain financial ratios and tests. The requirement that we comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

If we are unable to comply with the restrictions and covenants in our revolving credit facility, there could be an event of default under the terms of our revolving credit facility, which could result in an acceleration of repayment.

If we are unable to comply with the restrictions and covenants in our revolving credit facility, there could be an event of default under the terms of this facility. Our ability to comply with these restrictions and covenants, including meeting the financial ratios and tests under our revolving credit facility, may be affected by events beyond our control. As a result, we cannot assure that we will be able to comply with these restrictions and covenants or meet such financial ratios and tests. In the event of a default under our revolving credit facility, the lenders could terminate their commitments to lend or accelerate the loans and declare all amounts borrowed due

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and payable. If any of these events occur, our assets might not be sufficient to repay in full all of our outstanding indebtedness and we may be unable to find alternative financing. Even if we could obtain alternative financing, it might not be on terms that are favorable or acceptable to us. Additionally, we may not be able to amend our revolving credit facility or obtain needed waivers on satisfactory terms.

Our borrowings under our revolving credit facility expose us to interest rate risk.

Our earnings are exposed to interest rate risk associated with borrowings under our revolving credit facility, which bear interest at a rate elected by us that is based on the prime, LIBOR or federal funds rate plus margins ranging from 1.25% to 3.50% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. As of September 30, 2012, the weighted average interest rate on outstanding borrowings under our revolving credit facility was 3.72%. If interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

Any significant reduction in our borrowing base under our revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Under our revolving credit facility, which currently provides for a $100.0 million borrowing base, we are subject to semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves. Our revolving credit facility currently provides that the borrowing base will remain at $100.0 million through July 15, 2013 or, if earlier, the closing date of this offering, at which time the borrowing base will be reduced to $90.0 million, subject to the periodic and elective borrowing base redeterminations discussed above, and without consideration of the impact of the Gulfport transaction and the Windsor UT properties. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise may negatively impact our liquidity and our ability to fund our operations and, as a result, may have a material adverse effect on our financial position, results of operation and cash flow.

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, 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.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Related to this Offering and Our Common Stock

Our two largest stockholders control a significant percentage of our common stock, and their interests may conflict with those of our other stockholders.

Upon completion of this offering (including the purchase by Wexford or its affiliates of 1,717,126 shares of our common stock), Wexford and Gulfport will beneficially own approximately 46.7% and 22.5%, respectively, of our common stock, or approximately 44.4% and 21.4%, respectively, if the underwriters exercise their option to purchase additional shares in full. See *Principal Stockholders* beginning on page 140 of this prospectus. In addition, individuals affiliated with Wexford and Gulfport serve on our Board of Directors, and Gulfport has the right to designate one individual as a nominee for election to our Board of Directors so long as it continues to beneficially own more than 10% of our outstanding common stock. As a result, Wexford and Gulfport, together, will be able to control, and Wexford alone will continue to be able to exercise significant influence over, matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. The interests of Wexford and Gulfport with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders. This continued concentrated ownership will make it impossible for another company to acquire us and for you to receive any related takeover premium for your shares unless Wexford approves the acquisition.

The corporate opportunity provisions in our certificate of incorporation could enable Wexford, our equity sponsor, or other affiliates of ours to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our certificate of incorporation, among other things:

- permits us to enter into transactions with entities in which one or more of our officers or directors are financially or otherwise interested;

- permits any of our stockholders, officers or directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and

- provides that if any director or officer of one of our affiliates who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to such affiliates and that director or officer will not be deemed to have (i) acted in a manner inconsistent with his or her fiduciary or other duties to us regarding the opportunity or (ii) acted in bad faith or in a manner inconsistent with our best interests.

These provisions create the possibility that a corporate opportunity that would otherwise be available to us may be used for the benefit of one of our affiliates.

We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies. As described under the caption *Related Party Transactions* beginning on page 134 of this prospectus, these include, among others, drilling services provided to us to Bison Drilling and Field Services, LLC, real property leased by us from Fasken Midland, LLC and certain administrative services provided to us by Everest Operations Management LLC. Each of these entites is either controlled by or affiliated with Wexford, and the resolution of any conflicts that may arise in connection with such related party transactions, including pricing, duration or other terms of service, may not always be in our or our stockholders best interests because Wexford may have the ability to influence the outcome of these conflicts. For a discussion of potential conflicts, see *Risks Related to this Offering and our Common Stock Our two largest stockholders control a significant percentage of our common stock, and their interests may conflict with those of our other stockholders* on page 39 of this prospectus.

We will incur increased costs as a result of being a public company, which may significantly affect our financial condition.

As a public company, we will incur significant legal, accounting and other expenses that we did not incur as a private company. We will incur costs associated with our public company reporting requirements. We also anticipate that we will incur costs associated with corporate governance requirements, including requirements under the Sarbanes-Oxley Act of 2002, as well as rules implemented by the SEC and the Financial Industry Regulatory Authority. We expect these rules and regulations to increase our legal and financial compliance costs and to make some activities more time-consuming and costly, particularly after we are no longer an emerging growth company. We also expect these rules and regulations may make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers. We are currently evaluating these rules, and we cannot predict or estimate the amount of additional costs we may incur or the timing of such costs.

However, for as long as we remain an emerging growth company as defined in the Jumpstart Our Business Startups Act of 2012, we intend to take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved. We intend to take advantage of these reporting exemptions until we are no longer an emerging growth company.

We will remain an emerging growth company for up to five years, although if the market value of our common stock that is held by non-affiliates exceeds $700 million as of any June 30 before that time, we would cease to be an emerging growth company as of the following December 31.

After we are no longer an emerging growth company, we expect to incur significant additional expenses and devote substantial management effort toward ensuring compliance with those requirements applicable to companies that are not emerging growth companies, including Section 404 of the Sarbanes-Oxley Act. See *Risks Related to the Oil and Natural Gas Industry and Our Business We will be subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we are unable to timely comply with Section 404 or if the costs related to compliance are significant, our profitability, stock price and results of operations and financial condition could be materially adversely affected* on page 36 of this prospectus.

We are an emerging growth company and we cannot be certain if the reduced disclosure requirements applicable to emerging growth companies will make our common stock less attractive to investors.

We are an emerging growth company, as defined in the Jumpstart our Business Startups Act of 2012, and we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies, including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved. We cannot predict if investors will find our common stock less attractive because we will rely on these exemptions. If some investors find our common stock less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

Under the Jumpstart Our Business Startups Act, emerging growth companies can delay adopting new or revised accounting standards until such time as those standards apply to private companies. We have irrevocably elected not to avail ourselves to this exemption from new or revised accounting standards and, therefore, we will be subject to the same new or revised accounting standards as other public companies that are not emerging growth companies.

There has been no public market for our common stock and if the price of our common stock fluctuates significantly, your investment could lose value.

Prior to this offering, there has been no public market for our common stock. Although we have applied to have our common stock listed on The NASDAQ Select Global Market, we cannot assure you that an active public market will develop for our common stock or that our common stock will trade in the public market subsequent to this offering at or above the initial public offering price. If an active public market for our common stock does not develop, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or float for our stock, the market price for our common stock may fluctuate significantly more than the stock market as a whole. Without a large float, our common stock is less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us. The initial offering price, which will be negotiated between us and the underwriters, may not be indicative of the trading price for our common stock after this offering. In addition, the stock market is subject to significant price and volume fluctuations, and the price of our common stock could fluctuate widely in response to several factors, including:

- our quarterly or annual operating results;
- changes in our earnings estimates;
- investment recommendations by securities analysts following our business or our industry;
- additions or departures of key personnel;
- changes in the business, earnings estimates or market perceptions of our competitors;
- our failure to achieve operating results consistent with securities analysts projections;
- changes in industry, general market or economic conditions; and
- announcements of legislative or regulatory change.

The stock market has experienced extreme price and volume fluctuations in recent years that have significantly affected the quoted prices of the securities of many companies, including companies in our industry. The changes often appear to occur without regard to specific operating performance. The price of our common stock could fluctuate based upon factors that have little or nothing to do with our company and these fluctuations could materially reduce our stock price.

Future sales of our common stock, or the perception that such future sales may occur, may cause our stock price to decline.

Sales of substantial amounts of our common stock in the public market after this offering, or the perception that these sales may occur, could cause the market price of our common stock to decline. See *Shares Eligible for Future Sale* on page 145 of this prospectus. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock. After this offering, we will have shares of common stock outstanding, excluding stock options. All of the shares sold in this offering, except for any shares purchased by our affiliates, will be freely tradable.

DB Holdings, Gulfport and our directors and executive officers will be subject to agreements that limit their ability to sell our common stock held by them. These holders cannot sell or otherwise dispose of any shares of our common stock for a period of at least 180 days after the date of this prospectus, which period may be extended under limited circumstances, without the prior written approval of Credit Suisse Securities (USA) LLC. However, these lock-up agreements are subject to certain specific exceptions, including transfers of common stock as a *bona fide* gift or by will or intestate succession and transfers to such person s immediate family or to a trust or to an entity controlled by such holder, provided that the recipient of the shares agrees to be bound by the same restrictions on sales. In the event that one or more of our stockholders sells a substantial amount of our common stock in the public market, or the market perceives that such sales may occur, the price of our stock could decline.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our stock or if our operating results do not meet their expectations, our stock price could decline.

Purchasers in this offering will experience immediate dilution and will experience further dilution with the future exercise of stock options granted to certain of our executive officers under their respective employment agreements.

The initial public offering price is substantially higher than the pro forma net tangible book value per share of our outstanding common stock. As a result, you will experience immediate and substantial dilution of approximately $4.95 per share, representing the difference between our net tangible book value per share as of June 30, 2012 after giving effect to this offering and the initial public offering price of $17.50. If the options granted to certain of our executive officers under their respective employment agreements are exercised in full, the investors in this offering will experience further dilution. See *Dilution* beginning on page 49 of this prospectus for a description of dilution.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of the company, which could adversely affect the price of our common stock.

The existence of some provisions in our certificate of incorporation and bylaws and Delaware corporate law could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders. Our certificate of incorporation and bylaws contain provisions that may make acquiring control of our company difficult, including:

- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders;

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- limitations on the ability of our stockholders to call a special meeting and act by written consent;

- the ability of our board of directors to adopt, amend or repeal bylaws, and the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained for stockholders to amend our bylaws;

- the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to remove directors;

- the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to amend our certificate of incorporation; and

- the authorization given to our board of directors to issue and set the terms of preferred stock without the approval of our stockholders.

These provisions also could discourage proxy contests and make it more difficult for you and other stockholders to elect directors and take other corporate actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

We do not intend to pay cash dividends on our common stock in the foreseeable future, and therefore only appreciation of the price of our common stock will provide a return to our stockholders.

We currently anticipate that we will retain all future earnings, if any, to finance the growth and development of our business. We do not intend to pay cash dividends in the foreseeable future. Any future determination as to the declaration and payment of cash dividends will be at the discretion of our board of directors and will depend upon our financial condition, results of operations, contractual restrictions capital requirements, business prospects and other factors deemed relevant by our board of directors. In addition, the terms of our credit facilities prohibit us from paying dividends and making other distributions. As a result, only appreciation of the price of our common stock, which may not occur, will provide a return to our stockholders.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about our:

- business strategy;
- exploration and development drilling prospects, inventories, projects and programs;
- oil and natural gas reserves;
- identified drilling locations;
- ability to obtain permits and governmental approvals;
- technology;
- financial strategy;
- realized oil and natural gas prices;
- production;
- lease operating expenses, general and administrative costs and finding and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this prospectus, are forward-looking statements. These forward-looking statements may be found in the *Prospectus Summary, Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations* and *Business* beginning on pages 1, 18, 61 and 90, respectively, and other sections of this prospectus. In some cases, you can identify forward-looking statements by terminology such as may, could, should, expect, plan, project, anticipate, believe, estimate, predict, potential, pursue, target, seek, objective or continue, the negative of such terms or other terminology.

The forward-looking statements contained in this prospectus are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, our management s assumptions about future events may prove to be inaccurate. Our management cautions all readers that the forward-looking statements contained in this prospectus are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the many factors including those described in the *Risk Factors* section and elsewhere in this prospectus. All forward-looking statements speak only as of the date of this prospectus. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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USE OF PROCEEDS

Our net proceeds from the sale of 12,500,000 shares of common stock in this offering are estimated to be approximately $204.6 million, after deducting underwriting discounts and commissions and estimated offering expenses. The net proceeds would be approximately $235.3 million if the underwriters option to purchase additional shares is exercised in full. Following the closing of this offering, we intend to use:

- $100.0 million of the net proceeds to repay the outstanding borrowings under our revolving credit facility;
- approximately $63.6 million to repay the Gulfport transaction note;
- $30.0 million to repay the outstanding borrowings under our subordinated note with an affiliate of Wexford; and
- approximately $8.4 million to settle the existing crude oil swaps.

We intend to use the balance of the proceeds from this offering to fund a portion of our exploration and development activities and for general corporate purposes, which may include leasehold interest and property acquisitions, working capital and the post-closing cash adjustment payable to Gulfport under the terms of the Gulfport transaction. Upon repayment of the outstanding borrowings under our revolving credit facility, we will have $90.0 million of borrowing capacity under that facility to further fund our exploration and development activities and for general corporate purposes.

All borrowings under our revolving credit facility are due and payable on October 15, 2014. As of September 30, 2012, $100.0 million was outstanding under our revolving credit facility and bore interest at a weighted average rate of 3.72% per annum. The amounts initially borrowed under our revolving credit facility were used to repay in full the outstanding indebtedness under our prior credit facility and for general corporate purposes. The Gulfport transaction note, which will be issued immediately prior to the effectiveness of the registration statement relating to this prospectus in connection with the Gulfport transaction, is due upon completion of this offering and does not bear interest unless it is not paid when due.

All borrowings under our subordinated note are due and payable on January 31, 2015 or the earlier completion of this offering. On May 14, 2012, we received an initial advance of $8.1 million under this note which provides for aggregate outstanding borrowings of up to $45.0 million. On September 30, 2012, $30.0 million was outstanding under this note. The note bears interest at a rate equal to LIBOR plus 0.28% or 8% per annum, whichever is lower. Our borrowings under the subordinated note were used to fund our 2012 drilling program and for general corporate purposes.

DIVIDEND POLICY

We have never declared or paid any cash dividends on our capital stock. We currently intend to retain all available funds and any future earnings for use in the operation and expansion of our business and do not anticipate declaring or paying any cash dividends in the foreseeable future. Any future determination as to the declaration and payment of dividends will be at the discretion of our board of directors and will depend on then-existing conditions, including our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors that our board of directors considers relevant. In addition, the terms of our revolving credit facility restrict the payment of dividends to the holders of our common stock and any other equity holders.

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CAPITALIZATION

The following table sets forth our cash and cash equivalents and capitalization as of June 30, 2012:

on an actual basis;

on a pro forma basis to give effect to (a) the issuance of 14,697,496 shares of our common stock to an affiliate of Wexford in the merger of Diamondback Energy LLC with and into Diamondback Energy, Inc., (b) the issuance of 7,914,036 shares of our common stock and the Gulfport transaction note to Gulfport in connection with the Gulfport transaction and (c) the Windsor UT contribution; and

on a pro forma basis described above as adjusted to give effect to the sale of shares of our common stock in this offering (including the shares being purchased by Wexford or its affiliates) at an initial public offering price of $17.50 per share, our receipt of an estimated $204.6 million of net proceeds from this offering after deducting underwriting discounts and commissions and estimated offering expenses and the use of a portion of those proceeds to repay outstanding borrowings as described under the caption *Use of Proceeds* on page 46 of this prospectus.

You should read the following table in conjunction with *Management s Discussion and Analysis of Financial Condition and Results of Operations* beginning on page 61 and our consolidated financial statements and related notes appearing elsewhere in this prospectus.

	As of June 30, 2012		
	Actual[1]	Pro Forma	Pro Forma As Adjusted
		(in thousands)	
Cash and cash equivalents	$ 2,067	$ 2,342	$ 20,826[3]
Debt:			
Revolving credit facility	$ 100,000	$ 100,000	$
Note payable-Wexford[2]	14,110	14,110	
Note payable-Gulfport		63,590	
Note payable-other	411	411	411
Total debt	114,521	178,111	411
Member s equity	123,874		
Stockholders equity:			
Common stock, par value $0.01; 100 shares authorized and 100 shares issued and outstanding actual; 100,000,000 shares authorized and 22,611,532 shares issued and outstanding pro forma; and 100,000,000 shares authorized and 35,111,532 shares issued and outstanding pro forma as adjusted		226	351
Additional paid-in capital		276,493	480,952
Accumulated deficit[4]		(39,541)	(39,541)
Total stockholders equity		237,178	441,762
Total capitalization	$ 238,395	$ 415,289	$ 442,173

(1)

Diamondback Energy, Inc. was incorporated on December 30, 2011 in Delaware as a holding company and will not conduct any material business operations prior to the completion of the offering. The data in this table has been derived from the historical consolidated financial statements and other financial information included in this prospectus which pertain to the assets, liabilities, revenues and expenses of Windsor Permian LLC. Immediately prior to the effectiveness of the registration statement relating to this prospectus, Windsor Permian LLC became our wholly-owned subsidiary.

(2) At September 30, 2012, long term debt was $130.4 million, which consists primarily of $30.0 million in borrowings under our subordinated note with an affiliate of Wexford and $100.0 million in borrowings under our revolving credit facility.

(3) Does not reflect the repayment of an additional $15.9 million in borrowings under our subordinated note with an affiliate of Wexford borrowed subsequent to June 30, 2012, which repayment will reduce cash and cash equivalents. See *Use of Proceeds* on page 46 of this prospectus.

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(4) Upon completion of the merger of Diamondback Energy LLC with and into Diamondback Energy, Inc. and the Windsor UT contributions, we will recognize deferred tax liabilities and assets for temporary differences between the historical cost basis and tax basis of our assets and liabilities. Based on estimates of those temporary differences as of June 30, 2012, a net deferred tax liability of approximately \$39.5 million will be recognized with a corresponding charge to earnings.

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DILUTION

Our reported net tangible book value as of June 30, 2012 was $235.2 million, or $10.40 per share, based upon shares outstanding as of that date after giving pro forma effect to (a) the merger of Diamondback Energy LLC with and into Diamondback Energy, Inc., (b) the Gulfport transaction and (c) the Windsor UT contribution. Net tangible book value per share is determined by dividing such number of outstanding shares of common stock into our net tangible book value, which is our total tangible assets less total liabilities. After the sale by us of 12,500,000 shares of common stock offered in this offering at the initial public offering price of $17.50 per share and after deducting the underwriting discounts and commissions and estimated offering expenses payable by us, our net tangible book value as of June 30, 2012 would have been approximately $440.7 million, or $12.55 per share, after giving pro forma effect to (a) the merger of Diamondback Energy LLC with and into Diamondback Energy, Inc. (b) to the Gulfport transaction and (c) the Windsor UT contribution. This represents an immediate increase in net tangible book value of $2.15 per share to our existing stockholders and an immediate dilution of $4.95 per share to new investors purchasing shares at the initial public offering price.

The following table illustrates the per share dilution:

Initial public offering price per share		$ 17.50
Pro forma net tangible book value per share as of June 30, 2012	$ 10.40	
Increase per share attributable to new investors	$ 2.15	
As adjusted net tangible book value per share after the offering		$ 12.55
Dilution per share to new investors		$ 4.95

The following table sets forth, as of June 30, 2012, after giving pro forma effect to the merger of Diamondback Energy LLC with and into Diamondback Energy, Inc., the Gulfport transaction and the Windsor UT contribution, the number of shares of common stock issued by us to DB Holdings and Gulfport, which will be our existing stockholders immediately prior to the closing of this offering, and by the new investors at the initial public offering price of $17.50 per share, together with the total consideration paid and average price per share paid by each of these groups, before deducting underwriting discounts and commissions and estimated offering expenses.

	Shares Purchased		Total Consideration		Average Price
	Number	Percent	Amount	Percent	Per Share
Existing stockholders	22,611,532	64.4%	$ 353,801,632	61.8%	$ 15.65
New investors	12,500,000	35.6%	218,750,000	38.2%	17.50
Total	35,111,532	100.0%	$ 572,551,632	100.0%	$ 16.31

If the underwriters option to purchase additional shares is exercised in full, the number of shares held by new investors will be increased to 14,375,000, or approximately 38.9% of the total number of shares of common stock. The shares attributable to new investors include 1,717,126 shares being purchased by Wexford or its affiliates in this offering at the same price as the price to the public.

The data in the table excludes 2,500,000 shares of common stock reserved for issuance under our equity incentive plan, including, based on the initial public offering price of $17.50 per share:

245,716 restricted stock units to be issued to certain employees following the closing of this offering under the terms of their employment agreements, of which 57,143 will be vested on the closing date of this offering;

33,330 restricted stock units to be issued to our non-employee directors following the closing of this offering as part of their director compensation, of which 11,110 will be vested on the closing date of this offering; and

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options to purchase 850,000 shares of our common stock to be granted to certain employees following the closing of this offering under the terms of their employment agreements, of which options to purchase 200,000 shares will be vested on the closing date of this offering.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following selected historical consolidated financial data as of December 31, 2011 and 2010 and for each of the years in the three-year period ended December 31, 2011 are derived from our audited consolidated financial statements included elsewhere in this prospectus. The selected consolidated balance sheet data as of December 31, 2009 and 2008 and the selected historical consolidated financial data for 2008 and the period from inception on October 23, 2007 to December 31, 2007 are derived from our audited financial statements not included in this prospectus. The balance sheet data as of December 31, 2007 is derived from our unaudited financial statements not included in this prospectus. The summary consolidated financial data as of June 30, 2012 and for the six months ended June 30, 2012 and 2011 are derived from our historical unaudited consolidated financial statements included elsewhere in this prospectus. The summary consolidated balance sheet data as of June 30, 2011 are derived from our unaudited consolidated balance sheet as of such date, which is not included in this prospectus. The unaudited pro forma data presented gives effect to income taxes assuming that the Company operated as a taxable corporation throughout the periods presented. Operating results for the periods ended December 31, 2011, 2010, 2009, 2008 and 2007 and the six months ended June 30, 2012 and 2011 are not necessarily indicative of results that may be expected for any future periods. You should review this information together with *Management s Discussion and Analysis of Financial Condition and Results of Operations* beginning on page 61 and our historical consolidated financial statements and related notes included elsewhere in this prospectus.

	Six Months Ended June 30,		Year Ended December 31,				Period from Inception (October 23, 2007) to December 31,
	2012	2011	2011	2010	2009	2008	2007
Statement of Operations Data:							
Oil and natural gas revenues	$ 31,757,923	$ 22,038,729	$ 47,180,802	$ 26,441,927	$ 12,716,011	$ 18,238,692	$ 578,336
Other revenues		1,490,910	1,490,910	811,247			
Expenses:							
Lease operating expense	6,134,714	4,283,671	10,345,355	4,588,559	2,366,623	3,375,419	25,684
Production taxes	1,550,154	1,093,899	2,333,853	1,346,879	663,068	1,008,991	136,077
Gathering and transportation	146,320	85,944	201,828	105,870	42,091	53,407	2,637
Oil and natural gas services		1,732,892	1,732,892	811,247			
Depreciation, depletion and amortization	10,235,730	7,441,366	15,402,826	8,145,143	3,215,891	10,199,581	138,066
Impairment of oil and gas properties						83,164,230	
General and administrative	2,815,051	1,421,313	3,603,479	3,051,627	5,062,618	5,459,874	6,609
Asset retirement obligation accretion expense	40,195	28,736	63,259	37,856	27,934	23,569	514
Total expenses	20,922,164	16,087,821	33,683,492	18,087,181	11,378,225	103,285,071	309,587
Income (loss) from operations	10,835,759	7,441,818	14,988,220	9,165,993	1,337,786	(85,046,379)	268,749
Other income (expense):							
Interest income	2,004	6,988	11,197	34,474	35,075	625,086	23,581
Interest expense	(2,053,706)	(1,097,053)	(2,528,058)	(836,265)	(10,938)		
Other income	1,058,043						
Gain (loss) on derivative contracts	5,164,987	(28,181)	(13,009,393)	(147,983)	(4,068,005)	(9,528,220)	(4,791,587)
Loss from equity investment	(66,654)		(7,017)				
Total other income (expense), net	4,104,674	(1,118,246)	(15,533,271)	(949,774)	(4,043,868)	(8,903,134)	(4,768,006)
Net income (loss)	$ 14,940,433	$ 6,323,572	$ (545,051)	$ 8,216,219	$ (2,706,082)	$ (93,949,513)	$ (4,499,257)

Pro Forma C Corporation Data:[(1)]							
Net income (loss) before income taxes	$ 14,940,433	$ 6,323,572	$ (545,051)	$ 8,216,219	$ (2,706,082)	$ (93,949,513)	$ (4,499,257)
Pro forma for income taxes							
Pro forma net income (loss)	$ 14,940,433	$ 6,323,572	$ (545,051)	$ 8,216,219	$ (2,706,082)	$ (93,949,513)	$ (4,499,257)
Pro forma income (loss) per common share basic and diluted[(2)]	$ 1.07		$ (0.04)				
Weighted average pro forma shares outstanding basic and diluted[(2)]	14,000,000		14,000,000				

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	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008	Period from Inception (October 23, 2007) to December 31, 2007
Selected Cash Flow and Other Financial Data:							
Net income (loss)	$ 14,940,433	$ 6,323,572	$ (545,051)	$ 8,216,219	$ (2,706,082)	$ (93,949,513)	$ (4,499,257)
Depreciation, depletion and amortization	10,235,730	7,943,855	15,905,315	8,145,143	3,215,891	10,199,581	138,066
Other non-cash items	(4,273,541)	177,309	13,844,010	344,461	4,108,464	92,716,019	4,792,101
Change in operating assets and liabilities	1,406,699	(925,350)	1,179,920	(11,529,999)	(1,916,707)	3,076,317	(2,448,557)
Net cash provided by (used in) operating activities	$ 22,309,321	$ 13,519,386	$ 30,384,194	$ 5,175,824	$ 2,701,566	$ 12,042,404	$ (2,017,647)
Net cash used in investing activities	$ (59,382,142)	$ (38,363,561)	$ (76,314,042)	$ (53,134,641)	$ (32,149,617)	$ (84,196,562)	$ (86,863,149)
Net cash provided by financing activities	$ 32,337,149	$ 23,292,499	$ 48,642,492	$ 49,618,254	$ 23,849,250	$ 80,182,600	$ 88,881,463

	As of June 30, 2012	As of June 30, 2011	As of December 31, 2011	As of December 31, 2010	As of December 31, 2009	As of December 31, 2008	As of December 31, 2007
Balance sheet data:							
Cash and cash equivalents	$ 2,066,717	$ 2,538,068	$ 6,802,389	$ 4,089,745	$ 2,430,308	$ 8,029,109	$ 667
Other current assets	23,197,048	23,855,341	24,130,450	20,947,659	2,263,097	1,389,810	2,489,231
Oil and gas properties, net using full cost method of accounting	254,189,321	164,635,560	206,342,604	135,782,510	89,777,517	73,786,284	83,375,502
Well equipment to be used in development of oil and gas properties					5,413,310	8,503,178	
Other property and equipment, net	1,540,452	3,435,130	684,015	11,059,220	105,564	161,103	
Other assets	1,997,772	12,286,037	11,524,427	637,562	82,813		
Total assets	$ 282,991,310	$ 206,750,136	$ 249,483,885	$ 172,516,696	$ 100,072,609	$ 91,869,484	$ 85,865,400
Current liabilities	$ 51,806,938	$ 23,996,533	$ 42,418,305	$ 20,010,276	$ 13,972,080	$ 18,011,452	$ 126,757
Note payable-long term	338,560						
Note payable-credit facility-long term	90,000,000	68,400,000	85,000,000	44,766,687			
Note payable-related party-long term	14,109,782						
Derivative contracts-long term	1,666,639	1,498,517	6,138,573	1,373,864	1,416,431	2,868,452	1,141,587
Asset retirement obligations	1,195,662	893,471	1,079,725	727,826	481,887	374,287	214,850
Members equity	123,873,729	111,961,615	114,847,282	105,638,043	84,202,211	70,615,293	84,382,206
Total liabilities and members equity	$ 282,991,310	$ 206,750,136	$ 249,483,885	$ 172,516,696	$ 100,072,609	$ 91,869,484	$ 85,865,400

	Six Months Ended June 30,		Year Ended December 31,				Period from Inception (October 23, 2007) to December 31,
	2012	2011	2011	2010	2009	2008	2007
Other financial data:							
Adjusted EBITDA[3]	$ 22,687,298	$ 15,421,397	$ 31,505,264	$ 17,383,466	$ 4,616,686	$ 8,966,087	$ 430,910

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(1) Diamondback Energy, Inc. was incorporated on December 30, 2011 in Delaware as a holding company and will not conduct any material business operations prior to the transaction described below. Our historical consolidated financial statements and other financial information included in this prospectus pertain to assets, liabilities, revenues and expenses of Windsor Permian LLC, which is an entity controlled by our equity sponsor, Wexford. Windsor Permian LLC was treated as a partnership for federal income tax purposes. As a result, essentially all of Windsor Permian LLC s taxable earnings and losses were passed through to Wexford, and Windsor Permian LLC did not pay federal income taxes at the entity level. Prior to the effectiveness of the registration statement relating to this prospectus, Windsor Permian LLC became our wholly-owned subsidiary and, because we are a subchapter C corporation under the Internal Revenue Code, the earnings at Windsor Permian LLC will prospectively become subject to federal income tax. For comparative purposes, we have included pro forma financial data to give effect to income taxes assuming the earnings of Windsor Permian LLC had been subject to federal income tax as a subchapter C corporation since inception. If the earnings of Windsor Permian LLC had been subject to federal income tax as a subchapter C corporation since inception, we would have incurred net operating losses for income tax purposes in each period. We would have been in a net deferred tax asset, or DTA, position as a result of such tax losses and would have recorded a valuation allowance to reduce each period s DTA balance to zero. A valuation allowance to reduce each period s DTA would have resulted in an equal and offsetting credit for the respective expenses or an equal and offsetting debit for the respective benefits for income taxes, with the resulting tax expenses for each of the above periods of zero. The unaudited pro forma data is presented for informational purposes only, and does not purport to project our results of operations for any future period or our financial position as of any future date.

(2) Unaudited pro forma basic and diluted income (loss) per share has been presented for the latest fiscal year and interim period on the basis of the aggregate number of shares attributable to Windsor Permian LLC issued to DB Holdings in connection with the merger of Diamondback Energy LLC with and into Diamondback Energy, Inc.

(3) Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDA as net income (loss) before loss on derivative contracts, interest expense, depreciation, depletion and amortization, impairment of oil and gas properties, non-cash equity based compensation and asset retirement obligation accretion expense. Adjusted EBITDA is not a measure of net income (loss) as determined by United States generally accepted accounting principles, or GAAP. Management believes Adjusted EBITDA is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measure of other companies or to such measure in our credit facility.

The following tables present a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measure of net income (loss).

	Six Months Ended June 30,		**Year Ended December 31,**				**Period from Inception (October 23, 2007) to December 31,**
	2012	**2011**	**2011**	**2010**	**2009**	**2008**	**2007**
Reconciliation of Adjusted EBITDA to net income (loss):							
Net income (loss)	$ 14,940,433	$ 6,323,572	$ (545,051)	$ 8,216,219	$ (2,706,082)	$ (93,949,513)	$ (4,499,257)
Gain (loss) on derivative contracts	(5,164,987)	28,181	13,009,393	147,983	4,068,005	9,528,220	4,791,587
Interest expense	2,053,706	1,097,053	2,528,058	836,265	10,938		
Depreciation, depletion and amortization	10,235,730	7,943,855	15,905,315	8,145,143	3,215,891	10,199,581	138,066
Impairment of oil and gas properties						83,164,230	
Equity-based compensation expense	582,221		544,290				

Asset retirement obligation accretion expense	40,195	28,736	63,259	37,856	27,934	23,569	514
Adjusted EBITDA	$ 22,687,298	$ 15,421,397	$ 31,505,264	$ 17,383,466	$ 4,616,686	$ 8,966,087	$ 430,910

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UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Diamondback Energy, Inc.

Unaudited Pro Forma Condensed Consolidated Financial Statements

Introduction

The following unaudited pro forma condensed consolidated financial statements and related notes of the Company have been prepared to show the effect of the Transactions and the distribution by Windsor Permian to its equity holders of its minority equity interests in Bison and Muskie. The unaudited pro forma condensed consolidated financial statements should be read together with the historical financial statements of Windsor Permian and Windsor UT and the historical Statements of Revenues and Direct Operating Expenses of certain property interests of Gulfport Energy Corporation included in this prospectus. The accompanying unaudited pro forma condensed consolidated financial statements are based on assumptions and include adjustments as explained in the accompanying notes.

The acquisition of certain property interests of Gulfport Energy Corporation (the Gulfport properties) will be treated as a business combination accounted for under the acquisition method of accounting with the identifiable assets recognized at fair value on the date of transfer.

The Windsor UT contribution is treated as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in the accounts of the transferring entity at the date of transfer.

The pro forma data presented reflect events directly attributable to the Transactions and other described transactions and certain assumptions the Company believes are reasonable. The pro forma data are not necessarily indicative of financial results that would have been attained had the described transactions occurred on the dates indicated below. The pro forma data also necessarily exclude various operation expenses related to the Gulfport properties and the financial statements should not be viewed as indicative of operations in future periods. As the current operator of the properties acquired by the Company upon completion of the Gulfport transaction and the Windsor UT contribution, the Company does not expect any material impact from these transactions on its existing employees or infrastructure.

The Transactions were completed immediately prior to the effectiveness of the registration statement relating to this prospectus and the distribution of the equity interests in Bison and Muskie occurred in June 2012.

The unaudited pro forma condensed consolidated balance sheet assumes that the Transactions occurred on June 30, 2012. The unaudited pro forma condensed consolidated statements of operations for the year ended December 31, 2011 and for the six months ended June 30, 2012 assume that the Transactions and other described transactions occurred on January 1, 2011.

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Diamondback Energy, Inc.

Unaudited Pro Forma Condensed Consolidated Balance Sheet

June 30, 2012

Assets	Windsor Permian Historical	Windsor UT Historical	Pro Forma Adjustments	Pro Forma
Cash and cash equivalents	$ 2,066,717	$ 274,749		$ 2,341,466
Other current assets	23,197,048	70,285		23,267,333
Total current assets	25,263,765	345,034		25,608,799
Oil and natural gas properties, net using full cost method of accounting	254,189,321	14,162,818	225,786,010[(a)]	494,138,149
Other property and equipment	1,540,452			1,540,452
Other assets	1,997,772			1,997,772
Total assets	$ 282,991,310	$ 14,507,852	$ 225,786,010	$ 523,285,172
Liabilities and Members /Stockholders Equity				
Current liabilities	$ 51,806,938	$ 132,864	$ 72,075,132[(a)]	$ 124,014,934
Note payable-long term	338,560			338,560
Note payable-credit facility-long term	90,000,000			90,000,000
Note payable-related party-long term	14,109,782			14,109,782
Derivative contracts-long term	1,666,639			1,666,639
Asset retirement obligations	1,195,662	25,167	679,006[(c)]	1,899,835
Deferred income taxes			54,077,259[(e)]	54,077,259
Members /stockholders equity	123,873,729	14,349,821	98,954,613[(a)(e)]	237,178,163
Total liabilities and members /stockholders equity	$ 282,991,310	$ 14,507,852	$ 225,786,010	$ 523,285,172

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

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Diamondback Energy, Inc.

Unaudited Pro Forma Condensed Consolidated Statement of Operations

Year ended December 31, 2011

	Windsor Permian Historical	Gulfport Transaction Historical	Windsor UT Historical	Pro Forma Adjustments	Pro Forma
Revenues:					
Oil and natural gas revenues	$ 47,180,802	$ 23,052,000	$ 694,666	$	$ 70,927,468
Oil and natural gas services	1,490,910			(1,490,910)[(b)]	
Total revenues	48,671,712	23,052,000	694,666	(1,490,910)	70,927,468
Costs and expenses:					
Lease operating expenses	10,345,355	5,484,000	251,824		16,081,179
Production taxes	2,333,853	1,276,000	32,016		3,641,869
Gathering and transportation	201,828				201,828
Oil and natural gas services	1,732,892			(1,732,892)[(b)]	
Depreciation, depletion and amortization	15,402,826		198,712	8,060,000[(d)]	23,661,538
General and administrative expenses	3,603,479		37,044	(118,292)	3,522,231
Asset retirement obligation accretion expense	63,259		1,255	38,893[(c)]	103,407
Total costs and expenses	33,683,492	6,760,000	520,851	6,247,709	47,212,052
Income from operations	14,988,220	16,292,000	173,815	(7,738,619)	23,715,416
Other income (expense)					
Interest income	11,197				11,197
Interest expense	(2,528,058)				(2,528,058)
Loss on derivative contracts	(13,009,393)				(13,009,393)
Loss from equity investment	(7,017)			7,017[(b)]	
Total other expense, net	(15,533,271)			7,017	(15,526,254)
Net income (loss)	$ (545,051)	$ 16,292,000	$ 173,815	$ (7,731,602)	$ 8,189,162
Pro forma income before income taxes					$ 8,189,162
Pro forma for income taxes[(f)]					2,919,436
Pro forma net income					$ 5,269,726
Pro forma income per common share basic and diluted[(g)]					$ 0.23
Weighted average pro forma shares outstanding basic and diluted[(g)]					22,611,532

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

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Diamondback Energy, Inc.

Unaudited Pro Forma Condensed Consolidated Statement of Operations

Six Months ended June 30, 2012

	Windsor Permian Historical	Gulfport Transaction Historical	Windsor UT Historical	Pro Forma Adjustments	Pro Forma
Revenues:					
Oil and natural gas revenues	$ 31,757,923	$ 14,192,000	$ 622,697	$	$ 46,572,620
Costs and expenses:					
Lease operating expenses	6,134,714	3,914,000	183,443		10,232,157
Production taxes	1,550,154	735,000	28,699		2,313,853
Gathering and transportation	146,320				146,320
Depreciation, depletion and amortization	10,235,730		179,956	4,872,000[(d)]	15,287,686
General and administrative expenses	2,815,051		69,226		2,884,277
Asset retirement obligation accretion expense	40,195		900	24,174[(c)]	65,269
Total costs and expenses	20,922,164	4,649,000	462,224	4,896,174	30,929,562
Income from operations	10,835,759	9,543,000	160,473	(4,896,174)	15,643,058
Other income (expense)					
Interest income	2,004				2,004
Interest expense	(2,053,706)				(2,053,706)
Other income	1,058,043				1,058,043
Gain on derivative contracts	5,164,987				5,164,987
Loss from equity investment	(66,654)			66,654[(b)]	
Total other income (expense), net	4,104,674			66,654	4,171,328
Net income	$ 14,940,433	$ 9,543,000	$ 160,473	$ (4,829,520)	$ 19,814,386
Pro forma income before income taxes					19,814,386
Pro forma for income taxes[(f)]					7,063,829
Pro forma net income					$ 12,750,557
Pro forma income per common share basic and diluted[(g)]					$ 0.56
Weighted average pro forma shares outstanding basic and diluted[(g)]					22,611,532

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

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Diamondback Energy, Inc.

Notes to Unaudited Pro Forma Condensed Consolidated

Financial Statements

1. Basis of Presentation

The historical financial information is derived from the historical financial statements of Windsor Permian and Windsor UT and the historical statements of revenues and direct operating expenses of certain property interests of Gulfport Energy Corporation. The unaudited pro forma condensed consolidated balance sheet as of June 30, 2012 has been prepared as if the Transactions had taken place on June 30, 2012. The unaudited pro forma condensed consolidated statements of operations for the year ended December 31, 2011 and the six months ended June 30, 2012 assume that the Transactions and other described transactions had occurred on January 1, 2011.

2. Pro Forma Assumptions and Adjustments

We made the following adjustments in the preparation of the unaudited pro forma condensed consolidated financial statements.

(a) To record the acquisition of the Gulfport properties at fair value for approximately $225.8 million for 7,914,036 shares of our common stock valued at the initial public offering price of $17.50 per share, which will represent 35% of our outstanding common stock immediately prior to the closing of this offering, and $63,590,050 in the form of a non-interest bearing promissory note that will be repaid in full upon the closing of this offering. The aggregate consideration payable to Gulfport is subject to a post-closing cash adjustment which amount, when calculated at June 30, 2012 for purposes of these pro forma condensed consolidated financial statements only, was $8,485,082. The allocation of the purchase price to the assets acquired and the cash adjustment amount are preliminary and, therefore, subject to change.

(b) To record the effects of the distribution of minority equity interests in Bison and Muskie to Windsor Permian s sole member which occurred on June 15, 2012.

(c) To record incremental asset retirement obligation and related accretion of discount associated with the Gulfport transaction.

(d) To record incremental depletion, depreciation, and amortization of oil and natural gas properties associated with the Transactions, amortized on a unit-of-production basis over the remaining life of total proved reserves, as applicable, due to the following:

	Six Months Ended June 30, 2012	Year Ended December 31, 2011
Purchase accounting basis adjustment for Gulfport properties	$ 1,596,000	2,685,000
Using a larger quantity of reserves in the units of production computation	3,276,000	5,375,000
Total incremental depletion, depreciation and amortization	$ 4,872,000	$ 8,060,000

(e) To record estimated net deferred tax liabilities for temporary differences between the historical cost basis and tax basis of our assets and liabilities as the result of our change in tax status to a subchapter C corporation of approximately $39.5 million. A corresponding charge to earnings has not been reflected in the pro forma Statement of Operations, as the charge is considered non-recurring. Also to record estimated net deferred tax liabilities resulting from the Gulfport transaction of approximately $14.5 million.

(f) To record the effect of income taxes assuming earnings had been subject to federal income tax as a subchapter C corporation, effective January 1, 2011.

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Diamondback Energy, Inc.

Notes to Unaudited Pro Forma Condensed Consolidated

Financial Statements

(g) To report basic and diluted income per share on the basis of the aggregate number of shares to be issued in connection with the Gulfport transaction and to DB Holdings in connection with the merger of Diamondback Energy LLC with and into Diamondback Energy, Inc. and the Windsor UT contribution.

3. Oil and Natural Gas Producing Activities

The following table presents estimated unaudited pro forma volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2011 and changes in proved reserves during the year, assuming continuation of economic conditions prevailing at the end of the year. The weighted average prices at December 31, 2011 used for reserve report purposes are $93.09 per Bbl of oil, $56.62 per Bbl of natural gas liquids and $3.96 per Mcf of natural gas, respectively.

The Company emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data.

	Year Ended December 31, 2011											
	Windsor Permian Historical			Gulfport Transaction Historical			Windsor UT Historical			Total Pro Forma		
	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)
Proved Developed and Undeveloped Reserves:												
As of January 1, 2011	18,819	5,564	21,663	9,358	3,107	11,926	811	269	1,033	28,988	8,940	34,621
Extensions, discoveries and other additions	1,706	448	1,824	764	217	992	94	18	60	2,564	683	2,876
Revisions of prior reserve estimates	(3,366)	(1,162)	(3,454)	(1,828)	(474)	(599)	487	(1)	(160)	(4,707)	(1,637)	(4,213)
Production	(442)	(87)	(413)	(208)	(59)	(273)	(8)			(658)	(146)	(686)
As of December 31, 2011	16,717	4,763	19,620	8,086	2,791	12,046	1,384	286	933	26,187	7,840	32,598
Proved Developed Reserves:												
January 1, 2011	3,308	1,105	4,255	1,840	794	3,048	64	21	82	5,212	1,920	7,385
December 31, 2011	3,805	1,233	5,187	2,097	706	3,050	144	30	99	6,046	1,969	8,336
Proved Undeveloped Reserves:												
January 1, 2011	15,511	4,459	17,407	7,518	2,313	8,878	747	248	951	23,776	7,020	27,236
December 31, 2011	12,912	3,530	14,432	5,989	2,085	8,996	1,240	256	834	20,141	5,871	24,262

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Diamondback Energy, Inc.

Notes to Unaudited Pro Forma Condensed Consolidated

Financial Statements

The following pro forma standardized measure of discounted estimated future net cash flows and changes therein relating to the combined proved oil and natural gas reserves of Windsor Permian and the Transactions as of and for the year ended December 31, 2011 were made in accordance with the provisions of the FASB ASU 2010-03, Extractive Activities Oil and Gas (Topic 932).

	Year Ended December 31, 2011				
	Windsor Permian Historical	Gulfport Transaction Historical	Windsor UT Historical	Pro Forma Adjustments	Total Pro Forma
Future cash flows	$ 1,900,958,750	$ 960,918,000	$ 148,561,281	$	$ 3,010,438,031
Future development costs	(373,750,281)	(236,336,000)	(36,600,000)		(646,686,281)
Future production costs	(458,936,062)	(166,899,000)	(38,872,202)		(664,707,264)
Future production taxes	(97,444,617)	(50,235,000)	(7,410,910)		(155,090,527)
Future income taxes				(500,721,253)	(500,721,253)
Future net cash flows	970,827,790	507,448,000	65,678,169	(500,721,253)	1,043,232,706
10% discount to reflect timing of cash flows	(623,808,665)	(305,160,000)	(48,085,065)	316,869,273	(660,184,457)
Standardized measure of discounted future net cash flows	$ 347,019,125	$ 202,288,000	$ 17,593,104	$ (183,851,980)	$ 383,048,249

The primary changes in the pro forma standardized measure of discounted estimated future net cash flows were as follows for 2011:

	Year Ended December 31, 2011				
	Windsor Permian Historical	Gulfport Transaction Historical	Windsor UT Historical	Pro Forma Adjustments	Total Pro Forma
Sales and transfers of oil and gas produced, net of production costs	$ (34,299,766)	$ (16,292,000)	$ (410,826)	$	$ (51,002,592)
Net changes in prices and production costs and development costs	86,655,407	48,089,000	383,765		135,128,172
Extension and discoveries	69,375,680	29,432,000	4,195,434		103,003,114
Revisions of previous quantity estimates, less related production costs	(100,433,225)	(71,088,000)	1,899,993		(169,621,232)
Accretion of discount	33,035,782	16,211,000	864,314		50,111,096
Change in production rates and other	(37,672,573)	33,830,000	2,017,284		(1,825,289)
Acquisition of Gulfport properties				162,106,000	162,106,000
Contribution of Windsor UT				8,643,140	8,643,140
Net change in income taxes				(70,742,868)	(70,742,868)
Total change in standardized measure of discounted future net cash flows	$ 16,661,305	$ 40,182,000	$ 8,949,964	$ 100,006,272	$ 165,799,541

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MANAGEMENT S DISCUSSION AND ANALYSIS OF

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the Selected Historical Consolidated Financial Data and the combined financial statements and related notes included elsewhere in this prospectus. This discussion contains forward-looking statements reflecting our current expectations and estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in the sections entitled Risk Factors and Cautionary Note Regarding Forward-Looking Statements appearing elsewhere in this prospectus.

Overview

We are an independent oil and natural gas company focused on the acquisition, development, exploration and exploitation of unconventional, long-life, onshore oil and natural gas reserves in the Permian Basin in West Texas. We intend to grow our reserves and production through development drilling, exploitation and exploration activities on our multi-year inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves.

We intend to increase stockholder value by profitably growing reserves and production, primarily through drilling operations. We seek high quality exploration and development projects with potential for providing long-term drilling inventories that generate high returns. Substantially all of our revenues are generated through the sale of oil, natural gas liquids and natural gas production. Our production was approximately 74% oil, 15% natural gas liquids and 11% natural gas for both the year ended December 31, 2011 and the six months ended June 30, 2012.

We began operations in December 2007 with our acquisition of certain strategic oil and gas properties located in the Permian Basin of West Texas from ExL Petroleum, LP, Ambrose Energy I, Ltd. and certain other sellers for approximately $85.0 million. Through this transaction, we acquired 4,174 net acres with production at the time of acquisition of approximately 800 net barrels of oil equivalent, or BOE/d, from 34 gross (16.8 net) wells. Subsequently, we acquired approximately 26,878 additional net acres, which brought our total net acreage position in the Permian Basin to approximately 31,052 net acres at August 31, 2012 and, after giving effect to the Transactions, we had 51,709 net acres in the Permian Basin. Since our initial acquisition in the Permian Basin through August 31, 2012, we drilled or participated in the drilling of 177 gross (105 net) wells (or 183 gross (161 net) wells after giving effect to the Transactions) on our acreage in this area, primarily targeting the Wolfberry play. We are the operator of approximately 99% of our Permian Basin acreage.

We have increased our initial leasehold position through acquisitions in the Wolfberry play for an aggregate net cost of $44.9 million through June 30, 2012. These acquisitions include the following:

- In 2008, we acquired 6,247 net acres at the Spanish Trail and Munn prospects in Midland County, Texas through 11 leases and one mineral deed, with 5,146 net acres attributable to one lease;

- Commencing in 2008 and ending in 2010, we acquired leases at the Barron prospect in Midland County, Texas that currently cover 225 net acres;

- Commencing in 2008 and ending in 2011, we acquired leases at the Gist prospect in Ector County, Texas covering 1,452 net acres;

- Commencing in 2008 and ending in 2012, we acquired 37 leases at the UL prospect in Andrews, Upton and Reagan Counties, Texas covering a total of 10,006 net acres;

- Beginning in 2008, we acquired 17 leases at the Hurt/WHL prospect in Ector County, Texas covering 2,779 net acres;

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- In 2009, we acquired one lease at the Cumberland prospect located in Midland County, Texas covering 207 net acres;
- In 2010, we acquired leases at the North Howard prospect located in Howard County, Texas that currently cover 131 net acres;
- In 2010 and 2011, we acquired leases at the Big Max prospect located in Andrews County, Texas that currently cover 851 net acres; and
- In 2012, we acquired leases at the Clete prospect in Crockett County, Texas that currently cover 3,110 net acres.

In July 2012, we further increased our leasehold position and acquired leases in the Hume prospect in Crockett County, Texas that currently covers 1,869 net acres.

Diamondback Energy, Inc. was incorporated in Delaware on December 30, 2011 as a holding company and did not conduct any material business operations prior to the transaction described below. Our historical financial information included in this prospectus pertains to assets, liabilities, revenues and expenses of Windsor Permian LLC. Windsor Permian LLC was a wholly-owned subsidiary of Diamondback Energy LLC, which was an entity controlled by our equity sponsor, Wexford. Prior to the effectiveness of the registration statement relating to this prospectus, Diamondback Energy LLC merged with and into Diamondback Energy, Inc. and Diamondback Energy, Inc. continued as the surviving corporation. In the merger, DB Holdings was issued shares of our common stock, and Windsor Permian LLC became our wholly-owned subsidiary. In addition, Wexford caused all the outstanding equity interests in Windsor UT to be contributed to Windsor Permian prior to the merger. After the merger but prior to the effectiveness of the registration statement relating to this prospectus, Gulfport completed the Gulfport transaction in exchange for shares of our common stock.

In June 2012, Windsor Permian distributed to its sole member its minority equity interests in Bison Drilling and Field Services LLC, or Bison, and Muskie Holdings LLC, or Muskie. Bison was formed in November 2010 as a wholly-owned subsidiary of Windsor Permian. Between March 2011 and April 2012, Gulfport and various entities controlled by Wexford acquired interests in Bison, which reduced Windsor Permian s interest to approximately 22%. Bison owns and operates four drilling rigs and various oil and natural gas well servicing equipment and has performed drilling and field services for us. Muskie was formed in October 2011 when Windsor Permian contributed certain assets, real estate and rights in a lease covering land in Wisconsin to Muskie in exchange for a 48.6% equity interest. The contributed lease is prospective for oil and natural gas fracture grade sand. At the time of the contribution, the remaining interests in Muskie were held by Gulfport and entities controlled by Wexford. Through additional contributions from the Wexford-controlled entities, Windsor Permian s equity interest in Muskie decreased to approximately 33%. Windsor Permian s interests in Bison and Muskie were distributed to Windsor Permian s sole member in June 2012 so we may focus our activities on our oil and natural gas exploration and development activities. We recorded revenues attributable to Bison in our consolidated statements of operations of $0.8 million during 2010 and $1.5 million during the first quarter of 2011, at which time Bison was deconsolidated for financial reporting purposes. Muskie was formed in 2011, and we recorded a loss from equity method investments of $7,017 for 2011. The interests in Bison and Muskie are reflected in Investments-equity method on our consolidated balance sheets. For additional information regarding Bison and Muskie, see *Unaudited Pro Forma Condensed Consolidated Financial Statements* and *Related Party Transactions* beginning on pages 54 and 134, respectively, of this prospectus and Note 5 to our consolidated financial statements appearing elsewhere in this prospectus.

Since we began operations, we have increased our drilling activity, evaluated potential acquisitions and added to our acreage portfolio. Because of our growth through acquisitions and development of our properties, our historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results.

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Like all oil and natural gas exploration and production companies, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well naturally decreases. Thus, an oil and natural gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on managing costs associated with drilling and the development and production of reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. We expect the permitting and approval process to become more difficult with increased activism from environmental and other groups which may extend the time it takes us to receive permits. Because of our relatively small size and concentrated property base, we can be disproportionately disadvantaged by delays in obtaining or failing to obtain drilling approvals compared to companies with larger or more dispersed property bases. As a result, we are less able to shift drilling activities to areas where permitting may be easier and we have fewer properties over which to spread the costs related to complying with these regulations and the costs or foregone opportunities resulting from delays.

Reserves and pricing

In December 2008, the SEC released the final rule for Modernization of Oil and Gas Reporting. Among other changes, the final rule requires us to report oil and natural gas reserves and calculate the full cost ceiling value using the unweighted arithmetic average first-day-of-the-month oil and natural gas prices during the 12-month period ending in the reporting period. The prior SEC rule required using prices at period end. The requirements of this standard became effective for the year ended December 31, 2009. These revisions and requirements affect the comparability between reporting periods prior to and after the year ended December 31, 2009 for reserve volume and value estimates, full cost pool write-down calculations and the calculations of depletion of oil and gas assets.

In the table below, Ryder Scott estimated all of our proved reserves at December 31, 2011 and Pinnacle estimated all of our proved reserves at December 31, 2010 and 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.

	2011	2010	2009
Estimated Net Proved Reserves:			
Oil (Bbls)	16,716,869	18,819,050	29,230,940
Natural gas (Mcf)	19,618,867	21,662,720	27,481,820
Natural gas liquids (Bbls)	4,763,273	5,563,978	7,522,225
Total (BOE)	24,749,953	27,993,481	41,333,468

	2011	2010	2009
	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
Oil (Bbls)	$ 93.09	$ 77.61	$ 58.84
Natural gas (Mcf)	$ 3.91	$ 4.14	$ 3.64
Natural gas liquids (Bbls)	$ 56.33	$ 40.74	$ 29.37

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 gas reserves.

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Sources of our revenue

Our revenues are derived from the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. For the six months ended June 30, 2012 and the year ended December 31, 2011, our revenues were derived 89% and 84%, respectively, from oil sales, 9% and 10%, respectively, from natural gas liquids sales, 2% and 3%, respectively, from natural gas sales and none and 3%, respectively, from oil and natural gas services. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Oil, natural gas liquids and natural gas prices have historically been volatile. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per Bbl in December 2008 to a high of $145.31 per Bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.82 per MMBtu in April 2012 to a high of $13.31 per MMBtu in July 2008. During 2011, West Texas Intermediate prices ranged from $75.40 to $113.39 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.84 to $4.92 per MMBtu. On August 31, 2012, the West Texas Intermediate posted price for crude oil was $96.47 per Bbl and the Henry Hub spot market price of natural gas was $2.72 per MMBtu.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time-to-time we enter into derivative arrangements for our crude oil and natural gas production. We utilize commodity derivatives to reduce our exposure to fluctuations in NYMEX WTI benchmark prices. While these derivative contracts stabilize our cash flows when market prices are below our contract prices, they also prevent us from realizing increases in our cash flow when market prices are higher than our contract prices. We will sustain realized and unrealized losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will sustain realized and unrealized gains to the extent our derivatives contract prices are higher than market prices. Our derivatives contracts are not designated as accounting hedges and, as a result, gains or losses on derivatives contracts are recorded as other income (expense) in our statements of operations.

Principal components of our cost structure

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

Production taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and gas properties.

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.

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 other fixed assets.

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Impairment expense. This is the cost to reduce proved oil and gas properties to the calculated full cost ceiling value.

Other income (expense)

Interest income. This represents the interest received on our cash and cash equivalents.

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our credit facility. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender 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.

Loss on derivative contracts. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of crude oil. 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.

Loss from equity investment. This line item represents our proportionate share of the earnings and losses from our investment in the membership interests of Muskie, an equity method investment.

Income tax expense. As of June 30, 2012, we were a limited liability company treated as a disregarded entity for federal income tax purposes. Accordingly, no provision for federal or state corporate income taxes has been provided for the six months ended June 30, 2012 or prior fiscal years because taxable income is allocated directly to our equity holders. Prior to the completion of this offering, Windsor Permian will become our wholly-owned subsidiary and, because we are a subchapter C corporation under the Internal Revenue Code, the earnings at Windsor Permian will become subject to federal and state entity-level taxation. We will establish a net deferred tax liability for differences between the tax and book basis of our assets and liabilities, and we will record a corresponding first day tax expense to net income from continuing operations. On a pro forma basis, at June 30, 2012 the amount of this charge would have been $37.4 million. It is anticipated that the company will be subject to a future, total combined federal and state income tax rate of 34% to 36%.

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Results of Operations

The following table sets forth selected historical operating data for the periods indicated.

	Six Months Ended June 30,		Year Ended December 31,		
	2012	2011	2011	2010	2009
	(unaudited)				
Operating Results:					
Revenues					
Oil and natural gas revenues	$ 31,757,923	$ 22,038,729	$ 47,180,802	$ 26,441,927	$ 12,716,011
Other revenue		1,490,910	1,490,910	811,247	
Operating expenses					
Lease operating expense	6,134,714	4,283,671	10,345,355	4,588,559	2,366,623
Production taxes	1,550,154	1,093,899	2,333,853	1,346,879	663,068
Gathering and transportation expense	146,320	85,944	201,828	105,870	42,091
Oil and natural gas services		1,732,892	1,732,892	811,247	
Depreciation, depletion and amortization	10,235,730	7,441,366	15,402,826	8,145,143	3,215,891
General and administrative	2,815,051	1,421,313	3,603,479	3,051,627	5,062,618
Asset retirement obligation accretion expense	40,195	28,736	63,259	37,856	27,934
Total expenses	20,922,164	16,087,821	33,683,492	18,087,181	11,378,225
Income from operations	10,835,759	7,441,818	14,988,220	9,165,993	1,337,786
Net interest income (expense)	(2,051,702)	(1,090,065)	(2,516,861)	(801,791)	24,137
Other income	1,058,043				
Gain (loss) on derivative contracts	5,164,987	(28,181)	(13,009,393)	(147,983)	(4,068,005)
Loss from equity investment	(66,654)		(7,017)		
Total other income (expense)	4,104,674	(1,118,246)	(15,533,271)	(949,774)	(4,043,868)
Net income (loss)	$ 14,940,433	$ 6,323,572	$ (545,051)	$ 8,216,219	$ (2,706,082)
Production Data:					
Oil (Bbls)	311,175	199,331	441,822	280,721	168,741
Natural gas (Mcf)	290,171	182,862	413,640	323,847	253,321
Natural gas liquids (Bbl)	65,188	44,820	86,815	79,978	70,384
Combined volumes (BOE)	424,725	274,628	597,577	414,674	281,345
Daily combined volumes (BOE/d)	2,334	1,517	1,637	1,136	771
Average Prices[(1)]:					
Oil (per Bbl)	$ 91.23	$ 95.60	$ 92.26	$ 76.51	$ 58.01
Natural gas (per Mcf)	2.27	4.03	3.98	4.32	3.64
Natural gas liquids (per Bbl)	41.58	50.09	54.98	44.56	28.49
Combined (per BOE)	74.77	80.25	78.95	63.77	45.20
Average Costs (per BOE):					
Lease operating expense	$ 14.44	$ 15.60	$ 17.31	$ 11.07	$ 8.41
Gathering and transportation expense	0.34	0.31	0.34	0.26	0.15
Production taxes	3.65	3.98	3.91	3.25	2.36
Production taxes as a % of sales	4.9%	5.0%	4.9%	5.1%	5.2%
Depreciation, depletion and amortization	24.10	27.10	25.78	19.64	11.43
General and administrative	6.63	5.18	6.03	7.36	17.99

(1) After giving effect to our hedging arrangements in effect during the six months ended June 30, 2012 and 2011, respectively, the average prices per Bbl of oil and per BOE were $80.07 and $66.60, respectively, during the six months ended June 30, 2012 and $95.46 and $80.15, respectively, during the six months ended June 30, 2011. After giving effect to our hedging arrangements in effect during 2009, the average prices per Bbl of oil and per BOE (on a combined basis) were $41.59 and $35.35, respectively, during that year. Average prices for our hydrocarbons were not impacted by our hedging arrangements during 2011 or 2010.

Six Months ended June 30, 2012 Compared to Six Months ended June 30, 2011

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $9.7 million, or 45%, to $31.7 million for the six months ended June 30, 2012 from $22.0 million for the six months ended June 30, 2011. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 817 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 $9.7 million is largely attributable to higher oil, natural gas liquids 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 111,844 Bbls of oil, 20,368 Bbls of natural gas liquids and 107,309 Mcf of 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 decreases in prices of approximately $2.4 million (calculated as the change in period-to-period average prices times current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $12.1 million (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas times the period average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ (4.37)	311,175	$ (1,360)
Natural gas liquids	$ (8.51)	65,188	$ (555)
Natural gas	$ (1.76)	290,171	$ (512)
Total revenues due to change in price			$ (2,427)

	Change in production volumes(1)	Prior Period Average Prices	Total net dollar effect of change (in thousands)
Effect of changes in volumes:			
Oil	111,844	$ 95.60	$ 10,693
Natural gas liquids	20,368	$ 50.09	$ 1,020
Natural gas	107,309	$ 4.03	$ 433
Total revenues due to change in volumes			$ 12,146
Total change in revenues			$ 9,719

(1) Production volumes are presented in Bbls for oil and natural gas liquids and in Mcf for natural gas.

Lease Operating Expense. Lease operating expense was $6.1 million ($14.44 per BOE) for the six months ended June 30, 2012, an increase of $1.8 million, or 42%, from $4.3 million ($15.60 per BOE) for the six months ended June 30, 2011. The increase is due to increased drilling activity, which resulted in additional producing wells for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. On a per-BOE basis, our lease operating expense decreased $1.16, or 7%, as our well failure rate decreased period-to-period

under the leadership of our new executive team, resulting in reduced costs for the repair and replacement of downhole equipment and reduced downtime and loss of production as these failures were remediated. Our lease operating expense during both periods was also adversely impacted by the cost of processing and treating non-hydrocarbon gases from certain of our wells that came on-line in 2011. During the third quarter of 2012, we intend to complete both oil and water gathering systems that will transport this gas stream to a sour gas pipeline, thereby eliminating the monthly processing and treating expense, and reducing water trucking, respectively. We believe that our reduced well failure rate and the completion of the gathering systems will help reduce our lease operating expense on a per-BOE basis in future periods.

Production Tax Expense. Production taxes as a percentage of oil and natural gas sales were 4.9% for the six months ended June 30, 2012, a decrease of 0.1% from 5.0% for the six months ended June 30, 2011. Production taxes are primarily based on the market value of our production at the wellhead and may vary across the different counties in which we operate. Total production taxes increased $0.5 million, from $1.1 million during the six months ended June 30, 2011 to $1.6 million during the six months ended June 30, 2012 as a result of higher production and an increase in the market value of our production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $2.8 million, or 38%, from $7.4 million for the six months ended June 30, 2011 to $10.2 million for the six months ended June 30, 2012. The weighted average depletion rate was $24.22 per BOE for the six months ended June 30, 2012 and $26.72 per BOE for the six months ended June 30, 2011. The decrease in depletion rate was due primarily to an increase in proved reserves at June 30, 2012.

General and Administrative Expense. General and administrative expense increased $1.4 million from $1.4 million for the six months ended June 30, 2011 to $2.8 million for the six months ended June 30, 2012. A $2.7 million increase primarily attributable to salary and equity based compensation expense for our new executive team was partially offset by the capitalization of $1.8 million of such salary and equity based compensation expense.

Interest Expense. Interest expense for the six months ended June 30, 2012 was $2.1 million, as compared to $1.1 million for the six months ended June 30, 2011, an increase of $1.0 million. Our weighted average outstanding principal under our credit agreement was $96.0 million for the six months ended June 30, 2012 as compared to $57.0 million for the same period in 2011 with increased borrowings primarily used to fund our increased drilling activity.

Hedging Activities. We have used price swap derivatives to reduce price volatility associated with certain of our oil sales. In these swaps, we received the fixed price per the contract and paid a floating market price to the counterparty based on New York Mercantile Exchange Light Sweet Crude Oil pricing. The fixed-price payment and the floating-price payment are offset, resulting in a net amount due to or from the counterparty.

On October 4, 2011, in an effort to lock-in prices on our anticipated base level of production, while at the same time providing downside protection for our borrowing base, we entered into West Texas Intermediate light sweet crude oil swaps on the NYMEX for the calendar years 2012 and 2013 of 1,000 barrels per day priced at $78.50 and $80.55, respectively. The counterparties to our derivative contracts as of June 30, 2012 are Hess Corporation, or Hess, and BNP Paribas, or BNP, which we believe are acceptable credit risks.

All derivative financial instruments are recorded on our consolidated balance sheets at fair value. The fair value of swaps is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity.

Set forth below are the summarized amounts, terms and fair values of outstanding instruments held as of June 30, 2012 and December 31, 2011. As of June 30, 2012, we had unrealized losses under all of our crude oil swaps. We intend to settle these swaps after the closing of this offering with a portion of the net proceeds.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	June 30, 2012 Fair Value Liability	December 31, 2011 Fair Value Liability
Crude Oil Swaps:				
January May 2012	152,000	$ 78.50	$	$ 3,149,475
June November 2012	183,000	$ 78.50	1,253,237	3,683,790
December 2012	31,000	$ 78.50	270,388	594,223
January May 2013	151,000	$ 80.55	1,143,741	2,445,330
June November 2013	183,000	$ 80.55	1,433,554	2,674,819
December 2013	31,000	$ 80.55	233,087	424,201

We enter into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. The counter-swap is effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap.

In December 2007, we entered into a swap contract covering 1,680,000 Bbls of crude oil for the period from January 2008 to December 2012 at various fixed prices. In April 2008, we entered into a series of counter-swaps to lock-in the value of certain of these swaps settling 1,188,000 Bbls of crude oil swaps. In June 2009, we entered into an additional series of counter-swaps to lock-in the value of the remaining swaps settling 324,000 Bbls of crude oil swaps. Hess is the counterparty to this swap and each counter-swap.

Set forth below are the summarized amounts, terms and fair values of the locked-in swaps from the April 2008 settlements as of June 30, 2012 and December 31, 2011, respectively.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price (per Bbl)	June 30, 2012 Fair Value Liability	December 31, 2011 Fair Value Liability
Crude Oil Swaps:					
December 2011	22,500	$ 82.90	$ 98.50 $102.20	$	$ 378,750
January May 2012	112,500	$ 85.07	$ 98.25 $101.80		1,615,774
June December 2012	157,500	$ 85.07	$ 98.25 $101.80	2,261,527	2,261,185

Set forth below are the summarized amounts, terms and fair values of the locked-in swaps from the June 2009 settlements as of June 30, 2012 and December 31, 2011, respectively.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price (per Bbl)	June 30, 2012 Fair Value Asset	December 31, 2011 Fair Value Asset
Crude Oil Swaps:					
December 2011	7,500	$ 82.90	$ 78.42	$	$ 33,600
January May 2012	37,500	$ 85.07	$ 80.52		170,615
June December 2012	52,500	$ 85.07	$ 80.52	238,801	238,765

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None of our derivatives have been designated as hedges. As such, all changes in fair value are immediately recognized in earnings. The following summarizes the loss on derivative contracts included in the consolidated statements of operations:

	Six Months Ended June 30, 2012	2011
Unrealized (gain) on open non-hedge derivative instruments	$ (8,637,831)	$
Loss on settlement of non-hedge derivative instruments	3,472,844	28,181
Loss on derivative contracts	$ (5,164,987)	$ 28,181

We are required to provide margin deposits whenever our unrealized losses with Hess exceed predetermined credit limits. We had a margin deposit held by Hess of $0.8 million and $2.3 million as of June 30, 2012 and December 31, 2011, respectively, which earns interest that is remitted to us. Under our master netting agreement with Hess, we have offset this margin deposit against its derivative positions.

Year ended December 31, 2011 Compared to Year ended December 31, 2010

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $20.8 million, or 78%, to $47.2 million for the year ended December 31, 2011 from $26.4 million for the year ended December 31, 2010. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 501 BOE/d during the year ended December 31, 2011 as compared to the same period in 2010. The total increase in revenue of approximately $20.8 million is largely attributable to higher oil, natural gas liquids and natural gas production volumes and an increase in the prices of oil and natural gas liquids realized for the year ended December 31, 2011 as compared to the year ended December 31, 2010. Production increased by 161,101 Bbls of oil, 6,837 Bbls of natural gas liquids and 89,793 Mcf of natural gas for the year ended 2011 as compared to the year ended 2010. The net dollar effect of the increase in prices of approximately $7.7 million (calculated as the change in year-to-year average prices times current year production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $13.0 million (calculated as the increase in year-to-year volumes for oil, natural gas liquids and natural gas times the prior year average prices) are shown below.

	Change in prices	Production volumes[1]	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 15.75	441,822	$ 6,959
Natural gas liquids	$ 10.42	86,815	$ 905
Natural gas	$ (0.34)	413,640	$ (141)
Total revenues due to change in price			$ 7,723

	Change in production volumes[1]	Prior Period Average Prices	Total net dollar effect of change (in thousands)
Effect of changes in volumes:			
Oil	161,101	$ 76.51	$ 12,326
Natural gas liquids	6,837	$ 44.56	$ 305
Natural gas	89,793	$ 4.32	$ 388
Total revenues due to change in volumes			$ 13,019
Total change in revenues			$ 20,742

(1) Production volumes are presented in Bbls for oil and natural gas liquids and in Mcf for natural gas.

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Lease Operating Expense. Lease operating expense was $10.3 million ($17.31 per BOE) for the year ended December 31, 2011, an increase of $5.7 million, or 125%, from $4.6 million ($11.07 per BOE) for the year ended December 31, 2010. The increase is due to increased drilling activity, which resulted in additional producing wells for the year ended December 31, 2011 as compared to the year ended December 31, 2010. On a per-BOE basis, the increase is due to cost increases in services and supplies (primarily as a result of higher demand for such services and supplies in the Permian Basin and higher commodity prices), the cost of repairing and replacing downhole equipment due to rod and tubing configurations and pumping practices that resulted in a higher rate of well failures during 2011 and the associated downtime and loss of production as these failures were remediated. Our lease operating expense for the year ended December 31, 2011 was also adversely impacted by the cost of processing and treating non-hydrocarbon gases from certain of our wells that came on line in 2011.

During the third quarter of 2012, we intend to complete both oil and water gathering systems that will transport this gas stream to a sour gas pipeline, thereby eliminating the monthly processing and treating expense, and reduce water trucking, respectively. We believe that our reduced well failure rate and the completion of the gathering systems will help reduce our lease operating expense on a per-BOE basis in future periods.

Production Tax Expense. Production taxes as a percentage of oil and natural gas sales were 4.9% for the year ended December 31, 2011 as compared to 5.1% for the year ended December 31, 2010. Production taxes are primarily based on the market value of our production at the wellhead and vary across the different counties in which we operate. Total production taxes increased $1.0 million, or 73.3%, from $1.3 million during the year ended December 31, 2010 to $2.3 million during the year ended December 31, 2011 as a result of higher production and an increase in the market value of our production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $7.3 million, or 89.1%, from $8.1 million for the year ended December 31, 2010 to $15.4 million for the year ended December 31, 2011. The weighted average depletion rate was $25.40 per BOE for the year ended December 31, 2011 and $17.78 per BOE for the year ended December 31, 2010. The depletion rate increase was due primarily to an increase in costs and a decrease in proved reserves at December 31, 2011 for the reasons described in *Business Oil and Gas Data* beginning on page 98 of this prospectus.

General and Administrative Expense. General and administrative expense increased $0.5 million from $3.1 million for the year ended December 31, 2010 to $3.6 million for the year ended December 31, 2011. A $1.9 million increase primarily attributable to salary and equity based compensation expense for our new executive team was partially offset by the capitalization of $0.9 million of such expense and a $0.5 million increase in COPAS overhead payments due to increased drilling activity.

Interest Expense. Interest expense for the year ended December 31, 2011 was $2.5 million, as compared to $0.8 million for the year ended December 31, 2010, an increase of $1.7 million. Our weighted average outstanding principal under our credit agreement was $68.5 million for the year ended December 31, 2011 as compared to $24.3 million for 2010 due to our increased drilling activity.

Hedging Activities. We have used price swap derivatives to reduce price volatility associated with certain of our oil sales. In these swaps, we received the fixed price per the contract and paid a floating market price to the counterparty based on New York Mercantile Exchange Light Sweet Crude Oil pricing. The fixed-price payment and the floating-price payment are offset, resulting in a net amount due to or from the counterparty.

On October 4, 2011, in an effort to lock-in prices on our anticipated base level of production, while at the same time providing downside protection for our borrowing base, we entered into West Texas Intermediate light sweet crude oil swaps on the NYMEX with BNP for the calendar years 2012 and 2013 of 1,000 barrels per day priced at $78.50 and $80.55, respectively. The counterparties to our derivative contracts as of December 31, 2011 are Hess and BNP, which we believe are acceptable credit risks.

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All derivative financial instruments are recorded on our consolidated balance sheets at fair value. The fair value of swaps is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity.

Set forth below are the summarized amounts, terms and fair values of outstanding instruments held as of December 31, 2011. As of December 31, 2011, we had unrealized losses under all of our crude oil swaps. We intend to settle these swaps after the closing of this offering with a portion of the net proceeds.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	December 31, 2011 Fair Value Liability
Crude Oil Swaps:			
January November 2012	335,000	$ 78.50	$ 6,833,265
December 2012	31,000	78.50	594,223
January December 2013	365,000	80.55	5,544,350

We enter into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. The counter-swap is effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap.

In December 2007, we entered into a swap contract covering 1,680,000 Bbls of oil for the period from January 2008 through December 2012 at various fixed prices. In April 2008, we entered into a series of counter-swaps to lock-in the value of certain of these swaps settling 1,188,000 Bbls of oil swaps. In June 2009, we entered into an additional series of counter-swaps to lock-in the value of the remaining swaps settling 324,000 Bbls of oil swaps.

Set forth below are the summarized amounts, terms and fair values of the locked-in swaps from the April 2008 settlements as of December 31, 2011 and December 31, 2010.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price (per Bbl)	December 31, 2011 Fair Value Liability	December 31, 2010 Fair Value Liability
Oil Swaps:					
December 2010	22,000	$ 82.80	$ 99.45 103.20	$	$ 392,462
January November 2011	180,000	82.90	98.50 102.20		4,159,695
December 2011	90,000	82.90	98.50 102.20	378,750	377,314
January December 2012	270,000	85.07	98.25 101.80	3,876,959	3,844,101

Set forth below are the summarized amounts, terms and fair values of the locked-in swaps from the June 2009 settlements as of December 31, 2011 and December 31, 2010.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price (per Bbl)	December 31, 2011 Fair Value Asset	December 31, 2010 Fair Value Asset
Oil Swaps:					
December 2010	8,000	$ 82.80	75.00	$	$ 62,400
January November 2011	82,500	82.90	78.42		369,205
December 2011	7,500	82.90	78.42	33,600	33,503
January December 2012	90,000	85.07	80.52	409,380	406,489

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None of our derivatives have been designated as hedges. As such, all changes in fair value are immediately recognized in earnings. The following table summarizes the loss on derivative contracts included in our consolidated statements of operations:

	Years Ended December 31,		
	2011	2010	2009
Unrealized loss on open non-hedge derivative instruments	$ 12,971,838	$	$
Unrealized loss on locked-in non-hedge derivative instruments			1,297,979
Loss on settlement of non-hedge derivative instruments	37,555	147,983	2,770,026
Loss on derivative contracts	$ 13,009,393	$ 147,983	$ 4,068,005

We are required to provide margin deposits whenever our unrealized losses with Hess exceed predetermined credit limits. We had a margin deposit held by Hess of $2.3 million and $6.5 million as of December 31, 2011 and 2010, respectively, which earns interest that is remitted to us. Under our master netting agreement with Hess, we have offset this margin deposit against its derivative positions.

Year ended December 31, 2010 Compared to Year ended December 31, 2009

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $13.7 million, or 108%, to $26.4 million during the year ended December 31, 2010 from $12.7 million for the year ended December 31, 2009. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 365 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 $13.7 million is largely attributable to higher oil, natural gas liquid and natural gas production volumes as well as an increase in oil, natural gas liquid and natural gas prices realized for the year ended December 31, 2010 as compared to year ended December 31, 2009. Production increased by 111,980 Bbls of oil, 9,594 Bbls of natural gas liquids and 70,526 Mcf of natural gas during 2010 as compared to 2009. The net dollar effect of the increase in prices of approximately $6.7 million (calculated as the change in year-to-year average prices times current year production volumes for oil, natural gas liquids and natural gas) and the net dollar effect of the change in production of approximately $7.0 million (calculated as the increase in year-to-year volumes for oil, natural gas liquids and natural gas times the prior year average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 18.50	280,721	$ 5,193
Natural gas liquids	$ 16.07	79,978	$ 1,285
Natural gas	$ 0.68	323,847	$ 220
Total revenues due to change in price			$ 6,698
	Change in production volumes(1)	**Prior Period Average Prices**	
Effect of changes in volumes:			
Oil	111,980	$ 58.01	$ 6,496
Natural gas liquids	9,594	$ 28.49	$ 273
Natural gas	70,526	$ 3.64	$ 257
Total revenues due to change in volumes			$ 7,026
Total change in revenues			$ 13,724

(1) Production volumes are presented in Bbls for oil and natural gas liquids and in Mcf for natural gas.

Lease Operating Expense. Lease operating expense was $4.6 million ($11.07 per BOE) for the year ended December 31, 2010, an increase of $2.2 million, or 92%, from $2.4 million ($8.41 per BOE) for the year ended December 31, 2009. The increase is due to increased drilling activity, which resulted in additional producing wells in 2010 as compared to 2009. On a per-BOE basis, the increase is due to cost increases in services and supplies, primarily as a result of the increased demand for such services and supplies in the Permian Basin, and increased commodity prices as well as additional well failure repairs coupled with downtime associated with the failures impacting production.

Production Tax Expense. Production taxes as a percentage of oil and natural gas sales were 5.1% for the year ended December 31, 2010 as compared to 5.2% for the year ended December 31, 2009. Production taxes are primarily based on the market value of our production at the wellhead and vary across the different counties in which we operate. Total production taxes increased $0.6 million, or 86%, from $0.7 million for the year ended December 31, 2009 to $1.3 million for the year ended December 31, 2010 as a result of higher production and an increase in the market value of our production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $4.9 million, or 153%, from $3.2 million for the year ended December 31, 2009 to $8.1 million for the year ended December 31, 2010. The weighted average depletion rate was $11.21 per BOE in 2009 and $17.78 per BOE in 2010. The higher depletion rate in 2010 was due primarily to downward reserve revisions due to undeveloped locations being scheduled for development beyond five years and thus being excluded from proved reserves.

On December 31, 2009, we adopted the new SEC rules related to disclosures of oil and natural gas reserves. As a result of these new SEC rules, we recorded additional proved reserves and utilized the additional proved reserves in our depletion computation for 2009. Our 2009 depletion expense rate was $11.21 per BOE, which is lower in part due to these additional proved reserves.

General and Administrative Expense. General and administrative expense decreased $2.0 million, or 39%, from $5.1 million for the year ended December 31, 2009 to $3.1 million for the year ended December 31, 2010. This decrease was primarily due to a reduction in our labor force. As our capital expenditure programs result in increased production levels, we expect that general and administrative expense per unit of production will continue to decrease.

Interest Expense. Interest expense for 2010 was $0.8 million as compared to an interest expense of $0.01 million for 2009. During the year ended December 31, 2010, $0.2 million of our interest was capitalized and our weighted average outstanding principal under our credit agreement was $24.3 million, which was used primarily to fund our increased drilling program. During the year ended December 31, 2009, most of the interest was capitalized and our weighted average outstanding principal was $5.7 million.

Hedging Activities. We have used price swap derivatives to reduce price volatility associated with certain of our oil sales. In these swaps, we received the fixed price per the contract and paid a floating market price to the counterparty based on New York Mercantile Exchange Light Sweet Crude Oil pricing. The fixed-price payment and the floating-price payment are offset, resulting in a net amount due to or from the counterparty. The counterparty to all of our derivative contracts is Hess, which we believe is an acceptable credit risk.

All derivative financial instruments are recorded on our consolidated balance sheets at fair value. The fair value of swaps is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity.

We enter into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. The counter-swap is effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap.

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In December 2007, we entered into a swap contract covering 1,680,000 Bbls of oil for the period from January 2008 through December 2012 at various fixed prices. In April 2008, we entered into a series of counter-swaps to lock-in the value of certain of these swaps settling 1,188,000 Bbls of oil swaps. In June 2009, we entered into an additional series of counter-swaps to lock-in the value of the remaining swaps settling 324,000 Bbls of oil swaps. We have not entered into any new swap contracts since the initial contract in December 2007. As of December 31, 2010 and 2009, all swap contracts were locked-in with counter swaps.

Set forth below are the summarized amounts, terms and fair values of the locked-in swaps from the April 2008 settlements as of December 31, 2010 and 2009.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price (per Bbl)	December 31, 2010 Fair Value Liability	December 31, 2009 Fair Value Liability
Oil Swaps:					
December 2009	22,000	$ 83.75	$ 102.25 105.90	$	$ 432,550
January November 2010	242,000	82.80	99.45 103.20		4,312,111
December 2010	22,000	82.80	99.45 103.20	392,462	390,714
January December 2011	270,000	82.90	98.50 102.20	4,537,009	4,485,047
January December 2012	270,000	85.07	98.25 101.80	3,844,101	3,737,855

Set forth below are the summarized amounts, terms and fair values of the locked-in swaps from the June 2009 settlements as of December 31, 2010 and 2009.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price (per Bbl)	December 31, 2010 Fair Value Asset	December 31, 2009 Fair Value Asset
Oil Swaps:					
December 2009	8,000	$ 83.75	$ 71.03	$	$ 101,757
January November 2010	88,000	82.80	75.00		685,405
December 2010	8,000	82.80	75.00	62,400	62,108
January December 2011	90,000	82.90	78.42	402,708	397,880
January December 2012	90,000	85.07	80.52	406,489	394,696

None of our derivatives have been designated as hedges. As such, all changes in fair value are immediately recognized in earnings. The following summarizes the loss on derivative contracts included in the consolidated statements of operations as follows:

	Years ended December 31, 2010	Years ended December 31, 2009
Unrealized loss on locked-in non-hedge derivative instruments	$	$ 1,297,979
Loss on settlement of non-hedge derivative instruments	147,983	2,770,026
Loss on derivative contracts	$ 147,983	$ 4,068,005

We are required to provide margin deposits whenever our unrealized losses with Hess exceed predetermined credit limits. We had a margin deposit held by Hess of $6.5 million and $10.3 million as of December 31, 2010 and 2009, respectively. Interest earned on the deposit is remitted to us. As we have a master netting agreement with Hess, we have offset this margin deposit against derivative positions.

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Liquidity and Capital Resources

Historically, our primary sources of liquidity have been capital contributions and loans from our equity sponsor, borrowings under our credit facility and cash flows from operations. Our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. We regularly evaluate potential capital sources, including equity and debt financings, in an effort to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

Liquidity and cash flow

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

	Six Months Ended June 30,		Year Ended December 31,		
	2012	2011	2011	2010	2009
Net cash provided by operating activities	$ 22,309,321	$ 13,519,386	$ 30,384,194	$ 5,175,824	$ 2,701,566
Net cash used in investing activities	(59,382,142)	(38,363,561)	(76,314,042)	(53,134,641)	(32,149,617)
Net cash provided by financing activities	$ 32,337,149	$ 23,292,499	48,642,492	49,618,254	23,849,250
Net change in cash	$ (4,735,672)	$ (1,551,676)	$ 2,712,644	$ 1,659,437	$ (5,598,801)

Operating Activities

On a historical basis, net cash provided by operating activities was $22.3 million for the six months ended June 30, 2012 as compared to $13.5 million for the six months ended June 30, 2011. The increase in operating cash flows is due to an overall increase in production revenues, partially offset by increased expenses, as discussed above in *Results of Operations* beginning on page 66. The increase in production is largely a result of our increased drilling activities throughout 2012 and 2011.

Net cash provided by operating activities was $30.4 million for the year ended December 31, 2011 as compared to $5.2 million for the year ended December 31, 2010. The increase in operating cash flows is due to an overall increase in production revenues, partially offset by increased expenses, as discussed above in *Results of Operations* on page 66. The increase in production is largely a result of our increased drilling activities throughout 2011.

Net cash provided by operating activities was $5.2 million for the year ended December 31, 2010 as compared to $2.7 million for the year ended December 31, 2009. The increase in operating cash flows is due to an overall increase in production revenues, partially offset by increased expenses, as discussed above in *Results of Operations* on page 66. The increase in production volumes is largely a result of our increased drilling program in 2010. The increase in operating activities was partially offset by changes in our working capital components in 2010 which consisted primarily of the purchase of inventory of tubular goods for our drilling program and increased accounts receivables due to the increase in our drilling activities in 2010.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for the oil and natural gas we produce. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

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Investing Activities

On a historical basis, we used cash for investing activities of $59.4 million and $38.4 million during the six months ended June 30, 2012 and 2011, respectively.

During the first six months ended 2012, we spent $47.3 million on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 24 gross (16 net) wells. We spent an additional $7.7 million on leasehold costs, $0.6 million for the purchase of other property and equipment and $3.8 million, net, on the settlement of our derivative transactions.

The purchase and development of oil and natural gas properties accounted for the majority of our cash outlays for investing activities. We used cash for investing activities of $76.3 million, $53.1 million and $32.1 million during the years ended December 31, 2011, 2010 and 2009, respectively.

During 2011, we spent $72.2 million on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 54 gross (31 net) wells. We spent an additional $3.2 million on leasehold costs, $0.4 million for the purchase of other property and equipment, $4.2 million for the purchase of certain assets, real estate and leasehold interests which were subsequently contributed to Muskie and $2.5 million for the purchase of drilling rigs and other equipment which were subsequently contributed to Bison. These amounts were partially offset by proceeds of $6.0 million from a partial sale of our equity investment, $0.05 million from the sale of property and equipment and $0.08 million from the settlement of non-hedge derivative investments and margin deposits.

During 2010, we spent $39.0 million on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 40 gross (25 net) wells. We spent an additional $3.5 million for the purchase and development of leasehold interests, $11.7 million for the purchase of drilling rigs, well servicing equipment and other equipment which were subsequently contributed to Bison and $0.2 million for the settlement of non-hedge derivative instruments and margin deposits. These amounts were partially offset by the $1.3 million we received from the sale of approximately 10,946 net acres of non producing acreage in the Permian Basin.

During 2009, we spent $24.0 million on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 12 gross (nine net) wells. We spent an additional $2.7 million for the purchase and development of leasehold interests in the Permian Basin and $5.5 million for the net amount of the settlement of non-hedge derivative instruments and margin deposits.

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Our investment activities for the six months ended June 30, 2012 and 2011 and the years ended December 31, 2011, 2010 and 2009 are summarized in the following table:

	Six Months Ended June 30,		Year Ended December 31,		
	2012	2011	2011	2010	2009
Drilling and completion of wells	$ (47,277,804)	$ (32,491,866)	$ (72,165,677)	$ (38,979,629)	$ (23,955,667)
Purchase of leasehold acquisitions	(7,693,156)	(519,058)	(3,213,932)	(3,493,464)	(2,667,068)
Purchase of other property and equipment	(637,160)	(5,494,482)	(7,064,972)	(11,741,073)	(8,856)
Proceeds from sale of property and equipment	9,770	54,909	54,909	1,270,075	2,000
Settlement of non-hedge derivative instruments	(5,262,846)	(2,055,901)	(4,126,800)	(3,962,440)	(2,770,026)
Receipt (payment) on derivative margins	1,479,054	2,152,373	4,202,467	3,771,890	(2,750,000)
Proceeds from equity investment, net		(9,536)	5,999,963		
Net cash used in investing activities	$ (59,382,142)	$ (38,363,561)	$ (76,314,042)	$ (53,134,641)	$ (32,149,617)

Financing Activities

Net cash provided by financing activities for the first six months of 2012 was $32.3 million as compared to $23.3 million for the first six months of 2011. During the first six months of 2012 and 2011, we borrowed $15.0 million and $23.6 million, respectively, under our revolving credit facility and received capital contributions from entities controlled by Wexford, our equity sponsor, of $4.0 million and zero, respectively. During the first six months of 2012, we also borrowed $14.1 million of subordinated debt from Wexford. These proceeds were used primarily to fund our drilling costs and purchase property and equipment. During the six months ended June 30, 2012, we paid $0.7 million for costs associated with this offering.

Net cash provided by financing activities for 2011 was $48.6 million as compared to $49.6 million for 2010. During 2011, we borrowed $40.2 million under our revolving credit facility and received capital contributions from entities controlled by Wexford, our equity sponsor, of $9.2 million. These proceeds were used primarily to fund our drilling costs and purchase property and equipment.

Net cash provided by financing activities for 2010 was $49.6 million as compared to $23.8 million for 2009. The net cash provided by financing activities in 2010 is primarily attributable to borrowings of $61.1 million under our revolving credit facility, partially offset by principal payments of $24.0 million under our prior credit facility with the Bank of Oklahoma, N.A. During 2010, we received capital contributions from entities controlled by Wexford, our equity sponsor, of $18.8 million which were partially offset by distributions to Wexford of $5.6 million. We paid $0.7 million in debt issuance costs in 2010. We used the net proceeds from our financing activities during 2010 to fund our drilling costs, the purchase of property and equipment, the purchase of tubular goods inventory and the acquisition and development of leasehold.

Net cash provided by financing activities for 2009 was $23.8 million as compared to $80.2 million for 2008. The net cash provided by financing activities in 2009 is attributable to borrowings of $7.7 million under our revolving credit facility and $16.9 million of capital contributions from entities controlled by Wexford, our equity sponsor, which amounts were partially offset by distributions to Wexford of $0.6 million. We paid $0.1 million for debt issuance costs and costs relating to the preparation for the initial public offering. We used the net proceeds from our financing activities to fund our drilling program, the purchase of property and equipment, the acquisition and development of leasehold and the settlement of our non-hedge derivative instruments.

Existing Revolving Credit Facility

On October 15, 2010, we entered into a senior secured revolving credit agreement with BNP Paribas, or BNP, as administrative agent for the several lenders, as amended, providing for a revolving credit facility. The maximum availability under the facility is subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves. The outstanding borrowings bear interest at a rate elected by us that is currently based on the prime, LIBOR or federal funds rate plus margins ranging from 1.25% to 3.50% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base.

Principal may be optionally repaid from time to time and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise, and (b) at the maturity date of October 15, 2014. We are obligated to pay a quarterly commitment fee equal to 0.5% per year of the unused portion of the borrowing base. The loan is secured by substantially all of our assets. The borrowing base is re-determined semi-annually with effective dates of April 1st and October 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any 12-month period. The borrowing base was $45.0 million at December 31, 2010. The borrowing base was increased several times during 2011 as a result of redeterminations and at December 31, 2011 the borrowing base was $100.0 million. Under the terms of the revolving credit agreement as currently in effect, the borrowing base will remain at $100.0 million through July 15, 2013 or, if earlier, the closing date of this offering, at which time the borrowing base will be reduced to $90.0 million, subject to the periodic and elective borrowing base redeterminations described above. However, we expect that our borrowing base will be increased above the $90.0 million borrowing base level as a result of our acquisition of the oil and gas properties subject to the Gulfport transaction and those properties owned by Windsor UT. Notwithstanding future redeterminations of the borrowing base, the aggregate maximum credit amount under the revolving credit agreement is $250.0 million. As of September 30, 2012 and December 31, 2011, we had outstanding borrowings of $100.0 million and $85.0 million, respectively. Borrowings under the revolving credit agreement bore interest at a weighted average rate of 3.72% at September 30, 2012 and 3.3% at December 31, 2011. We intend to repay the outstanding borrowings under our revolving credit facility with a portion of the net proceeds of this offering.

Our revolving credit agreement contains various affirmative and restrictive covenants. These covenants, among other things, prohibit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of various financial ratios described below.

On May 10, 2012, our revolving credit agreement was further amended to provide for the resignation of BNP, and the appointment of Wells Fargo Bank, National Association, or Wells Fargo, as administrative agent for the lenders. The amendment also permitted certain restricted payments and subordinated debt in an initial principal amount not to exceed $30.0 million, including any such indebtedness evidenced by our subordinated note with an affiliate of Wexford described in more detail under *Subordinated Note* below.

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As of July 24, 2012, our revolving credit agreement was amended and restated to include Diamondback Energy LLC and its subsidiaries as additional guarantors to the facility. The covenant prohibiting additional indebtedness was also amended to allow the issuance of unsecured debt of up to $250.0 million and, in connection with any such issuance, the reduction of the borrowing base by 25% of the principal amount of such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. The amendment also provided that redemptions of any unsecured debt will be restricted unless certain liquidity requirements are met. Further, the amendment modified certain financial ratios, the current requirements of which are described below.

Financial Covenant	Required Ratio
Ratio of EBITDAX to interest expense	Not less than 2.5 to 1.0
Ratio of total debt to EBITDAX	Not greater than 4.5 to 1.0
Ratio of total debt to EBITDAX (after closing date of this offering)	Not greater than 4.0 to 1.0
Ratio of debt under revolving credit agreement to EBITDAX	Not greater than 3.0 to 1.0
Ratio of current assets to liabilities	Not less than 1.0 to 1.0

Our revolving credit agreement defines EBITDAX, for any period, as the sum of our consolidated net income for such period plus the following expenses or charges to the extent deducted from our consolidated net income for such period: interest; income taxes; depreciation, depletion, amortization and exploration expenses; extraordinary items and other similar non-cash charges, including expenses related to stock-based compensation and hedging, minus all non-cash income added to our consolidated net income.

On July 31, 2012, we further amended our revolving credit agreement to provide for the issuance to Gulfport of the Gulfport transaction note and the payment of the Gulfport transaction note from the proceeds of this offering.

As of June 30, 2012 and December 31, 2012, we were in compliance with all financial covenants under our revolving credit facility. The lenders may accelerate all of the indebtedness under our revolving credit facility upon the occurrence of any event of default unless we cure any such default within any applicable cure period. For payments of interest under our revolving credit facility, we have a three business day grace period, and a 30-day cure period for most covenant defaults, except for defaults of certain covenants, including the financial covenants and negative covenants under our revolving credit facility.

Subordinated Note

Effective May 14, 2012, we issued a subordinated note to an affiliate of Wexford pursuant to which, as amended to date, the Wexford affiliate may, from time to time, advance up to an aggregate $45.0 million. These advances are solely at the lender s discretion and neither Wexford nor any of its affiliates has any commitment or obligation to provide further capital support to us. The note bears interest at a rate equal to LIBOR plus 0.28% or 8% per annum, whichever is lower. Interest is due quarterly in arrears beginning on July 1, 2012. Interest payments are payable in kind by adding such amounts to the principal balance of the note. The unpaid principal balance and all accrued interest on the note are due and payable in full on January 31, 2015 or the earlier completion of this offering. Any indebtedness evidenced by this note is subordinate in the right of payment to any indebtedness outstanding under our revolving credit facility. As of September 30, 2012, there was $30.0 million in aggregate principal amount outstanding under this note. We will repay the outstanding borrowings under this note with a portion of the net proceeds of this offering.

Prior Revolving Credit Facility

On September 17, 2009, we entered into a revolving credit facility with the Bank of Oklahoma, N.A., or BOK. The BOK revolving credit facility had a maximum principal amount of $50.0 million, subject to a collateral borrowing base calculation which was based on the underlying reserve value of the oil and natural gas properties securing the credit facility and outstanding letters of credit. The BOK revolving credit facility was repaid in full in October 2010 with borrowings under the BNP revolving credit facility and then terminated.

Borrowings under the BOK revolving credit facility bore interest at our election of either BOK s listed national prime rate plus an interest rate spread ranging from 1.0% to 2.5% (based on borrowing levels) payable monthly or at LIBOR rates plus an interest rate spread ranging from 2.5% to 4.0% (based on borrowing levels) payable at the end of the applicable interest period. The credit facility agreement allowed BOK to charge a 0.25% commitment fee on the unused available borrowing.

The BOK revolving credit facility was collateralized by oil and natural gas properties and contained certain financial and non-financial covenants, which included: providing quarterly financial statements and annual audited financial statements; providing semi-annual reserve engineering reports; restrictions on distributions to members; restrictions on incurring additional debt; restrictions on financial derivative contracts; maintaining a funded debt to earnings before hedge gains or losses, asset gains or losses, depreciation, depletion, amortization and interest expense of no greater than 3.0 to 1.0.

Capital Requirements and Sources of Liquidity

We currently anticipate our 2012 capital budget for drilling and infrastructure will be approximately $150.0 million to $160.0 million after giving effect to the Transactions. We intend to allocate these expenditures as follows:

- $126.0 million for the drilling and completion of operated wells;
- $11.0 million for our participation in the drilling and completion of non-operated wells;
- $6.0 million for leasehold interest and property acquisitions; and
- $12.0 million for the construction of infrastructure to support production, including investments in water disposal infrastructure and gathering line projects.

During the six months ended June 30, 2012, aggregate capital expenditures for drilling and infrastructure after giving effect to the Transactions were $70.7 million while our capital expenditures without giving effect to the Transactions were $55.0 million.

However, the amount and timing of these capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned 2012 capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners.

Based upon current oil and natural gas price expectations for 2012, following the closing of this offering we believe that our cash flow from operations, proceeds of this offering and borrowings under our revolving credit facility will be sufficient to fund our operations through year-end 2013. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. We cannot assure you that operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our capital expenditure budget for 2012 allocates $6.0 million for leasehold interest and property acquisitions. In the event we make additional acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital. If we require additional capital for that or other reasons, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means. We cannot assure you that

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needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling programs, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to replace our reserves.

Contractual and Commercial Commitments

The following table summarizes our contractual obligations and commercial commitments as of December 31, 2011:

	Payments Due By Year				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
	(in thousands)				
Long term debt[1]	$	$ 85,000	$	$	$ 85,000
Derivative contracts	8,320	6,139			14,459
Asset retirement obligation[2]			19	1,061	1,080
Operating leases	219	690	358		1,267
Total	$ 8,539	$ 91,829	$ 377	$ 1,061	$ 101,806

(1) Consists of the outstanding principal amount at December 31, 2011 under our revolving credit facility. This table does not include future commitment fees, interest expense or other fees payable under this floating rate facility as we cannot predict the timing of future borrowings and repayments or interest rates to be charged. All borrowings under our revolving credit facility are due on October 15, 2014.

(2) Amounts represent our estimates 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. Please read Note 4 to our audited financial statements.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our financial statements. See Note 2 of the notes to our consolidated financial statements appearing elsewhere in this prospectus for a discussion of additional accounting policies and estimates made by management.

Use of Estimates

Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated by our management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities and our disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Actual results could differ from those estimates.

We evaluate these estimates on an ongoing basis, using historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved reserve quantities and related estimates of the present value of future net revenues, the carrying value of oil and gas properties and asset retirement obligations.

Method of accounting for oil and natural gas properties

We account for our oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. We also capitalize direct operating costs for services performed with internally owned drilling and well servicing equipment. General and administrative costs capitalized to the full cost pool represent management s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Income from services provided to working interest owners of properties in which we also own an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves.

Costs associated with unevaluated properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. We assess all items classified as unevaluated property on a quarterly basis for possible impairment. We assess properties on an individual basis or as a group if properties are individually insignificant. 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 inclusion of our unevaluated costs into the amortization base is expected to be completed within three years.

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

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. 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.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality

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of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Revenue recognition

Oil and natural gas revenues are recorded when title passes to the purchaser, net of royalty interests, discounts and allowances, as applicable. We account for oil and natural gas production imbalances using the sales method, whereby a liability is recorded when our volumes exceed our estimated remaining recoverable reserves. No receivables are recorded for those wells where we have taken less than our ownership share of production. We did not have any gas imbalances as of December 31, 2011, 2010 and 2009 or as of June 30, 2012. Revenues from oil and natural gas services are recognized as services are provided.

Impairment

The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depreciation, depletion, amortization, impairment and deferred income taxes exceed the discounted future net revenues of proved oil and natural gas reserves, less any related income tax effects, the excess capitalized costs are charged to expense. In calculating future net revenues, effective December 31, 2009, 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

ASC Topic 410 requires companies to record a liability relating to the retirement and removal of assets used in their businesses. ASC Topic 410 requires that the fair value of a liability for an asset s retirement obligation be recorded in the period in which it is incurred if a reasonable estimate of fair value can be made and that the corresponding cost be capitalized as part of 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 asset retirement obligation 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.

We determine the asset retirement obligation by calculating the present value of estimated cash flows related to the liability. Estimating the future asset retirement obligation requires management to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous 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 asset retirement obligation liability, a corresponding adjustment is made to the related asset.

Derivatives

From time to time, we have used energy derivatives for the purpose of mitigating the risk resulting from fluctuations in the market price of crude oil. We recognize all of our derivative instruments as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and further on the type of hedging relationship. We enter into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, we receive a floating price for the hedged commodity and pay a

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fixed price to the counterparty. The counter-swap is effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. For those derivative instruments that are designated and qualify as hedging instruments, we designate the hedging instrument, based on the exposure being hedged, as either a fair value hedge or a cash flow hedge. Changes in the fair value of instruments designated as a fair value hedge offset changes in the fair value of the hedge item and changes in the fair value of instruments designated as cash flow hedges are shown in accumulated other comprehensive income until the hedged item is recognized in earnings. For derivative instruments not designated as hedging instruments, the unrealized gain or loss on the change in fair value of these instruments are recognized in earnings during the period of change. None of our derivatives were designated as hedging instruments during the years ended December 31, 2011, 2010 and 2009 or for the six months ended June 30, 2012.

Equity-Based Compensation

During the year ended December 31, 2011, we granted to our executive officers options to acquire membership interests in our Company. Such options vest in four equal annual installments commencing on the first anniversary of the date of grant and are exercisable for five years from the date of grant. Generally, in the event more than 50% of the combined voting power of our Company is not owned by Wexford or its affiliates and there is a material change in the terms of the option holder s employment, the options will vest immediately. Summarized below are the grant dates with the total exercise prices and total fair values of the underlying options:

Months Ended	Membership Interests Granted	Exercise Price	Fair Value at Date of Grant
April 2011	1.00%	$ 3,600,000	$ 1,452,851
August 2011	1.20%	6,000,000	1,383,976
September 2011	1.25%	5,900,000	1,532,612
November 2011	0.25%	1,250,000	288,328
	3.70%	$ 16,750,000	$ 4,657,767

At June 30, 2012 and December 31, 2011, for outstanding options, the intrinsic value was $112,500 and $112,500, respectively, and the weighted-average remaining contractual terms were 4.1 and 4.6 years, respectively. Also, at June 30, 2012 and December 31, 2011, no options were exercisable.

We account for such options issued using a fair-value-based method calculated on the grant-date of the award. The resulting cost is recognized on a straight-line basis over the vesting period of the entire option.

The fair value of the options issued was estimated using the Black-Scholes option-pricing model. One of the inputs to this model is the estimate of the fair value of the underlying membership interest on the date of grant. The other inputs include an estimate of the expected volatility of the membership interest, an option s expected term, the risk-free interest rate over the option s expected term, the option s exercise price and our expectations regarding dividends.

We do not have a history of market prices for our membership interests because such interests are not publicly traded. We utilized the observable data for a group of peer companies that grant options to assist in developing our volatility assumption. The expected volatility was determined using the historical volatility for a peer group of companies. The expected term for options issued was determined based on the contractual terms of the awards. The weighted-average risk-free interest rate was based on the daily U.S. treasury yield curve rate whose term was consistent with the expected life of the options. We do not anticipate paying cash dividends; therefore, the expected dividend yield was assumed to be zero.

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A summary of the significant assumptions used to estimate the fair value of the options to acquire membership interests during the year ended December 31, 2011 is as follows:

Expected term	5 years
Risk-free interest rate	0.96%
Expected volatility	45.50%
Expected dividend yield	0.00%

We assumed no annual forfeiture rate because of our lack of turnover and lack of history for this type of award. We will continue to evaluate the appropriateness of the forfeiture rate based on actual forfeiture experience, analysis of employee turnover behavior and other factors. Changes in the estimated forfeiture rate can have a significant effect on reported equity-based compensation expense, because the cumulative effect of adjusting the rate for all expense amortization is recognized in the period the forfeiture estimate is changed.

We perform annual valuations to estimate our enterprise value. Our valuations consider a number of objective and subjective factors that we believe market participants would consider, including: (a) our business, financial condition, and results of operations, including related industry trends affecting our operations; (b) our forecasted operating performance and projected future cash flows; (c) the liquid or illiquid nature of our membership interest; (d) liquidation preferences, redemption rights and other rights and privileges of our membership interest; (e) market multiples of our most comparable public peers; and (f) market conditions affecting our industry.

We used the income approach to estimate our enterprise value. The income approach involves applying an appropriate risk-adjusted discount rate to projected cash flows based on forecasted revenue and costs. The valuations were based primarily on our independent engineering oil and gas reserve reports which are generally a cash flow model of the Company. There were no significant events during the year that caused us to adjust these values at the various grant dates.

There is inherent uncertainty in our forecasts and projections and, if we had made different assumptions and estimates than those described previously, the amount of our equity-based compensation expense could have been materially different.

Equity-based compensation expense recorded for the six months ended June 30, 2012 was $582,221. The unrecognized equity-based compensation expense as of June 30, 2012 and December 31, 2011 was $3,531,255 and $4,113,477, respectively, related to these awards which is expected to be recognized over a weight-average period of 3.1 and 3.6 years, respectively. Equity-based compensation expense for the six months ended June 30, 2011 was not material.

Recent accounting pronouncements

Fair Value

In December 2011, the FASB issued Accounting Standards Update, or ASU, No. 2011-11, which increases disclosures about offsetting assets and liabilities. New disclosures are required to enable users of financial statements to understand significant quantitative differences in balance sheets prepared under GAAP and International Financial Reporting Standards related to the offsetting of financial instruments. The existing GAAP guidance allowing balance sheet offsetting, including industry-specific guidance, remains unchanged. The guidance in ASU No. 2011-11 is effective for annual and interim reporting periods beginning on or after January 1, 2013. The disclosures should be applied retrospectively for all prior periods presented. We do not expect the adoption of this new guidance to have a significant impact on our financial position, results of operations or cash flow.

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Comprehensive Income

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, Comprehensive Income: Presentation of Comprehensive Income, which provides amendments to FASB ASC Topic 220, Comprehensive Income. The purpose of the amendments in this update is to provide a more consistent method of presenting non-owner transactions that affect an entity s equity. The amendments eliminate the option to report other comprehensive income and its components in the statement of changes in stockholders equity and require an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. In December 2011, the FASB issued Accounting Standards Update 2011-12 which defers the requirement in Accounting Standards Update 2011-05 that companies present reclassification adjustments for each component of accumulated other comprehensive income in both net income and other comprehensive income on the face of the financial statements. Both amendments are effective for interim and annual periods beginning after December 15, 2011 and should be applied retrospectively. The adoption of this guidance will not have a significant impact on our financial position, results of operations or cash flow.

Emerging Growth Company

The JOBS Act permits an emerging growth company like us to take advantage of an extended transition period to comply with new or revised accounting standards applicable to public companies. We are choosing to opt out of this provision and, as a result, we will comply with new or revised accounting standards as required when they are adopted. This decision to opt out of the extended transition period is irrevocable.

Internal Controls and Procedures

We are not currently required to comply with the SEC s rules implementing Section 404 of the Sarbanes Oxley Act of 2002, and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a public company, we will be required to comply with the SEC s rules implementing Section 302 of the Sarbanes-Oxley Act of 2002, which will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. We will not be required to make our first assessment of our internal control over financial reporting under Section 404 until the year following our first annual report required to be filed with the SEC.

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 years ended 2009, 2010 and 2011. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations.

Quantitative and Qualitative Disclosure about Market Risks

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control.

We use price swap derivatives to reduce price volatility associated with certain of our oil sales. Under these swap contracts, we receive a fixed price per barrel of oil and pay a floating market price per barrel of oil to the counterparty based on New York Mercantile Exchange Light Sweet Crude Oil pricing. The fixed-price payment and the floating-price payment are offset, resulting in a net amount due to or from the counterparty. For the purpose of locking-in the value of a swap, we enter into counter-swaps from time to time. Under the counter-swap, we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. The counter-swap is effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap.

In December 2007, we placed a swap contract covering 1,680,000 Bbls of crude oil for the period from January 2008 to December 2012 at various fixed prices. In April 2008, we entered into a series of counter-swaps to lock-in the value of certain of these swaps settling 1,188,000 Bbls of crude oil swaps. In June 2009, we entered into an additional series of counter-swaps to lock-in the value of the remaining swaps settling 324,000 Bbls of crude oil swaps. In October 2011 we placed a swap contract covering 731,000 Bbls of crude oil for the period from January 2012 to December 2013 at a fixed price of $78.50 for 2012 and $80.55 for 2013. Such contracts and any future hedging arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

At June 30, 2012, we had a net liability derivative position of $5.5 million related to our price swap derivatives.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from joint interest receivables (approximately $10.4 million at June 30, 2012) and receivables from the sale of our oil and natural gas production (approximately $4.8 million at June 30, 2012).

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. For the six months ended June 30, 2012, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (63%); Andrews Oil Buyers Inc. (13%); and Occidental Energy Marketing, Inc. (12%). For the years ended December 31, 2011 and 2010, one purchaser, Windsor Midstream LLC, an entity controlled by Wexford, our equity sponsor, accounted for approximately 78% and 81% of our revenue, respectively. For the year ended December 31, 2009, two purchasers accounted for more than 10% of our revenue: Windsor Midstream LLC (68%) and DCP Midstream, LP (15%). No other customer accounted for more than 10% of our revenue during these periods.

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 whether these entities will participate in our wells. At June 30, 2012, we had two customers that represented approximately 96% of our total joint operations receivables. At each of December 31, 2011 and 2010, we had one customer that represented approximately 68% and 62%, respectively, of our total joint operations receivables. Prior to 2010, we did not operate the wells and, therefore, did not have joint operations receivables.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility with Wells Fargo. The terms of our revolving credit facility with Wells Fargo provide for interest on borrowings at a floating rate equal to prime, LIBOR or federal funds rate plus margins ranging from

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1.25% to 3.50% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. Borrowings under our revolving credit facility bore interest at a weighted average rate of 3.75% as of June 30, 2012. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our net income (loss) of approximately $1.0 million annually, based on the $100.0 million outstanding in the aggregate under our revolving credit facility as of June 30, 2012, and assuming no interest is capitalized. We intend to repay the outstanding borrowings under our revolving credit facility with a portion of the net proceeds from this offering.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements. Please read Note 11 to our consolidated financial statements included elsewhere in this prospectus for a discussion of our commitments and contingencies, some of which are not recognized in the balance sheets under GAAP.

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BUSINESS

General

Overview

We are an independent oil and natural gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. This basin, which is one of the major producing basins in the United States, is characterized by an extensive production history, a favorable operating environment, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators.

We began operations in December 2007 with our acquisition of 4,174 net acres with production at the time of acquisition of approximately 800 BOE/d from 34 gross (16.8 net) wells in the Permian Basin. Subsequently, we acquired approximately 26,878 additional net acres, which brought our total net acreage position in the Permian Basin to 31,052 net acres at August 31, 2012 and, after giving effect to the Transactions, we had 51,709 net acres. We are the operator of approximately 99% of this acreage. As of August 31, 2012, after giving effect to the Transactions, we had drilled 167 gross (155 net) wells, and participated in an additional 16 gross (seven net) non-operated wells, in the Permian Basin. Of these 183 gross wells, 171 were completed as producing wells and 12 were in various stages of completion. In the aggregate, as of August 31, 2012, we held interests in 205 gross (185 net) producing wells in the Permian Basin.

We built our current leasehold position through the following acquisitions and development activities in the Wolfberry play:

- In 2008, we acquired 6,247 net acres at the Spanish Trail and Munn prospects in Midland County, Texas through 11 leases and one mineral deed, with 5,146 net acres attributable to one lease;
- Commencing in 2008 and ending in 2010, we acquired leases at the Barron prospect in Midland County, Texas that currently cover 225 net acres;
- Commencing in 2008 and ending in 2011, we acquired leases at the Gist prospect in Ector County, Texas covering 1,452 net acres;
- Commencing in 2008 and ending in 2012, we acquired 37 leases at the UL prospect in Andrews, Upton and Reagan Counties, Texas covering a total of 10,006 net acres;
- Beginning in 2008, we acquired 17 leases at the Hurt/WHL prospect in Ector County, Texas covering 2,779 net acres;
- In 2009, we acquired one lease at the Cumberland prospect located in Midland County, Texas covering 207 net acres;
- In 2010, we acquired leases at the North Howard prospect located in Howard County, Texas that currently cover 131 net acres;
- In 2010 and 2011, we acquired leases at the Big Max prospect located in Andrews County, Texas that currently cover 851 net acres; and
- In 2012, we acquired leases in the Clete and Hume prospects in Crockett County, Texas that currently cover 4,979 net acres.

Our activities are primarily focused on the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations, which we refer to collectively as the Wolfberry play. The Wolfberry play is characterized by high oil and liquids rich natural gas, multiple vertical and horizontal target horizons, extensive production history, long-lived reserves and high drilling success rates. The Wolfberry play is a modification and extension of the Spraberry play, the majority of which is designated in the Spraberry Trend area field. According to the U.S. Energy Information Administration, the Spraberry trend area ranks as the second largest oilfield in the United States, based on 2009 reserves.

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As of December 31, 2011, our estimated proved oil and natural gas reserves pro forma for the Transactions were 39,460 MBOE based on reserve reports prepared by Ryder Scott Company L.P., or Ryder Scott, our independent reserve engineers. Of these reserves, approximately 21.7% are classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate are from 329 gross well locations on 40-acre spacing. As of December 31, 2011, these proved reserves were approximately 66% oil, 20% natural gas liquids and 14% natural gas.

We have 916 identified potential vertical drilling locations based on our evaluation of applicable geologic and engineering data as of August 31, 2012, and we have an additional 1,122 identified potential vertical drilling locations based on 20-acre downspacing. These identified potential drilling locations do not include any potential horizontal drilling locations. We intend to grow our reserves and production through development drilling, exploitation and exploration activities on this multi-year project inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves. Our estimated ultimate recoveries, or EURs, from future PUD wells on 40-acre spacing, as estimated by Ryder Scott, range from 102 MBOE per well, consisting of 46 MBbls of oil, 143 MMcf of natural gas and 32 MBbls of natural gas liquids, to 158 MBOE per well, consisting of 112 MBbls of oil, 113 MMcf of natural gas and 27 MBbls of natural gas liquids, with an average EUR per well of 135 MBOE, consisting of 93 MBbls of oil, 102 MMcf of natural gas and 25 MBbls of natural gas liquids. We also intend to continue to refine our drilling pattern and completion techniques in an effort to increase our average EUR per well from vertical wells drilled on 40-acre spacing. We currently anticipate a reduction of approximately 20% in our EURs from vertical wells drilled on 20-acre spacing. Our 2012 drilling plan currently contemplates drilling 48 gross (43 net) vertical wells on 40-acre spacing and two gross (two net) horizontal wells in the Wolfberry play. As of August 31, 2012, we were using two drilling rigs and, upon completion of this offering, intend to increase our drilling program to six rigs.

We believe the experience gained from our historical drilling programs and the information obtained from the results of extensive industry drilling activity in the Permian Basin have helped us reduce the risk and uncertainity associated with drilling vertical wells on our Permian Basin acreage. We intend to supplement our vertical development drilling activity with horizontal wells targeting various intervals in the Wolfberry play. Our horizontal drilling program is intended to further capture the upside potential that may exist on our properties and increase our well performance and recoveries as compared to drilling vertical wells alone.

During 2011, we assembled a new executive team and, beginning with the fourth quarter of 2011, this team assumed management control of our operations and development activities in the Permian Basin. With an average of approximately 24 years of industry experience per person, this team has extensive experience in the Permian Basin as well as other resource plays in North America, including significant experience in drilling and completing horizontal wells. Under the direction of our new executive team, the average drilling time required to reach total depth, or TD, was shortened by 25% to 14 days during the period from April 2012 through August 2012 from 20 days during the second quarter of 2011. We also reduced the time from spud to production from an average of 68 days during the fourth quarter of 2011 to an average of 56 days during the second quarter of 2012. Also, during the quarter ended June 30, 2012 our average daily production, pro forma for the Transactions, was 3,637 BOE/d, consisting of 2,579 Bbls/d of oil, 2,757 Mcf/d of natural gas and 599 Bbls/d of natural gas liquids, an increase of 13%, or 408 BOE/d, from 3,229 BOE/d, consisting of 2,365 Bbls/d of oil, 2,267 Mcf/d of natural gas and 486 Bbls/d of natural gas liquids, for the quarter ended March 31, 2012. This increase was due primarily to improved strategies and procedures introduced by our new executive team relating to wellbore configuration, completion, execution, fluid recovery and well pumping practices that significantly reduced the level of required well remediation and the associated loss of production. We anticipate further increases in efficiencies as our new executive team executes on our development strategies across our acreage base.

The following table provides a summary of selected operating information of our properties, pro forma for the Transactions. The information is as of August 31, 2012 except as otherwise noted.

Basin	Net Acreage	Average Working Interest	Identified Potential Drilling Locations[(1)] Gross	Net	2012 Budget Gross Wells[(2)]	Net Wells[(2)]	Capex (In millions)	Estimated Net Proved Reserves at December 31, 2011 MBOE	% Developed	Average Daily Production (BOE/d)[(3)]
Permian	51,709	87%	916	849	59	48	$ 150.0 - $160.0	39,460	23.9	3,712

(1) Reflects identified potential vertical drilling locations on 40-acre spacing based on our evaluation of applicable geologic and engineering data. We have an additional 1,122 gross (1,027 net) identified potential vertical drilling locations based on 20-acre downspacing. These identified potential drilling locations do not include any potential horizontal drilling locations. The drilling locations on which we actually drill wells will ultimately depend on the availability of capital, regulatory approvals, oil and natural gas prices, costs, actual drilling results and other factors.

(2) Includes 50 gross (45 net) wells, of which two gross (two net) wells are horizontal, for which we are the operator and nine gross (three net) non-operated wells, of which three gross (one net) wells are horizontal wells.

(3) During August 2012.

We currently anticipate our 2012 capital budget for drilling and infrastructure will be approximately $150.0 million to $160.0 million after giving effect to the Transactions. Of this amount, we plan to spend approximately $126.0 million on the drilling and completion of 48 gross (43 net) operated vertical wells and two gross and two net horizontal wells, $11.0 million for the drilling and completion of nine gross (three net) non-operated wells, $6.0 million for leasehold acquisitions and $12.0 million for the construction of infrastructure to support production, including investments in water disposal infrastructure and gathering line projects. During the six months ended June 30, 2012, our aggregate capital expenditures for drilling and infrastructure after giving effect to the Transactions were $70.7 million.

Our Business Strategy

Our business strategy is to increase stockholder value through the following:

Grow production and reserves by developing our oil-rich resource base. We intend to actively drill and develop our acreage base in an effort to maximize its value and resource potential. Through the conversion of our undeveloped reserves to developed reserves, we will seek to increase our production, reserves and cash flow while generating favorable returns on invested capital. As of August 31, 2012, after giving effect to the Transactions, we had 916 identified potential vertical drilling locations on our acreage in the Permian Basin based on 40-acre spacing and an additional 1,122 such locations based on 20-acre downspacing. We believe the drilling of these locations will provide us with the critical subsurface data necessary to target potential horizontal horizons. Our 2012 drilling plan currently contemplates drilling 48 gross (43 net) vertical wells and two gross (two net) horizontal wells in the Wolfberry play. We ended 2011 with a two rig drilling program which we increased to four drilling rigs in 2012. As of August 31, 2012, we were using two drilling rigs. Upon completion of this offering, we intend to increase our drilling program to six rigs. Subject to market conditions and rig availability, we expect to operate six rigs throughout 2013, which we expect will allow us to significantly increase our drilling program in 2013.

Focus on increasing hydrocarbon recovery through horizontal drilling and increased well density. We believe there are opportunities to target various intervals in the Wolfberry play with horizontal wells. In June 2012, we completed our first horizontal operated well, in which we have a 100% interest, in the Wolfcamp B interval in Upton County and currently plan to drill one additional gross (one net) horizontal operated well in 2012, also targeting the Wolfcamp B interval. Our first horizontal operated well had a 3,842 foot lateral, a 24-hour initial production rate of 618 BOE/d and a 30-day average initial production rate of 486 BOE/d, of which 86% was oil. Based on the decline curve analysis of the current production, we anticipate that the EUR for this well will be in the range of 400 to 500 MBOE, of which 67% is expected to be oil. Additionally, since June 2012, we have participated in three gross (one net) horizontal non-operated wells in Midland and Ector Counties. See *Prospectus Summary Recent Developments* on page 6. Our horizontal

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drilling program is designed to further capture the upside potential that may exist on our properties. We also believe our horizontal drilling program may significantly increase our recoveries per section as compared to drilling vertical wells alone. Horizontal drilling may also be economical in areas where vertical drilling is currently not economical or logistically viable. In addition, we believe increased well density opportunities may exist across our acreage base. We closely monitor industry trends with respect to higher well density, which could increase the recovery factor per section and enhance returns since infrastructure is typically in place.

Leverage our experience operating in the Permian Basin. Our executive team, which has an average of approximately 24 years of industry experience per person and significant experience in the Permian Basin, intends to continue to seek ways to maximize hydrocarbon recovery by refining and enhancing our drilling and completion techniques. The time to reach TD for our vertical Wolfberry wells decreased from an average of 20 days during the second quarter of 2011 to an average of 14 days during the period from April 2012 through August 2012, resulting in a lower total well cost. Our focus on efficient drilling and completion techniques, and the resulting reduction in time to reach TD, is an important part of the continuous drilling program we have planned for our significant inventory of identified potential drilling locations. In addition, we believe that the experience of our new executive team in deviated and horizontal drilling and completions should help reduce the execution risk normally associated with these complex well paths. Additionally, our completion techniques are continually evolving as we evaluate hydraulic fracturing practices that may potentially increase recovery and reduce completion costs. Our executive team regularly evaluates our operating results against those of other operators in the area in an effort to benchmark our performance against the best performing operators and evaluate and adopt best practices.

Enhance returns through our low cost development strategy of resource conversion, capital allocation and continued improvements in operational and cost efficiencies. In the current commodity price environment, our oil and liquids rich asset base provides attractive returns. Our acreage position in the Wolfberry play is generally in contiguous blocks which allows us to develop this acreage efficiently with a manufacturing strategy that takes advantage of economies of scale and uses centralized production and fluid handling facilities. We are the operator of approximately 99% of our acreage. This operational control allows us to more efficiently manage the pace of development activities and the gathering and marketing of our production and control operating costs and technical applications, including horizontal development. Our average 87% working interest in our acreage pro forma for the Transactions allows us to realize the majority of the benefits of these expected improvements and cost efficiencies.

Pursue strategic acquisitions with exceptional resource potential. We have a proven history of acquiring leasehold positions in the Permian Basin that we believe have substantial oil-weighted resource potential and can achieve attractive returns on invested capital. Our executive team, with its extensive experience in the Permian Basin, has what we believe is a competitive advantage in identifying acquisition targets and a proven ability to evaluate resource potential. We intend to continue to pursue acquisitions that meet our strategic and financial targets.

Maintain financial flexibility. We seek to maintain a conservative financial position. As of June 30, 2012, on a pro forma basis after giving effect to this offering and the use of proceeds from this offering to repay the outstanding borrowings under our revolving credit facility, we would have had $90.0 million of available borrowing capacity under such facility.

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Our Strengths

We believe that the following strengths will help us achieve our business goals:

Oil rich resource base in one of North America s leading resource plays. All of our leasehold acreage is located in one of the most prolific oil plays in North America, the Permian Basin in West Texas. As of September 21, 2012, the Baker Hughes Rig Count survey reported that there were 501 rigs drilling in the Permian Basin. The majority of our current properties are well positioned in the core of the Wolfberry play. We believe that our historical vertical development success will be complemented with horizontal drilling locations that could ultimately translate into an increased recovery factor on a per section basis. Our production was approximately 74% oil, 15% natural gas liquids and 11% natural gas for both the year ended December 31, 2011 and the six months ended June 30, 2012. As of December 31, 2011, after giving effect to the Transactions, our estimated net proved reserves were comprised of approximately 66% oil and 20% natural gas liquids. This oil and liquids exposure allows us to benefit from their currently more favorable prices as compared to natural gas.

Multi-year drilling inventory in one of North America s leading oil resource plays. We have identified a multi-year inventory of potential drilling locations for oil-weighted reserves that we believe provides attractive growth and return opportunities. As of August 31, 2012, after giving effect to the Transactions, we had 916 identified potential vertical drilling locations based on 40-acre spacing and an additional 1,122 identified potential vertical drilling locations based on 20-acre downspacing. In 2012, after giving effect to the Transactions, we anticipate drilling 48 gross (43 net) vertical operated wells, which represent only approximately 5.1% of our identified vertical potential drilling locations on 40-acre spacing at August 31, 2012. We also believe that there are a significant number of horizontal locations that could be drilled on our acreage. In June 2012, we completed our first horizontal operated well, in which we have a 100% interest, in the Wolfcamp B interval in Upton County and currently expect to drill one additional gross (one net) horizontal operated well during 2012, also targeting the Wolfcamp B interval. Additionally, since June 2012, we have participated in three gross (one net) non-operated horizontal wells. Management currently estimates that EURs for our horizontal wells will be approximately 500 to 600 MBOE for lateral lengths averaging 7,500 feet. In addition, the liquids rich natural gas component of our inventory adds value with Btu content ranging from 1,225 MMBtu to 1,528 MMBtu and our June 2012 natural gas liquids yield was 118 Bbls/MMcf. In addition, we have approximately 117 square miles of proprietary 3-D seismic data covering our acreage. This data facilitates the evaluation of our existing drilling inventory and provides insight into future development activity, including horizontal drilling opportunities and strategic leasehold acquisitions.

Experienced, incentivized and proven management team. Our new executive team has an average of approximately 24 years of industry experience per person, most of which is focused on resource play development. This team has a proven track record of executing on multi-rig development drilling programs and extensive experience in the Permian Basin. In addition, our executive team has significant experience with both drilling and completing horizontal wells as well as horizontal well reservoir and geologic expertise, which will be of strategic importance as we expand our future development plans to include horizontal drilling. Prior to joining us, our Chief Executive Officer held management positions at Apache Corporation, Laredo Petroleum Holdings, Inc. and Burlington Resources.

Favorable and stable operating environment. We have focused our drilling and development operations in the Permian Basin, one of the oldest hydrocarbon basins in the United States, with a long and well-established production history and developed infrastructure. With approximately 380,000 wells drilled in the Permian Basin since the 1940s, we believe that the geological and regulatory environment is more stable and predictable, and that we are faced with less operational risks, in the Permian Basin as compared to emerging hydrocarbon basins.

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High degree of operational control. We are the operator of approximately 99% of our Permian Basin acreage. This operating control allows us to better execute on our strategies of enhancing returns through operational and cost efficiencies and increasing ultimate hydrocarbon recovery by seeking to continually improve our drilling techniques, completion methodologies and reservoir evaluation processes. Additionally, as the operator of substantially all of our acreage, we retain the ability to adjust our capital expenditure program based on commodity price outlooks. This operating control also enables us to obtain data needed for efficient exploration of horizontal prospects.

Financial flexibility to fund expansion. Upon the completion of this offering, we will have a conservative balance sheet. We will seek to maintain financial flexibility to allow us to actively develop our drilling, exploitation and exploration activities in the Wolfberry play and maximize the present value of our oil-weighted resource potential. As of June 30, 2012, on a pro forma basis after giving effect to this offering and the use of proceeds from this offering to repay the outstanding borrowings under our revolving credit facility, we would have had $90.0 million of available borrowing capacity under our revolving credit facility. We expect that our borrowing base will be increased as a result of the Transactions.

Our Properties

Review of Exploration, Exploitation and Development Activities

The following table summarizes certain operating information of our properties, pro forma for the Transaction. The information is as of August 31, 2012 except as otherwise noted.

			Identified Potential Drilling Locations[1]		2012 Budget			Estimated Net Proved Reserves at December 31, 2011		Average Daily
Basin	Net Acreage	Average Working Interest	Gross	Net	Gross Wells[2]	Net Wells[2]	Capex (In millions)	MBOE	% Developed	Production (BOE/d)[3]
Permian	51,709	87%	916	849	59	48	$ 150.0 - $160.0	39,460	23.9	3,712

(1) Reflects identified potential vertical drilling locations on 40-acre spacing based on our evaluation of applicable geologic and engineering data. We have an additional 1,122 gross (1,027 net) identified potential vertical drilling locations based on 20-acre downspacing. These identified potential drilling locations do not include any potential horizontal drilling locations. The drilling locations on which we actually drill wells will ultimately depend on the availability of capital, regulatory approvals, oil and natural gas prices, costs, actual drilling results and other factors.

(2) Includes 50 gross (45 net) wells, of which two gross (two net) wells are horizontal, for which we are the operator and nine gross (three net) non-operated wells, of which three gross (one net) wells are horizontal wells.

(3) During August 2012.

Permian Basin

Location and Land

We acquired approximately 4,174 net acres in West Texas (near Midland) in the Permian Basin on December 20, 2007, with an effective date of November 1, 2007, from ExL Petroleum, LP, Ambrose Energy I, Ltd. and certain other sellers. Subsequently, we acquired approximately 26,878 additional net acres, which brought our total net acreage position in the Permian Basin to approximately 31,052 net acres at August 31, 2012 and, after giving effect to the Transactions, we had 51,709 net acres. Since our initial acquisition in the Permian Basin through August 31, 2012, we drilled or participated in the drilling of 177 gross (105 net) wells (or 183 gross (161 net) wells after giving effect to the Transactions) on our leasehold in this area, primarily targeting the Wolfberry play. We are the operator of approximately 99% of our Permian Basin acreage. The Permian Basin area covers a significant portion of western Texas and eastern New Mexico and is considered one of the major producing basins in the United States.

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Area History

Our proved reserves are located in the Permian Basin of West Texas, in particular in the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations. The Spraberry play was initiated with production from several new field discoveries in the late 1940s and early 1950s. It was eventually recognized that a regional productive trend was present, as fields were extended and coalesced over a broad area in the central Midland Basin. Development in the Spraberry play was sporadic over the next several decades due to typically low productive rate wells, with economics being dependent on oil prices and drilling costs.

The Wolfcamp formation is a long-established reservoir in West Texas, first found in the 1950s as wells aiming for deeper targets occasionally intersected slump blocks or debris flows with good reservoir properties. Exploration using 2-D seismic data located additional fields, but it was not until the use of 3-D seismic data in the 1990s that the greater extent of the Wolfcamp formation was revealed. The additional potential of the shales within this formation as reservoir rather than just source rocks was not recognized until very recently.

During the late 1990s, Atlantic Richfield Company, or Arco, began a drilling program targeting the base of the Spraberry formation at 10,000 feet, with an additional 200 to 300 feet drilled to produce from the upper portion of the Wolfcamp formation. Henry Petroleum, a private firm, owned interests in the Pegasus field in Midland and Upton counties. While drilling in the same area as the Arco project, Henry Petroleum decided to drill completely through the Wolfcamp section. Henry Petroleum mapped the trend and began acquiring acreage and drilling wells using multiple slick-water fracturing treatments across the entire Wolfcamp interval. In 2005, former members of Henry Petroleum s Wolfcamp team formed their own private company, ExL Petroleum, and began replicating Henry Petroleum s program. After ExL had drilled 32 productive Wolfcamp/Spraberry wells through late 2007, they monetized a portion of their acreage position, which led to the acquisition that enabled us to begin our participation in this play. Recent advancements in enhanced recovery techniques and horizontal drilling continue to make this play attractive to the oil and gas industry. By mid-2010, approximately half of the rigs active in the Permian Basin were drilling wells in the Wolfberry play. As of August 31, 2012, we held interests in 205 gross (185 net) producing wells.

Geology

The Permian Basin formed as an area of rapid Mississippian-Pennsylvanian subsidence in the foreland of the Ouachita fold belt. It is one of the largest sedimentary basins in the U.S., and has oil and gas production from several reservoirs from Permian through Ordovician in age. The term Wolfberry was coined initially to indicate commingled production from the Permian Spraberry, Dean and Wolfcamp formations. In this prospectus, we refer to the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations collectively as the Wolfberry play. The Wolfberry play of the Midland Basin lies in the area where the historically productive Spraberry trend geographically overlaps the productive area of the emerging Wolfcamp play. The Spraberry was deposited as turbidites in a deep water submarine fan environment, while the Wolfcamp reservoirs consist of debris-flow and grain-flow sediments, which were also deposited in a submarine fan setting. The best carbonate reservoirs within the Wolfcamp are generally found in proximity to the Central Basin Platform, while the shale reservoirs within the Wolfcamp thicken basinward away from the Central Basin Platform. Both the Spraberry and Wolfcamp contain organic-rich mudstones and shales which, when buried to sufficient depth for maturation, became the source of the hydrocarbons found in the reservoirs.

The Wolfberry play can be generally characterized as a combination of low-permeability clastic, carbonate and shale reservoirs which are hydrocarbon-charged and are economic due to the overall thickness of the section (more than 3,000 feet) and application of enhanced stimulation (fracking) techniques. The Wolfberry is an unconventional basin-centered oil resource play, in the sense that there is no regional downdip oil/water contact.

Several shale intervals within the Wolfcamp formation are currently being evaluated for horizontal development potential, with initial drilling expected in 2012. The shales exhibit micro-darcy permeabilities,

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which result in relatively small drainage areas and recovery factors. Because of this, we believe the horizontal exploitation of these reservoirs will supplement, and not replace, the vertical development program.

There are also productive carbonate and shale intervals within the shallower Permian Clearfork formation. Two shale intervals within the Clearfork formation are currently being evaluated for potential horizontal development. Below the Wolfcamp formation lie the Pennsylvanian Strawn and Atoka formations. Although difficult to predict, there are conventional pay intervals that develop locally within these formations which, when present, can add significant reserves.

Debris flows within the Spraberry and Wolfcamp carbonates have been observed on 3-D seismic surveys. Initial tests have confirmed the presence of enhanced reservoir. Additionally, structural closures have been mapped and are being evaluated for drilling to test deeper targets. Our extensive geophysical database, which includes approximately 117 square miles of proprietary 3-D seismic data, will be used to enhance grading of future locations.

Ryder Scott, an independent petroleum engineering firm, has estimated that at December 31, 2011, proved reserves net to our interest in these assets were approximately 24,750 MBOE, of which 22.0% were classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate were from 293 gross well locations on 40-acre spacing. The proved reserves are generally characterized as long-lived, with predictable production profiles.

Production Status

In June 2012, net production from our Permian Basin acreage, pro forma for the Transactions, was 114,660 BOE, or an average of 3,822 BOE/d, of which 71% was oil, 17% was natural gas liquids and 12% was natural gas. From January 1, 2011 through December 31, 2011, our average daily net production from our Permian Basin acreage, pro forma for the Transactions, was 2,512 BOE/d, of which 72% was from oil, 16% was from natural gas liquids and 12% was from natural gas.

Facilities

Our land oil and gas processing facilities are typical of those found in the Permian Basin. Our facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

Recent and Future Activity

During 2011, 54 gross (31 net) wells were drilled on our Permian Basin acreage for an aggregate estimated net cost of $82.2 million. On a pro forma basis after giving effect to the Transactions, 56 gross (49 net) wells were drilled on our Permian acreage during 2011. As of August 31, 2012, we had 916 identified potential vertical drilling locations based on 40-acre spacing and an additional 1,122 identified potential vertical drilling locations based on 20-acre downspacing. We currently expect to drill an estimated 48 gross (43 net) vertical wells and two gross (two net) horizontal wells on our acreage in 2012. The wells are expected to be drilled to approximately 11,200 feet at an estimated average completed gross well cost of approximately $1.9 million to $2.4 million per vertical well and $6.0 million to $9.6 million per horizontal well with lateral lengths ranging from 4,500 to 9,500 feet. In this prospectus, we define identified potential drilling locations as locations specifically identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic and engineering data on 40-acre or 20-acre downspacing as indicated. The availability of local infrastructure, drilling support assets and other factors as management may deem relevant, such as 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.

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Oil and Gas Data

Proved Reserves

SEC Rule-Making Activity

In December 2008, the SEC released its final rule for Modernization of Oil and Gas Reporting. These rules require disclosure of oil and gas proved reserves by significant geographic area, using the arithmetic 12-month average beginning-of-the-month price for the year, as opposed to year-end prices as had previously been required unless contractual arrangements designate the price to be used. Other significant amendments included the following:

- Disclosure of unproved reserves: probable and possible reserves may be disclosed separately on a voluntary basis.

- Proved undeveloped reserve guidelines: reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

- Reserves estimation using new technologies: reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

- Reserves personnel and estimation process: additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

- Non-traditional resources: the definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted the rules effective December 31, 2009, as required by the SEC.

Evaluation and Review of Reserves

Our historical reserve estimates were prepared by Ryder Scott as of December 31, 2011 and by Pinnacle as of December 31, 2010 and 2009, in each case with respect to our assets in the Permian Basin. Reserve estimates for properties attributable to Windsor UT and the properties subject to the Gulfport transaction were prepared, in each case, by Ryder Scott as of December 31, 2011.

Each of Ryder Scott and Pinnacle is an independent petroleum engineering firm. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to 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. Neither independent third-party engineering firm owns an interest in any of our properties or is employed by us on a contingent basis.

Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. 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. All of our 2011 proved reserves were estimated using a deterministic method. 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 established under SEC rules. 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. The proved reserves for our properties were estimated by performance methods, analogy or a combination of both methods. Approximately 85% of the proved producing reserves attributable to producing wells were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of available historical production and pressure data. The remaining 15% of the proved reserves were estimated by analogy, or a combination of performance and analogy methods. The analogy method was 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. All proved developed non-producing and undeveloped reserves were estimated by the analogy method.

To estimate economically recoverable proved reserves and related future net cash flows, Ryder Scott considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves included production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the Permian Basin. Our internal technical team members met with our independent reserve engineers periodically during the period covered by the reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Our Vice President Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. Our Vice President Reservoir Engineering is a petroleum engineer with over 30 years of reservoir and operations experience and our geoscience staff has an average of approximately 26 years of industry experience per person. Our technical staff uses historical information for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by our Vice President Reservoir Engineering or under his direct supervision;
- review by our Vice President Reservoir Engineering of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- direct reporting responsibilities by our Vice President Reservoir Engineering to our Chief Executive Officer; and
- verification of property ownership by our land department.

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The following table presents our estimated net proved oil and natural gas reserves and the present value of our reserves as of December 31, 2011, based on the reserve report prepared by Ryder Scott, and as of December 31, 2010 and 2009, based on the reserve reports prepared by Pinnacle, each an independent petroleum engineering firm, and such reserve reports have been prepared in accordance with the rules and regulations of the SEC. All our proved reserves included in the reserve reports are located in North America. Ryder Scott and Pinnacle prepared all our reserve estimates as of the periods covered by their respective reports. The following table also sets forth estimates of our net proved oil and natural gas reserves as of December 31, 2011 on a pro forma basis after giving effect to the contribution of Windsor UT to Windsor Permian and the Gulfport contribution as if they had occurred on December 31, 2011. The reserves attributable to the Windsor UT properties and the properties subject to the Gulfport transaction have been prepared by Ryder Scott. Copies of the reserve reports as of December 31, 2011 prepared by Ryder Scott with respect to our properties, the Windsor UT properties and the properties subject to the Gulfport transaction are attached to this prospectus as Appendices B, C and D. Our estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency other than the SEC in connection with this offering.

	Pro Forma Year Ended December 31, 2011	Historical Year Ended December 31, 2011	2010	2009
Estimated proved developed reserves:				
Oil (Bbls)	6,046,099	3,805,291	3,307,550	1,954,060
Natural gas (Mcf)	8,335,945	5,186,941	4,255,300	2,453,750
Natural gas liquids (Bbls)	1,969,710	1,233,318	1,105,216	591,532
Total (BOE)	9,405,133	5,903,099	5,121,983	2,954,550
Estimated proved undeveloped reserves:				
Oil (Bbls)	20,140,377	12,911,578	15,511,500	27,276,880
Natural gas (Mcf)	24,261,522	14,431,926	17,407,420	25,028,070
Natural gas liquids (Bbls)	5,870,849	3,529,955	4,458,762	6,930,693
Total (BOE)	30,054,813	18,846,854	22,871,499	38,378,918
Estimated Net Proved Reserves:				
Oil (Bbls)	26,186,476	16,716,869	18,819,050	29,230,940
Natural gas (Mcf)	32,597,467	19,618,867	21,662,720	27,481,820
Natural gas liquids (Bbls)	7,840,559	4,763,273	5,563,978	7,522,225
Total (BOE)(1)	39,459,946	24,749,952	27,993,481	41,333,468
Percent proved developed	23.8%	23.9%	18.3%	7.1%

(1) Estimates of reserves as of December 31, 2011, 2010 and 2009 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods ended December 31, 2011, 2010 and 2009, respectively, in accordance with revised SEC guidelines applicable to reserves estimates as of the end of such periods. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

The foregoing reserves are all located within the continental United States. Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See *Risk Factors* beginning on page 18 of this prospectus. We have not filed any estimates of total, proved net oil or natural gas reserves with any federal authority or agency other than the SEC.

Additional information regarding our proved reserves can be found in *Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations* and *Critical Accounting Policies and Estimates* beginning on pages 66 and 82, respectively, of this prospectus, the notes to our consolidated financial statements included elsewhere in this prospectus and the reserve reports as of December 31, 2011 included as Appendices B, C and D to this prospectus.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2011, our proved undeveloped reserves totaled 12,912 MBbls of oil, 14,432 MMcf of natural gas and 3,530 MBbls of natural gas liquids, for a total of 18,847 MBOE. On a pro forma basis after giving effect to the Transactions, at December 31, 2011 our total proved undeveloped reserves would have totaled 20,140 MBbls of oil, 24,262 MMcf of natural gas and 5,871 MBbls of natural gas liquids for a total of 30,055 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

Changes in PUDs that occurred during 2011 on a pro forma basis after giving effect to the Transactions were primarily due to:

- Additions of 7,133 MBOE attributable to extensions resulting from strategic drilling of wells by us to delineate our acreage position;
- Conversion of approximately 3,630 MBOE attributable to PUDs into proved developed reserves;
- Negative revisions of approximately 1,679 MBOE in PUDs due to revisions related to offset well performance;
- Exclusion of 1,447 MBOE attributable to PUD locations that were not scheduled to be drilled within the next five years; and
- Movement of 6,116 MBOE from PUD to probable reserves due to changes in booking methodology used by our new independent petroleum engineers and well performance in one prospect area. The 2011 reserve report prepared by Ryder Scott assigned PUDs only in close proximity to seasoned production. The prior reports prepared by Pinnacle utilized a methodology consistent with large resource basins where geologic risk is minimal. The methodology utilized by Pinnacle typically results in a greater number of PUD locations than the close proximity method used by Ryder Scott. There was also a shift of 2,748 MBOE from proved to probable reserves in one prospect area where existing well performance declined more quickly than originally projected. Locations in this area were moved to the probable reserve category until more production history is obtained to confirm the economic viability of the area.

Costs incurred relating to the development of PUDs were approximately $53.9 million during 2011 and approximately $80.9 million on a pro forma basis after giving effect to the Transactions as if they had occurred on January 1, 2011. Estimated future development costs relating to the development of PUDs are projected to be approximately $85.6 million in 2012, $158.3 million in 2013, $131.8 million in 2014, $114.1 million in 2015 and $79.9 million in 2016 after giving effect to the Transactions. Since our new executive team assumed management control in 2011, our average drilling costs and drilling times have been reduced. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years.

All of our PUD drilling locations are scheduled to be drilled prior to the end of 2016.

As of December 31, 2011, 2% of our total proved reserves were classified as proved developed non-producing.

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Oil and Gas Production Prices and Production Costs

Production and Price History

The following table sets forth information regarding net production of oil, natural gas and natural gas liquids, and certain price and cost information for each of the periods indicated:

	Pro Forma		Historical				
	Six Months Ended June 30, 2012	Year Ended December 31, 2011	Six Months Ended June 30, 2012	2011	Year Ended December 31, 2011	2010	2009
Production Data:							
Oil (Bbls)	449,865	657,803	311,175	199,331	441,822	280,721	168,741
Natural gas (Mcf)	457,136	685,633	290,171	182,862	413,640	323,847	253,321
Natural gas liquids (Bbl)	98,760	144,818	65,188	44,820	86,815	79,978	70,384
Combined volumes (BOE)	624,814	916,893	424,725	274,628	597,577	414,674	281,345
Daily combined volumes (BOE/d)	3,433	2,512	2,334	1,517	1,637	1,136	771
Average Prices[1]:							
Oil (per Bbl)	$ 91.79	$ 91.80	$ 91.23	$ 95.60	$ 92.26	$ 76.51	$ 58.01
Natural gas (per Mcf)	2.40	3.96	2.27	4.03	3.98	4.32	3.64
Natural gas liquids (per Bbl)	42.38	54.02	41.58	50.09	54.98	44.56	28.49
Combined (per BOE)	74.54	77.36	74.77	80.25	78.95	63.77	45.20
Average Costs (per BOE):							
Lease operating expense	$ 16.38	$ 17.54	$ 14.44	$ 15.60	$ 17.31	$ 11.07	$ 8.41
Gathering and transportation expense	0.23	0.22	0.34	0.31	0.34	0.26	0.15
Production taxes	3.70	3.97	3.65	3.98	3.91	3.25	2.36
Production taxes as a % of sales	5.0%	5.1%	4.9%	5.0%	4.9%	5.1%	5.2%
Depreciation, depletion and amortization	$ 24.47	25.81	24.10	27.10	25.78	19.64	11.43
General and administrative	4.62	3.84	6.63	5.18	6.03	7.36	17.99

(1) After giving effect to our hedging arrangements in effect during the six months ended June 30, 2012 and 2011, respectively, the average prices per Bbl of oil and per BOE were $80.07 and $66.60, respectively, during the six months ended June 30, 2012 and $95.46 and $80.15, respectively, during the six months ended June 30, 2011. After giving effect to our hedging arrangements in effect during 2009, the average prices per Bbl of oil and per BOE (on a combined basis) were $41.59 and $35.35, respectively, during that year. Average prices for our hydrocarbons were not impacted by our hedging arrangements during 2011 or 2010.

Productive Wells

As of August 31, 2012, we owned an average 58.4% working interest in 201 gross (117 net) productive wells. On a pro forma basis after giving effect to the Transactions, at August 31, 2012 we would have owned an average 91.0% working interest in 205 gross (185 net) productive wells. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

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Developed and Undeveloped Acreage

The following table sets forth information as of August 31, 2012 relating to our leasehold acreage:

	Developed Acreage(1)		Undeveloped Acreage(2)		Total Acreage	
Basin	**Gross(3)**	**Net(4)**	**Gross(3)**	**Net(4)**	**Gross(3)**	**Net(4)**
Permian	8,280	4,541	46,147	26,511	54,428	31,052

(1) Developed acres are acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease.
(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.
(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.
(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

On a pro forma basis after giving effect to the Transactions, at August 31, 2012 our net developed, undeveloped and total acreage would have been 7,130, 44,579 and 51,709, respectively.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. The following table sets forth the gross and net undeveloped acreage (after giving effect to the Transactions), as of August 31, 2012, that will expire over the next five 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		2016	
Basin	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Permian	201	201	400	222	2,651	2,065	21,315	17,766	6,893	6,893

Drilling Results

The following table sets forth information with respect to the number of wells completed during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Year ended December 31,					
	2011		2010		2009	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development:						
Productive	39	23	41	27	11	8
Dry						
Exploratory:						
Productive	7	4				
Dry						
Total:						
Productive	46	27	41	27	11	8
Dry						

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As of December 31, 2011, we had 12 gross (6.4 net) wells in the process of drilling, completing or dewatering or shut in awaiting infrastructure that are not reflected in the above table. Since our initial acquisition in the Permian Basin through August 31, 2012, we drilled or participated in the drilling of 177 gross (105 net) wells in the Permian Basin (or 183 gross (161 net) wells after giving effect to the Transactions), of which we operate 154 gross (95 net) wells (or 167 gross (155 net) net wells after giving effect to the Transactions). Of the 183 gross wells drilled, 171 were completed as producing wells and 12 are in various stages of completion.

Operations

General

We are the operator of approximately 99% of our Permian Basin acreage. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We market the majority of the oil and natural gas production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our natural gas production to purchasers at market prices. In March 2009, we entered into an agreement with Windsor Midstream LLC, or Midstream, an entity controlled by Wexford, our equity sponsor. During 2010 and 2011, Midstream purchased a significant portion of our oil volumes. For a description of this agreement, see *Related Party Transactions Marketing Services* on page 136 of this prospectus. We sell all of our natural gas under contracts with terms of greater than twelve months and all of our oil under contracts with terms of twelve months or less.

We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. For the six months ended June 30, 2012, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (63%); Andrews Oil Buyers, Inc. (13%); and Occidental Energy Marketing, Inc. (12%). For the years ended December 31, 2011 and 2010, one purchaser, Midstream, accounted for approximately 78% and 81% of our revenue, respectively. For the year ended December 31, 2009, two purchasers accounted for more than 10% of our revenue: Windsor Midstream LLC (68%) and DCP Midstream, LP (15%). No other customer accounted for more than 10% of our revenue during these periods. If a major customer decided to stop purchasing oil and natural gas from us, revenue could decline and our operating results and financial condition could be harmed. However, based on the current demand for oil and natural gas, and the availability of other purchasers, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition and results of operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

On May 24, 2012, we entered into an oil purchase agreement with Shell Trading (US) Company, or Shell Trading, in which we agreed to sell specified quantities of oil to Shell Trading. We are obligated to commence delivery of our oil to Shell Trading upon completion of the reversal of the Longhorn pipeline and its conversion for oil shipment, which we refer to as the completion date, which is currently anticipated to occur at the end of the first quarter of 2013. Our agreement with Shell Trading has an initial term of five years from the completion date. Each party has the right to terminate the agreement by written notice to the other party without any obligations to the other party in the event that the completion date does not occur by January 15, 2014. The agreement may also be terminated by Shell Trading by written notice to us in the event that Shell Trading s contract for transportation on the pipeline is terminated.

Our delivery obligation under this agreement is 5,000 barrels per day from the service commencement date to March 31, 2013, 6,000 barrels per day from April 1, 2013 to September 30, 2013 and 8,000 barrels per day during the remainder of the term of the agreement. We have a one-time right to elect to decrease the contract quantity by not more than 20% of the then-current quantity, which decreased contract quantity will be effective for the remainder of the term of the agreement. Shell Trading has agreed to pay to us the price per barrel of oil based on the arithmetic average of the daily settlement price for Light Sweet Crude Oil Prompt Month future contracts reported by the New York Mercantile Exchange over the one-month period, as adjusted based on adjustment formulas specified in the agreement. If we fail to deliver the required quantities of oil under the agreement during any three-month period following the service commencement date, we have agreed to pay Shell Trading a deficiency payment, which is calculated by multiplying (i) the volume of oil that we failed to deliver as required under the agreement during such period by (ii) Magellan s Longhorn Spot tariff rate in effect for transportation from Crane, Texas to the Houston Ship Channel for the period of time for which such deficiency volume is calculated.

Transportation

During the initial development of our fields we consider all gathering and delivery infrastructure in the areas of our production. Our oil is transported from the wellhead to our tank batteries by our gathering systems. The oil is then transported by the purchaser by truck to a tank farm where it is further transported by pipeline. Our natural gas is generally transported from the wellhead to the purchaser s pipeline interconnection point through our gathering system.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and 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 oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or more integrated 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 prospects and producing oil and natural gas properties.

Title to Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

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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 18.75% to 25.00%, resulting in a net revenue interest to us generally ranging from 81.25% to 75.00%.

Regulation

Environmental Matters and Regulation

Our oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency, or EPA, issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. 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 and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing 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 our operations or relate to our owned or operated facilities. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

Waste Handling. The Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under RCRA, such wastes may constitute solid wastes that are subject to the less stringent requirements of non-hazardous waste provisions. However, we cannot assure you that the EPA or state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as hazardous wastes. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current

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costs of managing our wastes, as presently classified, to be significant, 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.

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as CERCLA or the Superfund law, and analogous state laws, generally imposes strict and joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed responsible parties may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such hazardous substances have been released.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, the Safe Drinking Water Act, the Oil Pollution Act, or OPA, and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as 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 Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. These laws and regulations also prohibit certain activity in wetlands 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. In addition, on October 20, 2011, the EPA announced a schedule to develop pre-treatment standards for wastewater discharges produced by natural gas extraction from underground coalbed and shale formations. The EPA stated that it will gather data, consult with stakeholders, including ongoing consultation with industry, and solicit public comment on a proposed rule for coalbed methane in 2013 and a proposed rule for shale gas in 2014. 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 Oil Pollution Act is the primary federal law for 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 develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability 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.

Noncompliance with the Clean Water Act or OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The federal Clean Air Act, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, on April 17, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new emission controls for oil and natural gas production and processing operations, which regulations are discussed in more detail on page 109 in *Regulation of Hydraulic Fracturing*. These laws and regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas projects.

Climate Change. Many nations have agreed to limit emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are greenhouse gases, or GHGs, regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol at this time, several states or geographic regions have adopted legislation and regulations to reduce emissions of GHGs. Additionally, on April 2, 2007, the U.S. Supreme Court ruled, in *Massachusetts, et al. v. EPA*, that the EPA has the authority to regulate the emission of carbon dioxide from automobiles as an air pollutant under the federal Clean Air Act. Thereafter, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth s atmosphere and other climatic changes. These findings by the EPA allowed 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. Subsequently, the EPA adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in April 2010 and it became effective January 2011, although it does not require immediate reductions in GHG emissions. The EPA adopted the stationary source rule, also known as the Tailoring Rule, in May 2010, and it also became effective January 2011, although it remains subject of several pending lawsuits filed by industry groups. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. More recently, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In addition, the EPA has continued to adopt GHG regulations of other industries, such as the March 2012 proposed GHG rule restricting future development of coal-fired power plants. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas emissions. Most of these 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 that correspond to 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 such allowances is expected to escalate significantly.

Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry. Currently, while we are subject to certain federal GHG monitoring and reporting requirements, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business.

Regulation of Hydraulic Fracturing

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The Safe Drinking Water Act, or SDWA, regulates the underground injection of substances through the Underground Injection Control, or UIC, program. Hydraulic fracturing generally is exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions. The EPA, however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as Class II UIC wells. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. As part of these studies, both the EPA and the House committee have requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

In March 2011, companion bills entitled the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, first introduced in 2009, were reintroduced in the United States Senate and House of Representatives. These bills, which are currently under consideration by Congress, would repeal the exemption for hydraulic fracturing from the SDWA, which would have the effect of allowing the EPA to promulgate regulations requiring permits and implementing potential new requirements on hydraulic fracturing under the SDWA. This development could, in turn, require state regulatory agencies in states with programs delegated under the SDWA to impose additional requirements on hydraulic fracturing operations. In addition, the bills would require persons using hydraulic fracturing, such as us, to disclose the chemical constituents, but not the proprietary formulas, of their fracturing fluids to a regulatory agency, which would make the information public via the internet. Additionally, fracturing companies would be required to disclose specific chemical contents of fluids, including proprietary chemical formulas, to state authorities or to a requesting physician or nurse if deemed necessary by the physician or nurse in connection with a medical emergency.

On April 17, 2012 the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA s rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds , or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule includes a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or green completions on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules will require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The federal government is currently undertaking several studies of hydraulic fracturing s potential impacts, the results of which are expected between later in 2012 and 2014.

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 authorities.

Several states, including Texas, and the Department of the Interior, in a May 4, 2012 proposed rule covering federal lands, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. On May 31, 2011, the Texas Legislature adopted new legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process. It was signed into law on June 17, 2011, effective as of September 1, 2011. The Texas Railroad Commission has adopted rules and regulations implementing this legislation that will apply to all wells for which the Railroad Commission issues an initial drilling permit on or after February 1, 2012. The new law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act (OSHA) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission.

There has been increasing public controversy regarding hydraulic fracturing with regard to use of fracturing fluids, impacts on drinking water supplies, use of waters and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing, such as the FRAC Act, are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our 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. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any 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 impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

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The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC s regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate and oil and natural gas liquids are not currently regulated and are made at market prices.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production or allowables ;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. 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. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the U.S. Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. FERC has

jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of our sales of our own production. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC s initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC s current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting gas to point-of-sale locations.

Oil Sales and Transportation. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

State Regulation. Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Operational Hazards and Insurance

The oil business involves a variety of operating risks, including the risk of fire, explosions, blow outs, pipe failures and, in some cases, abnormally high pressure formations which could lead to environmental hazards such as oil spills, natural gas leaks and the discharge of toxic gases. If any of these should occur, we could incur legal defense costs and could be required to pay amounts due to injury, loss of life, damage or destruction to property, natural resources and equipment, pollution or environmental damage, regulatory investigation and penalties and suspension of operations.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We currently have insurance policies for property (including leased oil and gas properties), general liability, operational control of certain wells, pollution, commercial auto, umbrella liability, inland marine, workers compensation and other coverage. The limits for certain of our policies are as follows:

- oil and gas lease property: $21,888,656 with a deductible ranging from $5,000 to $20,000 based on property value;
- general liability: $1,000,000 per occurrence and $2,000,000 in the aggregate with a $25,000 deductible;
- pollution: $1,000,000 per occurrence and $2,000,000 in the aggregate with a $50,000 deductible;
- umbrella liability: $5,000,000 per occurrence with $5,000,000 aggregate coverage; and
- inland marine: limit varies on a per rig basis from $3,586,000 to $7,155,000 with a $250,000 deductible per accident.

As noted above, most of our insurance coverage includes deductibles that must be met prior to recovery. Additionally, our insurance is subject to exclusion and limitations, and there is no assurance that such coverage will fully or adequately protect us against liability from all potential consequences, damages and losses. Any of these operational hazards could cause a significant disruption to our business. A loss not fully covered by insurance could have a material adverse affect on our financial position, results of operations and cash flows.

We reevaluate the purchase of insurance, policy terms and limits annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

Generally, we also require our third party vendors to sign master service agreements in which they agree to indemnify us for injuries and deaths of the service provider s employees as well as contractors and subcontractors hired by the service provider.

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Employees

As of June 30, 2012, we had approximately 54 full time employees, including three geologists, three engineers and three land professionals, all of whom are salaried administrative or supervisory employees. Of these 54 full time employees, 14 work in our office in Midland, Texas. None of our employees are represented by labor unions or covered by any collective bargaining agreements. We also hire independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist our full time employees.

Facilities

Our corporate headquarters is located in Midland, Texas. We also lease additional office space in Midland and in Oklahoma City, Oklahoma. We believe that our facilities are adequate for our current operations.

Legal Proceedings

Due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities, including workers compensation claims and employment related disputes. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

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MANAGEMENT

Executive Officers and Directors

Set forth below is the name, age, position and a brief account of the business experience of each of our executive officers and directors as of September 30, 2012.

Name	Age	Position
Travis D. Stice	50	Chief Executive Officer
Teresa L. Dick	42	Chief Financial Officer, Senior Vice President
Russell Pantermuehl	53	Vice President Reservoir Engineering
Paul Molnar	56	Vice President Geoscience
Michael Hollis	36	Vice President Drilling
William Franklin	58	Vice President Land
Jeff White	56	Vice President Operations
Randall J. Holder	58	Vice President, General Counsel and Secretary
Steven E. West	52	Director
Michael P. Cross	61	Director Nominee
Paul Jacobi	45	Director Nominee
David L. Houston	59	Director Nominee
Mark L. Plaumann	56	Director Nominee

Travis D. Stice Chief Executive Officer Mr. Stice has served as our Chief Executive Officer since January 2012. Prior to his current position with us, he served as our President and Chief Operating Officer from April 2011 to January 2012. Mr. Stice has also served on the board of managers of MidMar Gas LLC, or MidMar, an entity that owns a gas gathering system and processing plant, since 2011 and as Vice President and Secretary of MidMar since April 2012. From November 2010 to April 2011, Mr. Stice served as a Production Manager of Apache Corporation, an oil and gas exploration company. Mr. Stice served as a Vice President of Laredo Petroleum Holdings, Inc, an oil and gas exploration company, from September 2008 to September 2010. From April 2006 until August 2008, Mr. Stice served as a Development Manager of ConocoPhillips/Burlington Resources Mid-Continent Business Unit, an oil and gas exploration company. Prior to that, Mr. Stice held a series of positions at Burlington Resources, an oil and gas exploration company, most recently as a General Manager, Engineering, Operations and Business Reporting of its Mid Continent Division from January 2001 until Burlington Resources acquisition by ConocoPhillips in March 2006. Mr. Stice has over 26 years of industry experience in production operations, reservoir engineering, production engineering and unconventional oil and gas exploration and over 18 years of management experience. Mr. Stice graduated from Texas A&M University with a Bachelor of Science degree in Petroleum Engineering. Mr. Stice is a registered engineer in the State of Texas, and is a 25-year member of the Society of Petroleum Engineers.

Teresa L. Dick Chief Financial Officer, Senior Vice President Ms. Dick has served as our Chief Financial Officer and Senior Vice President since November 2009. Prior to her current position with us, Ms. Dick served as our Corporate Controller from November 2007 until November 2009. From June 2006 to November 2007, Ms. Dick held a key management position as the Controller/Tax Director at Hiland Partners, a publicly-traded midstream energy master limited partnership. Ms. Dick has over 19 years of accounting experience, including over eight years of public company experience in both audit and tax areas. Ms. Dick

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received her Bachelor of Business Administration degree in Accounting from the University of Northern Colorado. Ms. Dick is a certified public accountant and a member of the American Institute of CPAs and the Council of Petroleum Accountants Societies.

Russell Pantermuehl Vice President Reservoir Engineering Mr. Pantermuehl joined us in August 2011 as Vice President Reservoir Engineering. Prior to his current position with us, Mr. Pantermuehl served as a reservoir engineering supervisor for Concho Resources Inc., an oil and gas exploration company, from March 2010 to August 2011. Mr. Pantermuehl worked for ConocoPhillips Company as a reservoir engineering advisor from January 2005 to March 2010. Mr. Pantermuehl also worked as an independent consultant in the oil and gas industry from March 2000 to December 2004. Mr. Pantermuehl received a Bachelor of Science degree in Petroleum Engineering from Texas A&M University.

Paul Molnar Vice President Geoscience Mr. Molnar joined us in August 2011 as Vice President Geoscience. Prior to his current position with us, Mr. Molnar served as a Senior District Geologist for Samson Investment Company, an oil and gas exploration company, from March 2011 to August 2011. Mr. Molnar worked as an asset supervisor and geosciences supervisor for ConocoPhillips Company from April 2006 to February 2011. Mr. Molnar also worked as a geologic advisor for Burlington Resources, an oil and gas exploration company, from December 1996 to March 2006. Mr. Molnar has over 31 years of industry experience. Mr. Molnar received a Master of Science degree in Geology from The State University of New York at Buffalo, New York.

Michael Hollis Vice President Drilling Mr. Hollis joined us in September 2011 as Vice President Drilling. Prior to his current position with us, Mr. Hollis served in various roles, most recently as drilling manager at Chesapeake Energy Corporation, an oil and gas exploration company, from June 2006 to September 2011. Mr. Hollis worked for ConocoPhillips Company as a senior drilling engineer from January 2004 to June 2006 and as a process engineer from 2001 to 2003. Mr. Hollis also worked as a production engineer for Burlington Resources from 1998 to 2001 as well as from June 2003 to January 2004. Mr. Hollis received his Bachelor of Science degree in Chemical Engineering from Louisiana State University.

William Franklin Vice President Land Mr. Franklin joined us in August 2011 as Vice President Land. Prior to his current position with us, Mr. Franklin worked for ConocoPhillips Company in various land management roles from May 1983 until July 2011. Mr. Franklin received a Bachelor of Arts degree in History from Oklahoma City University.

Jeff White Vice President Operations Mr. White joined us in September 2011 as Vice President Operations. Prior to his current position with us, Mr. White worked for Laredo Petroleum Holdings, Inc. as a completion manager from May 2010 to September 2011. Mr. White also worked as a staff engineer for ConocoPhillips from February 2007 to May 2009. In addition, he worked in various engineering and management positions with Anadarko Petroleum from June 1988 to June 2005. Mr. White received a Bachelor of Science degree in Petroleum Engineering from Texas Tech University. He also received a Bachelor of Science degree in Fishery Biology from New Mexico State University.

Randall J. Holder Vice President, General Counsel and Secretary Mr. Holder joined us in November 2011 as General Counsel and Vice President responsible for legal and human resources. Prior to his current position with us, Mr. Holder served as General Counsel and Vice President for Great White Energy Services LLC, an oilfield services company, from November 2008 to November 2011. Mr. Holder served as Executive Vice President and General Counsel for R.L. Hudson and Company, a supplier of molded rubber and plastic components, from February 2007 to October 2008. Mr. Holder was in private practice of law and a member of Holder Betz LLC from February 2005 to February 2007. Mr. Holder served as Vice President and Assistant General Counsel for Dollar Thrifty Automotive Group, a vehicle rental company, from January 2003 to February 2005 and, before that, as Vice President and General Counsel for Thrifty Rent-A-Car System, Inc., a vehicle rental company, from September 1996 to December 2002. He also served as Vice President and General Counsel

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for Pentastar Transportation Group, Inc. from November 1992 to September 1996, which was wholly-owned by Chrysler Corporation. Mr. Holder started his legal career with Tenneco Oil Company where he served as a Division Attorney providing legal services to the company s mid-continent division for ten years. Mr. Holder received a Juris Doctorate degree from Oklahoma City University.

Steven E. West Director Mr. West has served as a director of our company since December 2011. Mr. West served as our Chief Executive Officer from January 1, 2009 to December 31, 2011. Since January 2011, Mr. West has been a partner at Wexford, focusing on Wexford s private equity energy investments. From August 2006 until December 2010, Mr. West served as senior portfolio advisor at Wexford. From August 2003 until August 2006, Mr. West was the chief financial officer of Sunterra Corporation, a former Wexford portfolio company. From December 1993 until July 2003, Mr. West held senior financial positions at Coast Asset Management and IndyMac Bank. Prior to that, Mr. West worked at First Nationwide Bank, Lehman Brothers and Peat Marwick Mitchell & Co., the predecessor of KPMG LLP. Mr. West holds a Bachelor of Science degree in Accounting from California State University, Chico. We believe Mr. West s background in finance, accounting and private equity energy investments, as well as his executive management skills developed as part of his career with Wexford, its portfolio companies and other financial institutions qualify him to serve on our board of directors.

Michael P. Cross Director Nominee Mr. Cross has agreed to serve as a director of our company and is expected to join our board prior to the closing of this offering. Mr. Cross is President and owner of Michael P. Cross, Inc., an independent oil and natural gas producer, a position he has held since July 1994. Mr. Cross also currently serves as a director of Warren Equipment Company, a position he has held since 2002. Mr. Cross has also served as a member of the Oklahoma Energy Resources Board since February 2005 and has been a member of the Executive Committee since 2007. Mr. Cross also served as a member of the Board of Directors of the Oklahoma Independent Petroleum Association for over 15 years. Mr. Cross served on the Board of Directors for OGE Energy GP LLC from October 2007 to October 2008. Mr. Cross also served as CEO and President of Windsor Energy Resources, Inc. from December 2005 until December 2006. Mr. Cross served as President and Manager of Twister Gas Services, L.L.C., an oil and gas exploration, production and marketing company, from its inception in 1996 until June 2003 and served as President of its predecessor, Twister Transmission Company, from 1990 to 1996. Mr. Cross graduated from Oklahoma State University in 1973 with a BS in Business Administration. We believe that Mr. Cross s strong oil and gas background and executive management experience qualify him for service on our board of directors.

Paul Jacobi Director Nominee Mr. Jacobi has agreed to serve as a director of our company and is expected to join our board prior to the closing of this offering. Since 1996, Mr. Jacobi has served in various positions at Wexford, including as a Vice President, and became a partner at Wexford in 2012, focusing on Wexford s private equity energy investments. From 1995 to 1996, Mr. Jacobi worked for Moody s Investors Services as an analyst covering the investment banking and asset management industries. From 1993 to 1995, Mr. Jacobi was employed by Kidder Peabody & Co. as a senior financial analyst in the investment banking group. From 1988 to 1993, Mr. Jacobi worked for KPMG Peat Marwick as an audit manager in the financial services practice. Mr. Jacobi holds a BS in accounting from Villanova University. We believe Mr. Jacobi s background in finance, accounting and private equity energy investments, as well as his executive management skills developed as part of his career with Wexford, its portfolio companies and other financial institutions qualify him to serve on our board of directors.

David L. Houston Director Nominee Mr. Houston has agreed to serve as a director of our company and is expected to join our board prior to the closing of this offering. Since 1991, Mr. Houston has been the principal of Houston & Associates, a firm that offers life and disability insurance, compensation and benefits plans and estate planning. Prior to 1991, Mr. Houston was President and Chief Executive Officer of Equity Bank for Savings, F.A., an Oklahoma-based savings bank and is the former chair of the Oklahoma State Ethics Commission and the Oklahoma League of Savings Institutions. In May 1992, in settlement of administrative litigation (and without any finding or admission of guilt) brought by the U.S. Office of Thrift Supervision against him in his capacity as an executive officer of a thrift institution, Mr. Houston entered into a consent order under which he agreed not to serve as an officer of, or participate in the affairs of, insured depository institutions. The order relates to alleged violations of certain lending practices in early 1990 or before. Mr. Houston served on the board of directors and executive committee of Deaconess

Hospital, Oklahoma City, Oklahoma, from January 1993 until December 2008. Mr. Houston has served as a director of Gulfport since July 1998 and is the chairman of its audit committee. He also served as a director of Bronco Drilling Company from May 2005 until December 2010 and was a member of its audit committee. Mr. Houston received a Bachelor of Science degree in business from Oklahoma State University and a graduate degree in banking from Louisiana State University. We believe that Mr. Houston s financial and executive management experience qualify him for service on our board of directors.

Mark L. Plaumann Director Nominee Mr. Plaumann has agreed to serve as a director of our company and is expected to join our board prior to the closing of this offering. He is currently a Managing Member of Greyhawke Capital Advisors LLC, or Greyhawke, which he co-founded in 1998. Prior to founding Greyhawke, Mr. Plaumann was a Senior Vice President of Wexford. Mr. Plaumann was formerly a Managing Director of Alvarez & Marsal, Inc. and the President of American Healthcare Management, Inc. He also was Senior Manager at Ernst & Young LLP. Mr. Plaumann served as a director and audit committee chairman for ICx Technologies, Inc. until October 2010 and currently serves as a director and audit committee chairman of Republic Airways Holdings, Inc., and a director of one private company. Mr. Plaumann also has served as a director, an audit committee chairman and a member of the conflicts committee of the general partner of Rhino Resource Partners LP, a coal operating company, since October 2010. Mr. Plaumann holds an M.B.A. and a B.A. in Business from the University of Central Florida. We believe that Mr. Plaumann s service on the boards of other public companies and his executive management experience, including previous experience as chairman of audit committees, qualifies him for service on our board of directors.

Our Board of Directors and Committees

Upon completion of this offering, our board of directors will consist of five directors, at least three of whom will satisfy the independence requirements of current SEC rules and The NASDAQ Global Select Market listing standards. Our certificate of incorporation provides that the terms of office of the directors are one year from the time of their election until the next annual meeting of stockholders or until their successors are duly elected and qualified.

Our certificate of incorporation provides that the authorized number of directors will generally be not less than five nor more than thirteen, and the exact number of directors will be fixed from time to time exclusively by the board of directors pursuant to a resolution adopted by a majority of the whole board. In addition, our certificate of incorporation and our bylaws provide that, in general, vacancies on the board may be filled by a majority of directors in office, although less than a quorum.

Our board of directors will establish an audit committee in connection with this offering whose functions include the following:

- assist the board of directors in its oversight responsibilities regarding the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent accountant s qualifications and independence and our accounting and financial reporting processes of and the audits of our financial statements;

- prepare the report required by the SEC for inclusion in our annual proxy or information statement;

- appoint, retain, compensate, evaluate and terminate our independent accountants;

- approve audit and non-audit services to be performed by the independent accountants;

- review and approve related party transactions; and

- perform such other functions as the board of directors may from time to time assign to the audit committee.

The specific functions and responsibilities of the audit committee will be set forth in the audit committee charter. Upon completion of this offering, our audit committee will include three directors who satisfy the

independence requirements of current SEC rules and The NASDAQ Global Select Market listing standards. We expect that one of the members of the audit committee will qualify as an audit committee financial expert as defined under these rules and listing standards, and the other members of our audit committee will satisfy the financial literacy standards for audit committee members under these rules and listing standards.

Pursuant to our bylaws, our board of directors may, from time to time, establish other committees to facilitate the management of our business and operations. In connection with this offering, we will establish a compensation committee composed of at least two independent directors. See *Executive Compensation Compensation Discussion and Analysis Compensation Policy* on page 120 of this prospectus. We will also establish a nominating committee composed of at least three independent directors.

In connection with the Gulfport transaction, Gulfport was granted the right to designate one individual as a nominee to serve on our board of directors for so long as Gulfport beneficially owns more than 10% of our outstanding common stock. Such nominee, if elected to our board,