Midstates Petroleum Company, Inc.
Form 10-K
March 21, 2013

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2012

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to .
Commission File Number: 001-35512

MIDSTATES PETROLEUM COMPANY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**45-3691816**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
4400 Post Oak Parkway, Suite 1900; Houston, Texas	**77027**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(713) 595-9400**

Securities registered pursuant to Section 12(b) of the Act:

Common stock, $0.01 par value	**New York Stock Exchange**
(Title of each class)	(Name of each exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: **None**

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III or any amendment to the Form 10-K ý

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. Check one:

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

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

The aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $317 million based upon the closing price of such stock on June 29, 2012, the last business day of the registrant's most recently completed second fiscal quarter, of $9.71 per share.

The number of shares outstanding of our stock at March 14, 2013 is shown below:

Class	**Number of shares outstanding**
Common stock, $0.01 par value	68,365,008

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements other than statements of historical fact included in this annual report are forward-looking statements, including, without limitation, statements regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management. When used in this annual report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategy;
- estimated future net reserves and present value thereof;
- technology;
- cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- availability of oilfield labor;
- the amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;
- drilling of wells, including our identified drilling locations;
- successful results from our identified drilling locations;
- marketing of oil and natural gas;

the integration and benefits of the Eagle Property Acquisition or the effects of the acquisition on our cash position and levels of indebtedness;

infrastructure for salt water disposal;

property acquisitions;

costs of developing our properties and conducting other operations;

general economic conditions;

effectiveness of our risk management activities;

environmental liabilities;

counterparty credit risk;

the outcome of pending and future litigation;

governmental regulation and taxation of the oil and natural gas industry;

developments in oil-producing and natural gas-producing countries;

uncertainty regarding our future operating results; and

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plans, objectives, expectations and intentions contained in this annual report that are not historical.

All forward-looking statements speak only as of the date of this annual report. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this annual report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk Factors" and elsewhere in this annual report.

These factors include:

- variations in the market demand for, and prices of, oil, natural gas liquids and natural gas;
- uncertainties about our estimated quantities of oil and natural gas reserves;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our revolving credit facility;
- access to capital and general economic and business conditions;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- risks in connection with acquisitions, including the Eagle Property Acquisition;
- risks related to the concentration of our operations onshore in central Louisiana, and Northern Oklahoma and Kansas;
- drilling results;
- the potential adoption of new governmental regulations; and
- our ability to satisfy future cash obligations and environmental costs.

These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make.

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

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

Boe: Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

Boe/d: Barrels of oil equivalent per day.

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

Dry hole: A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production do not exceed production expenses and taxes.

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

MMBoe: One million barrels of oil equivalent.

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

NYMEX: The New York Mercantile Exchange.

Proved reserves: Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the

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first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Reasonable certainty: A high degree of confidence.

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

Reserves: Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development projects to known accumulations.

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

Spud or Spudding: The commencement of drilling operations of a new well.

Wellbore: The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

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

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PART I

ITEM 1. BUSINESS

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties, and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See "Cautionary Note Regarding Forward Looking Statements" and "Risk Factors" located in this Form 10-K.

In this section, references to "the Company," "we," "us," "our," and "Midstates" when used in the present tense, prospectively or for historical periods since April 25, 2012, refer to Midstates Petroleum Company, Inc. and its subsidiary, and for historical periods prior to April 25, 2012, refer to Midstates Petroleum Holdings LLC and its subsidiary, unless the context indicates otherwise.

General

Midstates Petroleum Company, Inc. was incorporated pursuant to the laws of the State of Delaware on October 25, 2011 to become a holding company for Midstates Petroleum Company LLC ("Midstates Sub"), which was previously a wholly-owned subsidiary of Midstates Petroleum Holdings LLC. Pursuant to the terms of a corporate reorganization that was completed in connection with the closing of Midstates Petroleum Company, Inc.'s initial public offering on April 25, 2012, all of the interests in Midstates Petroleum Holdings LLC were exchanged for newly issued common shares of Midstates Petroleum Company, Inc., and as a result, Midstates Sub became a wholly-owned subsidiary of Midstates Petroleum Company, Inc. and Midstates Petroleum Holdings LLC ceased to exist as a separate entity. Our common stock, par value $0.01 per share, has been listed on the New York Stock Exchange (NYSE) since April 2012. At December 31, 2012, we operated oil and natural gas properties as one reportable segment: the exploration, development and production of oil, natural gas and natural gas liquids.

We are an independent exploration and production company focused on the application of modern drilling and completion techniques to oil-prone resources in the Upper Gulf Coast Tertiary trend onshore in Louisiana, which we refer to as our "Gulf Coast" operating area, and, with the October 1, 2012 closing of our acquisition ("Eagle Property Acquisition") of interests in producing oil and natural gas assets, unevaluated leasehold acreage in Oklahoma and Kansas and related hedging instruments from Eagle Energy Production, LLC ("Eagle Energy"), in the Mississippian Lime trend in Oklahoma and Kansas, which we refer to as our "Mid-Continent" operating area.

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The following table summarizes, by areas of operation, our estimated proved reserves as of December 31, 2012, their corresponding pre-tax PV-10 values and our fourth quarter 2012 average daily production rates:

	Proved Reserves(1)					PV-10(3)	Average Daily Production for Three Months Ended December 31, 2012
Areas of Operation	**Oil (MBbl)**	**Gas (MMcf)**	**NGL (MBbl)**	**Total(2) (MBoe)**	**(% Oil)(4)**	**(In thousands)**	**(Boe/day)**
Gulf Coast	22,905	48,625	5,757	36,766	78%	$ 1,006,217	8,385
Mid-Continent	14,622	93,778	8,441	38,693	60%	482,870	7,207
Total	**37,527**	**142,403**	**14,198**	**75,459**	**69%**	**$ 1,489,087**	**15,592**
Discounted Future Income Taxes						(339,613)	
Standardized Measure of Discounted Future Net Cash Flows(3)						**$ 1,149,474**	

(1) Oil, natural gas liquids and natural gas reserve quantities and related discounted future net cash flows have been derived from oil, natural gas liquids and natural gas prices calculated using an average of the first-day-of-the month price for each month within the 12 months ended December 31, 2012, pursuant to current SEC and FASB guidelines.

(2) Barrel of oil equivalents are determined using a ratio of one Bbl of crude to six Mcf of natural gas, which represents their approximate relative energy content.

(3) Pre-tax PV-10 may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Pre-tax PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income taxes. We believe pre-tax PV-10 is a useful measure for investors for evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV-10 as a basis for comparison of the relative size and value of our proved reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, pre-tax PV-10 is not a substitute for the standardized measure of discounted future net cash flows. Our pre-tax PV-10 does not purport to present the fair value of our proved oil and natural gas reserves.

(4) Includes volumes attributable to oil and NGLs.

During 2012, we incurred $1.1 billion in exploration, development and total acquisition expenditures, including $665 million for the Eagle Property Acquisition (includes $2.7 million of asset retirement obligations), $76.9 million for facilities and lease and seismic acquisition, and $361.0 million for the drilling of 79 gross (74 net) wells. Of these new wells, 72 gross (67 net) wells resulted in productive completions and 7 gross (and net) wells were unsuccessful, yielding a 91% success rate.

We expect to invest between $420 million and $450 million of capital for exploration, development and lease and seismic acquisition in 2013. Additionally, we expect to capitalize between $28 million to $32 million of interest expense.

Growth Strategy

Our goal is to grow our reserves, production and cash flows at an attractive rate of return on invested capital. We seek to achieve this goal through the following strategies:

Accelerate development of our multi-year drilling inventory. We intend to drill and develop our current acreage position to maximize the value of our primarily oil and liquids rich resource potential.

Gulf Coast. Our Gulf Coast assets are located in Louisiana and are characterized by thick geologic sections of tight sands within the Tertiary Wilcox featuring multiple productive zones located within large geologic structural traps that are identifiable with 2D and 3D seismic data. Our primary operating areas have well-established production histories. At December 31, 2012 we had approximately 154,400 gross acres (151,800 net acres) under lease and/or lease option, comprised of 98,800 gross acres (96,800 net acres) under lease; 55,600 gross acres (55,000 net acres) under lease options, targeting large, well-defined geologic structures that we believe will increase our reserves, production and cash flow. From the third quarter of 2008 until December 31, 2012, we drilled 130 gross (128 net) wells in the trend, approximately 92% of which produced commercially, making us the most active driller in this trend during that period. As of December 31, 2012, we had three drilling rigs in operation. We currently have three rigs in operation in the Gulf Coast area and expect to spud or sidetrack between 23 to 26 gross and net wells, including eight to ten horizontal projects, during 2013 in the trend.

Mid-Continent. Our Mid-Continent assets acquired on October 1, 2012 are located in Oklahoma and Kansas and target the Mississippian Lime and Hunton formations. The Mississippian Lime is an expansive carbonate hydrocarbon system located in the Anadarko Basin, primarily in northern Oklahoma and Kansas. We currently intend to continue development of these liquids rich properties using horizontal wells and multi-stage frac technology. The Hunton formation is a limestone formation that produces primarily natural gas from our acreage in Lincoln County, Oklahoma. Because the Hunton targets primarily natural gas reserves, our capital deployment in the Mid-Continent will be focused on the Mississippian Lime until natural gas prices improve from current levels. At December 31, 2012, we had approximately 98,000 net acres under lease in the Mid-Continent region, comprised of approximately 83,000 net leased acres in the Mississippian Lime and approximately 15,000 net acres in the Hunton. As of December 31, 2012, we had four drilling rigs in operation, and we currently have four drilling rigs in operation. We expect to spud between 72 to 78 gross (36 to 39 net) horizontal wells, including non-operated wells, during 2013 on this acreage.

Maintain our track record of disciplined financial management. We intend to maintain our historically disciplined approach to our financial management in order to preserve our financial stability. We believe that this approach includes targeting a conservative leverage profile and maintaining the liquidity to develop our asset base across industry cycles, as well as evaluating capital allocation decisions in the context of these goals. We have historically funded our activity through a combination of equity, bank debt and cash generated by operations. For example, we funded the Eagle Property Acquisition with a combination of cash proceeds from our $600 million 10.75% senior notes (the "Senior Notes") offering and through the issuance of convertible preferred equity to the sellers. In October 2012, our reserve-based borrowing base under our revolving credit facility was increased from $200 million to $250 million. Our March 2013 redetermination was recently completed, and our borrowing base was increased to $285 million. To reduce variability in cash flow from our properties and to enhance our reserve based borrowing facility, we periodically enter into commodity derivative contracts. In addition, we target hedging approximately 50% of our total current volumes from proved developed producing reserves to reduce the effect of volatility of oil and gas prices on our cash flows. We believe the resulting increase in the predictability of our cash flow allows us to better schedule our development activities and maximize the productivity of those efforts.

Maintain operatorship across a diverse asset base. Our diverse set of assets and high degree of operating control, facilitated by our position as operator on the substantial majority of our properties, provide flexibility with respect to drilling and completion techniques and the timing and amount of capital expenditures that support growth within our framework of financial discipline.

Utilize our technical and operating expertise to enhance returns. Our technical teams are focused on the application of modern reservoir evaluation and drilling and completion techniques to reduce risk and enhance returns in our core areas. We utilize 2D and 3D seismic data, existing sub-surface well control data, detailed reservoir characterization, geologic and geochemical modeling to identify areas with significant exploration and development potential. These areas become targets for our leasing activity. Once we have identified a potential target, we attempt to maximize returns by applying modern drilling and completion techniques that maximize recoveries in a cost efficient and economically attractive manner. We utilize reservoir evaluation methods such as conventional and rotary sidewall coring, pressure sampling and other reservoir description techniques to better understand the ultimate potential of a particular area. We believe future development across our acreage position can be further optimized with specialized completion techniques, infill drilling, horizontal wellbore optimization and enhanced recovery methods.

Strategically increase our acreage position. While we believe our existing acreage positions provide significant growth opportunities in both the Upper Gulf Coast Tertiary trend and the Mississippian Lime, we continue to strategically increase our leasehold position. In Louisiana, we are continuing our efforts to extend the trend both east and west of our existing acreage along the Cretaceous Shelf edge. We believe our current Oklahoma and Kansas acreage is highly prospective in the Mississippian Lime and Hunton horizons and may be prospective in several other horizons as well. In addition to increasing our acreage position through leasing, we may selectively pursue acquisitions of strategic assets or operating companies in these trends in and around our existing core areas to complement our operations. We plan to continue targeting additional onshore basins in North America that would allow us to extend our competencies to large undeveloped acreage positions in hydrocarbon trends similar to our existing core areas.

Apply rigorous investment analysis to capital allocation decisions. We employ rigorous investment analysis to determine the allocation of capital across our many drilling opportunities and in evaluating potential acquisitions. We are focused on maximizing the internal rate of return on our investment capital and screen drilling opportunities and acquisition opportunities by measuring risk and financial return, among other factors. We continually evaluate our inventory of potential investments by these measures, incorporating past drilling results, historical knowledge and new information we have gathered.

Our Competitive Strengths

We have a number of competitive strengths that we believe will help us to successfully execute our business strategies:

Oil and liquids weighted reserves, production and drilling locations with attractive economics. Our reserves, production and drilling locations are primarily oil with associated liquids rich natural gas. For the year ended December 31, 2012, our production was comprised of approximately 57% oil and 17% NGLs. In the Gulf Coast, we benefit from selling our oil production to the Louisiana Light Sweet ("LLS") market, which has historically commanded a premium to West Texas Intermediate ("NYMEX WTI") oil prices due to its proximity to U.S. Gulf Coast refiners and the higher quality of the oil production sold in the LLS market. This premium has averaged approximately $12.89 per Bbl for the three years ended December 31, 2012. For the year ended December 31, 2012, the average realized price before the effect of commodity derivative contracts for our oil production was $104.35 per Bbl, compared to an average NYMEX WTI price of $94.12 per Bbl for the same period.

Extensive technical knowledge, history and early mover advantage in our areas of operations. We have had operations in the Upper Gulf Coast Tertiary trend since 1993. We believe our extensive operating experience in the trend provides us with an expansive technical understanding of the geology underlying our acreage and of the application of completion technologies and infrastructure design and optimization to our properties. We believe our relatively long history in the Gulf Coast area and experience interpreting well control data, core data and 2D and 3D seismic data provides us with an information advantage over our competitors in this trend and has allowed us to identify and acquire quality acreage at a relatively low cost. In addition, Eagle Energy was an early mover in acquiring and developing acreage in the Mississippian Lime trend, spudding 76 horizontal wells since 2010 including the 13 wells we have spud since October 1, 2012. We believe our Mid-Continent team's early experience operating in this trend gives us a competitive advantage with respect to completion techniques and infrastructure development. We believe we have developed amicable and mutually beneficial relationships with acreage owners in our core operating areas, which we believe also provides us with a competitive advantage with respect to our leasing and development activity. We also benefit from long-term relationships with local service companies and infrastructure providers that we believe contribute to our efficient low-cost operations.

Experienced and aligned management team with extensive operating expertise. Our management team has extensive operating expertise in the oil and gas industry and significant public company executive experience at major and large independent oil and gas companies and oilfield services companies, including Apache Corporation, Burlington Resources, ConocoPhillips, Noble Corporation and SM Energy. Our management team has an average of 30 years of industry experience, including prior experience in various trends across the US and internationally. We believe our management team is one of our principal competitive strengths relative to our industry peers due to our team's proven track record of efficiently operating exploration and development programs. Additionally, our management team has a significant ownership interest in us, which we believe provides incentive for them to prudently grow the value of our business for the benefit of all our stakeholders.

Summary of Oil and Gas Properties and Operations

Gulf Coast Region

In our Gulf Coast region, our current acreage positions and evaluation efforts are concentrated in Louisiana in the Wilcox interval of the Upper Gulf Coast Tertiary trend.

The Upper Gulf Coast Tertiary trend extends from south Texas to Mississippi across our current operating areas in central Louisiana and is characterized by well-defined geology, including tight sands featuring multiple productive zones typically located within large geologic traps. Many of the oilfields in this trend were discovered by major oil companies in the 1940s and 1950s, but were not fully developed due to then-prevailing oil prices, the adoption of a state-level severance tax in Louisiana, restrictive production allowables and other regulatory limitations. We have applied modern formation evaluation and drilling and completion techniques to the trend. Our early entry and relatively long history in the trend have positioned us as a first-mover. As of December 31, 2012, we had accumulated approximately 96,800 net acres in the trend and options to acquire an aggregate of approximately 55,000 additional targeted net acres.

Our development operations in the Gulf Coast area are currently focused on drilling vertical and horizontal wells and commingling production from multi-stage hydraulically fractured completions across stacked oil-producing intervals. As of December 31, 2012, we had drilled 130 wells in the trend, approximately 92% of which produced commercially, since the third quarter of 2008. Since that time, we have increased our average daily production at a compound annual growth rate of 69%, from 995 Boe/d in the year ended December 31, 2008 to 8,187 Boe/d in the year ended December 31, 2012.

Our properties in this area represented 49% of our total proved reserves as of December 31, 2012. During the three months ended December 31, 2012, our average production from these properties was 8,385 net Boe/d consisting of 5,737 Bbls of oil, 1,170 Bbls of NGLs, and 8,869 Mcf of natural gas. As of December 31, 2012, we held an average working interest and average net revenue interest of 96% and 73%; respectively, on our acreage in this area.

During 2012, we invested approximately $397.9 million for exploration, development and lease and seismic acquisition and drilled 74 wells in the Gulf Coast area. In 2013, we currently plan to invest

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between $170 million and $180 million and drill between 23 to 26 wells. We currently have three drilling rigs operating in this core area.

Gulf Coast Areas of Operation

The Gulf Coast areas of operation are concentrated in four core fields in Beauregard and Evangeline Parishes, Louisiana. In 2012, 82% of our drilling and completion capital was concentrated on our primary fields: Pine Prairie, South Bearhead Creek, West Gordon and North Coward's Gully.

In Pine Prairie we spent $161.9 million of capital in 2012, continuing our vertical development of the deeper objectives in the Wilcox and Sparta and shallower drilling in the Frio and Miocene sections. We spent $57.2 million in capital during 2012 in South Bearhead Creek continuing our Upper and Lower Wilcox development program. This field was also developed vertically in 2012 with plans to drill horizontally in the coming years. Capital deployment in the West Gordon field was split between vertical and horizontal drilling in 2012. With significant oil in place, we are continuing to evaluate the most efficient method to maximize recovery in this field. Lastly, in 2012, we drilled an Upper Wilcox B horizontal test well in the North Coward's Gully field. The Musser Davis 8H-1 well established the viability of developing the field with horizontal wells. We have since drilled a successful follow up and plan to continue drilling horizontals in the future.

Expansion Areas Within Gulf Coast

In late 2010, we began acquiring seismic data and additional acreage in a focused effort to expand our asset base in the Gulf Coast area. During 2011, we negotiated seismic options to acquire an additional 31,700 net acres in the trend and committed to shoot 3D seismic over the optioned acreage. The 3D data is currently being processed with expected final delivery by the end of the first quarter of 2013. We may acquire additional acreage within the 3D seismic shoot pending evaluation of the results. At December 31, 2012, we held approximately 77,700 gross (75,800 net) acres in these expansion areas and we are currently evaluating prospects on this acreage.

We have also added approximately 30,900 net acres to the north of our existing acreage positions which we are currently evaluating and expect to be prospective for exploration in the Austin Chalk and Tuscaloosa Marine Shale formations.

In 2012, we spent $27.6 million testing exploration concepts in the Gulf Coast operating area. We drilled three vertical test wells; two of the three wells produced hydrocarbons at sub-commercial rates. The third well did not produce hydrocarbons.

During 2013, we currently plan to drill between one and three wells on prospects within this expansion acreage, including acreage covered by the 3D seismic shoot discussed above.

Mid-Continent Region

Our Mid-Continent assets were acquired on October 1, 2012 and at December 31, 2012, consisted of approximately 83,000 net prospective acres in the Mississippian Lime trend, with 77,000 net acres in Woods and Alfalfa Counties of Oklahoma, which we believe is the core of the trend. We also have approximately 6,000 net acres in Kansas, in which we owned an average working interest of approximately 58%. We currently intend to develop these oil and liquids rich properties using horizontal wells. We also own approximately 15,000 net acres in Lincoln County, Oklahoma, which produces from and is prospective in the Hunton formation.

Our properties in this area represented 51% of our total proved reserves as of December 31, 2012. During the three months ended December 31, 2012, our average production from these properties was 7,207 net Boe/d consisting of 2,216 Bbls of oil, 1,820 Bbls of NGLs, and 19,021 Mcf of natural gas. As of December 31, 2012, we held an average working interest and average net revenue interest of 68%

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and 54%, respectively, on our acreage in this area. Since the closing of the Eagle Property Acquisition on October 1, 2012 through December 31, 2012, we have accumulated an additional 1,000 acres in and around our main operating area for Mississippian Lime development. We are participating in a 3D seismic shoot in northwest Oklahoma that will cover approximately 304 square miles.

In the Mid-Continent, our main operating area is defined by de-risked acreage primarily in Woods County, where we are engaged in development drilling. Our current development drilling is targeting the Mississippian Lime interval, where we anticipate ultimate development of three to four horizontal wells per section. In the fourth quarter of 2012, we invested approximately $39.9 million and drilled 13 operated horizontal wells; in 2013, we plan to invest approximately $250 million to $270 million in the drilling of between 72 to 78 wells, including non-operated wells. Our plans are to continue to actively develop this area while testing expansion areas beyond our current position.

Expansion Areas Within Mid-Continent

Our acreage position in the Mississippian Lime that extends beyond our de-risked acreage is being tested with one rig assigned to hold our primary term acreage with production. We will continue to run one (or more) rigs in these areas to not only hold acreage but also de-risk the acreage.

Estimated Proved Reserves

	Oil (MBbl)	Gas (MMcf)	NGL (MBbl)	Total MBoe
2010				
Proved reserves				
Beginning Balance	7,577	13,258	105	9,892
Revisions of previous estimates	(2,220)	(1,043)	49	(2,346)
Extensions, discoveries and other additions	7,515	17,944	234	10,740
Sales of reserves in place				
Purchases of reserves in place				
Production	(945)	(2,253)	(74)	(1,394)
Net proved reserves at December 31, 2010	**11,927**	**27,906**	**314**	**16,892**
Proved developed reserves, December 31, 2010	**5,392**	**14,203**	**141**	**7,900**
Proved undeveloped reserves, December 31, 2010	**6,535**	**13,703**	**173**	**8,992**
2011				
Proved reserves				
Beginning balance	11,927	27,906	314	16,892
Revisions of previous estimates	(2,650)	(6,500)	1,661	(2,072)
Extensions, discoveries and other additions	8,049	22,204	2,364	14,114
Sales of reserves in place				
Purchases of reserves in place				
Production	(1,610)	(4,918)	(308)	(2,738)
Net proved reserves at December 31, 2011	**15,716**	**38,692**	**4,031**	**26,196**
Proved developed reserves, December 31, 2011	**6,479**	**17,987**	**1,802**	**11,279**
Proved undeveloped reserves, December 31, 2011	**9,237**	**20,705**	**2,229**	**14,917**
2012				
Proved reserves				
Beginning balance	15,716	38,692	4,031	26,196
Revisions of previous estimates	(1,368)	(8,533)	(193)	(2,982)
Extensions, discoveries and other additions	12,262	32,646	3,232	20,935
Sales of reserves in place				
Purchases of reserves in place	13,010	85,293	7,745	34,969
Production	(2,093)	(5,695)	(617)	(3,659)
Net proved reserves at December 31, 2012	**37,527**	**142,403**	**14,198**	**75,459**
Proved developed reserves, December 31, 2012	**13,207**	**54,775**	**5,437**	**27,774**
Proved undeveloped reserves, December 31, 2012	**24,320**	**87,628**	**8,761**	**47,685**

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Our proved reserves have grown from 16.9 to 26.2 MMBoe from year end 2010 to year end 2011 and from 26.2 to 75.5 MMBoe from year end 2011 to year end 2012. Our reserve growth in these periods is due directly to the extensions and discoveries associated with our drilling activities in each year and, during 2012, the Eagle Property Acquisition. As a result, we have increased our average daily production at a compound annual growth rate of 78% from 995 Boe/d in the year ended December 31, 2008 to 9,999 Boe/d in the year ended December 31, 2012.

Our proved undeveloped reserves have grown from 14.9 MMBoe to 47.7 MMBoe from December 31, 2011 to December 31, 2012. During this time, we spent $80 million of our capital expenditures on drilling proved undeveloped locations and converted 2.8 MMBoe from proved undeveloped reserves to proved developed reserves. In addition, we added 20.9 MMBoe of proved undeveloped reserves through extensions and discoveries and had a negative revision of 3.0 MMBoe related to proved undeveloped reserves, of which 1.6 MMBoe related to reductions at our Gulf Coast West Gordon field. With the closing of the Eagle Property Acquisition on October 1, 2012, we also added 35.0 MMBoe of proved reserves.

All of our proved undeveloped reserves as of December 31, 2012 are expected to be developed within five years of their initial booking.

Independent petroleum engineers

Our estimated reserves and related future net revenues at December 31, 2012, 2011 and 2010 are based on reports prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines in effect during such period established by the SEC.

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Robert C. Barg, Mr. Philip R. Hodgson, and Mr. David T. Miller. Mr. Barg has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Barg is a Licensed Professional Engineer in the State of Texas (No. 71658) and has over 30 years of practical experience in petroleum engineering, with over 24 years of experience in the estimation and evaluation of reserves. He graduated from Purdue University in 1983 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Hodgson has been practicing consulting petroleum geology at NSAI since 1988. Mr. Hodgson is a Licensed Professional Geoscientist in the State of Texas, Geophysics (No.1314) and has over 29 years of practical experience in petroleum geosciences, with over 15 years of experience in the estimation and evaluation of reserves. He graduated from University of Illinois in 1982 with a Bachelor of Science Degree in Geology and from Purdue University in 1984 with a Master of Science Degree in Geophysics. Mr. Miller is a Licensed Professional Engineer in the State of Louisiana (No. 22695) and has over 31 years of practical experience in petroleum engineering, with over 16 years of experience in the estimation and evaluation of reserves. He graduated from University of Kentucky in 1981 with a Bachelor of Science Degree in Civil Engineering and from Southern Methodist University in 1994 with a Masters of Business Administration Degree. All technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; all are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

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Technology used to establish proved reserves

Under Rule 4-10(a)(22) of Regulation S-X, as promulgated by the SEC, 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. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, NSAI employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data.

Internal controls over reserves estimation process

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to NSAI in their reserves estimation process. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with geoscientists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from the Company's accounting records, which are subject to external quarterly reviews, annual audits and their own set of internal controls over financial reporting. All current financial data such as commodity prices, lease operating expenses, production taxes and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. The Company's current ownership in mineral interests and well production data are incorporated into the reserve database as well and verified to ensure their accuracy and completeness. Curtis Newstrom, PE, our Vice President of Business Development, is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has 27 years of industry experience with positions of increasing responsibility in engineering and evaluations and holds a Bachelor of Science degree in Petroleum Engineering from Marietta College. Mr. Newstrom reports directly to the CEO and is a registered professional engineer in the state of Louisiana (License No. 25260). Throughout each fiscal year, our technical team meets with representatives of our independent reserve engineers to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a preliminary copy of the reserve report is reviewed by our senior management with representatives of our independent reserve engineers and internal technical staff.

Production, revenues and price history

Oil and natural gas are commodities. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand for oil and natural gas in the United States has increased dramatically during this decade. However, the current economic slowdown reduced this demand during the second half of 2008 and through 2009. Demand for oil increased

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during 2010, 2011 and 2012, but demand for natural gas remained sluggish. Additionally, the price of natural gas has remained relatively depressed due to increasing supplies from shale plays. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets.

The following table sets forth information regarding oil, natural gas liquids and natural gas production, revenues and realized prices and production costs for the years ended December 31, 2012, 2011 and 2010. For additional information on price calculations, see information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operation."

	Years Ended December 31,		
	2012	**2011**	**2010**
Operating Data:			
Net production volumes:			
Oil (MBbls)	2,093	1,610	945
NGLs (MBbls)	617	308	74
Natural gas (MMcf)	5,695	4,918	2,253
Total oil equivalents (MBoe)	3,659	2,737	1,394
Average daily production (Boe/d)	9,999	7,499	3,820
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$ 104.35	$ 110.25	$ 80.29
Oil, with realized derivatives (per Bbl)	$ 95.05	$ 99.85	$ 79.37
Natural gas liquids, without realized derivatives (per Bbl)	$ 38.27	$ 50.98	$ 36.92
Natural gas liquids, with realized derivatives (per Bbl)	$ 40.48	(a)	(a)
Natural gas, without realized derivatives (per Mcf)	$ 2.81	$ 4.20	$ 4.66
Natural gas, with realized derivatives (per Mcf)	$ 3.21	(a)	(a)
Costs and Expenses (per Boe of production):			
Lease operating and workover	$ 8.34	$ 5.89	$ 9.23
Severance and other taxes	$ 6.81	$ 4.98	$ 5.01
Asset retirement accretion	$ 0.20	$ 0.12	$ 0.13
Depreciation, depletion, and amortization	$ 34.32	$ 33.50	$ 30.00
General and administrative	$ 8.35	$ 25.18	$ 12.09
Acquisition and transaction costs	$ 4.07	$	$

(a) We did not have any hedges in place on our natural gas or NGL production prior to October 1, 2012.

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The following table sets forth information regarding oil, NGLs and natural gas production for each of the fields that represented more than 15% of our estimated total proved reserves as of December 31, 2012:

	Years Ended December 31,		
	2012	2011	2010
Pine Prairie			
Net production volumes:			
Oil (MBbls)	1,109	786	745
NGLs (MBbls)	221	190	59
Natural gas (MMcf)	2,509	2,476	1,850
Total oil equivalents (MBoe)	1,748	1,389	1,113
Mississippian(1)			
Net production volumes:			
Oil (MBbls)	203		
NGLs (MBbls)	123		
Natural gas (MMcf)	1,289		
Total oil equivalents (MBoe)	541		

(1) Mississippian volumes include production from October 1, 2012, the date of acquisition for the Eagle Properties, through December 31, 2012.

Productive Wells

The following table presents the total gross and net productive wells as of December 31, 2012:

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Total productive wells	231	192	63	52	294	244

Gross wells are the number of wells in which a working interest is owned, and net wells are the total of our fractional working interest owned in gross wells.

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we have a controlling interest as of December 31, 2012 for each of our operating areas. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	14,637	14,626	139,710	137,138	154,347	151,764
Mid-Continent	71,275	48,626	64,728	49,349	136,003	97,975
Total	**85,912**	**63,252**	**204,438**	**186,487**	**290,350**	**249,739**

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2012 that will expire over the next three years by operating area unless production is established within

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the spacing units covering the acreage or we make additional lease rental payments prior to the expiration dates:

	Expiring 2013		Expiring 2014		Expiring 2015	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	3,036	3,002	7,989	7,913	16,619	16,618
Mid-Continent	24,489	17,866	31,959	25,374	4,116	3,456
Total Undeveloped Acreage Expirations	**27,525**	**20,868**	**39,948**	**33,287**	**20,735**	**20,074**

Excluding the acreage acquired as part of the Eagle Property Acquisition, approximately 32% of our net acreage, including acreage under option, was acquired in 2012, with the majority of such leases under five year primary term leases. In addition, our typical lease terms along with unit regulatory rules provide us flexibility to continue lease ownership through either establishing production or actively drilling prospects.

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2012, 2011 and 2010. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	Years Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	68	64	29	29	16	16
Dry holes	7	7			2	2
Total	75	71	29	29	18	18
Exploratory wells:						
Productive	4	3	2	2	1	1
Dry holes						
Total	4	3	2	2	1	1
Total wells	**79**	**74**	**31**	**31**	**19**	**19**

As of December 31, 2012, no exploratory wells were being drilled and 16 gross (13 net) development wells are currently drilling or have been drilled and are undergoing completion.

Our drilling activity has increased over the last three years, and we were operating seven drilling rigs on our properties as of December 31, 2012. Our drilling activity has primarily focused on delineation and appraisal of our primary operating areas in the Pine Prairie, South Bearhead Creek/Oretta, West Gordon and North Cowards Gully fields, as well as recent expansion into newly acquired Mississippian Lime acreage. In addition to the drilling activity listed above, a portion of our capital program over the last three years has also been focused on re-entering and recompleting productive zones in existing wellbores. In 2012 we had a total of seven gross and net wells that were deemed dry wells, five of which were geologic dry holes and two of which were caused by mechanical problems encountered while drilling which prevented us from reaching the reservoir targets.

Marketing and Major Customers

We sell our oil, natural gas liquids and natural gas to third-party purchasers. We are not dependent upon, or contractually limited to, any one purchaser or small group of purchasers. However, for the year ended December 31, 2012, Chevron, Gulfmark and Targa accounted for 41%, 32% and 10% of our revenues, respectively. For the year ended December 31, 2011, Chevron and Gulfmark accounted

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for 39% and 38% of our revenues, respectively. For the year ended December 31, 2010, Chevron, Crosstex, and Gulfmark accounted for 66%, 19%, and 12% of our revenues, respectively. Due to the nature of oil, natural gas and NGL markets, and because we sell our oil production to purchasers that transport by truck rather than by pipelines, we do not believe the loss of a single purchaser or a few purchasers would materially adversely affect our ability to sell our production.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect defects affecting those properties, we are typically responsible for curing any such defects at our expense. We generally will not commence drilling operations on a property until we have cured known material title defects on such property. We have reviewed the title to 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 natural gas industry. Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant properties and, depending on the materiality of properties, we may obtain a title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our credit facility, liens for current taxes and other burdens which we believe do not materially interfere with their use or affect our carrying value of the properties.

Seasonality

Generally, demand for oil and natural gas decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Winter weather conditions can limit or temporarily halt our drilling and producing activities and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting our well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operations.

Competition

The oil and natural gas industry is highly competitive. We compete with numerous entities, including major domestic and foreign oil companies, other independent oil and natural gas concerns and individual producers and operators. Many of these competitors are large, well established companies and have financial and other resources substantially greater than ours. Our ability to acquire additional oil and natural gas properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment.

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate properties for oil and natural gas production have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations, such laws and regulations are frequently amended or reinterpreted. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

Regulation of transportation and sale of oil

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. The price we receive from the sale of these products may be affected by the cost of transporting the products to market. For our oil production, much of that transportation is currently via truck and we do not rely on interstate or intrastate pipelines.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

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In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC's pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC under Order No. 637 will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission ("CFTC") and the Federal Trade Commission ("FTC"). Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order No. 704, some of our operations may be required to annually report to FERC on May 1 of each year for the previous calendar year. Order No. 704 requires certain natural gas market participants to report information regarding their reporting of transactions to price index publishers and their blanket sales certificate status, as well as certain information regarding their wholesale, physical natural gas transactions for the previous calendar year depending on the volume of natural gas transacted.

Gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states onshore and in state waters. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case by case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future. Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the

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locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Other federal laws and regulations affecting our industry

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 ("EPAct 2005"). EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides the FERC with the power to assess civil penalties of up to $1 million per day for violations of the NGA and increases the FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1 million per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations, and orders, we could be subject to substantial penalties and fines.

FERC Market Transparency Rules. On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting.

Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the FTC issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale from: (a) knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate

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as a fraud or deceit upon any person; or (b) intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1 million per day per violation, in addition to any applicable penalty under the Federal Trade Commission Act.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Environmental and occupational health and safety regulation

Our oil and natural gas exploration, development and production operations are subject to stringent and comprehensive federal, regional, state and local laws and regulations governing occupational safety and health, the discharge of materials into the environment and environmental protection. Numerous governmental entities, including the U.S. Environmental Protection Agency, EPA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may, among other things (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (v) impose specific safety and health criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations and the issuance of orders enjoining performance of some or all of our operations. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in federal or state environmental laws and regulations or re-interpretation of applicable enforcement policies that result in more stringent and costly well construction, drilling, water management or completion activities, or waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on our financial condition or results of operations, there is no assurance that we will be able to remain in compliance in the future with such existing or any new laws and regulations or that such future compliance will not have a material adverse effect on our business and operating results.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and wastes

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These classes of persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "responsible persons" may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the U.S. EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. 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 or other pollutants into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We also are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes and nonhazardous solid wastes. Under the authority of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although RCRA currently exempts certain drilling fluids, produced waters, and other wastes associated with exploration, development and production of oil and natural gas from regulation as hazardous wastes, we can provide no assurance that this exemption will be preserved in the future. For instance, in September 2010, the Natural Resources Defense Council filed a petition for rulemaking with the EPA requesting reconsideration of the continued application of this RCRA exclusion but, to date, the EPA has not taken any action on the petition. Repeal or modification of this exclusion or similar exemptions under state law could increase the amount of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating costs, which could have a significant impact on us as well as the natural gas and oil industry in general. In any event, these excluded wastes are subject to regulation as nonhazardous solid wastes. In addition, we generate petroleum hydrocarbon wastes and ordinary industrial wastes in the course of our operations that may be regulated as hazardous wastes.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where these petroleum hydrocarbons and wastes have been taken for recycling or disposal. In addition, certain of these properties have been operated by the third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination.

Air emissions

The Clean Air Act, as amended ("CAA"), and comparable state laws, regulate emissions of various air pollutants through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, on August 16, 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAP, programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare after October 15, 2012. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2013. We are currently reviewing this new rule and assessing its potential impacts on our operations. Compliance with these requirements could increase our costs of development and production, which costs could be significant.

Climate change

Based on findings made by the EPA in December 2009 that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the Earth's atmosphere and other climatic changes, the EPA adopted regulations under existing provisions of the federal Clean Air Act that restrict emissions of GHGs, including one that requires reductions in emissions of GHGs from motor vehicles and another one that requires certain construction and operating permit reviews for GHG emissions from large stationary sources. The EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs, pursuant to which these permitting programs have been tailored to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas production facilities, which may include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations. In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption and implementation of any legislation or regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Water discharges

The Federal Water Pollution Control Act, as amended (the "Clean Water Act"), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure 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. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for noncompliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990, as amended ("OPA"), amends the Clean Water Act and sets minimum standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties including owners and operators of onshore facilities may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Hydraulic fracturing activities

Hydraulic fracturing is an important and common industry practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. Some states, including Louisiana and Oklahoma, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nevertheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third-party claims related to hydraulic fracturing operations conducted by third parties and associated legal expenses in accordance with, and subject to, the terms of such policies.

Endangered Species Act considerations

The federal Endangered Species Act, as amended ("ESA"), may restrict exploration, development and production activities that may affect endangered and threatened species or their habitats. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States, and prohibits the taking of endangered species. Federal agencies are required to insure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to make a determination on a listing of more than 250 species as endangered or threatened under the ESA over the next six years, through the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted 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 reserves.

OSHA

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and

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Community Right-to- Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Employees

As of December 31, 2012, we employed 93 people, including 35 technical (geosciences, engineering, land), 25 field operations, 27 corporate (finance, planning, business development, legal, office management) and 6 management.

Offices

We currently lease approximately 41,196 square feet of office space in Houston, Texas at 4400 Post Oak Parkway, Suite 1900, where our principal offices are located. The lease for our Houston office expires in April 2018. We also lease two field offices in Louisiana and office space in Tulsa, Oklahoma at 321 South Boston Avenue, Suite 600.

Available Information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol "MPO." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website (http://www.midstatespetroleum.com) all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Financial Code of Ethics, and the charters of our audit committee, compensation committee and nominating and governance committee are also available on our website and in print free of charge to any stockholder who requests them. Requests should be sent by mail to 4400 Post Oak Parkway, Suite 1900; Houston, Texas 77027, attention Corporate Counsel. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K. We intend to disclose on our website any amendments or waivers to our Code of Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K.

ITEM 1A. RISK FACTORS

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition or results of operations could suffer. 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.

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Risks Related to the Oil and Gas Industry and Our Business

A substantial or extended decline in oil and, to a lesser extent, natural gas, prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and, to a lesser extent, natural gas, heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil and natural gas-producing countries;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic, local and foreign governmental regulations and taxes;
- speculation as to the future price of oil and natural gas and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than 12-month) contracts at market based prices. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. If oil and natural gas prices deteriorate, we anticipate that the borrowing base under our revolving credit facility, which is revised periodically, may be reduced. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically. Substantial decreases in oil and natural gas prices could render uneconomic a significant portion of our identified drilling locations. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

A reduction in the premium to NYMEX WTI oil prices we receive by selling to the LLS market could significantly reduce the relative price advantage we receive for our production.

Because a substantial portion of our producing properties are geographically concentrated in central Louisiana, we are vulnerable to fluctuations in pricing in that area. Our Gulf Coast oil production is generally sold in the LLS market, which has recently commanded a premium to NYMEX WTI prices due to its proximity to U.S. Gulf Coast refiners and international markets that are typically correlated with Brent oil prices as well as take-away constraints at the Cushing, Oklahoma hub where NYMEX WTI contracts are settled. A reduction in this premium could significantly reduce the relative price advantage we receive for a substantial portion of our production. In addition, as a result of this geographic concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, transportation capacity constraints and curtailment or interruption of production from the wells in these areas.

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

Our future financial condition and results of operations will depend on the success of our development, drilling and production activities. Our oil and natural gas drilling and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore or develop drilling locations or properties will depend in part on the evaluation of data obtained through 2D and 3D seismic data, geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The production and operating data that is available with respect to the Upper Gulf Coast Tertiary and Mississippian Lime trends based on modern drilling and completion techniques is relatively limited compared to trends where multiple operators have been active for a significant period of time. As a result, we face more uncertainty in evaluating data than operators in more developed trends. For a discussion of the uncertainty involved in these processes, see " Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these assumptions will materially affect the quantities and present value of our reserves." Our costs of drilling, completing and operating wells are often uncertain before drilling commences. In addition, the application of new techniques in these trends, such as high-graded stimulation designs and horizontal completions, some of which we may not have previously employed, may make it more difficult to accurately estimate these costs. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of, or delays in, obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- pressure or irregularities in geological formations;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems; and
- limitations in the market for oil and natural gas.

In addition, the Company's hydraulic fracturing operations require significant quantities of water. Regions in which the Company operates have recently experienced drought conditions. Any diminished access to water for use in hydraulic fracturing, whether due to usage restrictions or drought or other weather conditions, could curtail the Company's operations or otherwise result in delays in operations or increased costs.

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The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2012, 2011 and 2010, we based the discounted future net cash flows from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Prior to our corporate reorganization in April 2012 in connection with our initial public offering, we were not subject to entity level taxation. Accordingly, our standardized measure for periods prior to such reorganization does not provide for federal or state corporate income taxes because taxable income was passed through to our equity holders. However, as a result of our corporate reorganization, we are now treated as a taxable entity for federal income tax purposes and our income taxes are dependent upon our taxable income. Actual future prices and costs may differ materially from those used in the present value estimates included in this report which could have a material effect on the value of our reserves.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties. We use the full cost method of accounting for our oil and gas properties.

Accordingly, we capitalize and amortize all productive and nonproductive costs directly associated with property acquisition, exploration and development activities. Under the full cost method, the capitalized cost of oil and gas properties, less accumulated amortization and related deferred income taxes may not exceed the "cost center ceiling" which is equal to the sum of the present value of estimated future net revenues from proved reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, plus the costs of properties not subject to amortization, plus the lower of the cost or estimated fair value of unproved properties included in the costs being amortized, less related income tax effects. If the net capitalized costs exceed the cost center ceiling, we recognize the excess as an impairment of oil and gas properties. This impairment does not impact cash flows from operating activities but does reduce our earnings and shareholders' equity. The risk that we will be required to recognize impairments of our oil and natural gas properties increases during periods of low commodity prices. In addition, impairments would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices increase the cost center ceiling applicable to the subsequent period. We could incur impairments of oil and natural gas properties in the future, particularly as a result of a decline in commodity prices.

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We have incurred losses from operations during certain periods since the beginning of 2008 and may continue to do so in the future.

We incurred losses from operations of $15.6 million and $11.8 million for the years ended December 31, 2010 and 2009, respectively, and $13.1 million for the period from August 30, 2008 to December 31, 2008. 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 report may impede our ability to economically acquire and develop 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.

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these assumptions could materially affect the estimated quantities and present value of reserves shown in this report. See "Summary of Oil and Gas Properties and Operations" for information about our estimated oil and natural gas reserves.

In order to prepare our estimates, we must estimate production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Estimates of oil and natural gas reserves are inherently imprecise. In addition, reserve estimates for properties that do not have a lengthy production history, including the areas in which we operate, are less reliable than estimates for fields with lengthy production histories. There can be no assurance that analysis of previous production data relating to the Upper Gulf Coast Tertiary trend or Mississippian Lime and Hunton formations will accurately predict future production, development expenditures or operating expenses from wells drilled and completed using modern techniques. In addition, this data is partially based on vertically drilled wells, which may not accurately reflect production, development expenditures or operating expenses that may result from the application of horizontal drilling techniques.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

The development of our proved undeveloped reserves in our areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 63% of our total estimated proved reserves were classified as proved undeveloped as of December 31, 2012. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the future net revenues estimated for such 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.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

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

Drilling locations that we have identified may not yield oil or natural gas in commercially viable quantities.

We describe some of our drilling locations and our plans to explore those drilling locations in this report. Our drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. 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, resulting in a reduction in production from 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. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which in certain instances could prevent production prior to the expiration date of leases for such locations. In addition, we may not be able to raise the amount of capital that would be necessary to drill a substantial portion of our identified drilling locations.

Our management team has identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage and acreage currently under option. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these drilling locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, drilling results, lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous 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 drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques. The results of our horizontal drilling activities are subject to drilling and completion technique risks, and actual drilling results may not meet our expectations for reserves or production. As a result, we may

incur material impairment of the carrying value of our unevaluated properties, and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

In the Upper Gulf Coast Tertiary trend, our experience with horizontal drilling utilizing the latest drilling and completion techniques is limited. We drilled our first horizontal well in the Upper Gulf Coast Tertiary trend in the fourth quarter of 2011 and seven additional horizontal wells and horizontal sidetracks in 2012. We are currently applying the preliminary results from these wells to plan for the eight to ten horizontal wells we expect to drill in the Upper Gulf Coast Tertiary trend during 2013. Risks that we face while horizontally 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 horizontal 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. Ultimately, the success of these horizontal drilling and completion techniques can only be evaluated over time as more wells are drilled in the Upper Gulf Coast Tertiary trend and production profiles are established over a sufficiently long time period. If our horizontal drilling results in the Upper Gulf Coast Tertiary trend are less than anticipated, the return on our investment in this area may not be as attractive as we anticipate. The carrying value of our unevaluated properties could become impaired, which would increase our depletion rate per Boe or result in a ceiling test impairment if there were no corresponding additions to recoverable reserves, and the value of our undeveloped acreage in this area could decline in the future.

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

We utilize third-party services to maximize the efficiency of our organization. The cost of oilfield services may increase or decrease depending on the demand for services by other oil and gas companies. There is no assurance that we will be able to contract for such services on a timely basis or that the cost of such services will remain at a satisfactory or affordable level. Shortages or the high cost of frac crews, drilling rigs, equipment, supplies, personnel or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Our business depends on transportation by truck for our oil and condensate production, and our natural gas production depends on transportation facilities that are owned by third parties.

We transport all of our oil and condensate production by truck, which is more expensive and less efficient than transportation via pipeline. Our natural gas production depends in part on the availability, proximity and capacity of pipeline systems and processing facilities owned by third parties. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

The disruption of third-party facilities due to maintenance or weather could negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored or what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flows, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flows.

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

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

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

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

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

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

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, or increases in interest rates. 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 drill our identified locations and pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent and 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.

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Our revolving credit facility and the indenture governing our Senior Notes contains certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our revolving credit facility and the indenture governing our Senior Notes includes certain covenants that, among other things, restrict:

- our ability to incur or assume additional debt or provide guarantees in respect of obligations of other persons;
- issue redeemable stock and preferred stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase certain debt;
- make loans and investments;
- create or incur liens;
- restrict distributions from our subsidiaries;
- sell assets and capital stock of our subsidiaries;
- consolidate or merge with or into another entity, or sell all or substantially all of our assets; and
- enter into new lines of business.

A breach of the covenants under the indenture governing the Senior Notes or under the revolving credit facility could result in an event of default under the applicable indebtedness. An event of default may allow the creditors to accelerate the related debt and may result in an acceleration of any other debt to which a cross-acceleration or cross-default provision applies. In addition, an event of default under our credit facility would permit the lenders under the facility to terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders under our revolving credit facility could proceed against the collateral granted to them to secure that debt.

In addition, our revolving credit facility requires us to maintain certain financial ratios, including a leverage ratio. All of these restrictive covenants may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our revolving credit facility may be impacted by changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our revolving credit facility, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our revolving credit facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. If the indebtedness under our revolving credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

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

As of December 31, 2012, we had $156 million available and a borrowing base of $250 million under our revolving credit facility and $600 million in Senior Notes outstanding. In the future, we may incur significant additional 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;

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- 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;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, such competitors 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 may 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.

In addition, our bank borrowing base is subject to periodic redeterminations on a semi-annual basis, effective September 1 and March 1 and up to one additional time per six-month period following each scheduled borrowing base redetermination, as may be requested by either us or the administrative agent under our revolving credit facility. In connection with the March 2013 redetermination, our borrowing base was increased to $285 million, primarily as a result of the growth of our proved reserves. In the future we could be forced to repay a portion of our then outstanding bank borrowings due to future redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are unable to arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

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

We are subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The largest purchaser of our oil and natural gas during the year ended December 31, 2012 and 2011 was Chevron, accounting for 41% and 39% of our total revenues for these periods, respectively. We generally do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial condition and results of operations.

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

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil, we enter into derivative instruments for a portion of our oil, NGL and natural gas

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production. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures About Market Risk" and Note 4 to our Consolidated Financial Statements for a summary of our oil commodity derivative positions. We did not designate any of our derivative instruments as hedges for accounting purposes, and we record all derivative instruments in our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

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

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contractual obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received for basis differentials.

In addition, our derivative arrangements limit the benefit we would receive from increases in the prices for oil.

All of our current operations are located in central Louisiana and in the Mississippian Lime trend in northwestern Oklahoma, making us vulnerable to risks associated with operating in a limited number of geographic areas.

As of December 31, 2012, all of our proved reserves and our annual production were located in central Louisiana and in northwestern Oklahoma. This concentration could disproportionately expose us to operational and regulatory risk or other adverse developments in these areas, including, for example, transportation or treatment capacity constraints, curtailment of production or treatment plant closures for scheduled maintenance or weather. These factors could have a significantly greater impact on our financial condition, results of operations and cash flows than if our properties were more diversified.

Large competitors may be attracted to our core operating areas, which may increase our costs.

Our operations in the Upper Gulf Coast tertiary trend and in the Mississippian Lime formation in northwestern Oklahoma and Kansas may attract companies that have greater resources than we do. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or identify, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Their presence in our areas of operations may also restrict our access to, or increase the cost of, oil and natural gas infrastructure, drilling rigs, equipment, supplies, personnel and oilfield services, including fracking equipment and crews. 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. See "Business Competition" for additional discussion of the competitive environment in which we operate.

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

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

Title to the properties in which we have an interest may be impaired by title defects.

We do not obtain title insurance and have not necessarily obtained drilling title opinions on all of our oil and natural gas properties. The existence of title deficiencies with respect to our oil and natural gas properties could reduce the value or render such properties worthless, which could have a material adverse effect on our business and financial results. A significant portion of our acreage is undeveloped leasehold acreage, which has a greater risk of title defects than developed acreage. Frequently, as a result of title examinations, certain curative work may be required to correct identified title defects, and such curative work entails time and expense. Our inability or failure to cure title defects could render some locations undrillable or cause us to lose our rights to some or all production from some of our oil and natural gas properties, which could have a material adverse effect on our business and financial results if a comparable additional location to drill a development well cannot be identified.

We may be subject to risks in connection with acquisitions, including the Eagle Property Acquisition, and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis. Indemnification from Eagle Energy is generally limited to an escrow account equal to 20% of the Preferred Stock issued as consideration, effective only during the 12-month period after the closing and subject to certain dollar limitations and minimums. We may not be able to collect on such indemnification because of disputes with Eagle Energy or its inability to pay. Moreover, there is a risk that we could ultimately be liable for unknown obligations related to the Eagle Property Acquisition, which could materially adversely affect our financial condition, results of operations or cash flows.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;

- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

In addition, even after successfully integrating Eagle Energy's operations or another acquisition, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices in oil and natural gas industry conditions, risks and uncertainties relating to the exploratory prospects of the combined assets or operations, failure to retain key personnel, an increase in operating or other costs or other difficulties. We may experience additional challenges integrating the business of a privately operated company, like Eagle Energy. If we fail to realize the benefits we anticipate from an acquisition, our results of operations and stock price may be adversely affected.

The proposed U.S. federal budget for fiscal year 2013 and proposed legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations and cash flows.

The Obama administration's budget proposals for fiscal year 2013 contains numerous proposed tax changes, and from time to time, legislation has been introduced that would enact many of these proposed changes. The proposed budget and legislation would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and impose new fees. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the domestic manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing federal oil and gas leases. Should some or all of these provisions become law our taxes could increase, potentially significantly, after net operating losses are exhausted, which would have a negative impact on our net income and cash flows and could reduce our drilling activities. We do not know the ultimate impact these proposed changes may have on our business.

We are subject to various governmental regulations that may cause us to incur substantial costs.

From time to time, in varying degrees, political developments and federal and state laws and regulations affect our operations. In particular, price controls, taxes and other laws relating to the oil and natural gas industry, changes in these laws and changes in administrative regulations have affected, and in the future could affect, oil and natural gas production, operations and economics. We cannot predict how agencies or courts will interpret existing laws and regulations or the effect of these adoptions and interpretations may have on our business or financial condition.

Our business is subject to laws and regulations promulgated by federal, state and local authorities relating to the exploration for, and the development, production and marketing of, oil and natural gas, as well as safety matters. Legal requirements are frequently changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be required to make significant expenditures to comply with governmental laws and regulations. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government, and third parties and may require us to incur substantial costs of remediation.

The Company's sales of oil and gas may expose us to extensive regulation.

The FERC, the Commodity Futures Trading Commission and the Federal Trade Commission hold statutory authority to monitor certain segments of the physical energy commodities markets relevant to the Company's business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to the Company's physical sales, if any, of oil and gas, the partnership is required to observe the market-related regulations enforced by these agencies.

Our operations are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration, production and development operations are subject to stringent federal, regional, state and local laws and regulations governing the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling, completion and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, and impose substantial liabilities for pollution resulting from our operations. We may be required to make significant capital and operating expenditures to prevent releases, manage wastewater discharges and control air emissions or perform remedial or other corrective actions at our wells and properties to comply with the requirements of these environmental laws and regulations or the terms or conditions of permits issued pursuant to such requirements. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, loss of our leases, incurrence of investigatory or remedial obligations and the issuance of orders limiting or prohibiting some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and other hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations and waste disposal practices. Spills or other releases of regulated substances, including such spills and releases that occur in the future, could expose us to material losses, expenditures and liabilities under applicable environmental laws and regulations. Under certain of such laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and even if our operations met previous standards in the industry at the time they were conducted.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, air emissions control or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general in addition to our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance.

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Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we produce.

In December 2009, the U.S. Environmental Protection Agency, or EPA, determined that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one regulation that requires a reduction in emissions of GHGs from motor vehicles and another that regulates emissions of GHGs from certain large stationary sources, effective January 2, 2011. In addition, the EPA adopted rules requiring the monitoring and reporting of GHGs from certain sources in the United States, including, among others, certain onshore and offshore oil and natural gas production facilities.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

Recently approved final rules regulating air emissions from natural gas production operations could cause us to incur increased capital expenditures and operating costs, which may be significant.

On August 16, 2012, the EPA published final regulations under the Clean Air Act that require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements, effective in 2012, regarding emissions from dehydrators, storage tanks and other production equipment. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, which could adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely utilize hydraulic fracturing techniques in many of our oil and natural gas drilling and completion programs. The process is typically regulated by state oil and natural gas commissions. However, the EPA has exercised federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act, or SDWA, and recently

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released draft permitting guidance for hydraulic fracturing activities using diesel. In addition, on November 23, 2011, the EPA announced that it was granting in part a petition to initiate rulemaking under the Toxic Substances Control Act, relating to chemical substances and mixtures used in oil and gas exploration and production. Congress has also considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, on May 4, 2012, the Department of the Interior's Bureau of Land Management, or BLM, announced a proposed rule that, if adopted, would require companies to publicly disclose the chemicals used in hydraulic fracturing operations, set requirements for well bore integrity, and establish flowback water standards for all hydraulic fracturing operations on federal and American Indian Tribal lands. Moreover, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations under certain circumstances. For instance, on October 20, 2011, Louisiana adopted new regulations that require hydraulic fracturing operators to publicly disclose the volume of hydraulic fracturing fluid, the type, trade name, supplier and volume of additives, and a list of chemical compounds contained in the additive, along with its maximum concentration, subject to certain trade secret protections. However, even trade secret chemicals will have to be identified by their chemical family. A mandatory disclosure of information regarding the constituents of hydraulic fracturing fluids could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based upon allegations that specific chemicals used in the fracturing process could adversely affect the environment. Similarly, on July 1, 2012, Oklahoma adopted regulations requiring operators to publicly disclose the total volume of the hydraulic fracturing base fluid, the trade name, supplier, and general purpose of each chemical added to the fluid, and the chemical abstract service numbers of each additive to the fluid, subject to certain trade secret protections.

In addition, there are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA announced on October 20, 2011 that it is launching a study of wastewater resulting from hydraulic fracturing activities and currently plans to propose pretreatment regulations by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Certain members of the Congress have also called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These on-going or proposed studies could spur initiatives to further regulate hydraulic fracturing under the SDWA or otherwise. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements and attendant permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Our operations are dependent on our rights and ability to receive or renew the required permits and other approvals from governmental authorities and other third parties.

Performance of our operations require that we obtain and maintain numerous environmental and land use permits and other approvals authorizing our regulated activities. A decision by a governmental authority or other third party to deny, delay or restrictively condition the issuance of a new or renewed permit or other approval, or to revoke or substantially modify an existing permit or other approval, could have a material adverse effect on our ability to initiate or continue operations at the affected location or facility. Expansion of our existing operations is also predicated on securing the necessary environmental or land use permits and other approvals, which we may not receive in a timely manner or at all.

The enactment of derivatives legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices.

On July 21, 2010 new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, that participate in that market. The Dodd-Frank Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Dodd-Frank Act the CFTC has issued final 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 would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Colombia in September of 2012 although the CFTC has stated that it will appeal the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of "swap," "security-based swap," "swap dealer" and "major swap participant". The Dodd-Frank Act and CFTC Rules also will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC has delayed the compliance dates for various regulations already finalized. As a result it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us and the timing of such effects. The Dodd-Frank Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and 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 existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

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Risks Relating to our Common Stock

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to other public companies.

In April 2012, the current president signed into law the Jumpstart Our Business Startups Act, or the JOBS Act. The JOBS Act contains provisions that, among other things, relax certain reporting requirements for "emerging growth companies," including certain requirements relating to accounting standards and compensation disclosure. We are classified as an emerging growth company. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to (1) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404, (2) comply with any new or revised financial accounting standards applicable to public companies until such standards are also applicable to private companies, (3) comply with any new requirements adopted by the Public Company Accounting Oversight Board, or the PCAOB, requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuers, (4) comply with any new audit rules adopted by the PCAOB after April 5, 2012 unless the SEC determines otherwise, (5) provide certain disclosure regarding executive compensation required of larger public companies or (6) hold shareholder advisory votes on executive compensation.

Because we are a relatively small company, the requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act of 2002, may strain our resources, increase our costs and divert management attention, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the requirements of the New York Stock Exchange, or the NYSE, with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We are required to:

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;
- involve and retain to a greater degree outside counsel and accountants in the above activities; and
- establish an investor relations function.

In addition, being a public company subject to these rules and regulations could require us, in the future, to accept less director and officer liability insurance coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract new or additional qualified members to our board of directors, particularly to serve on our audit committee and compensation committee, and qualified executive officers.

In connection with certain audits of our financial statements, our independent registered public accounting firm identified and reported misstatements to management. Certain of such adjustments were deemed to be the result of internal control deficiencies that constituted a material weakness in our internal control over financial reporting. If one or more material weaknesses recur or if we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected.

Prior to our initial public offering, we were a private company with limited accounting personnel to adequately execute our accounting processes and limited other supervisory resources with which to address our internal control over financial reporting. As such, we did not maintain an effective control environment to ensure that the design and execution of our controls has consistently resulted in effective review of our financial statements and supervision by appropriate individuals. The lack of adequate staffing levels resulted in insufficient time spent on review and approval of certain information used to prepare our financial statements. As a result of these factors, certain material misstatements in our annual financial statements were discovered and brought to the attention of our management by our independent registered public accounting firm for correction. We and our independent registered public accounting firm concluded that these control deficiencies constituted a material weakness in our control environment as of December 31, 2011. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

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 until our 2013 fiscal year. We are 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. Our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting until the later of the year following our first annual report required to be filed with the SEC or the date we are no longer an "emerging growth company," which may be up to five full fiscal years following our initial public offering. To comply with the requirements of being a public company, we will need to implement additional financial and management controls, reporting systems and procedures and hire additional accounting, finance and legal staff. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future and comply with the certification and reporting obligations under Sections 302 and 404 of the Sarbanes-Oxley Act of 2002. Further, our remediation efforts may not enable us to remedy or avoid material weaknesses or significant deficiencies in the future. Any failure to remediate deficiencies and to develop or maintain effective controls, or any difficulties encountered in our implementation or improvement of our internal controls over financial reporting could result in material misstatements that are not prevented or detected on a timely basis, which could potentially subject us to sanctions or investigations by the SEC, the NYSE or other regulatory authorities. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

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We do not intend to pay, and we are currently prohibited from paying, dividends on our common stock and, consequently, your only opportunity to achieve a return on your investment is if the price of our common stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we are currently prohibited from making any cash dividends pursuant to the terms of our revolving credit facility and the Indenture of our Senior Notes. Consequently, your only opportunity to achieve a return on your investment in us will be if you sell your common stock at a price greater than you paid for it.

Pursuant to the recently enacted JOBS Act, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 for so long as we are an emerging growth company and we may take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards.

We will be required to disclose changes made in our internal control over financial reporting on a quarterly basis and we will be required to assess the effectiveness of our controls annually. However, for as long as we are an "emerging growth company" under the recently enacted JOBS Act, our independent registered accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. Even if we conclude that our internal controls over financial reporting are effective, our independent registered public accounting firm may still decline to attest to our assessment or may issue a report that is qualified if it is not satisfied with our controls or the level at which our controls are documented, designed, operated or reviewed, or if it interprets the relevant requirements differently from us.

In addition, Section 107 of the JOBS Act also provides that an "emerging growth company" can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards. In other words, an "emerging growth company" can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. We may take advantage of these reporting exemptions until we are no longer an "emerging growth company."

We are currently controlled by First Reserve, and First Reserve and Riverstone collectively hold a majority of the voting power of our common stock and certain actions by us will require the consent of First Reserve or Riverstone. Their interests as equity holders may conflict with the interests of our other shareholders or our noteholders.

First Reserve currently owns an economic interest in us through FR Midstates Interholding LP ("FRMI"), which owns approximately 41% of our shares of common stock and is controlled by First Reserve. Eagle Energy, which is controlled by Riverstone Holdings, LLC ("Riverstone"), holds Preferred Stock issued as consideration in the Eagle Property Acquisition. On a pro forma basis following conversion of the Preferred Stock at a conversion price of $13.50, FRMI and Riverstone (together with Eagle Energy management) will own 30% and 27% of our shares of common stock, respectively.

While they hold these interests, these entities will have significant influence over our operations, will have representatives on our board of directors and have significant influence over all matters that require approval by our stockholders, including the approval of significant corporate transactions. 'This concentration of ownership will limit the ability of our stockholders to influence corporate matters, and as a result, actions may be taken that our shareholders may not view as beneficial.

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In addition, we, FRMI and certain of our other stockholders have entered into a stockholders' agreement that permits FRMI to designate certain of our director nominees and prohibits us from engaging in certain transactions without the written consent of FRMI.

The stockholders' agreement provides that the following actions by us require the consent of FRMI:

- incurrence of debt that would result in a total net indebtedness to EBITDA ratio in excess of 2.50:1;
- authorization, creation or issuance of any equity securities (other than pursuant to compensation plans approved by the compensation committee or in connection with certain permitted acquisitions);
- redemption, acquisition or other purchase of any securities of the Company (other than certain repurchases from employees and directors);
- amendment, repeal or alteration of our amended and restated certificate of incorporation or amended and restated bylaws;
- any acquisition or disposition (where the amount of consideration exceeds $100 million in a single transaction or $200 million in any series of transactions during a calendar year);
- consummation of a "change in control" transaction;
- adoption, approval or issuance of any "poison pill" or similar rights plan; and
- entry into any plan of liquidation, dissolution or winding-up of the Company.

These actions by us require the consent of FRMI until the earlier of (i) receipt by our board of directors of FRMI's written election to waive its rights, (ii) the date FRMI ceases to hold at least 35% of our outstanding common stock, (iii) the third anniversary of the closing of our initial public offering or (iv) the date on which there are no directors nominated by FRMI serving as members of our board of directors.

The terms of the preferred stock permit Riverstone to designate one of our director nominees, who must be an employee of Riverstone or one of its affiliates, and prohibit us from engaging in certain transactions without the consent of Riverstone, including the following actions:

- the creation or issuance of any class of capital stock senior to or on parity with the Preferred Stock;
- the redemption, acquisition or purchase by us of any of our equity securities, other than a repurchase from an employee or director in connection with such person's termination or as provided in the agreement pursuant to which such equity securities were issued;
- any change to our certificate of incorporation or bylaws that adversely affects the rights, preferences, privileges or voting rights of the holders of the Preferred Stock;
- acquisitions or dispositions for which the amount of consideration exceeds 20% of our market capitalization in any single transaction or 40% of our market capitalization for any series of transactions during a calendar year;

entering into certain transactions with affiliates, other than transactions that do not exceed, in the aggregate, $10 million in any calendar year;

certain corporate transactions unless the holders of the Preferred Stock would receive consideration consisting solely of cash and/or marketable securities with an aggregate fair market value equal to or greater than the liquidation preference on such shares of Preferred Stock; and

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any increase or decrease in the size of our board of directors.

As a result of FRMI's and Riverstone's equity ownership or voting power, director nominees and consent rights, our ability to engage in financing transactions or other significant transactions, such as a merger, acquisition, disposition or liquidation, may be limited. In connection with such transactions, conflicts of interest could arise between us and FRMI or Riverstone, and any conflict of interest may be resolved in a manner that does not favor us.

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

Conflicts of interest could arise in the future between us, on the one hand, and First Reserve and its affiliates, including its portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities. First Reserve is a private equity firm in the business of making investments in entities primarily in the global energy sector. As a result, First Reserve's existing and future portfolio companies which it controls may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.

Our amended and restated certificate of incorporation provides that, to the fullest extent permitted by applicable law, we renounce any interest or expectancy in, or in being offered an opportunity to participate in, any business opportunity that may be from time to time presented to First Reserve or its affiliates or any of their respective officers, directors, agents, shareholders, members, partners, affiliates and subsidiaries (other than us and our subsidiaries) or business opportunities that such parties participate in or desire to participate in, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such person shall be liable to us for breach of any fiduciary or other duty, as a director or officer or controlling stockholder or otherwise, by reason of the fact that such person pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us unless, in the case of any such person who is our director or officer, any such business opportunity is expressly offered to such director or officer solely in his or her capacity as our director or officer.

As a result, First Reserve or its affiliates may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to First Reserve and its affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

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

Upon completion of our initial public offering and the Eagle Property Acquisition, Riverstone, First Reserve and certain of our stockholders, including the Stephen P. McDaniel (a member of our Board of Directors) and members of our executive management team, control a majority of the combined voting power of all classes of our outstanding voting stock and we are a "controlled company" within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a "controlled company" and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

a majority of the board of directors consist of independent directors;

- the nominating and corporate governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- there be an annual performance evaluation of the nominating and corporate governance and compensation committees.

These requirements will not apply to us as long as we remain a "controlled company." We may utilize some or all of these exemptions. We will rely on the phase-in rules of the SEC and the NYSE with respect to the independence of our audit committee. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of December 31, 2012, we did not have any unresolved comments from the SEC staff that were received 180 or more days prior to year-end.

ITEM 2. PROPERTIES

Information regarding our properties is included in "Item 1. Business" above.

ITEM 3. LEGAL PROCEEDINGS

The information set forth under "Litigation" in Note 14 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

None.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market for Registrant's Common Equity.

Our common stock is listed on the New York Stock Exchange under the symbol "MPO."

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

	Price Range	
2012	**High**	**Low**
Second Quarter(1)	$ 16.95	$ 9.27
Third Quarter	$ 11.11	$ 7.30
Fourth Quarter	$ 9.15	$ 4.71
2013		
First Quarter(2)	$ 8.94	6.80

(1) Our common stock began trading on the New York Stock Exchange on April 20, 2012.

(2) First quarter 2013 high and low ranges are calculated through March 13, 2013.

Holders.

The number of shareholders of record of our common stock was approximately 187 on March 13, 2013.

Dividends.

We have not paid any cash dividends since inception. In addition, our reserve-based revolving credit facility and the indenture governing our Senior Notes limit and restrict our ability to pay dividends on our capital stock. We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Recent Sale of Unregistered Securities.

On October 1, 2012, we completed the Eagle Property Acquisition. Pursuant to the Eagle purchase agreement, we acquired certain interests in producing oil and natural gas assets, unevaluated leasehold acreage in Oklahoma and Kansas and the related hedging instruments in exchange for $325 million in cash and the issuance of 325,000 shares of Convertible Preferred Stock. We paid for the cash portion of the purchase price using a portion of the net proceeds from the sale of $600 million of Senior Notes. We issued the Convertible Preferred Stock to Eagle in a private issuance exempt from registration under Section 4(2) of the Securities Act and Rule 506 of Regulation D. See the Form 8-K that was filed with the SEC on October 2, 2012. The shares of Convertible Preferred Stock have an initial liquidation value of $1,000 per share. The holders of the Convertible Preferred Stock may not convert before October 1, 2013. After such time, the Convertible Preferred Stock may be converted, in whole but not in part, at the option of the holders of a majority of the outstanding shares of Convertible Preferred Stock, into a number of shares of our common stock calculated by dividing the then-current liquidation preference by the conversion price of $13.50 per share. In addition, the Convertible Preferred Stock will be subject to mandatory conversion into shares of our common stock on September 30, 2015 at a conversion price no greater than $13.50 per share and no less than $11.00 per share. Dividends on the Convertible Preferred Stock will accrue at a rate of 8.0% per annum, payable semiannually, at our sole option, in cash or through an increase in the liquidation preference.

Use of Proceeds.

The proceeds of our initial public offering, based on the public offering price of $13.00 per share, were approximately $358.8 million. After subtracting underwriting discounts and commissions of

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$21.5 million and the net proceeds to the selling stockholders of $117.3 million, we received net proceeds of approximately $220.0 million from the registration and sale of 18,000,000 common shares (or $213.6 million net of offering expenses paid directly by us). We used $67.1 million of the net proceeds to redeem convertible preferred units in Midstates Petroleum Holdings LLC ("Holdings LLC"), including interest and other charges, and $99.0 million to repay a portion of the borrowings under our revolving credit facility. We used the remaining $47.5 million to fund the execution of our growth strategy through our drilling program. We did not receive any of the proceeds from the sale of the 9,600,000 shares by the selling stockholders. Immediately after the initial public offering and exercise of the over-allotment option, First Reserve Midstates Interholding LP and its affiliates owned approximately 41.4% of our outstanding common stock.

Stock Performance Graph.

The following performance graph and related information shall not be deemed "soliciting material" or is not to be filed with the SEC, such information shall not be incorporated by reference into any future filing under the Securities Act or Exchange Act, except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

The performance graph below shows the cumulative total return to our commons stock holders from April 20, 2012, the date on which our common stock began trading on the NYSE, through December 31, 2012, as compared to the cumulative five-year total returns on the Standard and Poor's 500 Index ("S&P 500") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P O&G E&P"). The comparison was prepared on the following assumptions:

- $100 was invested in our common stock at its initial public offering price of $13 per share and invested in the S&P 500 and the S&P O&G E&P on April 20, 2012 at the closing price on such date; and

- Dividends, if any, are reinvested.

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected financial data of the Company and its consolidated subsidiary over the five-year period ended December 31, 2012, which information has been derived from the Company's audited financial statements. This information should be read in conjunction with, and is qualified in its entirety by, the more detailed information in the Company's financial statements set forth in Part IV, Item 15 of this Form 10-K.

Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the years ended December 31, 2012, 2011 and 2010 and the balance sheet data as of December 31, 2012 and 2011 are derived from our audited consolidated financial statements and the notes thereto included elsewhere in this Annual Report on Form 10-K. The historical financial data for the year ended December 31, 2009 and the balance sheet data as of December 31, 2010 and 2009 are derived from our audited financial statements not included in this Annual Report on Form 10-K. The historical financial data as of and for the period from August 30, 2008 through December 31, 2008, has been derived from our audited consolidated financial statements not included elsewhere in this Annual Report on Form 10-K. Selected historical consolidated financial data for the period from January 1 to August 29, 2008 of Midstates Petroleum Corporation, our accounting predecessor, has been derived from the audited financial statements of Midstates Petroleum Corporation not included elsewhere in this Annual Report on Form 10-K.

	Successor					Predecessor
	As of and for the Year Ended December 31,				Period from August 30 to December 31,	Period from January 1 to August 29,
	2012(1)	2011	2010	2009	2008	
	(In thousands, except per share amounts)					
Income Statement Data						
Total revenues	$ 247,673	$ 209,433	$ 63,052	$ 24,254	$ 22,794	$ 19,893
Net income (loss)	(150,097)	16,657	(15,635)	(11,752)	(13,132)	6,710
Net income (loss) available to common shareholders(2)	(156,597)	16,657	(15,635)	(11,752)	(13,132)	6,710
Net income (loss) per share (pro forma)						
Basic	$ (2.61)	N/A	N/A	N/A	N/A	N/A
Diluted	$ (2.61)	N/A	N/A	N/A	N/A	N/A
Balance Sheet Data						
Total assets	$ 1,684,010	$ 624,656	$ 427,004	$ 284,034	$ 222,074	N/A
Long-term debt	694,000	234,800	89,600	29,800	21,800	N/A
Stockholders'/members' equity	643,581	285,502	255,879	235,334	192,006	N/A
Common shares outstanding (weighted)	59,979	N/A	N/A	N/A	N/A	N/A

(1) The year ended December 31, 2012 reflects the Eagle Property Acquisition. For a discussion of significant acquisitions, see Note 6 Acquisition of Oil and Gas Properties in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

(2) The year ended December 31, 2012 includes the effect of an undeclared preferred stock dividend of $6.5 million, which is at the Company's option to be paid in shares upon conversion or in cash. See Note 10 Equity and Share Based Compensation in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

	As of and for the Year Ended December 31,				
	2012(1)	2011	2010	2009	2008
Balance Sheet Data					
Cash and cash equivalents	$ 18,878	$ 7,344	$ 11,917	$ 4,353	$ 3,214
Net property and equipment	1,567,408	574,079	397,126	271,726	209,939
Total assets	1,684,010	624,656	427,004	284,034	222,074
Long-term debt	694,000	234,800	89,600	29,800	21,800
Stockholders'/members' equity	643,581	285,502	255,879	235,334	192,006

	For the Year Ended December 31,				
	2012(1)	2011	2010	2009	2008
Other Financial Data					
Net cash provided by operating activities	$ 137,249	$ 141,550	$ 50,768	$ 10,595	$ 13,716
Net cash used in investing activities	(773,608)	(242,619)	(139,618)	(75,215)	(14,931)
Net cash provided by financing activities	647,893	96,496	96,414	65,759	6,967
Adjusted EBITDA(2)	144,619	152,616	53,274	12,539	18,445

(1) The year ended December 31, 2012 reflects the Eagle Property Acquisition. For a discussion of significant acquisitions, see Note 6 Acquisition of Oil and Gas Properties in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

(2) 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) and net cash provided by operating activities, see "Non-GAAP Financial Measures and Reconciliations" below.

Non-GAAP Financial Measures and Reconciliations

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDA as earnings before interest income and expense, income taxes, depreciation, depletion and amortization, property impairments, asset retirement obligation accretion, unrealized derivative gains and losses and non-cash share-based compensation expense. Adjusted EBITDA is not a measure of net income or cash flows as determined by United States generally accepted accounting principles, or GAAP. We believe that Adjusted EBITDA is useful because it allows us 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 items such as property impairments, asset retirement obligation accretion, unrealized derivative gains and losses and non-cash share-based compensation expense from net income 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 or cash flows from operating activities 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 measures of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

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The following table presents a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP measure of net income (loss) and net cash provided by operating activities, respectively.

	For the Year Ended December 31,				
	2012	2011	2010	2009	2008
Adjusted EBITDA reconciliation to net income (loss):					
Net income (loss):	$ (150,097)	$ 16,657	$ (15,635)	$ (11,752)	$ (6,422)
Depreciation, depletion and amortization	125,561	91,699	41,827	12,363	6,112
Impairment in carrying value of oil and gas properties				4,297	26,776
Change in unrealized (gain) loss on commodity derivative contracts	(4,667)	(11,889)	25,398	7,283	(8,972)
Income taxes	157,886				
Interest income	(245)	(23)	(9)	(6)	(19)
Interest expense, net of amounts capitalized	12,999	2,094			854
Asset retirement obligation accretion	723	334	175	120	116
Share-based compensation	2,459	53,744	1,518	234	
Adjusted EBITDA	**$ 144,619**	**$ 152,616**	**$ 53,274**	**$ 12,539**	**$ 18,445**

	For the Year Ended December 31,				
	2012	2011	2010	2009	2008
Adjusted EBITDA reconciliation to net cash provided by operating activities:					
Net cash provided by operating activities	$ 137,249	$ 141,550	$ 50,768	$ 10,595	$ 13,716
Changes in working capital	(3,854)	9,845	2,829	1,950	3,894
Interest income	(245)	(23)	(9)	(6)	(19)
Interest expense, net of amounts capitalized	12,999	2,094			854
Amortization of deferred financing costs	(1,530)	(850)	(314)		
Adjusted EBITDA	**$ 144,619**	**$ 152,616**	**$ 53,274**	**$ 12,539**	**$ 18,445**

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains "forward-looking statements" that are based on management's current expectations, estimates and projections about our business and operations, and involves risks and uncertainties. Our actual results may differ materially from those currently anticipated and expressed in such forward-looking statements as a result of a number of factors, including those we discuss under "Risk Factors," "Cautionary Note Regarding Forward-Looking Statements" and elsewhere in this Annual Report on Form 10-K.

We are an independent exploration and production company focused on the application of modern drilling and completion techniques to oil-prone resources in the Upper Gulf Coast Tertiary trend onshore in Louisiana, which we refer to as our "Gulf Coast" operating area, and, with the October 1, 2012 closing of the acquisition ("Eagle Property Acquisition") of interests in producing oil and natural gas assets, unevaluated leasehold acreage in Oklahoma and Kansas and related hedging instruments from Eagle Energy Production, LLC ("Eagle Energy"), in the Mississippian Lime trend in Oklahoma and Kansas, which we refer to as our "Mid-Continent" operating area.

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As of December 31, 2012, our properties consisted of approximately 294 gross active producing wells, 92% of which we operate, and in which we held an average working interest of approximately 83% across our approximate 250,000 net acre leasehold. As of December 31, 2012, our estimated net proved reserves were 75.5 MMBoe, of which 69% was oil or NGLs and 37% was proved developed. During the three months and year ended December 31, 2012, our properties had aggregate average net daily production of approximately 15,592 Boe per day and 9,999 Boe per day, respectively.

Prior to the October 1, 2012 Eagle Property Acquisition, all of our growth has been driven through the development of our leasehold acreage. We initiated operations in 1993 in our North Cowards Gully project area and slowly aggregated leasehold acreage in that project area and others over the next eighteen years. In August 2008, First Reserve acquired a majority interest in us and, along with members of our senior management, provided a significant amount of growth capital to expand our exploration and development program. Our current activities are focused on evaluating and developing our asset base, optimizing our acreage position, and identifying potential expansion areas across our operating areas. As of December 31, 2012, we had drilled 136 wells (including six in our Mid-Continent assets during the fourth quarter of 2012), approximately 92% of which produced commercially, since the third quarter of 2008.

Acquisitions

On October 1, 2012, we closed on the acquisition of all of Eagle Energy's producing properties as well as their developed and undeveloped acreage primarily in the Mississippian Lime oil play in Oklahoma and Kansas for $325 million in cash, before customary post-closing adjustments, and 325,000 shares of the Company's newly designated Series A Mandatorily Convertible Preferred Stock with an initial liquidation preference value of $1,000 per share (the "Series A Preferred Stock"). The Company funded the cash portion of the Eagle Property Acquisition purchase price with a portion of the net proceeds from the private placement (which also closed on October 1, 2012) of $600 million in aggregate principal amount of 10.75% senior unsecured notes due October 1, 2020 (the "Senior Notes"). Subsequent to the closing of the Eagle Property Acquisition, we now have oil and gas operations in Louisiana and Oklahoma, and undeveloped acreage in Kansas.

Sources of Our Revenue

Oil, natural gas and natural gas liquids. Our revenues are derived from the sale of oil and natural gas production, as well as the sale of NGLs that are extracted from our high Btu content natural gas. Our oil and gas revenues do not include the effects of derivatives, and may vary significantly from period to period as a result of changes in production volumes or commodity prices.

Realized and unrealized gain (loss) on commodity derivative financial contracts. We utilize commodity derivatives to reduce our exposure to fluctuations in the prices of oil, natural gas and natural gas liquids. In addition, we utilize derivatives to help mitigate our exposure to fluctuations in Louisiana Light Sweet ("LLS") oil prices, which is the index price we receive for our Gulf Coast oil production, as compared to West Texas Intermediate ("NYMEX WTI") benchmark oil prices. Accordingly, our income statements reflect (i) the recognition of unrealized gains and losses associated with our open derivative contracts as commodity prices change and commodity derivatives contracts expire or new ones are entered into, and (ii) our realized gains or losses on the settlement of these commodity derivative contracts. Unrealized gains and losses result from changes in market valuations of derivatives as future commodity price expectations change compared to the contract prices on the derivatives. If the expected future commodity prices increase compared to the contract prices on the derivatives, unrealized losses are recognized. Conversely, if the expected future commodity prices decrease compared to the contract prices on the derivatives, unrealized gains are recognized. Since we have elected not to apply hedge accounting to our derivatives, we reflect the unrealized and realized gains and losses in our current income statement periods based on the mark-to-market value at the end of each month. Cash flows associated with derivative financial instruments are reflected in cash flow from operations in our consolidated statement of cash flows.

Commodity prices. Our revenues are heavily influenced by commodity prices, which are subject to wide fluctuations in response to changes in supply and demand. For a description of factors that may impact future commodity prices, please read "Risk Factors Risks Related to the Oil and Natural Gas Industry and Our Business" beginning on page 23. The table below sets forth the prices we received per unit of volume for our oil, natural gas, and NGLs, both including and excluding the effects of our commodity derivative contracts.

	Year Ended December 31,		
	2012	2011	2010
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$ 104.35	$ 110.25	$ 80.29
Oil, with realized derivatives (per Bbl)	$ 95.05	$ 99.85	$ 79.37
Natural gas, without realized derivatives (per Mcf)	$ 2.81	$ 4.20	$ 4.66
Natural gas, with realized derivatives (per Mcf)	$ 3.21	(a)	(a)
Natural gas liquids, without realized derivatives (per Bbl)	$ 38.27	$ 50.98	$ 36.92
Natural gas liquids, with realized derivatives (per Bbl)	$ 40.48	(a)	(a)

(a) The Company did not have hedges in place on its natural gas or NGL production prior to October 1, 2012.

Other revenue. Other revenue consists of income derived from the recovery of administrative overhead, gas compression charges and saltwater disposal fees from third parties for their share of costs on company owned assets.

Our Expenses

Lease operating and workover expenses. These are daily costs incurred to bring oil and gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include natural gas transportation and treating expenses, as well as maintenance and repair expenses related to our oil and gas properties. Lease operating expenses include both a portion of costs that are fixed in nature, such as infrastructure costs, as well as variable costs resulting from additional wells and production. As production increases, our average lease operating expense per barrel of oil equivalent is typically reduced because fixed costs do not increase proportionately with production. Workover expense includes major remedial operations on a completed well to restore, maintain, or improve a well's production and is closely correlated to the levels of workover activity. Because workover projects are pursued on an as needed basis and are not regularly scheduled, workover expense is not necessarily comparable from period to period.

Severance and other taxes. Severance taxes are paid on produced oil and gas based on a percentage of revenues from products sold at market prices or at fixed rates established by federal, state, or local taxing authorities. We attempt to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the severance taxes we pay correlate to the changes in oil and gas revenues. Ad valorem taxes are property taxes assessed based on the value of property and are also included in this expense category.

Depreciation, depletion and amortization. Under the full cost accounting method, we capitalize costs within a cost center and systematically expense those costs on a unit 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 for which proved reserves have not yet been assigned, less accumulated amortization; (ii) estimated future expenditures to be incurred in developing proved reserves; and (iii) estimated dismantlement and abandonment costs.

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Impairment of oil and gas properties/Ceiling test. Our historical policy as a privately-owned company had been to perform a ceiling test on an annual basis, and we performed a ceiling test at December 31, 2011 and 2010. However, subsequent to the initial public offering, we have applied Rule 4-10 of Regulation S-X, which requires the ceiling test to be performed on at least a quarterly basis. The test establishes a limit (ceiling) on the book value of oil and gas properties. The capitalized costs of proved oil and gas properties, net of accumulated depreciation, depletion and amortization (DD&A) and the related deferred income taxes, may not exceed this "ceiling." The ceiling limitation is equal to the sum of: (i) the present value of estimated future net revenues from the projected production of proved oil and gas reserves, excluding future cash outflows associated with settling asset retirement obligations accrued on the balance sheet, calculated using the average oil and natural gas sales price we received as of the first trading day of each month over the preceding twelve months (such average price is held constant throughout the life of the properties) and a discount factor of 10%; (ii) the cost of unproved and unevaluated properties excluded from the costs being amortized; (iii) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; and (iv) related income tax effects. If capitalized costs exceed this ceiling, the excess is charged to impairment expense in the accompanying consolidated statements of operations.

General and administrative expense. General and administrative expense consists of overhead, including payroll and benefits for our corporate staff, non-cash charges for share-based compensation, costs of maintaining our headquarters, franchise taxes, audit and other professional fees, legal compliance, Exchange Act reporting expenses, expenses associated with Sarbanes-Oxley compliance, investor relations, director and officer liability insurance costs, and director compensation.

Certain of our employees hold units in Midstates Incentive Holdings LLC that entitle the holders to a portion of the proceeds to be received by First Reserve, our private equity sponsor, upon sales of our common stock by FRMI. Any payments with respect to these units will only occur if and when First Reserve achieves certain minimum return hurdles (defined as certain multiples of First Reserve's capital contributions plus investment expenses) on its investment through the sale of its shares of our common stock. While these proceeds will not involve any cash payment by us, we will recognize a non-cash compensation expense, which may be material, in the period any such payment is made. See Note 10 to our audited financial statements for the year ended December 31, 2012.

Acquisition and transaction costs. The Eagle Property Acquisition qualifies as the acquisition of a business under Accounting Standards Codification Topic 805, Business Combinations ("ASC 805"). Acquisition and transaction costs are costs the Company has incurred as a result of the Eagle Property Acquisition and include finders' fees; advisory, legal, accounting, valuation and other professional and consulting fees; and general and administrative costs. ASC 805 requires these types of acquisition related costs to be expensed as incurred and as services are received.

Interest expense. We issued $600 million in Senior Notes on October 1, 2012. Additionally, we finance a portion of our working capital requirements and capital expenditures with borrowings under our revolving credit facility. As a result, we incur interest expense, a portion of which is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our note holders and the lenders under our revolving credit facility in interest expense, net of amounts capitalized to unproved properties.

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Results of Operations

The following tables summarize our revenues, production and price data for the periods indicated:

Revenues

	Years Ended December 31,					
	2012		2011		2010	
REVENUES:						
Oil sales	$ 218,430	85%	$ 177,464	83%	$ 75,875	85%
Natural gas sales	16,030	6%	20,665	10%	10,505	12%
Natural gas liquid sales	23,617	9%	15,683	7%	2,731	3%
Total oil, natural gas, and natural gas liquids sales	$ 258,077	100%	$ 213,812	100%	$ 89,111	100%
Realized gains (losses) on commodity derivative contracts, net	(15,825)	142%	(16,733)	345%	(870)	3%
Unrealized gains (losses) on commodity derivative contracts, net	4,667	(42)%	11,889	(245)%	(25,398)	97%
Losses on commodity derivative contracts net	$ (11,158)	100%	$ (4,844)	100%	$ (26,268)	100%
Other	754		465		209	
Total revenues	**$ 247,673**		**$ 209,433**		**$ 63,052**	

Production

	Year Ended December 31,				
	2012	Increase (Decrease)	2011	Increase (Decrease)	2010
PRODUCTION DATA:					
Oil (MBbls)	2,093	30%	1,610	70%	945
Natural gas (MMcf)	5,695	16%	4,918	118%	2,253
Natural gas liquids (MBbls)	617	101%	308	316%	74
Oil equivalents (MBoe)	3,659	34%	2,737	96%	1,394
Oil (Boe/day)	5,719	30%	4,410	70%	2,589
Natural gas (Mcf/day)	15,559	16%	13,475	118%	6,171
Natural gas liquids (Boe/day)	1,686	101%	843	316%	203
Average daily production (Boe/d)	9,999	34%	7,499	96%	3,820

Prices

	Year Ended December 31,				
	2012	Increase (Decrease)	2011	Increase (Decrease)	2010
AVERAGE SALES PRICES:					
Oil, without realized derivatives (per Bbl)	$ 104.35	(5)%	$ 110.25	37%	$ 80.29
Oil, with realized derivatives (per Bbl)	$ 95.05	(5)%	$ 99.85	26%	$ 79.37
Natural gas, without realized derivatives (per Mcf)	$ 2.81	(33)%	$ 4.20	(10)%	$ 4.66
Natural gas, with realized derivatives (per Mcf)	$ 3.21		(a)		(a)
Natural gas liquids, without realized derivatives (per Bbl)	$ 38.27	(25)%	$ 50.98	38%	$ 36.92
Natural gas liquids, with realized derivatives (per Bbl)	$ 40.48		(a)		(a)

(a) The Company did not have hedges in place on its natural gas or NGL production prior to October 1, 2012.

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Oil, Natural Gas and Natural Gas Liquids Revenues.

Year Ended December 31, 2012 as Compared to the Year Ended December 31, 2011

Our oil sales revenues increased by $40.9 million, or 23%, to $218.4 million during the year ended December 31, 2012 as compared to $177.5 million for the year ended December 31, 2011. Oil volumes sold increased 483 MBbls or 30% to 2,093 MBbls for the year ended December 31, 2012 from 1,610 MBbls for the year ended December 31, 2011. The increase in oil volumes sold was attributable to a 279 MBbls increase in production from our Gulf Coast area, plus the addition of 204 MBbls of production volumes from our Mid-Continent area, beginning on October 1, 2012. Average oil sales prices, without realized derivatives, decreased by $5.90 per barrel, or 5%, to $104.35 per barrel for the year ended December 31, 2012 as compared to $110.25 for the year ended December 31, 2011 partly due to lower oil prices during 2012, as well as lower oil prices received for our Mid-Continent production, which is priced off WTI as opposed to LLS for our Gulf Coast production. Of the $218.4 million in total oil sales revenues, $201.9 million was from Gulf Coast operations and $16.5 million was from Mid-Continent.

Our natural gas sales revenues decreased by $4.7 million, or 23%, to $16.0 million during the year ended December 31, 2012 as compared to $20.7 million for the year ended December 31, 2011. Natural gas volumes sold increased 777 MMcf, or 16%, to 5,695 MMcf for the year ended December 31, 2012 as compared to 4,918 MMcf for the year ended December 31, 2011. The increase in natural gas volumes sold was attributable to a 973 MMcf decrease in production from our Gulf Coast area, offset by the addition of 1,750 MMcf of production volumes from our Mid-Continent area, beginning on October 1, 2012. Average natural gas prices, without realized derivatives, decreased by $1.39 per Mcf, or 33%, to $2.81 per Mcf for the year ended December 31, 2012 as compared to $4.20 per barrel for the year ended December 31, 2011. Of the $16.0 million in total natural gas sales revenues, $10.9 million was from Gulf Coast operations and $5.1 million was from Mid-Continent.

Our natural gas liquid sales revenues increased by $7.9 million, or 50%, to $23.6 million during the year ended December 31, 2012 as compared to $15.7 million for the year ended December 31, 2011. Natural gas liquid volumes sold increased 309 MBbls, or 101%, to 617 MBbls for the year ended December 31, 2012 as compared to 308 MBbls for the year ended December 31, 2011. The increase in natural gas liquids volumes sold was attributable to a 142 MBbls increase in production from our Gulf Coast area, plus the addition of 167 MBbls of production volumes from our Mid-Continent area, beginning on October 1, 2012. Average natural gas liquid prices, without realized derivatives, decreased by $12.71 per barrel, or 25%, to $38.27 per barrel for the year ended December 31, 2012 as compared to $50.98 per barrel for the year ended December 31, 2011. Of the $23.6 million in total natural gas liquid sales revenues, $18.0 million was from Gulf Coast operations and $5.6 million was from Mid-Continent.

Year Ended December 31, 2011 as Compared to the Year Ended December 31, 2010

Our oil sales revenues increased by $101.6 million, or 134%, to $177.5 million during the year ended December 31, 2011 as compared to $75.9 million for the year ended December 31, 2010. Oil volumes sold increased 665 MBbls, or 70%, to 1,610 MBbls for the year ended December 31, 2011 from 945 MBbls for the year ended December 31, 2010. The increase in volumes sold during 2011 was attributable to our increased drilling activity during the year. Average oil prices, without realized derivatives, increased by $29.96 per barrel, or 37%, to $110.25 per barrel for the year ended December 31, 2011.

Our natural gas sales revenues increased by $10.2 million, or 97%, to $20.7 million during the year ended December 31, 2011 as compared to $10.5 million for the year ended December 31, 2010. Natural gas volumes sold increased 2,665 MMcf, or 118%, to 4,918 MMcf for the year ended December 31, 2011 as compared to 2,253 MMcf for the year ended December 31, 2010. The increase in volumes sold

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during 2011 was attributable to our increased drilling activity during the year. Average natural gas prices, without realized derivatives, decreased by $0.46 per Mcf, or 10%, to $4.20 per Mcf for the year ended December 31, 2011 as compared to $4.66 per Mcf for the year ended December 31, 2010.

Our natural gas liquid sales revenues increased by $13.0 million, or 481%, to $15.7 million during the year ended December 31, 2011 as compared to $2.7 million for the year ended December 31, 2010. Natural gas liquid volumes sold increased 234 MBbls, or 316%, to 308 MBbls for the year ended December 31, 2011 as compared to 74 MBbls for the year ended December 31, 2010. Average natural gas liquid prices, without realized derivatives, increased by $14.06 per barrel, or 38%, to $50.98 per barrel for the year ended December 31, 2011 as compared to $36.92 per barrel for the year ended December 31, 2010.

Gains/Losses on Commodity Derivative Contracts Net.

Year Ended December 31, 2012 as Compared to the Year Ended December 31, 2011

Our mark-to-market ("MTM") derivative positions moved from an unrealized gain of $11.9 million as of December 31, 2011 to an unrealized gain of $4.7 million for the year ending December 31, 2012. The MTM change results from higher average hedge volumes and favorable price variances versus the market price for our production on December 31, 2012. We entered into additional derivative contracts during 2012 and, with the closing of the Eagle Property Acquisition on October 1, 2012, we assumed the related oil, natural gas liquids and natural gas hedging instruments associated with those acquired properties. The NYMEX WTI closing price on December 31, 2012 was $91.82 per barrel compared to a closing price of $98.83 per barrel on December 30, 2011 (the last day of trading of 2011).

The realized loss on derivatives for the year ended December 31, 2012 was $15.8 million compared to a realized loss of $16.7 million for the year ended December 31, 2011. With the closing of the Eagle Property Acquisition, we assumed hedges on natural gas and natural gas liquids. Therefore, our realized gains/losses for the year ended December 31, 2012 included realized gains/losses on these commodities in addition to oil. Prior to assuming these derivatives as part of this acquisition, we only hedged oil. See the following table (in thousands):

	Year Ended December 31, 2012	
	Realized Gain (Loss)	**Average Sales Price**
Oil commodity contracts	$ (19,460)	$ 95.05
Natural gas commodity contracts	2,273	$ 3.21
Natural gas liquids commodity contracts	1,362	$ 40.48
	$ (15,825)	

Year Ended December 31, 2011 as Compared to the Year Ended December 31, 2010

Our MTM derivative positions moved from an unrealized loss of $25.4 million as of December 31, 2010 to an unrealized gain of $11.9 million as of December 31, 2011. The MTM change results from higher average hedge volumes and prices on December 31, 2011 compared to the open positions and price on December 31, 2010. The NYMEX WTI closing price on December 30, 2011 (the last trading day of 2011) was $98.83 per barrel compared to a closing price of $91.38 per barrel on December 31, 2010.

The realized loss on derivatives for the year ended December 31, 2011 was $16.7 million compared to a realized loss of $0.9 million for the year ended December 31, 2010. The loss for the year ended December 31, 2011 was a result of realized oil prices rising substantially for the year versus the prices at which we had oil production hedged for the period. Realized oil sales prices, without realized

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derivatives, averaged $110.25 per barrel for the year ended December 31, 2011 compared with $80.29 per barrel for the year ended December 31, 2010.

Expenses

	Year Ended December 31,			Year Ended December 31,		
	2012	2011	2010	2012	2011	2010
		(in thousands)			(per Boe)	
EXPENSES:						
Lease operating and workover	$ 30,500	$ 16,117	$ 12,861	$ 8.34	$ 5.89	$ 9.23
Severance and other taxes	24,921	13,640	6,986	$ 6.81	$ 4.98	$ 5.01
Asset retirement accretion	723	334	175	$ 0.20	$ 0.12	$ 0.13
Depreciation, depletion, and amortization	125,561	91,699	41,827	$ 34.32	$ 33.50	$ 30.00
General and administrative	30,541	68,915	16,847	$ 8.35	$ 25.18	$ 12.09
Acquisition and transaction costs	14,884			$ 4.07	$	$
Total expenses	**$ 227,130**	**$ 190,705**	**$ 78,696**	**$ 62.09**	**$ 69.67**	**$ 56.46**

Lease Operating and Workover.

Year Ended December 31, 2012 as Compared to the Year Ended December 31, 2011

Lease operating and workover expenses increased $14.4 million, or 89%, to $30.5 million for the year ended December 31, 2012 compared to $16.1 million for the year ended December 31, 2011. Lease operating expenses increased $12.5 million, or 89%, to $26.5 million for the year ended December 31, 2012 as compared to $14.0 million for the year ended December 31, 2011. This increase was due to the Eagle Property Acquisition completed on October 1, 2012 and the associated lease operating costs of $2.6 million, as well as increased surface maintenance costs of $3.0 million, saltwater disposal costs of $1.3 million and an increase in costs associated with higher producing well count of $5.4 million. During the fourth quarter of 2012, we completed saltwater disposal wells in the Pine Prairie, South Bearhead Creek and West Gordon areas which we believe will reduce our saltwater disposal costs in the future. Workover expenses increased $1.9 million, or 90%, to $4.0 million for the year ended December 31, 2012, of which the Eagle Property Acquisition accounted for $1.0 million, as compared to $2.1 million for the year ended December 31, 2011. We completed 28 workovers in 2012, which was an increase of four projects over the 24 workovers completed in 2011. Lease operating and workover expenses increased to $8.34 per Boe for the year ended December 31, 2012 from $5.89 per Boe for the year ended December 31, 2011, an increase of 42%, which was primarily attributable to the factors discussed above.

Year Ended December 31, 2011 as Compared to the Year Ended December 31, 2010

Lease operating and workover expenses increased $3.2 million, or 25%, to $16.1 million for the year ended December 31, 2011 compared to $12.9 million for the year ended December 31, 2010. Of this change, lease operating expenses increased $5.8 million, or 71%, to $14.0 million, due to 31 additional producing wells in operation during the period, which resulted in additional salt water disposal costs of $2.9 million, additional compression charges of $0.8 million, additional gas dehydration and chemical costs of $1.0 million, with the remaining variance primarily attributable to increases in labor related costs. Workover expenses decreased $2.6 million, or 55%, to $2.1 million for the year ended December 31, 2011 compared to $4.7 million for the year ended December 31, 2010. Lease operating and workover expenses decreased to $5.89 per Boe at December 31, 2011 from $9.23 per Boe at December 31, 2010, a decrease of 36%. This decrease was primarily a result of the 162% increase in production volumes from the year ended December 31, 2010 to the year ended December 31, 2011, without a commensurate increase in fixed costs.

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Severance and Other Taxes.

	Year Ended December 31,		
	2012	2011	2010
Total oil, natural gas, and natural gas liquids sales	$ 258,077	$ 213,812	$ 89,111
Severance taxes	22,121	12,421	6,431
Ad valorem	2,800	1,219	555
Severance and other taxes	$ 24,921	$ 13,640	$ 6,986
Severance taxes as a percentage of sales	8.6%	5.8%	7.2%
Severance and other taxes as a percentage of sales	9.7%	6.4%	7.8%

Year Ended December 31, 2012 as Compared to the Year Ended December 31, 2011

Severance and other taxes increased $11.3 million, or 83%, to $24.9 million for the year ended December 31, 2012 as compared to $13.6 million for the year ended December 31, 2011. Severance taxes increased by $9.7 million, or 78%, and accounted for $22.1 million of the 2012 amount. This increase was primarily attributable to higher oil, natural gas and NGLs sales revenue during the 2012 period. Severance taxes for the year ended December 31, 2012 and 2011 were 8.6% and 5.8%, respectively, as a percentage of oil, natural gas and NGLs sales revenue. The severance tax rate for the year ended December 31, 2012 was higher than the severance tax rate for the year ended December 31, 2011 due to a severance tax refund of $5.4 million in 2011 and higher oil, natural gas and NGL sales revenue during the year ended December 31, 2012. Excluding the refund, severance taxes for the year ended December 31, 2011 would have been $17.8 million, or 8.3% as a percentage of oil, natural gas and NGL sales revenue, as compared to 8.6% for the year ended December 31, 2012.

Ad valorem taxes increased $1.6 million, or 133%, to $2.8 million for the year ended December 31, 2012 as compared to the year ended December 31, 2011. This change directly correlates to the increase in active wells, which increased from 92 to 294 year over year.

Year Ended December 31, 2011 as Compared to the Year Ended December 31, 2010

Severance and other taxes increased $6.6 million, or 94%, to $13.6 million for the year ended December 31, 2011 as compared to $7.0 million for the year ended December 31, 2010. Severance taxes increased by $6.0 million, or 93%, and accounted for $12.4 million of the 2011 amount. This increase was primarily attributable to higher oil, natural gas and NGLs sales revenue during the 2011 period. Severance taxes for the year ended December 31, 2011 and 2010 were 5.8% and 7.2%, respectively, as a percentage of oil, natural gas and NGLs sales revenue. The severance tax rate for the year ended December 31, 2011 was lower than the severance tax rate for the year ended December 31, 2010 due to a severance tax refund of $5.4 million in 2011. Excluding the refund, severance taxes for the year ended December 31, 2011 would have been $17.8 million, or 8.3% as a percentage of oil, natural gas and NGL sales revenue, as compared to 7.2% for the year ended December 31, 2010.

Depreciation, Depletion and Amortization (DD&A).

Year Ended December 31, 2012 as Compared to the Year Ended December 31, 2011

DD&A expense increased $33.9 million, or 37%, to $125.6 million for the year ended December 31, 2012 compared to $91.7 million for the year ended December 31, 2011. The DD&A rate for the year ended December 31, 2012 was $34.32 per Boe compared to $33.50 per Boe for the year ended December 31, 2011. The increase in DD&A expense for the year ended December 31, 2012 was primarily due to higher capital expenditures related to increased drilling and completion activities during the year, which resulted in a higher amortization base, as well as DD&A expense related to the Eagle Property Acquisition, partially offset by the impact of higher proved reserves.

Year Ended December 31, 2011 as Compared to the Year Ended December 31, 2010

DD&A expense increased $49.9 million, or 119%, to $91.7 million for the year ended December 31, 2011 compared to $41.8 million for the year ended December 31, 2010. The DD&A rate for the year ended December 31, 2011 was $33.50 per Boe compared to $30.00 per Boe for the year ended December 31, 2010. The increase in DD&A expense for the year ended December 31, 2011 was primarily due to the higher capital expenditures related to increased drilling and completion activities during the year, which resulted in a higher amortization base, and increased oil, natural gas and NGLs production, partially offset by the impact of higher total proved reserves.

General and Administrative (G&A).

Year Ended December 31, 2012 as Compared to the Year Ended December 31, 2011

Our G&A expenses decreased to $30.5 million for the year ended December 31, 2012 from $68.9 million for the year ended December 31, 2011. The decrease in G&A expenses of $38.4 million, or 56%, was primarily due to the expenses related to share-based compensation, which included a $53.7 million non-cash charge for share-based compensation for the year ended December 31, 2011, compared to a $2.5 million non-cash charge for the year ended December 31, 2012. Share-based compensation expense for the year ended December 31, 2011 included expense related to the accelerated vesting in November 2011 of restricted stock of one of our affiliates held by certain of our employees, as well as expense attributable to the change in fair value of certain equity awards accounted for by the Company as liability awards up to December 5, 2011. (See "Notes to Consolidated Financial Statements Note 10 Member's Equity and Share-Based Compensation"). Offsetting this net decrease of $51.2 million, were additional expenses of $4.4 million related to the increase in headcount, which increased from 51 full-time employees at December 31, 2011 to 93 full-time employees at December 31, 2012; payments made under the Eagle Transition Services Agreement (TSA) of $1.3 million; bonus expense of $2.0 million; professional fees of $2.9 million; and rent and technology costs of $1.1 million.

Year Ended December 31, 2011 as Compared to the Year Ended December 31, 2010

Our G&A expenses increased to $68.9 million for the year ended December 31, 2011 from $16.8 million for the year ended December 31, 2010. The increase in G&A expenses of $52.1 million, or 310%, was primarily due to the expenses related to share-based compensation, which included a $53.7 million non-cash charge for share-based compensation for the year ended December 31, 2011, compared to a $1.5 million non-cash charge for the year ended December 31, 2010. Share-based compensation expense for the year ended December 31, 2011 included expense related to the accelerated vesting in November 2011 of restricted stock of one of our affiliates held by certain of our employees, as well as expense attributable to the change in fair value of certain equity awards accounted for by the Company as liability awards up to December 5, 2011. (See "Notes to Consolidated Financial Statements Note 10 Member's Equity and Share-Based Compensation"). As of December 31, 2011, we had 51 full-time employees as compared to 43 employees as of December 31, 2010. The additional expenses related to the increase in headcount and professional fees paid to contractors of approximately $1.9 million, were offset by approximately $2.4 million less being paid in employee bonuses between periods.

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Acquisition and Transaction Costs.

Year Ended December 31, 2012 as Compared to the Year Ended December 31, 2011

Our acquisition and transaction costs increased by $14.9 million for the year ended December 31, 2012 compared to no acquisition and transaction costs for the year ended December 31, 2011. These costs represent our expenses through December 31, 2012 related to the Eagle Property Acquisition and are primarily attributable to due diligence, legal and other advisory fees that are required to be expensed under US GAAP.

Other Income (Expenses)

	Year Ended December 31,		
	2012	**2011**	**2010**
OTHER INCOME (EXPENSE)			
Interest income	$ 245	$ 23	$ 9
Interest expense	(24,174)	(4,694)	(1,654)
Capitalized interest	11,175	2,600	1,654
Interest expense net of amounts capitalized	(12,999)	(2,094)	
Total other income (expense)	$ **(12,754)**	$ **(2,071)**	$ **9**

Interest Expense.

Year Ended December 31, 2012 as Compared to the Year Ended December 31, 2011

Interest expense before capitalized interest for the years ended December 31, 2012 and 2011 was $24.2 million and $4.7 million, respectively. The increase in interest expense was primarily due to the issuance of $600 million of 10.75% senior unsecured notes in October 2012 and higher average outstanding balance under our revolving credit facility during the 2012 period. Our average outstanding balance under the revolver was $160.0 million during the 2012 period, versus $147.3 million for the 2011 period, and related to $4.7 million of the total interest expense of $24.2 million. The remainder of the interest expense for the year ended December 31, 2012, $19.5 million, related to interest expense of $16.1 million on the Senior Notes, $2.1 million associated with our Preferred Units which were redeemed in April 2012, and amortization of deferred financing costs of $1.3 million. Of total interest expense, $11.2 million and $2.6 million was capitalized, resulting in $13.0 million and $2.1 million in interest expense for years ended December 31, 2012 and 2011, respectively.

Year Ended December 31, 2011 as Compared to the Year Ended December 31, 2010

Interest expense before capitalized interest for the years ended December 31, 2011 and December 31, 2010 was $4.7 million and $1.7 million, respectively. The increase in interest expense is primarily due to the increase in outstanding balances under our prior revolving credit facility, resulting in an additional $2.7 million of interest expense and an increase in our interest rate, which increased such expense by $0.3 million. Of total interest expenses, $2.6 million and $1.7 million was capitalized, resulting in $2.1 million and no interest expenses for the years ended December 31, 2011 and 2010, respectively.

Provision for Income Taxes.

Year Ended December 31, 2012 as Compared to the Year Ended December 31, 2011

Income tax expense was $157.9 million for the year ended December 31, 2012. We were not a tax paying entity during the 2011 corresponding period and therefore, no income tax expense was recorded.

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With the consummation of our reorganization in connection with our initial public offering completed on April 25, 2012, we became a tax paying entity and as such, were required to record a charge against income equal to the estimated tax effect of the excess of the book carrying value of our net assets (primarily producing oil and gas properties) over their collective estimated tax bases as of the reorganization date. As a result, during the year ended December 31, 2012, we recorded a tax charge of $149.5 million associated with the reorganization.

During the year ended December 31, 2012, we also recorded $8.4 million of income tax expense related to operations. This represents an application of our estimated effective tax rate (including state income taxes) for the year ended December 31, 2012 of 40% to our income earned from the reorganization date through the period end.

Liquidity and Capital Resources

We expect to invest between $420 million and $450 million of capital for exploration, development and lease and seismic acquisition in 2013. Additionally, we expect to capitalize between $28 million to $32 million of interest expense.

At December 31, 2012, our liquidity was $175 million, consisting of $156 million of available borrowing capacity under our revolving credit facility and $19 million million of cash and cash equivalents.

Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil and natural gas prices decline or costs increase significantly, we could defer a significant portion of our budgeted capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control.

Recent Developments Impacting our Liquidity

On October 1, 2012, we completed the private issuance of $600 million in aggregate principal amount of Senior Notes. The Senior Notes mature on October 1, 2020 and were issued at 100% of face value. The net proceeds from the Senior Notes offering of $582 million (net of the initial purchasers' discount and related offering expenses) were used to fund the cash portion of, and expenses related to, the Eagle Energy Acquisition, to pay the expenses related to the amendments of our revolving credit facility, to repay $182.9 million in outstanding borrowings under our revolving credit facility, and for general corporate purposes. See " Significant Sources of Capital Senior Notes Offering" below for more information.

Also on October 1, 2012, as a result of the consummation of the Eagle Property Acquisition, certain previously executed amendments to our revolving credit facility became effective. As a result, the borrowing base under our revolving credit facility was increased to $250 million (subject to semi-annual redetermination beginning in March 2013) and the maturity date was extended to October 1, 2017. At October 1, 2012, after completion of the transactions detailed above and the payment of certain expenses directly related to the closing of the Eagle Property Acquisition, we had approximately $216 million of borrowing availability under the revolving credit facility and $38 million of cash and cash equivalents. Our March 2013 redetermination was recently completed and our borrowing base was increased to $285 million. See " Significant Sources of Capital Reserve-based Credit Facility" for more information.

Significant Sources of Capital

Mandatorily Redeemable Convertible Preferred Units.

In December 2011, Holdings LLC, FR Midstates Holdings LLC ("FR Midstates") and Midstates Petroleum Holdings, Inc. ("Petroleum Inc.") entered into an amended and restated limited liability company agreement, which was later amended in March 2012, to provide for the issuance of up to 65,000, or $65 million in aggregate value, of certain mandatorily redeemable convertible preferred units (the "Preferred Units") between December 15, 2011 and June 10, 2015. The Preferred Units had a liquidation value of $1,000 per unit and bore interest, compounded quarterly, at a rate of 8% plus the greater of LIBOR or 1.5%. The Preferred Units were convertible into units of Holdings LLC on or after the one year anniversary of the date of issuance into a number of common units with a fair market value (as determined by the Board) equal to the liquidation value plus any accrued interest and were redeemable for cash at any time at the option of Holdings LLC, but were mandatorily redeemable for cash on June 10, 2015, unless otherwise converted. In addition, a fixed interest charge of 1.5% of the aggregate capital invested in the Preferred Units was payable upon redemption or conversion.

On January 4, 2012, and again on February 9, 2012, Holdings LLC issued 20,000 Preferred Units (for a total of 40,000 Preferred Units) to FR Midstates for aggregate cash proceeds of $40.0 million. On April 3, 2012, Holdings LLC issued an additional 25,000 preferred units to FR Midstates for aggregate cash proceeds of $25.0 million.

On April 26, 2012, we used $67.1 million of the proceeds from our initial public offering to redeem the Preferred Units in full, including interest and other charges. Accordingly, there are no Preferred Units outstanding as of December 31, 2012. We recorded $2.1 million related to interest expense associated with these Preferred Units for the year ended December 31, 2012.

Reserve-based Credit Facility.

On June 8, 2012, we entered into a Second Amended and Restated Credit Agreement among Midstates Sub, as borrower, the Company, as guarantor, the lenders party thereto and SunTrust Bank, as the new administrative agent, consisting of a $500 million senior revolving credit facility (the "Credit Facility") with an initial borrowing base of $200 million. On September 7, 2012, and again on September 26, 2012, we entered into the Amendments to the Credit Facility among the Company, as parent, Midstates Sub, as borrower, SunTrust Bank, N.A., as administrative agent, and the other lenders and parties party thereto. The Amendments provided for, among other things, (a) $35 million of non-conforming borrowing base loans (thereby increasing the borrowing base from $200 million to $235 million), and (b) waiver of the requirement to comply with the minimum current ratio financial covenant for the quarter ending September 30, 2012. Upon the closing of the Eagle Property Acquisition, the Amendments also provided that the Credit Facility would automatically be amended to (a) accommodate the issuance, incurrence and/or compliance with the terms of the Series A Preferred Stock and the Senior Notes, (b) increase the allowance for the incurrence of certain unsecured indebtedness to allow for the issuance of $600 million of Senior Notes without a corresponding reduction in the borrowing base, (c) provide for an initial borrowing base of $250 million and (d) extend the maturity of the Credit Facility to October 1, 2017 (the "Amended Credit Facility"). These terms became effective with the closing of the Eagle Property Acquisition on October 1, 2012, and availability of non-conforming borrowing base loans ended as of that date.

Borrowings under the terms of the Amended Credit Facility bear interest at the same rates applicable to the Credit Agreement prior to the Amendments. Similarly, commitment fees are at the same rates applicable to the Credit Facility prior to the Amendments. Borrowings under the Amended Credit Facility are secured by substantially all of our oil and natural gas properties and currently bear interest at LIBOR plus an applicable margin between 1.75% and 2.75% per annum. At December 31, 2012 and December 31, 2011, the weighted-average interest rate was 2.9% and 3.2%, respectively.

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In addition to interest expense, the Amended Credit Facility requires the payment of a commitment fee each quarter. The commitment fee is computed at the rate of either 0.375% or 0.50% per annum based on the average daily amount by which the borrowing base exceeds the outstanding borrowings during each quarter.

The borrowing base under the Amended Credit Facility is subject to semiannual redeterminations in March and September and up to one additional time per six month period following each scheduled borrowing base redetermination, as may be requested by us or the administrative agent, acting on behalf of lenders holding at least two thirds of the outstanding loans and other obligations. The next scheduled borrowing base redetermination date was March 2013 and our borrowing base was increased to $285 million.

Under the terms of the Amended Credit Facility, we are required to repay the amount by which the principal balance of its outstanding loans and its letter of credit obligations exceed its redetermined borrowing base. We are permitted to make such repayment in six equal successive monthly payments commencing 30 days following the administrative agent's notice regarding such borrowing base reduction.

In June 2012, in connection with the Credit Facility, we incurred legal fees and fees payable to the lending banks of approximately $2.0 million, which together with the remaining unamortized fees associated with the revolving credit facility prior to the amendment, will be amortized as additional interest expense over the new maturity date of October 1, 2017. In addition, we incurred legal fees and fees payable to the lending banks of approximately $4.4 million in connection with the Amendments, which will have similar accounting treatment.

The Amended Credit Facility contains financial covenants, which, among other things, set a maximum ratio of debt to earnings before interest, income tax, depletion, depreciation, and amortization (EBITDA) of not more than 4.0 to 1, a minimum current ratio (as defined therein) of not less than 1.0 to 1.0 and various other standard affirmative and negative covenants including, but not limited to, restrictions on the Company's ability to make any dividends, distributions or redemptions.

As of December 31, 2012, the Company was in compliance with the minimum current ratio and the debt to EBITDA covenants as set forth in the Amended Credit Facility. The Company's current ratio at December 31, 2012 was 1.87 to 1.0. At December 31, 2012, the Company's ratio of debt to EBITDA was 3.70.

Initial Public Offering.

On April 25, 2012, we completed our initial public offering. Our net proceeds from the sale of 18,000,000 of our common shares in the initial public offering, after underwriting discounts and commissions, were $220.0 million (or $213.6 million after offering expenses paid directly by us). Of the net proceeds, $67.1 million was used to redeem the Preferred Units, including interest and other charges, and $99.0 million was used to repay a portion of our borrowings under our revolving credit facility. The remaining proceeds were retained to fund the execution of our growth strategy through our drilling program.

Senior Notes Offering.

On October 1, 2012, we issued $600 million in aggregate principal amount of Senior Notes in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act. The net proceeds from the offering of $582 million (net of the initial purchasers' discount and related offering expenses) were used to fund the cash portion of, and expenses related to, the Eagle Property Acquisition, to pay the expenses related to the amendments to our revolving credit facility, to repay $182.9 million in outstanding borrowings under our Credit Facility, and for general corporate purposes.

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The Senior Notes were co-issued on a joint and several basis by Midstates Petroleum Company, Inc. and its wholly-owned subsidiary, Midstates Petroleum Company, LLC. Midstates Petroleum Company, Inc. does not have any operations or independent assets other than its 100% ownership interest in Midstates Petroleum Company LLC and there are no other subsidiaries of the Company. The Senior Notes indenture does not create any restricted assets within Midstates Petroleum Company LLC, nor does it impose any significant restrictions on the ability of Midstates Petroleum Company LLC to pay dividends or make loans to Midstates Petroleum Company, Inc. or limit the ability of Midstates Petroleum Company, Inc. to advance loans to Midstates Petroleum Company LLC.

At any time prior to October 1, 2015, we may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the Senior Notes with the net proceeds of a public or private equity offering at a redemption price of 110.75% of the principal amount of the Senior Notes, plus any accrued and unpaid interest up to the redemption date.

In addition, at any time before October 1, 2016, we may redeem all or a part of the Senior Notes at a redemption price equal to 100% of the principal amount of Senior Notes redeemed plus the Applicable Premium (as defined in the Indenture) at the redemption date, plus any accrued and unpaid interest and Additional Interest (as defined in the Indenture), if any, up to the redemption date.

On or after October 1, 2016, we may redeem all or a part of the Senior Notes at varying redemption prices (expressed as percentages of principal amount) set forth in the Indenture plus accrued and unpaid interest and Additional Interest (as defined in the Indenture), if any, on the Senior Notes redeemed, up to the redemption date.

The Indenture contains covenants that, among other things, restrict our ability to: (i) incur additional indebtedness, guarantee indebtedness or issue certain preferred shares; (ii) make loans, investments and other restricted payments; (iii) pay dividends on or make other distributions in respect of, or repurchase or redeem, capital stock; (iv) create or incur certain liens; (v) sell, transfer or otherwise dispose of certain assets; (vi) enter into certain types of transactions with our affiliates; (vii) consolidate, merge or sell substantially all of our assets; (viii) prepay, redeem or repurchase certain debt; (ix) alter the business we conduct and (x) enter into agreements restricting the ability of our subsidiaries to pay dividends.

Upon the occurrence of certain change of control events, as defined in the Indenture, each holder of the Senior Notes will have the right to require that we repurchase all or a portion of such holder's Senior Notes in cash at a purchase price equal to 101% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

In connection with the private placement of the Senior Notes, on October 1, 2012, we entered into a Registration Rights Agreement (the "Notes Registration Rights Agreement") obligating us to use reasonable best efforts to file an exchange registration statement with the Securities and Exchange Commission (the "Commission") so that holders of the Senior Notes can offer to exchange the Senior Notes issued in the Senior Notes offering for registered notes having substantially the same terms as the Senior Notes and evidencing the same indebtedness as the Senior Notes. Under certain circumstances, in lieu of a registered exchange offer, we must use reasonable best efforts to file a shelf registration statement for the resale of the Senior Notes. If we fail to satisfy these obligations on a timely basis, the annual interest borne by the Senior Notes will be increased by up to 1.0% per annum until the exchange offer is completed or the shelf registration statement is declared effective.

Series A Preferred Stock.

On October 1, 2012 we issued 325,000 shares of our Series A Preferred Stock as part of the purchase price paid to complete the Eagle Property Acquisition. The shares of Series A Preferred Stock have an initial liquidation value of $1,000 per share and are convertible into shares of our common stock on or after October 1, 2013. At such time, the Series A Preferred Stock may be converted, in whole but not in part, at the option of the holders of a majority of the outstanding shares of Series A Preferred Stock, into a number of shares of our common stock calculated by dividing the then-current liquidation preference by the conversion price of $13.50 per share. If not previously converted, the Series A Preferred Stock will be subject to mandatory conversion into shares of our common stock on September 30, 2015 at a conversion price based upon the volume weighted average price of our common stock during the 15 trading days immediately prior to the mandatory conversion date, but in no instance will the price be greater than $13.50 per share or less than $11.00 per share. Dividends on the Series A Preferred Stock will accrue at a rate of 8.0% per annum, payable semiannually, at our sole option, in cash or through an increase in the liquidation preference. The issuance of the Series A Preferred Stock to Eagle Energy pursuant to the Eagle Purchase Agreement was approved by our stockholders holding a majority of the outstanding shares of our common stock.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods presented (dollars in thousands). For information regarding the individual components of our cash flow amounts, please refer to the Audited Consolidated Statements of Cash Flows included under Item 15 of this Annual Report.

	For the Years Ended December 31,		
	2012	**2011**	**2010**
Net cash provided by operating activities	$ 137,249	$ 141,550	$ 50,768
Net cash used in investing activities	(773,608)	(242,619)	(139,618)
Net cash provided by financing activities	647,893	96,496	96,414
Net change in cash	$ 11,534	$ (4,573)	$ 7,564

Our operating cash flows are sensitive to a number of variables, the most significant of which is the volatility of oil and gas prices. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of these commodities. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" beginning on page 67.

The following information highlights the significant period-to-period variances in our cash flow amounts:

Cash flows provided by operating activities

Net cash provided by operating activities was $137.2 million, $141.6 million and $50.8 million for the years ended December 31, 2012, 2011 and 2010, respectively. The slight decrease in net cash provided by operating activities for the year ended December 31, 2012 compared to the year ended December 31, 2011 was primarily driven by a decrease in oil, natural gas and natural gas liquids prices, partially offset by an increase in production. The increase in net cash provided by operating activities for the year ended December 31, 2011 compared to the year ended December 31, 2010 was primarily the result of an increase in oil, natural gas and NGLs production as well as an increase in realized prices.

Cash flows used in investing activities

We had net cash used in investing activities of $773.6 million, $242.6 million and $139.6 million during the years ended December 31, 2012, 2011 and 2010, respectively, as a result of our capital expenditures for drilling, development and acquisition costs. The increase in net cash used in investing

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activities during the year ended December 31, 2012 ($531.0 million) compared to the year ended December 31, 2011 was primarily due to the Eagle Property Acquisition ($351.3 million) and continued expansion of our drilling programs and growth of our business ($179.7 million).

The increase in net cash used in investing activities during the year ended December 31, 2011 ($103.0 million) compared to the year ended December 31, 2010 was primarily due to the expansion of our drilling program and growth of our business.

Cash flows provided by financing activities

Net cash provided by financing activities was $647.9 million, $96.5 million and $96.4 million for the years ended December 31, 2012, 2011 and 2010, respectively. For the year ended December 31, 2012, cash sourced through financing activities was provided primarily from proceeds from our initial public offering of $213.6 million and net long-term borrowings of $459.2 million, consisting of the Senior Notes offering in October 2012 of $600 million and advances from our revolving credit facility, offset by repayments of our revolving credit facility during the year. For years prior to 2012, cash sourced through financing activities was provided primarily by First Reserve and members of our management and borrowings under our revolving credit facility. Our long-term debt was $694.0 million, $234.8 million and $89.6 million at December 31, 2012, 2011 and 2010, respectively.

Other Items

Obligations and commitments

We have the following contractual obligations and commitments as of December 31, 2012 (in thousands):

	Payments due by Period				
	Total	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Revolving credit facility(1)	$ 94,000			94,000	
Senior Notes(2)	$ 1,099,875	64,500	129,000	129,000	777,375
Drilling contracts(3)	$ 10,261	10,261			
Operating leases(3)	$ 11,723	1,723	3,917	4,052	2,031
Seismic contracts(3)	$ 6,698	6,698			
Asset retirement obligations(4)	$ 15,245				15,245
Other(3)	$ 334	334			
Total contractual obligations	**$ 1,238,136**	**$ 83,516**	**$ 132,917**	**$ 227,052**	**$ 794,651**

(1) Amount excludes interest on our revolving credit facility as both the amount borrowed and applicable interest rate is variable. As of December 31, 2012, we had $94 million of indebtedness outstanding under our revolving credit facility. See Note 8 to our Consolidated Financial Statements.

(2) Amount includes approximately $65 million of interest per year; see Note 8 to our Consolidated Financial Statements.

(3) See Note 14 to our Consolidated Financial Statements for a description of operating lease, drilling contract, seismic contract and other obligations.

(4) Amounts represent our estimate of future asset retirement obligations on an undiscounted basis. 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. See Note 7 to our Consolidated Financial Statements.

Critical Accounting Policies and Estimates

We prepare our financial statements and the accompanying notes in conformity with GAAP, which requires our management to make estimates and assumptions about future events that affect the reported amounts in our financial statements and the accompanying notes. We identify certain accounting policies as critical based on, among other things, their impact on the portrayal of our financial condition, results of operations or liquidity and the degree of difficulty, subjectivity and complexity in their deployment. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Our management routinely discusses the development, selection and disclosure of each of the critical accounting policies. Following is a discussion of our most critical accounting policies:

Reserves Estimates. Proved oil and gas reserves are the estimated quantities of natural gas, crude oil and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing operating conditions and government regulations. Proved undeveloped reserves include those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units-of-production method to amortize our oil and gas properties, the quantity of reserves could significantly impact our DD&A expense. Our oil and gas properties are also subject to a "ceiling" limitation based in part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Reserves as of December 31, 2012, 2011 and 2010 were calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each month, held flat for the life of the production, except where prices are defined by contractual arrangements.

We have elected not to disclose probable and possible reserves or reserve estimates in this filing.

Revenue Recognition. Our revenue recognition policy is significant because revenue is a key component of the results of operations and of the forward-looking statements contained in the analysis of liquidity and capital resources. We record revenue in the month our production is delivered to the purchaser, but payment is generally received 30 to 90 days after the date of production. At the end of each month, we estimate the amount of production that was delivered to the purchaser and the price that will be received. We use our knowledge of our properties, their historical performance, the anticipated effect of weather conditions during the month of production, NYMEX and local spot market prices and other factors as the basis for these estimates. We record the variances between our estimates and the actual amounts received in the month payment is received.

Share-Based Compensation. We account for share-based compensation awards in accordance with FASB ASC 718, *Compensation Stock Compensation.* We measure share-based compensation cost at fair value and generally recognize the corresponding compensation expense on a straight-line basis over the service period during which awards are expected to vest. We include share-based compensation expense in "General and administrative expense" in our consolidated statements of operations.

Financial Instruments. Our financial instruments consist of cash and cash equivalents, receivables, payables, debt, and commodity derivatives. Commodity derivatives are recorded at fair value. The carrying amount of our other financial instruments approximate fair value because of the short-term nature of the items or variable pricing.

Derivative financial instruments are recorded in our consolidated balance sheets as either an asset or liability measured at estimated fair value. Changes in the derivative's fair value are recognized currently in earnings as gains and losses in the period of change. The gains or losses are recorded within revenues in "Losses on commodity derivative contracts net." The related cash flow impact is reflected within cash flows from operating activities.

Asset Retirement Obligations. We have obligations to remove tangible equipment and facilities associated with our oil and natural gas wells, and to restore land at the end of oil and natural gas production operations. The removal and restoration obligations are associated with plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the present value calculations are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlements and changes in the legal, regulatory, environmental and political environments.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

Commodity price exposure. We are exposed to market risk as the prices of oil and natural gas fluctuate due to changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged in the past and expect to hedge a significant portion of our future production.

We utilize derivative financial instruments to manage risks related to changes in oil, NGL and natural gas prices. As of December 31, 2012, we utilized fixed price swaps, collars, deferred-premium puts and basis differential swaps to reduce the volatility of oil prices on a portion of our future expected oil production.

For derivative instruments recorded at fair value, the credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet.

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The following is a summary of our commodity derivative contracts as of December 31, 2012:

	Hedged Volume	Weighted-Average Fixed Price
Gulf Coast:		
Oil (Bbls):		
WTI Swaps 2013	1,700,874	$95.55
WTI Swaps 2014	809,950	$87.33
WTI Basis Differential Swaps 2013(1)	1,602,164	$5.89
WTI Basis Differential Swaps 2014(1)	501,000	$5.35
Mid-Continent:(2)		
Oil (Bbls):		
WTI Swaps 2013	237,600	$96.10
WTI Swaps 2014	156,000	$93.00
WTI Collars 2013	203,004	$85.27 - $100.70
WTI Collars 2014	164,400	$88.49 - $97.94
Natural Gas (Mmbtu):		
Collars 2013	2,232,996	$3.68 - $4.91
Collars 2014	1,685,004	$3.99 - $5.09
NGL (Bbls):		
NGL Swaps 2013	258,000	$63.42