Midstates Petroleum Company, Inc.
Form 10-K
March 24, 2014

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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, 2013

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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 $180 million based upon the closing price of such stock on June 28, 2013, the last business day of the registrant's most recently completed second fiscal quarter, of $5.41 per share.

The number of shares outstanding of our stock at March 18, 2014 is shown below:

Class	Number of shares outstanding
Common stock, $0.01 par value	70,420,804

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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;
- availability of third party natural gas gathering and processing capacity;
- 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 asset and property acquisitions or the effects of asset and property acquisitions or dispositions on our cash position and levels of indebtedness;

infrastructure for salt water disposal and electricity;

sources of electricity utilized in operations and the related infrastructures;

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;

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- uncertainty regarding our future operating results; and
- 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 and Anadarko Basin Acquisitions;
- risks related to the concentration of our operations onshore in Oklahoma, Texas and Louisiana;
- 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.

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.

MMBtu: One million British thermal units.

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

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period covered by the report, determined as an unweighted arithmetic average of the 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 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.

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

On May 31, 2013, the Company closed on the acquisition of producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma from Panther Energy Company, LLC and its partners for approximately $618 million in cash (the "Anadarko Basin Acquisition"), before customary post-closing adjustments. The Company funded the purchase price with a portion of the net proceeds from the private placement of $700 million in aggregate principal amount of 9.25% senior unsecured notes due 2021 (the "2021 Senior Notes" and, together with the 2020 Senior Notes, the "Senior Notes"), which also closed on May 31, 2013.

Subsequent to the closing of the Eagle Property Acquisition and the Anadarko Basin Acquisition, the Company has oil and gas operations and properties in Louisiana, Oklahoma and Texas. At December 31, 2013, the Company operated oil and natural gas properties and evaluated performance as one reportable segment as there were not significantly different economic or operational environments within its oil and natural gas properties.

On March 5, 2014, we executed a Purchase and Sale Agreement ("PSA") to sell all of our ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline

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Parish, Louisiana to a private buyer for a purchase price of $170 million in cash, subject to standard post-closing adjustments. The PSA has an effective date of November 1, 2013 and is expected to close on May 1, 2014. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres, and does not include our acreage and production in the western part of Louisiana in Beauregard Parish or other undeveloped acreage held outside the Pine Prairie field. The proceeds from the sale will be used to pay down our revolving credit facility.

The following table summarizes, by areas of operation, our estimated proved reserves as of December 31, 2013, their corresponding pre-tax PV-10 values and our fourth quarter 2013 average daily production rates (including those figures attributable to the Pine Prairie field that are subject to the PSA discussed above):

	Proved Reserves(1)					PV-10(3)	Average Daily Production for Three Months Ended December 31, 2013
Areas of Operation	**Oil (MBbl)**	**NGL (MBbl)**	**Gas (MMcf)**	**Total(2) (MBoe)**	**% Oil(4)**	**(in thousands)**	**(Boe/day)**
Mississippian	24,239	14,221	176,264	67,836	56%	$ 965,761	17,579
Anadarko Basin	15,816	8,555	75,612	36,973	66%	611,315	8,454
Gulf Coast	14,845	3,380	28,322	22,945	79%	490,758	5,154
Total	**54,900**	**26,156**	**280,198**	**127,754**	**63%**	**$ 2,067,834**	**31,187**
Discounted Future Income Taxes						(277,388)	
Standardized Measure of Discounted Future Net Cash Flows(3)						**$ 1,790,446**	

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(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, 2013, 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 natural 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 2013, we incurred $1.2 billion in exploration, development and property acquisition expenditures, including $624.7 million for the Anadarko Basin Acquisition and $64.9 million for facilities and lease and seismic acquisition. Of the 124 wells spud in 2013, 121 gross (98 net) wells

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resulted in productive completions and three gross (and net) wells were unsuccessful, yielding a 98% success rate.

We expect to invest between $500 million and $550 million of capital for exploration, development and lease and seismic acquisition in 2014. Additionally, we expect to capitalize between $16 million and $22 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:

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.

Mississippian. Our Mississippian assets acquired on October 1, 2012 are located in Oklahoma 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. 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, our capital deployment will be focused on the Mississippian Lime until natural gas prices demonstrate sustained improvement from recent levels. At December 31, 2013, we had approximately 137,500 gross (97,200 net) acres under lease in the area, comprised of approximately 120,000 gross (84,300 net) leased acres in the Mississippian Lime and approximately 17,500 gross (12,900 net) acres in the Hunton. As of December 31, 2013, we had five drilling rigs in operation, and we currently have five drilling rigs in operation. We expect to spud between 95 to 105 gross (70 to 80 net) horizontal wells, including non-operated wells, during 2014 on this acreage.

Anadarko Basin. Our Anadarko Basin assets acquired on May 31, 2013 are located in Western Oklahoma and Texas and target multiple objectives in the Pennsylvanian section. Specifically we are currently targeting the Cleveland, Marmaton, Cottage Grove and Tonkawa formations by utilizing horizontal wells and multi-stage frac technology. At December 31, 2013, we had approximately 161,500 gross (129,800 net) acres under lease in the Anadarko Basin, comprised of approximately 42,700 gross (34,300 net) leased acres in Oklahoma and approximately 118,800 gross (95,500 net) acres in the Texas. As of December 31, 2013, we had five drilling rigs in operation in this area, and we currently have five drilling rigs in operation. We expect to spud between 70 to 75 gross (47 to 50 net) horizontal wells, including non-operated wells, during 2014 on this acreage.

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, 2013 we had approximately 83,400 gross (81,200 net) acres under lease and/or lease option, comprised of 58,500 gross (56,500 net) acres under lease and 24,900 gross (24,700 net) acres under lease options, targeting large, well-defined geologic structures that we believe will increase our reserves, production and cash flow. With the addition of the Anadarko assets and increased activity in the Mississippian, we have shifted capital to those assets and dropped rigs in Louisiana. Our intent is to continue high grading inventory in Louisiana for future capital deployment. As of December 31, 2013, we had no drilling rigs in operation. We currently do not have any rigs in operation in the Gulf Coast area and expect a reduction in activity versus prior year due to our current focus on exploitation of our Mississippian assets and our recently

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acquired Anadarko Basin Assets. As discussed above, on March 5, 2014, we executed a PSA to sell all of our ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana to a private buyer. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres and is expected to close on May 1, 2014.

Disciplined financial management. We intend to maintain a 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 and debt securities, 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 2020 Senior Notes offering and through the issuance of our Series A Preferred Stock. We funded the Anadarko Basin Acquisition with cash proceeds from our $700 million 2021 Senior Notes offering. In September 2013, our reserve-based borrowing base under our revolving credit facility was increased from $425 million to $500 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 and target hedging the maximum volumes permitted under our revolving credit facility, which currently equates to approximately 80% of our total current oil volumes from proved developed producing reserves. 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. We may also consider the sale of selected assets or oil and gas interests to the extent those actions would help us achieve our targeted financial profile.

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 majority of our properties, provide flexibility with respect to drilling and completion techniques and the timing and amount of capital expenditures that support growth and help us meet our targeted financial profile.

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, 3D and micro seismic data, existing sub-surface well control data, detailed reservoir characterization and 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.

Selectively increase our acreage position. While we believe our existing acreage positions provide significant growth opportunities in the Mississippian Lime, Anadarko Basin and the Upper Gulf Coast Tertiary trend, we continue to strategically increase our leasehold position in what we believe are the most prospective areas of our acreage. We believe our current Oklahoma and Texas acreage is highly prospective in the Pennsylvanian and Mississippian Lime sections and may be prospective in both shallower and deeper geologic sections. 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, 2013, our production was comprised of approximately 45% oil and 20% NGLs and our year-end reserves consisted of 43% oil, 20% NGL and 37% natural gas. In the Gulf Coast, we also 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 $14.88 per Bbl for the three years ended December 31, 2013. For the year ended December 31, 2013, the average realized price before the effect of commodity derivative contracts for our oil production was $99.18 per Bbl, compared to an average NYMEX WTI price of $98.05 per Bbl for the same period.

Extensive technical knowledge, history and early mover advantage in our areas of operations. In our Mississippian Lime area, we and our predecessor in the field have demonstrated an early mover advantage in acquiring and developing acreage in the trend, spudding 151 horizontal wells between 2010 and December 31, 2013. We believe our Mississippian team's early experience operating in this trend gives us a competitive advantage with respect to completion techniques and infrastructure development. In the Anadarko Basin area, we also feel that we have an advantage due to the history of drilling horizontally in several of the Pennsylvanian sands since 2005. We successfully hired many of the operation and technical personnel from Panther Energy, which will allow us to continue to build on their success in this area. 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. We believe we have developed amicable and mutually beneficial relationships with acreage owners in all of 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 and Anadarko Petroleum Corporation. 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

Mississippian Lime

Our Mississippian assets were acquired on October 1, 2012 and at December 31, 2013, consisted of approximately 84,300 net prospective acres in the Mississippian Lime trend, with 79,800 net acres in Woods and Alfalfa Counties of Oklahoma, which we currently believe is the core of the trend. We currently intend to develop these liquids-rich properties using horizontal wells. We also own approximately 12,900 net acres in Lincoln County, Oklahoma, which produces from, and is prospective in, the Hunton formation.

Our properties in this area represented 53% of our total proved reserves as of December 31, 2013. As of December 31, 2013, we held an average working interest and average net revenue interest of 71% and 55%, respectively, on our acreage in this area.

For the three months ended December 31, 2013 and 2012 and the year ended December 31, 2013, our average daily production from this area was as follows:

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	Year Ended December 31, 2013	Year Ended December 31, 2012(1)
Average daily production:				
Oil (Boe/d)	6,325	2,216	4,567	557
Natural gas liquids (Boe/d)	3,622	1,820	2,620	458
Natural gas (Mcf/day)	45,794	19,021	34,784	4,781
Average daily production (Boe/d)	17,579	7,207	12,985	1,812

(1) Note that as the Eagle Property Acquisition closed on October 1, 2012, this represents the impact to average annual production for the period of October 1, 2012 through December 31, 2012.

In this area, 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 at least four horizontal wells per 640 acre section. We are also testing different completion techniques, including selective use of open hole completions, to determine the most cost effective design in this area.

During 2013, we invested approximately $315.9 million and drilled 75 horizontal wells in this region; in 2014, we plan to invest approximately $290 million to $330 million in the drilling of between 95 to 105 gross wells, including non-operated wells. Our plans are to continue to actively develop this area while evaluating exploration potential beyond our current position.

Expansion Areas Within Mississippian

All of our rigs currently operating in the Mississippian Lime are focused on infill drilling in our de-risked acreage; however, in the future, we plan to run one (or more) rigs in these areas to not only hold acreage but also de-risk the acreage.

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Anadarko Basin

Our Anadarko Basin assets were acquired on May 31, 2013, and at December 31, 2013, consisted of approximately 129,800 net acres in the Anadarko Basin, consisting of 95,500 net acres in Texas and 34,300 net acres in western Oklahoma. We took over operations of the properties on December 1, 2013. We currently intend to develop these liquids-rich properties using horizontal wells.

Our properties in this area represented 29% of our total proved reserves as of December 31, 2013. As of December 31, 2013, we held an average working interest and average net revenue interest of 80% and 53%, respectively, on our acreage in this area.

For the quarter ended December 31, 2013 and the period from May 31, 2013 through December 31, 2013, our average daily production from the area was as follows:

	Three Months Ended December 31, 2013	Year Ended December 31, 2013(1)
Average daily production:		
Oil (Boe/d)	3,940	2,239
Natural gas liquids (Boe/d)	1,816	1,082
Natural gas (Mcf/day)	16,190	9,559
Average daily production (Boe/d)	8,454	4,914

(1) Note that as the Anadarko Basin Acquisition closed on May 31, 2013, this represents the impact to average annual production for the period of May 31, 2013 through December 31, 2013. No data is available for the respective 2012 periods due to the timing of the acquisition.

During 2013, we invested approximately $96.2 million and drilled 35 horizontal wells; in 2014, we plan to invest approximately $170 million to $210 million in the drilling of between 70 to 75 gross wells, including non-operated wells. Our plans are to continue to actively develop this area while testing other potentially productive horizons within our current acreage and expansion areas beyond our current position.

Gulf Coast

In the Gulf Coast, our current acreage positions and evaluation efforts are concentrated in Louisiana in the Wilcox interval of the Upper Gulf Coast Tertiary trend and is characterized by well-defined geology, including tight sands featuring multiple productive zones typically located within large geologic traps. As of December 31, 2013, we had accumulated approximately 56,500 net acres in the trend and options to acquire an aggregate of approximately 24,700 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, 2013, we had drilled 144 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 from 995 Boe/d in the year ended December 31, 2008 to 6,027 Boe/d in the year ended December 31, 2013.

Our properties in this area represented 18% of our total proved reserves as of December 31, 2013. As of December 31, 2013, we held an average working interest and average net revenue interest of 97% and 73%; respectively, on our acreage in this area.

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For the quarter ended December 31, 2013 and 2012, and years ended December 31, 2013 and 2012, our average daily production from the area was as follows:

	Three Months Ended December 31,		Year Ended December 31,	
	2013	2012	2013	2012
Average daily production:				
Oil (Boe/d)	3,375	5,737	3,890	5,162
Natural gas liquids (Boe/d)	995	1,170	1,008	1,228
Natural gas (Mcf/day)	4,706	8,869	6,772	10,778
Average daily production (Boe/d)	5,154	8,385	6,027	8,187

During 2013, we invested approximately $148.9 million for exploration, development and lease and seismic acquisition and drilled 14 wells, including sidetracks, in the Gulf Coast area. In 2014, we currently plan to invest between $5 million and $10 million. We currently have no drilling rigs operating in this area as we have devoted our capital to developing our Mississippian and Anadarko Basin assets; however, we plan to continue to evaluate our acreage as well as other potential exploration opportunities in the Gulf Coast area.

The Gulf Coast areas of operation are concentrated in three core fields in Beauregard and Evangeline Parishes, Louisiana: Pine Prairie, South Bearhead Creek and North Coward's Gully. In Pine Prairie we spent $31.2 million of capital in 2013, continuing our vertical development of the deeper objectives in the Wilcox and Sparta with six vertical wells spud during the year. We spent $41.5 million in capital during 2013 in South Bearhead Creek spudding two horizontals and one vertical. Lastly, in 2013, we spent $55.6 million in capital and spud four horizontals, including one sidetrack, in the North Coward's Gully field.

On March 5, 2014, we executed a PSA to sell all of our ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana to a private buyer for a purchase price of $170 million, subject to standard post-closing adjustments. The PSA is expected to close on May 1, 2014. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres, and does not include our acreage and production in the western part of Louisiana in Beauregard Parish or other undeveloped acreage held outside the Pine Prairie field. Production from the assets included in this sale averaged 3,453 and 4,777 Boe/d during the years ended December 31, 2013 and 2012, respectively, and 2,366 and 5,361 Boe/d during the fourth quarters ended December 31, 2013 and 2012, respectively. Upon closing of the sale, our remaining Gulf Coast areas of operation will be concentrated in the South Bearhead and North Coward's Gully fields.

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Estimated Proved Reserves

	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Total (MBoe)
2011				
Proved Reserves				
Beginning Balance	11,927	314	27,906	16,892
Revision of previous estimates	(2,650)	1,661	(6,500)	(2,072)
Extensions, discoveries and other additions	8,049	2,364	22,204	14,114
Sales of reserves in place				
Purchases of reserves in place				
Production	(1,610)	(308)	(4,918)	(2,738)
Net proved reserves at December 31, 2011	**15,716**	**4,031**	**38,692**	**26,196**
Proved developed reserves, December 31, 2011	**6,479**	**1,802**	**17,987**	**11,279**
Proved undeveloped reserves, December 31, 2011	**9,237**	**2,229**	**20,705**	**14,917**
2012				
Proved Reserves				
Beginning Balance	15,716	4,031	38,692	26,196
Revision of previous estimates	(1,368)	(193)	(8,533)	(2,982)
Extensions, discoveries and other additions	12,262	3,232	32,646	20,935
Sales of reserves in place				
Purchases of reserves in place	13,010	7,745	85,293	34,969
Production	(2,093)	(617)	(5,695)	(3,659)
Net proved reserves at December 31, 2012	**37,527**	**14,198**	**142,403**	**75,459**
Proved developed reserves, December 31, 2012	**13,207**	**5,437**	**54,775**	**27,774**
Proved undeveloped reserves, December 31, 2012	**24,320**	**8,761**	**87,628**	**47,685**
2013				
Proved Reserves				
Beginning Balance	37,527	14,198	142,403	75,459
Revision of previous estimates	(13,511)	(3,259)	(20,762)	(20,230)
Extensions, discoveries and other additions	17,538	8,812	103,551	43,608
Sales of reserves in place				
Purchases of reserves in place	17,242	8,124	73,653	37,642
Production	(3,897)	(1,719)	(18,647)	(8,724)
Net proved reserves at December 31, 2013	**54,899**	**26,156**	**280,198**	**127,755**
Proved developed reserves, December 31, 2013	**19,853**	**10,321**	**111,410**	**48,743**
Proved undeveloped reserves, December 31, 2013	**35,046**	**15,835**	**168,788**	**79,012**

Our proved reserves have grown from 26.2 to 75.5 MMBoe from year end 2011 to year end 2012 and from 75.5 to 127.8 MMBoe from year end 2012 to year end 2013. 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 and during 2013, the Anadarko Basin Acquisition. As a result, we have increased our average daily production at a compound annual growth rate of 89% from 995 Boe/d in the year ended December 31, 2008 to 23,927 Boe/d in the year ended December 31, 2013.

Our proved undeveloped reserves have grown from 47.7 MMBoe to 79.0 MMBoe from December 31, 2012 to December 31, 2013. During this time, we spent $249.2 million of our capital expenditures on drilling proved undeveloped locations and converted 11.3 MMBoe from proved undeveloped reserves to proved developed reserves. In addition, we added 43.6 MMBoe of proved

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undeveloped reserves through extensions and discoveries and had negative revisions of 20.2 MMBoe related to proved undeveloped reserves, of which 14.4 MMBoe related to reductions at our Gulf Coast Pine Prairie and West Gordon fields. These net negative revisions in the Gulf Coast were primarily due to higher development and lease operating costs which resulted in certain proved undeveloped locations becoming uneconomic as of December 31, 2013. We also added 37.6 MMBoe of proved reserves, primarily related to the closing of the Anadarko Basin Acquisition.

All of our proved undeveloped reserves as of December 31, 2013 are expected to be developed within five years of their initial booking.

Independent petroleum engineers

Mississippian and Gulf Coast Area Reserves

Our estimated reserves and related future net revenues at December 31, 2013 for the Mississippian and Gulf Coast areas 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. Our estimated reserves and related future net revenues for all areas at December 31, 2012 and 2011 were based on reports prepared by 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 and Mr. Philip R. Hodgson. 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 1998. Mr. Hodgson is a Licensed Professional Geoscientist in the State of Texas, Geophysics (No. 1314) and has over 29 years of experience in geological and geophysical studies and evaluations. He graduated from The 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. 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.

Anadarko Area Reserves

For our Anadarko area, our estimated reserves and related future net revenues at December 31, 2013 are based on reports prepared by Cawley, Gillespie & Associates, Inc. ("CGA"), 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 CGA, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. CGA was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the reserves report incorporated herein was

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Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 26 years of practical experience in petroleum engineering, with over 24 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds 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; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

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 and CGA 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 and CGA 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. At December 31, 2013, Clifford G. Zwahlen, PE, our former Vice President Corporate Reserves, was the technical person primarily responsible for overseeing the preparation of our reserve estimates and reported directly to the CEO. Prior to joining Midstates in March 2013, Mr. Zwahlen was the Manager of Reservoir Engineering Southern Region for Devon Energy, an oil and gas exploration and production company, from November 2011 to February 2013. Prior to that, from September 2009 to October 2011, he was the Reservoir Engineering

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Manager and Asset Lead for Devon's Carthage District in East Texas. From February 2008 to August 2009, Mr. Zwahlen was the Director of the Project Management Office for Devon's Shared Services Group and from March 2005 to February 2008 he held the position of Manager of Corporate Planning for Devon's Exploration and Production Business Unit. He also held management and engineering positions with EOG Resources and PetroCorp, Inc. Mr. Zwahlen currently serves on the Advisor Board for the MPGE School of the University of Oklahoma and the Petroleum Engineering Industry Board at Texas A&M University. He holds a degree in Petroleum Engineering from Texas A&M University and is a registered Professional Engineer in the state of Texas (License No. 76924). 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.

In connection with our annual evaluation of the effectiveness of our internal control over financial reporting, we determined that, as of December 31, 2013, we did not maintain effective internal control over the accuracy and valuation of oil and gas reserves estimates. Specifically, controls were not operating effectively over the validation of the accuracy and completeness of certain source data provided to the independent third party reserve engineers. We also did not perform adequate management review of the independent third party reserves reports to determine if reserves estimates were complete and consistent with management's capital spending plans. These control deficiencies resulted in errors that, if not corrected, would have resulted in the misstatement of disclosures related to the value of oil and gas properties and associated reserve estimates. Please see "Management's Annual Report on Internal Control Over Financial Reporting" in Item 9A of this Annual Report.

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 the past decade. However, the current economic slowdown during the second half of 2008 and through 2009 reduced this demand. Demand for oil increased during 2010, 2011 and 2012, but demand for natural gas has remained sluggish. Additionally, the price of natural gas has remained relatively depressed due to increasing supplies from shale plays, but has increased in recent months due to shortages caused by severe winter weather. 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, 2013, 2012 and

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2011. 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,		
	2013	2012	2011
Operating Data:			
Net production volumes:			
Oil (MBbls)	3,904	2,093	1,610
NGLs (MBbls)	1,719	617	308
Natural gas (MMcf)	18,657	5,695	4,918
Total oil equivalents (MBoe)	8,733	3,659	2,737
Average daily production (Boe/d)	23,927	9,999	7,499
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$ 99.18	$ 104.35	$ 110.25
Oil, with realized derivatives (per Bbl)	$ 93.41	$ 95.05	$ 99.85
Natural gas liquids, without realized derivatives (per Bbl)	$ 36.26	$ 38.27	$ 50.98
Natural gas liquids, with realized derivatives (per Bbl)	$ 37.09	$ 40.48	(a)
Natural gas, without realized derivatives (per Mcf)	$ 3.39	$ 2.81	$ 4.20
Natural gas, with realized derivatives (per Mcf)	$ 3.58	$ 3.21	(a)
Costs and Expenses (per Boe of production):			
Lease operating and workover	$ 8.41	$ 8.34	$ 5.89
Gathering and transportation	$ 0.62	$	$
Severance and other taxes	$ 3.12	$ 6.81	$ 4.98
Asset retirement accretion	$ 0.17	$ 0.20	$ 0.12
Depreciation, depletion and amortization	$ 28.67	$ 34.32	$ 33.50
Impairment of oil and gas properties	$ 51.91	$	$
General and administrative	$ 6.10	$ 8.35	$ 25.18
Acquisition and transaction costs	$ 1.35	$ 4.07	$
Other	$ 0.07	$	$

(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, 2013:

	Years Ended December 31,		
	2013	**2012**	**2011**
Mississippian(1)			
Net production volumes:			
Oil (MBbls)	4,550	203	
NGLs (MBbls)	1,908	123	
Natural gas (MMcf)	30,070	1,289	
Total oil equivalents (MBoe)	**11,470**	**541**	
Anadarko(2)			
Net production volumes:			
Oil (MBbls)	2,239		
NGLs (MBbls)	1,082		
Natural gas (MMcf)	9,559		
Total oil equivalents (MBoe)	**4,914**		

(1) These volumes represent only Mississippian Lime production and do not include Hunton volumes.

(2) Anadarko volumes include production from May 31, 2013, the date of acquisition of the Anadarko Basin Properties, through December 31, 2013.

Productive Wells

The following table presents our total gross and net productive wells as of December 31, 2013:

	Oil		Natural Gas		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Total productive wells	617	463	105	79	722	542

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, 2013 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
Mississippian	94,287	61,843	43,248	35,316	137,535	97,159
Anadarko Basin	102,992	82,783	58,541	47,054	161,533	129,837
Gulf Coast	16,326	16,313	67,061	64,899	83,387	81,212
Total	**213,605**	**160,939**	**168,850**	**147,269**	**382,455**	**308,208**

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Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2013 that will expire over the next three years by operating area unless production is established within the spacing units covering the acreage or we make additional lease rental payments prior to the expiration dates:

	Expiring 2014		Expiring 2015		Expiring 2016	
	Gross	Net	Gross	Net	Gross	Net
Mississippian	28,203	20,046	4,945	4,543	9,594	8,990
Anadarko Basin	39,861	32,039	13,578	8,066	11,696	6,949
Gulf Coast	1,914	1,875	3,738	3,537	33,235	32,318
Total Undeveloped Acreage Expirations	**69,978**	**53,960**	**22,261**	**16,146**	**54,525**	**48,257**

Excluding the Anadarko Basin Acquisition, approximately 12% of our net acreage, including acreage under option, was acquired in 2013, with the majority of such leases under three year primary term leases. In addition, our typical lease terms along with unit regulatory rules generally 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, 2013, 2012 and 2011. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	Years Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	121	98	68	64	29	29
Dry holes	1	1	7	7		
Total	**122**	**99**	**75**	**71**	**29**	**29**
Exploratory wells:						
Productive			4	3	2	2
Dry holes	2	2				
Total	**2**	**2**	**4**	**3**	**2**	**2**
Total wells	**124**	**101**	**79**	**74**	**31**	**31**

As of December 31, 2013, no exploratory wells were being drilled and seven gross (and net) development wells were currently drilling.

Our drilling activity has increased over the last three years, and we were operating ten drilling rigs on our properties as of December 31, 2013. Our recent drilling activity has primarily focused on development and delineation and appraisal of our primary operating areas in the Mississippian and Anadarko Basin. 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 2013 we had a total of three gross (and net) that were deemed dry hole wells, two of which were geologic dry holes and one of which was caused by mechanical problems encountered while drilling which prevented us from reaching the reservoir targets.

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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 other than in our Mississippian region where a portion of our natural gas production is dedicated to one purchaser for the economic life of the relevant assets. For the year ended December 31, 2013, ConocoPhillips, Chevron, Gulfmark, Semgas and Valero Marketing accounted for 28%, 16%, 13%, 12%, and 11% of our revenues, respectively. 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 for 39% and 38% 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, including gas processing, access to electricity and transportation. Additionally, once production comes back online following a cessation due to weather, it may take a period of time before production from a well reaches the level it was at prior to the cessation. 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.

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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 companies 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 successfully 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 produced during operations 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, all 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

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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.

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

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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 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 $1.0 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 $1.0 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 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 $1.0 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 oil and 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 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 complex federal, regional, state and local laws and regulations governing occupational safety and health, the emission or discharge of materials into the environment and environmental protection. Numerous governmental entities, including the U.S. Environmental Protection Agency ("EPA"), analogous state agencies, and, in certain instances, citizens' groups, 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 waste 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 injunctions prohibiting 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

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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 or that limit or otherwise restrict the emission of certain pollutants or organic compounds from wells or surface equipment 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 existing or any new laws and regulations or that future compliance with such laws and regulations 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 of or arranged for the disposal of the hazardous substances at a site where a release has occurred. Under CERCLA, these "responsible parties" may be subject to strict, joint and several liability for the costs of removing and cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover 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. Despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses crude oil and natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

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

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provide no assurance that this exemption will be preserved in the future. From time to time the EPA and analogous state agencies have considered repealing or modifying this exemption, and citizens' groups have also petitioned the agency consider its repeal. Repeal or modification of this exemption or similar exemptions under state law could have a significant impact on our operating costs as well as the oil and natural gas industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted. In any event, at present, 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 become regulated as hazardous wastes if such wastes have hazardous characteristics.

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, in August 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 ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("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 2012. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, beginning in January 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. We continue to review these rules and assess their potential impacts on our operations. Compliance with these requirements could increase our costs of development and production, which costs could be significant.

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Climate change

Recent scientific studies have suggested that emissions of certain greenhouse gases ("GHGs"), which include carbon dioxide and methane, may be contributing to warming of the earth's atmosphere and other climatic changes. In December 2009, the EPA published its findings that emissions of greenhouse gases, or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the federal Clean Air Act that establish pre-construction and operating permitting requirements for GHG emissions from certain large stationary sources. 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 oil and natural gas production facilities on an annual basis, which includes 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, in August 2012, the EPA established new source performance standards for volatile organic compounds and sulfur dioxide and an air toxic standard for oil and natural gas production, transmission, and storage activities. The rules include the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several other sources, such as storage tanks and other equipment, and limits methane emissions from these sources in an effort to reduce GHG emissions. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. We cannot predict which areas, if any, the EPA may choose to regulate with respect to GHG emissions next.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on our operations and the industry in general. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, such requirements could require us to obtain permits for our GHG emissions, install costly emission controls, and adversely affect demand for the oil and natural gas that 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, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of 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, including oil and natural gas production 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; however, to date, the agency has taken no action to do so. 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, Texas 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 in December 2012 and a final report expected to be available for public comment and peer review sometime in 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities sometime in 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 only use qualified contractors to perform hydraulic fracturing activities at our properties who have experience performing fracturing services on similar properties and who have demonstrated to our satisfaction that they employ appropriate safeguards to ensure that hydraulic fracturing will be performed in a safe and environmentally protective manner. 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 and coverage limits of such policies.

Endangered Species Act considerations

The federal Endangered Species Act, as amended ("ESA"), restricts 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 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, 2013, we employed 217 people, including 56 technical (geosciences, engineering, land), 100 field operations, 52 corporate (finance, accounting, planning, business development, legal, office management) and nine management.

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Offices

We currently lease approximately 41,200 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 2018. We also lease two field offices in Louisiana, one in Perryton, Texas and approximately 57,000 square feet of office space in Tulsa, Oklahoma at 321 South Boston Avenue, Suite 600. The lease for our Tulsa office expires in 2021.

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 in our other public filings, press releases and discussions with our management actually occurs, our business, financial condition or results of operations could suffer. The risks described below are the known material risk factors facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks Related to the Oil and 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;

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- 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 currently 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.

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 our operating areas 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

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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, our hydraulic fracturing operations require significant quantities of water. Regions where we operate have recently experienced drought conditions. These conditions could persist in the future, diminishing our access to water for hydraulic fracturing operations. Any diminished access to water for use in hydraulic fracturing, whether due to usage restrictions or drought or other weather conditions, could curtail our operations or otherwise result in delays in operations or increased costs.

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, 2013, 2012 and 2011, 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

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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. At December 31, 2013, we recognized an impairment of $319.6 million, net of taxes, for the amount by which our net capitalized costs exceeded the cost center ceiling. 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.

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

As of December 31, 2013, we had $99 million available and a borrowing base of $500 million under our revolving credit facility, $600 million in 2020 Senior Notes and $700 million in 2021 Senior Notes outstanding. In the future, we may incur significant additional indebtedness in order to make future acquisitions or to develop our properties.

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

- causing a significant portion of our cash flows to be used to service our indebtedness, thereby reducing the availability of cash flows for working capital, capital expenditures and other general business activities;

- increasing our vulnerability to general adverse economic and industry conditions;

- limiting our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;

- placing 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;

- causing our debt covenants to affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;

- making 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;

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impairing our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and

making it more difficult for us to satisfy our obligations under the indentures governing our Senior Notes.

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.

If we are unable to repay our debt out of our cash on hand, we could attempt to refinance such debt, obtain additional borrowings, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure you that refinancing, additional borrowings, proceeds from the sale of assets or equity financing will be available to pay or refinance such debt. Factors that may affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions, our market value, our reserve levels and our operating performance at the time of such offering or other financing. The inability to repay or refinance our debt could have a material adverse effect on our operations and could result in a reduction in our capital program or lead us to pursue other alternatives to develop our assets.

In addition, our bank borrowing base is subject to periodic redeterminations on a semi-annual basis, effective October 1 and April 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 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.

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 $407.4 million, $15.6 million and $11.8 million for the years ended December 31, 2013, 2010 and 2009, respectively. 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 Mississippian Lime, Anadarko Basin or Upper Gulf Coast Tertiary trend 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 62% of our total estimated proved reserves were classified as proved undeveloped as of December 31, 2013. 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 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

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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.

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 Mississippian Lime, Anadarko Basin and Upper Gulf Coast Tertiary trend and production profiles are established over a sufficiently long time period. If our horizontal drilling results in these trends 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.

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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 current market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flows.

Our drilling and production programs may not be able to obtain access on commercially reasonable terms or otherwise to truck transportation, pipelines, gas gathering, transmission, storage and processing facilities to market our oil and gas production.

The marketing of oil and gas production depends in large part on the capacity and availability of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities. Access to such facilities is, in many respects, beyond our control. If these facilities were unavailable to us on commercially reasonable terms or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transmit and sell our oil and gas production. Our plans to develop and sell our oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise. The amount of oil and gas that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

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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 disruptions and continuing 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.

Our revolving credit facility and the indentures 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 indentures 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 indentures 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.

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

We have previously acquired reserves, properties, prospects and leaseholds from third parties, including the Eagle Acquisition and the Anadarko Basin Acquisition. In addition, we will continue to evaluate other acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of assets and other producing properties requires an assessment of several factors, including:

recoverable reserves;

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- future oil and natural gas prices and their appropriate differentials;
- development and operating costs;
- potential for future drilling and production;
- validity of the sellers' title to the properties, which may be less than expected at the time of signing the purchase agreement; and
- potential environmental issues, litigation 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 sellers 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.

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;
- an inability to secure, on acceptable terms, sufficient financing that may be required in connection with expanded operations and unknown liabilities; 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 if we successfully integrate operations acquired in acquisitions, we 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 assets of privately operated companies. If we fail to realize the benefits we anticipate from an acquisition, our results of operations and stock price may be adversely affected.

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Our pending sale of 3,907 gross (3,757 net) acres in the Pine Prairie field area of Evangeline Parish, Louisiana is contingent upon the satisfaction of certain conditions and may not be consummated on the terms or timeline contemplated and may not achieve the intended results.

On March 5, 2014, we executed a PSA to sell all of our ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana to a private buyer for a purchase price of $170 million in cash, subject to standard post-closing adjustments. We expect this transaction to close on May 1, 2014. However, the parties' obligations to consummate this transaction are conditioned upon the satisfaction or waiver of certain closing conditions, including governmental and third party approvals. If these conditions are not satisfied or waived, the acquisition will not be consummated and we may be required to obtain funding for our future capital spending plans under the Bridge Facility or other sources. Furthermore, even if the transaction does close, we may not realize the anticipated benefits of the transaction fully or at all and may have to seek other sources of funding in order to fund our capital spending plans. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources" for a more information on the PSA and the Bridge Facility.

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, NGL and natural gas receivables with several significant customers. The largest purchaser of our oil, NGL and natural gas during the year ended December 31, 2013 was ConocoPhillips, accounting for 28%, and for the year ended December 31, 2012 the largest purchaser of was Chevron, accounting for 41% of our total revenues for these periods. 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 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, natural gas liquids and natural gas.

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

Our operations in the Mississippian Lime formation in northwestern Oklahoma, the Anadarko Basin in Texas and Oklahoma and the Upper Gulf Coast tertiary trend in Louisiana 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 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.

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.

The proposed U.S. federal budget for fiscal year 2014 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 2014 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.

Our 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 our business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales, if any, of oil and gas, we are 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 and complex 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 at our leased and owned properties. Spills or other releases of regulated substances, including such spills and releases that occur in the future, could

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expose us to material losses, expenditures and liabilities under applicable environmental laws and regulations. Under certain of such laws and regulations, we could be subject to strict, joint and several liability 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.

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. The EPA has also 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. 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, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

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

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fracturing activities involving diesel under the federal Safe Drinking Water Act, or SDWA, and recently released draft permitting guidance for hydraulic fracturing activities using diesel. In addition, in November 2011, the EPA announced plans to propose rules under the Toxic Substances Control Act relating to the disclosure of chemical substances and mixtures used in hydraulic fracturing; however, to date, the agency has not yet taken action to do so. On August 16, 2012, the EPA published final regulations under the Clean Air Act that require additional emissions controls for the oil and natural gas industry, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production 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.

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.

From time to time, Congress has considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. 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. 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. 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. 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 Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for, or linked to, certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. To the extent we engage in such transactions or transactions that become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception to the mandatory clearing requirements for swaps entered to hedge its commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we uses for hedging. In addition, the Act requires that regulators establish margin rules for uncleared swaps. Rules that require end-users to post initial or variation margin could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing its ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules for uncleared swaps are not yet final and their impact on us is not yet clear.

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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.

Additionally, 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.

The full impact of the Dodd-Frank Act and related regulatory requirements upon the our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. 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. Any of these consequences could have a material adverse effect on our financial condition and results of operations.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

Risks Relating to our Common Stock

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 debt and 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;

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- 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.

We have identified a material weakness in our internal control over financial reporting. This material weakness, if not corrected, could affect the reliability of our financial statements and have other adverse consequences.

Under Section 404 of the Sarbanes-Oxley Act of 2002, we are required to furnish a report by our management on internal control over financial reporting. This report must contain, among other matters, an assessment of the effectiveness of our internal control over financial reporting, including a statement as to whether or not our internal control over financial reporting is effective. This assessment must include disclosure of any material weaknesses in our internal control over financial reporting identified by our management. In addition, the report must contain a statement that our auditors have issued an attestation report on management's assessment of such internal control over financial reporting.

We have identified a material weakness in our internal control over financial reporting as of December 31, 2013, as disclosed in "Item 9A. Controls and Procedures". Failure to have effective internal controls could lead to a misstatement of our financial statements or prevent us from filing our financial statements in a timely manner. If, as a result of deficiencies in our internal controls, we cannot provide reliable financial statements, our business decision processes may be adversely affected, our business and operating results could be harmed, investors could lose confidence in our reported financial information, the price of our common shares could decrease and our ability to obtain additional financing, or additional financing on favorable terms, could be adversely affected. In addition, failure to maintain effective internal control over financial reporting could result in investigations or sanctions by regulatory authorities.

We intend to take further action to remediate the material weakness and improve the effectiveness of our internal control over financial reporting. However, we can give no assurances that the measures we may take will remediate the material weakness identified or that any additional material weaknesses will not arise in the future due to our failure to implement and maintain adequate internal control over financial reporting. In addition, even if we are successful in strengthening our controls and procedures, those controls and procedures may not be adequate to prevent or identify irregularities or ensure the fair presentation of our financial statements included in our periodic reports filed with the SEC.

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 indentures governing our Senior Notes. Consequently, your only

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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.

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 Series A Preferred Stock issued as consideration in the Eagle Property Acquisition. On a pro forma basis following conversion of the Series A 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.

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 of our securities (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.

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.

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The terms of the Series A 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 Series A 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 Series A 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 Series A 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 Series A Preferred Stock; and
- 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

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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 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of December 31, 2013, 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.

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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."

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

	Price Range	
	High	**Low**
2013		
First Quarter	$ 8.95	$ 6.80
Second Quarter	$ 8.58	$ 5.31
Third Quarter	$ 6.55	$ 4.26
Fourth Quarter	$ 6.73	$ 4.79
2014		
First Quarter(1)	$ 6.75	$ 4.13

(1) First quarter 2014 high and low ranges are calculated through March 18, 2014.

Holders.

The number of shareholders of record of our common stock was approximately 39 on March 18, 2014.

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.

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 the date our common stock began trading on the NYSE through December 31, 2013, 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") for the same period of time. 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.

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, 2013, 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, 2013, 2012 and 2011 and the balance sheet data as of December 31, 2013 and 2012 are derived from our audited consolidated financial statements and the notes thereto included elsewhere in this Annual Report 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

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2009 are derived from our audited financial statements not included in this Annual Report on Form 10-K.

	As of and for the Year Ended December 31,				
	2013(1)	2012(2)	2011	2010	2009
	(in thousands, except per share amounts)				
Income Statement Data					
Total revenues	$ 469,506	$ 247,673	$ 209,433	$ 63,052	$ 24,254
Net income (loss)	(343,985)	(150,097)	16,657	(15,635)	(11,752)
Net income (loss) attributable to common shareholders(3)	(359,574)	(156,597)	16,657	(15,635)	(11,752)
Net income (loss) per share attributable to common shareholders(4)					
Basic and diluted	$ (5.47)	$ (2.61)	N/A	N/A	N/A
Balance Sheet Data					
Total assets	$ 2,342,107	$ 1,684,010	$ 624,656	$ 427,004	$ 284,034
Long-term debt	1,701,150	694,000	234,800	89,600	29,800
Stockholders'/members' equity	339,999	677,469	285,502	255,879	235,334
Weighted average number of common shares outstanding	65,766	59,979	N/A	N/A	N/A

(1) The year ended December 31, 2013 reflects the Anadarko Basin Acquisition, which closed on May 31, 2013. 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 reflects the Eagle Property Acquisition, which closed on October 1, 2012. 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.

(3) The years ended December 31, 2013 and 2012 includes the effect of an undeclared Series A Preferred Stock dividend of $15.6 million and $6.5 million, which is, at the Company's option, to be paid in cash or in shares upon conversion. 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.

(4) The net loss per share attributable to common shareholders for the year ended December 31, 2012 is on a pro forma basis, as our common stock did not trade for the entirety of 2012 (trading began on the New York Stock Exchange on April 20, 2012).

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	As of and for the Year Ended December 31,				
	2013(1)	2012(2)	2011	2010	2009
	(in thousands)				
Balance Sheet Data					
Cash and cash equivalents	$ 33,163	$ 18,878	$ 7,344	$ 11,917	$ 4,353
Net property and equipment	2,094,894	1,567,408	574,079	397,126	271,726
Total assets	2,342,107	1,684,010	624,656	427,004	284,034
Long-term debt	1,701,150	694,000	234,800	89,600	29,800
Stockholders'/members' equity	339,999	677,469	285,502	255,879	235,334
Other Financial Data					
Net cash provided by operating activities	$ 227,102	$ 137,249	$ 141,550	$ 50,768	$ 10,595
Net cash used in investing activities	(1,193,846)	(773,608)	(242,619)	(139,618)	(75,215)
Net cash provided by financing activities	981,029	647,893	96,496	96,414	65,759
Adjusted EBITDA(3)	330,144	144,619	152,616	53,274	12,539

(1) The year ended December 31, 2013 reflects the Anadarko Basin 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 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.

(3) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) 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

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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.

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.

	As of and for the Year Ended December 31,				
	2013	2012	2011	2010	2009
	(in thousands)				
Adjusted EBITDA reconciliation to net income (loss):					
Net income (loss)	$ (343,985)	$ (150,097)	$ 16,657	$ (15,635)	$ (11,752)
Depreciation, depletion and amortization	250,396	125,561	91,699	41,827	12,363
Impairment in carrying value of oil and gas properties	453,310				4,297
Losses on commodity derivative contracts net	44,284	11,158	4,844	26,268	5,987
Net cash (paid) received for commodity derivative contracts not designated as hedging instruments	(17,585)	(15,825)	(16,733)	(870)	1,296
Income taxes	(146,529)	157,886			
Interest income	(33)	(245)	(23)	(9)	(6)
Interest expense, net of amounts capitalized	83,138	12,999	2,094		
Asset retirement obligation accretion	1,435	723	334	175	120
Share-based compensation	5,713	2,459	53,744	1,518	234
Adjusted EBITDA	**$ 330,144**	**$ 144,619**	**$ 152,616**	**$ 53,274**	**$ 12,539**

	As of and for the Year Ended December 31,				
	2013	2012	2011	2010	2009
	(in thousands)				
Adjusted EBITDA reconciliation to net cash provided by operating activities:					
Net cash provided by operating activities	$ 227,102	$ 137,249	$ 141,550	$ 50,768	$ 10,595
Changes in working capital	25,892	(3,854)	9,845	2,829	1,950
Interest income	(33)	(245)	(23)	(9)	(6)
Interest expense, net of amounts capitalized	83,138	12,999	2,094		
Amortization of deferred financing costs	(5,955)	(1,530)	(850)	(314)	
Adjusted EBITDA	**$ 330,144**	**$ 144,619**	**$ 152,616**	**$ 53,274**	**$ 12,539**

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.

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We are an independent exploration and production company focused on the application of modern drilling and completion techniques to oil-prone resources.

Prior to October 1, 2012, all of our growth had been driven through the development of our leasehold acreage located in Louisiana. 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 in Louisiana.

On October 1, 2012, the Company closed on the acquisition of all of Eagle Energy Production, LLC's producing properties as well as its developed and undeveloped acreage primarily in the Mississippian Lime liquids play in Oklahoma for $325 million in cash and 325,000 shares of the Series A Preferred Stock with an initial liquidation preference value of $1,000 per share (the "Eagle Property Acquisition"). The Company funded the cash portion of the Eagle Property Acquisition purchase price with a portion of the net proceeds from the private placement of $600 million in aggregate principal amount of 10.75% senior unsecured notes due 2020 (the "2020 Senior Notes"), which also closed on October 1, 2012.

On May 31, 2013, the Company closed on the acquisition of producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma from Panther Energy Company, LLC and its partners for approximately $618 million in cash (the "Anadarko Basin Acquisition"), before customary post-closing adjustments. The Company funded the purchase price with a portion of the net proceeds from the private placement of $700 million in aggregate principal amount of 9.25% senior unsecured notes due 2021 (the "2021 Senior Notes" and, together with the 2020 Senior Notes, the "Senior Notes"), which also closed on May 31, 2013.

Subsequent to the closing of the Eagle Property Acquisition and the Anadarko Basin Acquisition, the Company had oil and gas operations and properties in Louisiana, Oklahoma and Texas. At December 31, 2013, the Company operated oil and natural gas properties and evaluated performance based on one reportable segment as there were not significantly different economic or operational environments within its oil and natural gas properties.

Our current activities are focused on evaluating and developing our asset base, optimizing our acreage position, and identifying potential expansion areas across all of our operating areas. As of December 31, 2013, we had spud approximately 260 gross wells (including 81 in our Mississippian operating area since the fourth quarter of 2012 and 35 in our Anadarko operating area since the second quarter of 2013), approximately 95% of which produced commercially, since the third quarter of 2008.

As of December 31, 2013, our properties consisted of approximately 722 gross active producing wells, 86% of which we operate, and in which we held an average working interest of approximately 81% across our approximate 308,200 net acre leasehold. As of December 31, 2013, our estimated net proved reserves were 127.8 MMBoe, of which 63% was oil or NGLs and 38% was proved developed. During the three months and year ended December 31, 2013, our properties had aggregate average net daily production of approximately 31,090 Boe/d and 23,902 Boe/d, respectively.

On March 5, 2014, we executed a PSA to sell all of our ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana to a private buyer for a purchase price of $170 million, subject to standard post-closing adjustments. The PSA has an effective date of November 1, 2013 and is expected to close on May 1, 2014. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres, and does not include our acreage and production in the western part of Louisiana in Beauregard Parish or other undeveloped acreage held outside the Pine Prairie field. The proceeds from the sale will be used to pay down our revolving credit facility.

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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, NGLs and natural gas. 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 which is the index price we receive in the Mississippian and Anadarko Basin areas. 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 32. 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.

	Years Ended December 31,		
	2013	2012	2011
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$ 99.18	$ 104.35	$ 110.25
Oil, with realized derivatives (per Bbl)	$ 93.41	$ 95.05	$ 99.85
Natural gas liquids, without realized derivatives (per Bbl)	$ 36.26	$ 38.27	$ 50.98
Natural gas liquids, with realized derivatives (per Bbl)	$ 37.09	$ 40.48	(a)
Natural gas, without realized derivatives (per Mcf)	$ 3.39	$ 2.81	$ 4.20
Natural gas, with realized derivatives (per Mcf)	$ 3.58	$ 3.21	(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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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 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.

Gathering and transportation. These costs are incurred for the gathering and transportation of natural gas to the contractual delivery point. For 2013, these costs relate to the commencement of an amended gas transportation, gathering and processing contract during the third quarter of 2013 in the Mississippian Lime region that included a $0.36 MMBtu gathering fee.

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, net of any associated salvage value.

Impairment of oil and gas properties/Ceiling test. As a public company, we apply Rule 4-10 of Regulation S-X, which requires the full-cost ceiling test to be performed on 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

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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, 2013.

Acquisition and transaction costs. The Eagle Property Acquisition and the Anadarko Basin Acquisition qualify 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 these acquisitions and include finders' fees; advisory, legal, accounting, valuation and other professional and consulting fees; and acquisition related 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 and $700 million in Senior Notes on October 1, 2012 and May 31, 2013, respectively. 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, as well as the amortization of the related deferred financing costs,, net of amounts capitalized to unproved properties.

Results of Operations

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

Revenues

	Years Ended December 31,					
	2013		2012		2011	
REVENUES:						
Oil sales	$ 387,226	76%	$ 218,430	85%	$ 177,464	83%
Natural gas liquid sales	62,340	12%	23,617	9%	15,683	7%
Natural gas sales	63,187	12%	16,030	6%	20,665	10%
Total oil, natural gas liquids, and natural gas sales	**$ 512,753**	**100%**	**$ 258,077**	**100%**	**$ 213,812**	**100%**
Realized losses on commodity derivative contracts, net	(17,585)	40%	(15,825)	142%	(16,733)	345%
Unrealized gains (losses) on commodity derivative contracts, net	(26,699)	60%	4,667	-42%	11,889	-245%
Losses on commodity derivative contracts net	**$ (44,284)**	**100%**	**$ (11,158)**	**100%**	**$ (4,844)**	
Other	1,037		754		465	
Total revenues	**$ 469,506**		**$ 247,673**		**$ 209,433**	

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Production

	Years Ended December 31,				
	2013	Increase (Decrease)	2012	Increase (Decrease)	2011
PRODUCTION DATA:					
Oil (MBbls)	3,904	87%	2,093	30%	1,610
NGLs (MBbls)	1,719	179%	617	101%	308
Natural gas (MMcf)	18,657	228%	5,695	16%	4,918
Total oil equivalents (MBoe)	8,733	139%	3,659	34%	2,737
Oil (Boe/d)	10,697	87%	5,719	30%	4,410
Natural gas liquids (Boe/d)	4,711	179%	1,686	101%	843
Natural gas (Mcf/day)	51,116	228%	15,559	16%	13,475
Average daily production (Boe/d)	23,927	139%	9,999	34%	7,499

Prices

	Years Ended December 31,				
	2013	Increase (Decrease)	2012	Increase (Decrease)	2011
Average Sales Prices:					
Oil, without realized derivatives (per Bbl)	$ 99.18	-5%	$ 104.35	-5%	$ 110.25
Oil, with realized derivatives (per Bbl)	$ 93.41	-2%	$ 95.05	-5%	$ 99.85
NGLs, without realized derivatives (per Bbl)	$ 36.26	-5%	$ 38.27	-25%	$ 50.98
NGLs, with realized derivatives (per Bbl)	$ 37.09	-8%	$ 40.48		(a)
Natural gas, without realized derivatives (per Mcf)	$ 3.39	21%	$ 2.81	-33%	$ 4.20
Natural gas, with realized derivatives (per Mcf)	$ 3.58	11%	$ 3.21		(a)

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

Oil, Natural Gas and Natural Gas Liquids Revenues.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Our oil sales revenues increased by $168.8 million, or 77%, to $387.2 million during the year ended December 31, 2013 as compared to $218.4 million for the year ended December 31, 2012. Oil volumes sold increased 1,811 MBbls or 87% to 3,904 MBbls for the year ended December 31, 2013 from 2,093 MBbls for the year ended December 31, 2012. The increase in oil volumes sold was attributable to an increase of 1,463 MBbls in production volumes from our Mississippian area attributable to a full year of production from the assets (which were acquired on October 1, 2012) and the results from increased drilling activity in 2013, and the addition of 817 MBbls in production volumes from our Anadarko Basin area (which was acquired on May 31, 2013), partially offset by a decrease in Gulf Coast production of 469 MBbls. Production from the Gulf Coast declined due to lower drilling activity during the latter half of 2013 as we focused drilling capital on our newly acquired Anadarko Basin assets. Average oil sales prices, without realized derivatives, decreased by $5.17 per barrel, or 5%, to $99.18 per barrel for the year ended December 31, 2013 as compared to $104.35 for the year ended December 31, 2012, partly due to lower oil prices during 2013 as well as lower oil prices received for our Mississippian and Anadarko Basin production, which is priced off WTI as opposed to LLS for our Gulf Coast production. Of the $387.2 million in total oil sales revenues, $151.7 million was from Gulf Coast operations, $155.9 million was from Mississippian and $79.6 million was from Anadarko Basin.

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Our NGLs sales revenues increased by $38.7 million, or 164%, to $62.3 million during the year ended December 31, 2013 as compared to $23.6 million for the year ended December 31, 2012. NGLs volumes sold increased 1,102 MBbls, or 179%, to 1,719 MBbls for the year ended December 31, 2013 as compared to 617 MBbls for the year ended December 31, 2012. The increase in NGLs volumes sold was attributable to an increase of 789 MBbls of production volumes from our Mississippian area and the addition of 395 MBbls of production volumes from our Anadarko Basin area, partially offset by a decrease in Gulf Coast production of 82 MBbls. Average NGLs prices, without realized derivatives, decreased by $2.01 per barrel, or 5%, to $36.26 per barrel for the year ended December 31, 2013 as compared to $38.27 per barrel for the year ended December 31, 2012. Of the $62.3 million in total NGLs revenues, $13.9 million was from Gulf Coast operations, $34.5 million was from Mississippian and $13.9 million was from Anadarko Basin.

Our natural gas sales revenues increased by $47.2 million, or 295%, to $63.2 million during the year ended December 31, 2013 as compared to $16.0 million for the year ended December 31, 2012. Natural gas volumes sold increased 12,962 MMcf, or 228%, to 18,657 MMcf for the year ended December 31, 2013 as compared to 5,695 MMcf for the year ended December 31, 2012. The increase in natural gas volumes sold was attributable to an increase of 10,946 MMcf of production volumes from our Mississippian area and the addition of 3,489 MMcf of production volumes from our Anadarko Basin area, partially offset by a 1,473 MMcf decrease in production from our Gulf Coast area. Average natural gas prices, without realized derivatives, increased by $0.58 per Mcf, or 21%, to $3.39 per Mcf for the year ended December 31, 2013 as compared to $2.81 per Mcf for the year ended December 31, 2012. Of the $63.2 million in total natural gas sales revenues, $9.4 million was from Gulf Coast operations, $42.6 million was from Mississippian and $11.2 million was from Anadarko Basin.

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 Mississippian 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 Mississippian 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 Mississippian operations.

Our NGLs 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. NGLs 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 NGLs 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 Mississippian area, beginning on October 1, 2012. Average NGLs 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 NGLs sales revenues, $18.0 million was from Gulf Coast operations and $5.6 million was from Mississippian operations.

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

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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 Mississippian 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 Mississippian operations.

Gains/Losses on Commodity Derivative Contracts Net.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Our mark-to-market ("MTM") derivative positions moved from an unrealized gain of $4.7 million as of December 31, 2012 to an unrealized loss of $26.7 million for the year ending December 31, 2013. We entered into additional derivative contracts during 2013 and the MTM change resulted from higher average hedge volumes and unfavorable derivative contract price variances versus the forward strip price for our production on December 31, 2013. The NYMEX WTI closing price on December 31, 2013 was $98.42 per barrel compared to a closing price of $91.82 per barrel on December 31, 2012.

The realized loss on derivatives for the year ended December 31, 2013 was $17.6 million compared to a realized loss of $15.8 million for the year ended December 31, 2012. See the following table (in thousands):

	Year Ended December 31, 2013 Realized Gain (Loss)	Year Ended December 31, 2013 Average Sales Price
	(in thousands)	
Oil commodity derivative contracts	$ (22,529)	$ 93.41
Natural gas liquids commodity derivative contracts	1,428	$ 37.09
Natural gas commodity derivative contracts	3,516	$ 3.58
Realized net losses on commodity derivative contracts	**$ (17,585)**	

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

Our 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 derivative contract price variances versus the forward strip 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

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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
	(in thousands)	
Oil commodity derivative contracts	$ (19,460)	$ 95.05
Natural gas liquids commodity derivative contracts	1,362	$ 40.48
Natural gas commodity derivative contracts	2,273	$ 3.21
Realized net losses on commodity derivative contracts	**$ (15,825)**	

Expenses

	Year Ended December 31, 2013	2012	2011	Year Ended December 31, 2013	2012	2011
	(in thousands)			(per Boe)		
EXPENSES:						
Lease operating and workover	$ 73,414	$ 30,500	$ 16,117	$ 8.41	$ 8.34	$ 5.89
Gathering and transportation	5,455			$ 0.62	$	$
Severance and other taxes	27,237	24,921	13,640	$ 3.12	$ 6.81	$ 4.98
Asset retirement accretion	1,435	723	334	$ 0.17	$ 0.20	$ 0.12
Depreciation, depletion, and amortization	250,396	125,561	91,699	$ 28.67	$ 34.32	$ 33.50
Impairment in carrying value of oil and gas properties	453,310			$ 51.91	$	$
General and administrative	53,250	30,541	68,915	$ 6.10	$ 8.35	$ 25.18
Acquisition and transaction costs	11,803	14,884		$ 1.35	$ 4.07	$
Other	615			$ 0.07	$	$
Total expenses	**$ 876,915**	**$ 227,130**	**$ 190,705**	**$ 100.42**	**$ 62.09**	**$ 69.67**

Lease Operating and Workover.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Lease operating and workover expenses increased $42.9 million, or 141%, to $73.4 million for the year ended December 31, 2013 compared to $30.5 million for the year ended December 31, 2012. Lease operating expenses increased $38.8 million, or 146%, to $65.3 million for the year ended December 31, 2013 as compared to $26.5 million for the year ended December 31, 2012. Lease operating expenses for the year ended December 31, 2013, included a full year of costs related to the assets acquired in the Eagle Property Acquisition (compared to only three months for the year ended December 31, 2012) and seven months of costs related to the assets acquired in the Anadarko Basin Acquisition which closed on May 31, 2013. Of this increase, $31.3 million relates to the increase in producing well count in all areas, which increased approximately 150% year over year due to the Anadarko Basin Acquisition and increased drilling activity in the Mississippian area. The remaining $7.5 million is attributable to surface maintenance and other costs. During 2013, we continued to make investments in our operating areas to reduce lease operating costs, specifically in salt water disposal infrastructure in our Gulf Coast region and in our electrical infrastructure and salt water disposal infrastructure in the Mississippian. We expect these investments to reduce salt water disposal and electricity costs during 2014. Workover expenses increased $4.1 million, or 103%, to $8.1 million for the year ended December 31, 2013, as compared to $4.0 million for the year ended December 31, 2012. Of this increase, approximately $2.9 million relates to the Mississippian area workover costs and

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$1.3 million relates to the Anadarko area workover costs offset by a decrease of $0.1 million in Gulf Coast workover costs. Lease operating and workover expenses increased to $8.41 per Boe for the year ended December 31, 2013 from $8.34 per Boe for the year ended December 31, 2012, an increase of 1%, which was primarily attributable to the factors discussed above.

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.

Gathering and Transportation

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Gathering and transportation expenses were $5.5 million for the year ended December 31, 2013. These expenses are attributable to the commencement of an amended gas transportation, gathering and processing contract during the third quarter of 2013 in the Mississippian area that provided for additional third party natural gas processing capacity and restructured the contract pricing provisions to include a $0.36 MMBtu gathering fee based up on wellhead volumes.

Severance and Other Taxes.

	Year Ended December 31,		
	2013	2012	2011
		(in thousands)	
Total oil, NGL, and natural gas sales	**$ 512,753**	**$ 258,077**	**$ 213,812**
Severance taxes	21,338	22,121	12,421
Ad valorem	5,899	2,800	1,219
Severance and other taxes	**$ 27,237**	**$ 24,921**	**$ 13,640**
Severance taxes as a percentage of sales	**4.2%**	**8.6%**	**5.8%**
Severance and other taxes as a percentage of sales	**5.3%**	**9.7%**	**6.4%**

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Severance and other taxes increased $2.3 million, or 9%, to $27.2 million for the year ended December 31, 2013 as compared to $24.9 million for the year ended December 31, 2012. Severance taxes decreased by $0.8 million, or 4%, and accounted for $21.3 million of the 2013 amount. This decrease was primarily attributable to the geographic production mix, with lower oil, NGL and natural gas sales revenue from the Gulf Coast area, and to higher oil, NGLs and natural gas sales revenue from the Mississippian and Anadarko Basin, where severance tax rates are lower than in the Gulf Coast. Severance taxes for the year ended December 31, 2013 and 2012 were 4.2% and 8.6%, respectively, as a percentage of oil, NGL and natural gas sales revenue.

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Ad valorem taxes increased $3.1 million, or 111%, to $5.9 million for the year ended December 31, 2013 as compared to $2.8 million for the year ended December 31, 2012. This change directly correlates to the increase in active well count, which increased approximately 150% year over year due to the Anadarko Basin Acquisition and development drilling 2013 across all areas.

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, NGLs and natural gas 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.

Depreciation, Depletion and Amortization (DD&A).

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

DD&A expense increased $124.8 million, or 99%, to $250.4 million for the year ended December 31, 2013 compared to $125.6 million for the year ended December 31, 2012. The DD&A rate for the year ended December 31, 2013 was $28.67 per Boe compared to $34.32 per Boe for the year ended December 31, 2012. The increase in total DD&A expense for the year ended December 31, 2013 was primarily due to higher oil, NGLs and natural gas production attributable to a full year of production from the Mississippian assets acquired in October 2012, the addition of production from the Anadarko Basin Acquisition and developmental drilling during 2013. The lower DD&A rate per Boe is attributable to the addition of reserves with the Anadarko Basin Acquisition, as well as overall growth in proved reserves during 2013.

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.

Impairment of Oil and Gas Properties.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Our impairment of oil and gas properties pursuant to the full cost "ceiling test" was $319.6 million, net of taxes, for the year ended December 31, 2013. There was no impairment for the year ended December 31, 2012.

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The most significant factors affecting the impairment related to the transfer of unevaluated property costs to the full cost pool during 2013 and negative reserve revisions in our Gulf Coast area. During 2013, we transferred $61.2 million of Gulf Coast unevaluated property costs to the full cost pool based upon our lack of future plans for further evaluation or development of those leases, and $168.4 million of Mississippian unevaluated property costs attributable to leases that expired during 2013 or that we currently intend to allow to expire in 2014. The negative reserve revisions in our Gulf Coast area were mainly attributable to variability in well performance, our decision during the second quarter to halt further development in our West Gordon field and unfavorable cost revisions.

General and Administrative (G&A).

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Our G&A expenses increased to $53.3 million for the year ended December 31, 2013 from $30.5 million for the year ended December 31, 2012. The increase in G&A expenses of $22.8 million, or 75%, was primarily due to salary, benefits, and other expenses of $10.7 million related to the increase in headcount, which increased from 93 full-time employees at December 31, 2012 to 217 full-time employees at December 31, 2013; an increase in payments made under the Eagle Transition Services Agreement of $0.6 million; payments made under the Panther Transition Services Agreement of $10.2 million; and other costs of $1.3 million.

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.

Acquisition and Transaction Costs.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Our acquisition and transaction costs decreased by $3.1 million for the year ended December 31, 2013 from $14.9 million for the year ended December 31, 2012. These total costs of $11.8 million incurred in 2013 represent our expenses through December 31, 2013 related to the Anadarko Basin Acquisition and are primarily attributable to due diligence, legal and other advisory fees that are required to be expensed under US GAAP.

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.

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Other Income (Expense)

	Year Ended December 31,		
	2013	2012	2011
OTHER INCOME (EXPENSE)			
Interest income	$ 33	$ 245	$ 23
Interest expense	(115,383)	(24,174)	(4,694)
Capitalized Interest	32,245	11,175	2,600
Interest expense net of amounts capitalized	(83,138)	(12,999)	(2,094)
Total other income (expense)	**$ (83,105)**	**$ (12,754)**	**$ (2,071)**

Interest Expense.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Interest expense (before capitalized interest) for the years ended December 31, 2013 and 2012 was $115.4 million and $24.2 million, respectively. The increase in interest expense was primarily due to the issuance during 2013 of the 2021 Senior Notes (as discussed below) and a full year of interest expense associated with the 2020 Senior Notes (as discussed below) issued during 2012, in addition to a higher average outstanding balance under our revolving credit facility during the 2013 period. Our average outstanding balance under our revolving credit facility was $252.7 million during the 2013 period, versus $160.0 million for the 2012 period, and related to $7.1 million of the total interest expense of $115.4 million. The remainder of the interest expense for the year ended December 31, 2013, $108.3 million, related to interest expense of $37.8 million on the 2021 Senior Notes, $64.5 million on the 2020 Senior Notes, and amortization of deferred financing costs of $6.0 million. Of total interest expense, $32.2 million and $11.2 million was capitalized, resulting in $83.1 million and $13.0 million in net interest expense for years ended December 31, 2013 and 2012, respectively.

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 the 2020 Senior 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 2020 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.

Provision for Income Taxes.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Income tax benefit was $146.5 million for the year ended December 31, 2013. This represents an application of our estimated effective tax rate (including state income taxes) for the year ended December 31, 2013 of 29.9% to the loss incurred throughout the year. The significant reasons for the change from an income tax expense to a benefit during the year ended December 31, 2013 were the absence of a change in tax status charge during 2013 (as this event took place in 2012), and the occurrence of a book loss for the year ended December 31, 2013.

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In light of the impairment of oil and gas properties, we have recorded a $45.7 million valuation allowance against our federal and State of Louisiana tax net operating losses ("NOL"), as we do not believe that it is more-likely-than-not that this portion of our NOLs are realizable. We believe that the balance of the NOLs are realizable only to the extent of future taxable income primarily related to the excess of book carrying value of properties over their respective tax bases. No other sources of future taxable income are considered in this judgment.

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. 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

At December 31, 2013, our liquidity was $132 million, consisting of $99 million of available borrowing capacity under our revolving credit facility and $33 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. We expect to invest between $500 million and $550 million of capital for exploration, development and lease and seismic acquisition in 2014. Additionally, we expect to capitalize between $16 million and $22 million of interest expense. Our future success in growing proved reserves and production will be highly dependent on our ability to access additional outside sources of capital, via either the debt or equity markets, through growth in our reserve based credit facility or by securing other external sources of funding. As part of that process, on March 5, 2014, we executed a PSA to sell all of our ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana to a private buyer for a purchase price of $170 million in cash, subject to standard post-closing adjustments. The PSA has an effective date of November 1, 2013 and is expected to close on May 1, 2014. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres, and does not include our acreage and production in the western part of Louisiana in Beauregard Parish or other undeveloped acreage held outside the Pine Prairie field. The proceeds from the sale will be used to pay down our revolving credit facility.

Additionally, in order to provide additional capital resources during 2014, we entered into commitment letters with SunTrust Bank, SunTrust Robinson Humphrey, Inc., Morgan Stanley Senior Funding, Inc., Bank of America N.A., Goldman Sachs Bank USA, Merrill Lynch, Piece, Fenner & Smith Incorporated, Natixis New York Branch and Royal Bank of Canada on March 9, 2014 to, among other things, provide for a Senior Secured Bridge Facility ("Bridge Facility") in the amount of $125 million and to provide for a commitment ("RBL Backstop") to provide a backstop revolver credit facility in the event that an amendment to our existing revolving credit facility to permit the consummation of the Bridge Facility and a revised borrowing base of $475 million cannot be obtained.

The Bridge Facility would be secured by a first priority lien on our Gulf Coast assets and a second lien on our Mississippian and Anadarko assets. Any obligations under the Bridge Facility would be guaranteed by the same entities that guaranty the existing credit facility. Advances under the Bridge Facility would be available through September 30, 2014, would be funded in tranches of $50 million (subject to availability), initially bear interest at LIBOR plus 4.5% (subject to a 0.50% increase in interest rate at September 30, 2014, December 31, 2014 and March 31, 2015) and mature on the first anniversary of the closing date. Interest on any advances is payable quarterly in cash. Upon maturity, any amounts outstanding on the Bridge Facility would be converted into a senior secured term loan or, at any time thereafter at the option of the lenders, into senior secured exchange notes maturing in September 2019. Additionally, lenders under the Bridge Facility will have a securities demand if our total liquidity (as defined therein) falls below $50 million, provided that this provision will not apply until June 1, 2014, so long as the executed PSA discussed above remains in place. The Bridge Facility would be pre-payable in whole or in part without penalty or premium and would be subject to mandatory prepayment in the event of Louisiana asset sales (including the Pine Prairie transaction discussed above), issuance of debt or equity, occurrence of a change in control or certain other events. We have agreed to pay a 1.75% commitment fee, a 1.25% funding fee and a 2.25% fee upon the rollover. The definitive loan documentation for the Bridge Facility will include certain representations and warranties, affirmative, negative and financial covenants and events of default customary for bridge loan financings, including limitations on incurrence of indebtedness that, prior to any rollover, will be more restrictive than those contained in our existing credit facility.

In the event that an amendment accommodating the Bridge Facility, the transactions contemplated thereby and a borrowing base of $475 million cannot be obtained under the existing credit facility, the RBL Backstop provides a commitment to provide a new credit facility on substantially the same terms as our existing credit facility, including the notional amount of $750 million and a maturity date of May 2018, but with appropriate modifications to (i) release our Louisiana assets from the borrowing base facility to allow for the Bridge Facility and the potential sale pursuant to the PSA, (ii) reduce the borrowing base under the existing credit facility from $500 million to $475 million, (iii) increase the leverage ratio by 0.50 for the quarter of and the two quarters following the sale of Pine Prairie for net proceeds greater than $100 million, (iv) allow for the Bridge Facility to be secured by a second lien on the Mississippian and Anadarko assets, and (v) increase the applicable interest rate under the existing credit facility by 0.25%. Lenders participating in the RBL Backstop are to receive an underwriting fee of 0.25% whether the RBL Backstop is utilized or not. In the event the existing credit agreement is not amended for the above terms and the RBL Backstop is utilized, participating lenders will receive an additional underwriting fee of 1.00%. Other terms of the backstop credit facility would remain materially unchanged from those contained in our existing credit facility.

We expect to execute the definitive documentation of the new reserve based credit facility and the Bridge Facility during first quarter of 2014.

We believe that the proceeds from the sale of Pine Prairie discussed above or, in the event we are unable to close the PSA, proceeds available to us under our Bridge Facility, together with expected cash flow from operations and borrowings available under our amended credit facility, will be sufficient to fund our capital spending plans through 2015. We plan to continue pursuing additional strategic options that would improve our financial flexibility and provide additional long-term liquidity, including the sale of our remaining Gulf Coast producing assets, other non-core asset sales and possible joint-ventures or farm-outs on our properties. Discussions are in various states of progress with a variety of interested third parties regarding assets sales or potential joint-ventures, but we are currently unable to predict the timing of any transaction and no assurance can be given that we will reach any agreement with a potential counterparty.

Though we have no current plans to do so, we may from time to time seek to retire, purchase or exchange our outstanding debt in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our

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liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

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. We recorded no related interest expense in for the year ended December 31, 2013.

Reserve-based Credit Facility.

As of December 31, 2013, our credit facility consisted of a $750 million senior revolving credit facility (the "Credit Facility") with a borrowing base of $500 million, as recently redetermined on September 26, 2013, when the borrowing base was increased from $425 million. At December 31, 2013, outstanding letters of credit obligations total $0.2 million.

The Credit Facility matures on May 31, 2018 and borrowings thereunder are secured by substantially all of our oil and natural gas properties and currently bear interest at LIBOR plus an applicable margin, depending upon our borrowing base utilization, between 1.75% and 2.75% per annum. At December 31, 2013 and December 31, 2012, the weighted average interest rate was 2.5% and 2.5%, respectively.

In addition to interest expense, the 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 Credit Facility is subject to semiannual redeterminations in April and October 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 is October 1, 2014, assuming the financing discussed above in "Liquidity & Capital Resources" closes as planned.

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Under the terms of the 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.

On September 26, 2013, we entered into the Assignment and Fourth Amendment to the Second Amended and Restated Credit Agreement among the Company, as parent, Midstates Sub, as borrower, SunTrust Bank as administrative agent, and the other lenders and parties party thereto (the "Fourth Amendment").

The Fourth Amendment amended the Credit Facility to provide that the Company's ratio of total net indebtedness to EBITDA for the trailing four fiscal quarter period ending on the last day of such fiscal quarter cannot exceed (i) 4.75:1.0, for the fiscal quarters ending December 31, 2013 and March 31, 2014, (ii) 4.50:1.0, for the fiscal quarters ending June 30, 2014, (iii) 4.25:1.0, for the fiscal quarters ending September 30, 2014 and December 31, 2014, and (iv) 4.00:1.0, for the fiscal quarter ending March 31, 2015 and each fiscal quarter thereafter. We also agreed to pay a one-time fee of 0.50% to each lender on the portion of their commitment to the borrowing base under the Fourth Amendment in excess of their commitment prior to the Fourth Amendment, and a one-time fee of 0.10% to each lender on the lesser of such lenders commitment immediately prior to, or after giving effect to, the Fourth Amendment.

The Credit Facility contains financial covenants, in addition to the maximum ratio of debt to EBITDA discussed above, which, among other things, set 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 our ability to make any dividends, distributions or redemptions.

As of December 31, 2013, we were in compliance with the minimum current ratio and the ratio of debt to EBITDA covenants as set forth in the Credit Facility. Our current ratio at December 31, 2013 was 1.3 to 1.0. At December 31, 2013, our ratio of debt to EBITDA was 4.4 to 1.0.

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.

2020 Senior Notes.

On October 1, 2012, we issued $600 million in aggregate principal amount of 10.75% senior notes due 2020 (the "2020 Outstanding Notes") in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act of 1933, as amended (the "Securities Act"). On October 29, 2013, substantially all of the 2020 Outstanding Notes were exchanged for an equal principal amount of registered 10.75% senior subordinated notes due 2020 pursuant to an effective registration statement on Form S-4 filed on August 30, 2013 under the Securities Act (the "2020 Exchange Notes"). The 2020 Exchange Notes are identical to the 2020 Outstanding Notes except that the 2020 Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Form 10-K, the term "2020 Senior Notes" refers to both the 2020 Outstanding Notes and the 2020 Exchange Notes. The 2020 Senior Notes were co-issued on a joint and several basis with our wholly owned subsidiary, Midstates Sub.

At any time prior to October 1, 2015, we may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2020 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 2020 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 2020 Senior Notes at a redemption price equal to 100% of the principal amount of 2020 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 2020 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 2020 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 the Company's assets; (viii) prepay, redeem or repurchase certain debt; (ix) alter the business we conducts and (x) enter into agreements restricting the ability of our current and any future subsidiaries to pay dividends. The 2020 Senior Notes Indenture does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans to us or limit our ability to advance loans to Midstates Sub.

Upon the occurrence of certain change of control events, as defined in the Indenture, each holder of the 2020 Senior Notes will have the right to require that we repurchase all or a portion of such holder's 2020 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.

2021 Senior Notes.

On May 31, 2013, we issued $700 million in aggregate principal amount of 9.25% senior notes due 2021 (the "2021 Outstanding Notes") in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act. On October 29, 2013, all of the 2021 Outstanding Notes were exchanged for an equal principal amount of registered 9.25% senior subordinated notes due 2021 pursuant to an effective registration statement on Form S-4 filed on August 30, 2013 under the Securities Act (the "2021 Exchange Notes"). The 2021 Exchange Notes are identical to the 2021 Outstanding Notes except that the 2021 Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Form 10-K, the term "2021 Senior Notes" refers to both the 2021 Outstanding Notes and the 2021 Exchange Notes. The proceeds from the offering of $700 million (net of the initial purchasers' discount and related offering expenses) were used to fund the Anadarko Basin Acquisition and the related expenses, to pay the expenses related to an amendment to our revolving credit facility, to repay $34.3 million in outstanding borrowings under our Credit Facility, and for general corporate purposes.

The 2021 Senior Notes rank pari passu in right of payment with the 2020 Senior Notes.

The 2021 Senior Notes were co-issued on a joint and several basis with Midstates Sub.

On or prior to May 31, 2014, we may redeem up to $100.0 million of aggregate principal amount of the 2021 Senior Notes with the net cash proceeds from any Equity Offerings (as such term is defined in the 2021 Senior Notes Indenture) at a redemption price equal to 103% of the principal amount plus accrued and unpaid interest.

Prior to June 1, 2016, we may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes (less the amount of 2021 Senior Notes redeemed pursuant to the preceding paragraph) with the net proceeds of any Equity Offerings at a redemption price of 109.25% of the principal amount of the 2021 Senior Notes redeemed, plus any accrued and unpaid interest, if any, up to the redemption date. In addition, at any time before June 1, 2016, we may redeem all or a part of the 2021 Senior Notes at a redemption price equal to 100% of the principal amount of the 2021 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 2021 Senior Notes Indenture), if any, up to, the redemption date. On or after October 1, 2016, we may redeem all or a part of the 2021 Senior Notes at varying redemption prices (expressed as percentages of principal amount) set forth in the 2021 Senior Notes Indenture plus accrued and unpaid interest and Additional Interest (as defined in the 2021 Senior Notes Indenture), if any, on the 2021 Senior Notes redeemed, up to, the redemption date.

The terms of the covenants and change in control provisions in the 2021 Senior Notes Indenture are substantially identical to those of the 2020 Senior Notes discussed above. The 2021 Senior Notes indenture does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans to the Company or limit the ability of the Company to advance loans to Midstates Sub.

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,		
	2013	**2012**	**2011**
Net cash provided by operating activities	$ 227,102	$ 137,249	$ 141,550
Net cash used in investing activities	(1,193,846)	(773,608)	(242,619)
Net cash provided by financing activities	981,029	647,893	96,496
Net change in cash	**$ 14,285**	**$ 11,534**	**$ (4,573)**

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Our operating cash flows are sensitive to a number of variables, the most significant of which is the volatility of oil, NGLs and natural 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 80.

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 $227.1 million, $137.2 million and $141.6 million for the years ended December 31, 2013, 2012 and 2011, respectively. The increase in net cash provided by operating activities for the year ended December 31, 2013 compared to the year ended December 31, 2012 was primarily driven by an increase in production in all commodities and an increase in natural gas prices, offset by a decrease in oil and NGL prices. 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.

Cash flows used in investing activities

We had net cash used in investing activities of $1.2 billion, $773.6 million and $242.6 million during the years ended December 31, 2013, 2012 and 2011, respectively, as a result of our capital expenditures for drilling, development and acquisition costs. The increase in in net cash used in investing activities during the year ended December 31, 2013 compared to the year ended December 31, 2012 was primarily due to the Anadarko Basin Acquisition and continued expansion of our drilling programs. The increase in net cash used in investing activities during the year ended December 31, 2012 compared to the year ended December 31, 2011 was primarily due to the Eagle Property Acquisition and continued expansion of our drilling programs and growth of our business.

Cash flows provided by financing activities

Net cash provided by financing activities was $981.0 million, $647.9 million and $96.5 million for the years ended December 31, 2013, 2012 and 2011, respectively. For the year ended December 31, 2013, cash sourced through financing activities was provided primarily from net long-term borrowings of $1.0 billion, consisting of the 2021 Senior Notes of $700 million and borrowings under the revolver of $341.5 million, offset by repayments of our revolving credit facility of $34.3 million.

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 2020 Senior Notes 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 $1.7 billion, $694.0 million and $234.8 million at December 31, 2013, 2012 and 2011, respectively.

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Other Items

Obligations and commitments

We have the following contractual obligations and commitments as of December 31, 2013 (in thousands):

	Payments due by Period			
	Total	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Revolving credit facility(1)	$ 401,150	$	$ 401,150	$
2020 Senior Notes(2)	1,035,375	193,500	129,000	712,875
2021 Senior Notes(2)	1,185,625	194,250	129,500	861,875
Drilling contracts(3)	8,192	8,192		
Operating leases(3)	11,052	5,466	3,412	2,174
Seismic contracts(3)	4,410	4,410		
Asset retirement obligations(4)	26,308			26,308
Total contractual obligations	**$ 2,672,112**	**$ 405,818**	**$ 663,062**	**$ 1,603,232**

(1) Amount excludes interest on our revolving credit facility as both the amount borrowed and applicable interest rate is variable. As of December 31, 2013, we had $401.2 million of indebtedness outstanding under our revolving credit facility. See Note 8 to our Consolidated Financial Statements.

(2) Amount includes approximately $64.5 million and $65.8 million of interest per year for our 2020 Senior Notes and 2021 Senior Notes, respectively; 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 a discounted 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, 2013, 2012 and 2011 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 a portion of our production and expect to continue hedging a significant portion of our future production.

We utilize derivative financial instruments to manage risks related to changes in oil, NGLs and natural gas prices. As of December 31, 2013, we utilized fixed price swaps, collars and basis differential swaps to reduce the volatility of oil, NGLs and natural gas prices on a portion of our future expected 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.

The following is a summary of our commodity derivative contracts as of December 31, 2013:

	Hedged Volume	Weighted-Average Fixed Price
Oil (Bbls):		
WTI Swaps 2014	4,344,450	$88.76
WTI Swaps 2015	1,820,000	$86.55
WTI Collars 2014	164,400	$88.49 - $97.94
WTI to LLS Basis Differential Swaps 2014(1)	501,000	$5.35
NGL (Bbls):		
NGL Swaps 2014	151,500	$62.16
Natural Gas (MMBtu):		
Swaps 2014(2)	17,885,000	$4.17
Swaps 2015	18,250,000	$4.13
Collars 2014(3)	1,685,004	$3.99 - $5.09

(1) We enter into swap arrangements intended to preserve the positive differential between LLS pricing and NYMEX WTI pricing.

(2) Includes 1,519,000 MMBtu that priced in the fourth quarter of 2013, but had not cash settled as of December 31, 2013.

(3) Includes 64,667 MMBtu that priced in the fourth quarter of 2013, but had not cash settled as of December 31, 2013.

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		For the Year Ended December 31, 2013 (in thousands)
Derivative fair value at period end liability (included in balance sheet)	$	(30,812)
Realized net loss (included in the statement of operations)	$	(17,585)
Unrealized net loss (included in the statement of operations)	$	(26,699)

As of December 31, 2013, 2012 and 2011, assets and liabilities recorded at fair value in the balance sheets were categorized based upon the level of judgment associated with the inputs used to measure their value. Our only financial assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2013, 2012 and 2011 are the derivative instruments discussed above. At December 31, 2013 and 2012, all of our commodity derivative contracts were with seven and five bank counterparties, respectively, and are all classified as Level 2. Our policy is to net derivative liabilities and assets where there is a legally enforceable master netting agreement with the counterparty.

Interest rate risk. At December 31, 2013, we had indebtedness outstanding under our credit facility of $401.2 million, which bore interest at floating rates; we had $600 million outstanding in 2020 Senior Notes, which bore interest at 10.75%; and $700 million outstanding in 2021 Senior Notes which bore interest at 9.25%. The average annual interest rate incurred on this indebtedness for the years ended December 31, 2013, 2012 and 2011 was approximately 8.7%, 6.7% and 3.2%, respectively. A 1.0% increase in each of the average LIBOR and federal funds rate for the years ended December 31, 2013 and 2012 would have resulted in an estimated $2.1 million and $1.5 million, respectively, increase in interest expense, of which a portion may be capitalized.

We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. At December 31, 2013, we do not have any interest rate derivatives in place.

Counterparty and customer credit risk. Joint interest receivables arise from billing entities which own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers, including ConocoPhillips, Chevron and Gulfmark. See "Business Marketing and Major Customers" on page 22 for further detail about our significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties.

While we do not require our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation may include reviewing a counterparty's credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record, the financial ability of the customer's parent company to make payment if the customer cannot and undertaking the due diligence necessary to determine credit terms and credit limits. The counterparties on our current derivative instruments are lenders under our revolving credit facility with investment grade ratings, and we are likely to enter into any future derivative instruments with these or other lenders under our revolving credit facility which also carry investment grade ratings. Several of our significant customers for oil and gas receivables have a credit rating below investment grade or do not have rated debt securities. In these circumstances, we

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have considered the lack of investment grade credit rating in addition to the other factors described above.

Off-Balance Sheet Arrangements. Currently, we do not have any off-balance sheet arrangements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our Consolidated Financial Statements, together with the report of our independent registered public accounting firm begin on page F-1 of this Annual Report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were not effective at December 31, 2013 at the reasonable assurance level due to the material weakness discussed below.

Management's Annual Report on Internal Control over Financial Reporting. The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f) and 15d-15(f). Internal control over financial reporting is defined as a process designed by, or under the supervision of, the issuer's principal executive and principal financial officer's, or persons performing similar functions, and effected by the Company's board of directors, management, and other personnel, to provide reasonable assurance regarding reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures which (a) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of assets of the Company, (b) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of management and the board of directors, and (c) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of The Treadway Commission. Based on our evaluation under the *Internal Control Integrated Framework (2013)*, our management concluded that our internal control over financial reporting was not effective as of December 31, 2013 as a result of a material weakness described below.

Internal control over the preparation of oil and gas reserve estimates. We did not maintain effective internal control over the accuracy and valuation of oil and gas reserves estimates. Specifically, controls were not operating effectively over the validation of the accuracy and completeness of certain source data provided to the independent third party reserve engineers, or perform adequate management review of the independent third party reserves report to determine if reserves estimates were complete and consistent with management's capital spending plans. These control deficiencies resulted in errors that, if not corrected, would have resulted in the misstatement of disclosures related to the value of oil and gas properties and associated reserves estimates, which impacts our calculation of depletion of the cost of our oil and gas properties and the amount of our impairment of oil and gas properties, and the standardized measures of oil and gas.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Deloitte & Touche LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued their report on the effectiveness of the Company's internal control over financial reporting at December 31, 2013. The report, which expresses an adverse opinion on the effectiveness of the Company's internal control over financial reporting, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

Changes in internal control over financial reporting. During the quarter ended December 31, 2013, we completed the conversion to new accounting and land software. We took the necessary steps to monitor and maintain appropriate internal controls during this period of change. These steps included procedures to preserve the integrity of the data converted and a review by management to validate the data converted. Additionally, we provided training related to this system to individuals using the system to carry out their job responsibilities. We anticipate that the implementation of this software will strengthen the overall system of internal controls due to enhanced automation of workflow and controls, and further integration of related processes. We completed the design and documentation of internal control processes and procedures relating to the new system and modules to supplement and complement existing internal controls over certain respective job areas. Testing of the controls related to the new system implementation has been completed and was included in the scope of our assessment of internal control over financial reporting for 2013.

Management's plan for remediation of our material weakness. In response to the identified material weakness, our management, with oversight from our Audit Committee, is taking the following actions to remediate the material weakness related to the calculation of oil and gas reserves estimates described above:

- Redesign controls over management's review of reserves estimates to ensure an appropriate level of precision to address the associated risks;

- Further expand documentation of the procedures for reviewing data used as inputs into the reserve report calculations and for retaining evidence when such review is performed;

- Implement a process for documenting the key decisions and assumptions made by Company operations personnel during the reconciliation of reserves output between management's internal calculations and the outside reserve engineering firm's calculations; and

- Train the reserves engineering staff on the above procedures.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Midstates Petroleum Company, Inc.
Houston, Texas

We have audited the internal control over financial reporting of Midstates Petroleum Company, Inc. and subsidiary ("Midstates") as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Midstates' management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Midstates' internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management's assessment: internal controls over the preparation of oil and gas reserve estimates. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements as of and for the year ended December 31, 2013, of Midstates and this report does not affect our report on such financial statements.

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In our opinion, because of the effect of the material weakness identified above on the achievement of the objectives of the control criteria, the Company has not maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2013 of Midstates and our report dated March 24, 2014 expressed an unqualified opinion on those consolidated financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 24, 2014

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ITEM 9B. OTHER INFORMATION

None.

PART III.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANCE

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

ITEM 11. EXECUTIVE COMPENSATION

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDERS

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

PART IV.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

The following documents are included as exhibits to this report:

2.1	Master Reorganization Agreement, dated April 24, 2012, by and among the Company and certain of its affiliates, certain members of the Company's management and certain affiliates of First Reserve Corporation (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on April 25, 2012, and incorporated herein by reference).
2.2	Purchase and Sale Agreement, dated as of April 3, 2013, by and among Midstates Petroleum Company LLC, Panther Energy Company, LLC, Red Willow Mid-Continent, LLC and Linn Energy Holdings, LLC (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on April 4, 2013, and incorporated herein by reference).
3.1	Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K filed on April 25, 2012, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Midstates Petroleum Company, Inc. (filed as Exhibit 3.2 to the Company's Current Report on Form 8-K filed on April 25, 2012, and incorporated herein by reference).
3.3	Certificate of Designations of Series A Mandatorily Convertible Preferred Stock of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1/A on February 29, 2012, and incorporated herein by reference).
4.2	Indenture, dated October 1, 2012, by and among the Company, Midstates Petroleum Company LLC and Wells Fargo Bank, National Association, as trustee, governing the 10.75% senior notes due 2020 (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).
4.3	Registration Rights Agreement, dated October 1, 2012, by and among the Company, Midstates Petroleum Company LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers named therein, relating to the 10.75% senior notes due 2020 (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).
4.4	Registration Rights Agreement, dated October 1, 2012, by and among the Company, Eagle Energy Production, LLC, FR Midstates Interholding, LP and certain other of the Company's stockholders (filed as Exhibit 4.3 to the Company's Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).
4.5	Indenture, dated May 31, 2013, by and among the Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and the Well Fargo Bank, National Association, as trustee, governing the 9.25% senior notes due 2021 (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed on June 3, 2013, and incorporated herein by reference).

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4.6	Registration Rights Agreement, dated May 31, 2013, by and among the Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and Morgan Stanley & Co. LLC and SunTrust Robinson Humphrey, Inc., as representatives of the several initial purchasers named therein, relating to the 9.25% senior notes due 2021 (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K filed on June 3, 2013, and incorporated herein by reference).
10.1	Stockholders' Agreement among the Company and certain equity owners (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 25, 2012, and incorporated herein by reference).
10.2	Second Amended and Restated Credit Agreement, dated as of June 8, 2012, among the Company, Midstates Petroleum Company LLC, SunTrust Bank as administrative agent and the other lender parties thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 13, 2012, and incorporated herein by reference).
10.3	Assignment and First Amendment to the Second Amended and Restated Credit Agreement, dated as of September 7, 2012, among the Company, Midstates Petroleum Company LLC, SunTrust Bank as administrative agent and the other lenders and parties party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 12, 2012, and incorporated herein by reference).
10.4	Amendment to First Amendment to the Second Amended and Restated Credit Agreement, dated as of September 26, 2012, among the Company, Midstates Petroleum Company LLC, SunTrust Bank, as administrative agent, and the other lenders and parties party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 27, 2012, and incorporated herein by reference).
10.5	Second Amendment to Second Amended and Restated Credit Agreement, dated as of March 19, 2013, among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, SunTrust Bank, as administrative agent, and the other lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 22, 2013, and incorporated herein by reference).
10.6	Assignment and Third Amendment to the Second Amended and Restated Credit Agreement, dated as of May 20, 2013, among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, SunTrust Bank as administrative agent and the other lenders and parties party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 22, 2013, and incorporated herein by reference).
10.7	Assignment and Fourth Amendment to the Second Amended and Restated Credit Agreement, dated as of September 26, 2013, among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, SunTrust Bank as administrative agent and the other lenders and parties party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 30, 2013, and incorporated herein by reference).
10.8	Asset Purchase Agreement, dated as of August 11, 2012, among the Company, Midstates Petroleum Company, LLC and Eagle Energy Production, LLC (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on August 13, 2012, and incorporated herein by reference).
10.9**	Executive Employment Agreement dated as of April 25, 2012 between the Company and John A. Crum (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 30, 2012, and incorporated herein by reference).

10.10(a)**	Executive Employment Agreement dated as of April 25, 2012 between the Company and Nelson Haight.
10.11(a)**	Amendment to Executive Employment Agreement dated as of December 12, 2013 between the Company and Nelson Haight.
10.12(a)**	Executive Employment Agreement dated as of April 25, 2012 between the Company and Curtis A. Newstrom.
10.13(a)**	Executive Employment Agreement dated as of April 25, 2012 between the Company and Dexter Burleigh.
10.14**	Executive Employment Agreement dated as of April 25, 2012 between the Company and Thomas L. Mitchell (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on April 30, 2012, and incorporated herein by reference).
10.15**	Executive Employment Agreement dated as of April 25, 2012 between the Company and Stephen C. Pugh (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed on April 30, 2012, and incorporated herein by reference).
10.16**	Separation and Release Agreement, dated as of October 3, 2013 between Midstates Petroleum Company, Inc. and Stephen C. Pugh (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 4, 2013, and incorporated herein by reference).
10.17**	Midstates Petroleum Company Inc. 2012 Long Term Incentive Plan (filed as Exhibit 4.3 to the Company's Registration Statement on Form S-8 on April 20, 2012, and incorporated herein by reference).
10.18**	Midstates Petroleum Company, Inc. 2012 Long-Term Incentive Plan Form of Restricted Stock Agreement (Time Vesting) for 2012 Awards (filed as Exhibit 10.10 to the Company's Registration Statement on Form S-1/A on January 20, 2012, and incorporated herein by reference).
10.19**	Midstates Petroleum Company, Inc. 2012 Long-Term Incentive Plan Form of Restricted Stock Agreement (Time Vesting) for 2013 Awards (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on February 27, 2013, and incorporated herein by reference).
10.20**	Midstates Petroleum Company, Inc. Form of Notice of Grant of Restricted Stock (Time Vesting) (filed as Exhibit 10.11 to the Company's Registration Statement on Form S-1/A on January 20, 2012, and incorporated herein by reference).
10.21**	Form of Indemnification Agreement between the Company and each of the directors and executive officers thereof (filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1/A on February 16, 2012, and incorporated herein by reference).
12.1(a)	Statement of Computation of Ratio of Earnings to Fixed Charges
21.1(a)	List of subsidiaries of the Company.
23.1(a)	Consent of Deloitte & Touche LLP.
23.2(a)	Consent of Netherland, Sewell and Associates, Inc. Independent Petroleum Engineers
23.3(a)	Consent of Cawley, Gillespie & Associates, Inc. Independent Petroleum Engineers
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.

32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
99.1(a)	Report of Netherland, Sewell & Associates, Inc.
99.2(a)	Report of Cawley, Gillespie & Associates, Inc.
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Schema Document.
101.CAL(a)	XBRL Calculation Linkbase Document.
101.DEF(a)	XBRL Definition Linkbase Document.
101.LAB(a)	XBRL Labels Linkbase Document
101.PRE(a)	XBRL Presentation Linkbase Document.

(a) Filed herewith

(b) Furnished herewith

** Management contract or compensatory plan or arrangement

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

MIDSTATES PETROLEUM COMPANY, INC.

/s/ JOHN A. CRUM

John A. Crum
President, Chief Executive Officer and Chairman of the Board

Dated: March 24, 2014

KNOWN ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints John A. Crum, Nelson M. Haight and Eric J. Christ, each of whom may act without joinder of the other, as their true and lawful attorneys-in-fact and agents, each with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ JOHN A. CRUM John A. Crum	Chairman, President and Chief Executive Officer (principal executive officer)	March 24, 2014
/s/ NELSON M. HAIGHT Nelson M. Haight	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	March 24, 2014
/s/ ANASTASIA DEULINA Anastasia Deulina	Director	March 24, 2014
/s/ DR. PETER J. HILL Dr. Peter J. Hill	Director	March 24, 2014

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Signatures	Title	Date
/s/ THOMAS C. KNUDSON Thomas C. Knudson	Director	March 24, 2014
/s/ LOREN M. LEIKER Loren M. Leiker	Director	March 24, 2014
/s/ STEPHEN J. MCDANIEL Stephen J. McDaniel	Director	March 24, 2014
/s/ JOHN MOGFORD John Mogford	Director	March 24, 2014
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	March 24, 2014
/s/ ROBERT M. TICHIO Robert M. Tichio	Director	March 24, 2014

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MIDSTATES PETROLEUM COMPANY, INC.
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Midstates Petroleum Company, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Midstates Petroleum Company, Inc. and subsidiary ("Midstates") as of December 31, 2013 and 2012, and the related consolidated statements of operations, stockholders'/members' equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of Midstates' management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Midstates Petroleum Company, Inc. and subsidiary as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Midstates' internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 24, 2014 expressed an adverse opinion on Midstates' internal control over financial reporting because of a material weakness.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 24, 2014

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MIDSTATES PETROLEUM COMPANY, INC.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share amounts)

	December 31, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 33,163	$ 18,878
Accounts receivable:		
Oil and gas sales	102,483	35,618
Joint interest billing	42,631	10,815
Other	1,090	3,866
Commodity derivative contracts	700	5,695
Deferred income taxes	11,837	6,027
Other current assets	693	8,573
Total current assets	192,597	89,472
PROPERTY AND EQUIPMENT:		
Oil and gas properties, on the basis of full-cost accounting	3,060,661	1,836,664
Other property and equipment	11,113	5,038
Less accumulated depreciation, depletion, amortization and impairment	(976,880)	(274,294)
Net property and equipment	2,094,894	1,567,408
OTHER ASSETS:		
Commodity derivative contracts	19	1,717
Other noncurrent assets	54,597	25,413
Total other assets	54,616	27,130
TOTAL	**$ 2,342,107**	**$ 1,684,010**

LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 21,493	$ 29,196
Accrued liabilities	204,381	98,649
Commodity derivative contracts	27,880	7,582
Total current liabilities	253,754	135,427
LONG-TERM LIABILITIES:		
Asset retirement obligations	26,308	15,245
Commodity derivative contracts	3,651	3,943
Long-term debt	1,701,150	694,000
Deferred income taxes	15,291	156,737
Other long-term liabilities	1,954	1,189

Total long-term liabilities		1,748,354		871,114
COMMITMENTS AND CONTINGENCIES (Note 14)				
STOCKHOLDERS' EQUITY				
Preferred stock, $0.01 par value, 49,675,000 shares authorized; no shares issued or outstanding				
Series A mandatorily convertible preferred stock, $0.01 par value, $358,550 and $325,000 liquidation value at December 31, 2013 and December 31, 2012, respectively; 8% cumulative dividends; 325,000 shares issued and outstanding		3		3
Common stock, $0.01 par value, 300,000,000 shares authorized; 68,925,745 shares issued and 68,807,043 shares outstanding at December 31, 2013 and 66,619,711 shares issued and outstanding at December 31, 2012		689		666
Treasury stock		(664)		
Additional paid-in-capital		871,047		863,891
Retained deficit		(531,076)		(187,091)
Total stockholders' equity		339,999		677,469
TOTAL	**$**	**2,342,107**	**$**	**1,684,010**

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

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MIDSTATES PETROLEUM COMPANY, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended December 31,		
	2013	**2012**	**2011**
REVENUES:			
Oil sales	$ 387,226	$ 218,430	$ 177,464
Natural gas liquid sales	62,340	23,617	15,683
Natural gas sales	63,187	16,030	20,665
Losses on commodity derivative contracts net	(44,284)	(11,158)	(4,844)
Other	1,037	754	465
Total revenues	469,506	247,673	209,433
EXPENSES:			
Lease operating and workover	73,414	30,500	16,117
Gathering and transportation	5,455		
Severance and other taxes	27,237	24,921	13,640
Asset retirement accretion	1,435	723	334
Depreciation, depletion, and amortization	250,396	125,561	91,699
Impairment in carrying value of oil and gas properties	453,310		
General and administrative	53,250	30,541	68,915
Acquisition and transaction costs	11,803	14,884	
Other	615		
Total expenses	876,915	227,130	190,705
OPERATING INCOME (LOSS)	(407,409)	20,543	18,728
OTHER INCOME (EXPENSE)			
Interest income	33	245	23
Interest expense net of amounts capitalized	(83,138)	(12,999)	(2,094)
Total other income (expense)	(83,105)	(12,754)	(2,071)
INCOME (LOSS) BEFORE TAXES	(490,514)	7,789	16,657
Income tax benefit (expense)	146,529	(157,886)	
NET INCOME (LOSS)	**$ (343,985)**	**$ (150,097)**	**$ 16,657**
Preferred stock dividend	(15,589)	(6,500)	
Participating securities Series A Preferred Stock			
Participating securities Non-vested Restricted Stock			

NET LOSS ATTRIBUTABLE TO COMMON SHAREHOLDERS	**$**	**(359,574)**	**$**	**(156,597)**	**$**	**16,657**
Basic and diluted net loss per share attributable to common shareholders	$	(5.47)	$	(2.61)		N/A
Basic and diluted weighted average number of common shares outstanding		65,766		59,979		N/A

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

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MIDSTATES PETROLEUM COMPANY, INC.

CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS'/MEMBERS' EQUITY

(See Note 10 for Share History)

(In thousands)

	Series A Preferred Stock	Common Stock	Treasury Stock	Capital Contributions	Additional Paid-in-Capital	Retained Deficit/ Accumulated Loss	Total Stockholders' Equity
Balance as of January 1, 2011	**$**	**$**	**$**	**$ 309,530**	**$**	**$ (53,651)**	**$ 255,879**
Distribution to members				(50,572)			(50,572)
Members' contribution				2,870			2,870
Reclassification of liability for share-based awards				60,668			60,668
Net income						16,657	16,657
Balance as of December 31, 2011	**$**	**$**	**$**	**$ 322,496**	**$**	**$ (36,994)**	**$ 285,502**
Issuance of common stock		476		(476)			
Reclassification of members' contributions				(322,020)	322,020		
Proceeds from the sale of common stock		180			213,389		213,569
Tax attributes contributed at IPO reorganization date by shareholding entities					33,888		33,888
Issuance of preferred stock as consideration in the Eagle Property Acquisition	3				291,953		291,956
Share-based compensation		10			2,641		2,651
Net loss						(150,097)	(150,097)
Balance as of December 31, 2012	**$ 3**	**$ 666**	**$**	**$**	**$ 863,891**	**$ (187,091)**	**$ 677,469**
Share-based compensation		23			7,156		7,179
Acquisition of treasury stock			(664)				(664)
Net loss						(343,985)	(343,985)
Balance as of December 31, 2013	**$ 3**	**$ 689**	**$ (664)**	**$**	**$ 871,047**	**$ (531,076)**	**$ 339,999**

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

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MIDSTATES PETROLEUM COMPANY, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2013	**2012**	**2011**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (343,985)	$ (150,097)	$ 16,657
Adjustments to reconcile net loss to net cash provided by operating activities:			
Losses on commodity derivative contracts net	44,284	11,158	4,844
Net cash paid for commodity derivative contracts not designated as hedging instruments	(17,585)	(15,825)	(16,733)
Asset retirement accretion	1,435	723	334
Depreciation, depletion, and amortization	250,396	125,561	91,699
Impairment in carrying value of oil and gas properties	453,310		
Share-based compensation, net of amounts capitalized to oil and gas properties	5,713	2,459	53,744
Deferred income taxes	(146,529)	157,886	
Amortization of deferred financing costs	5,955	1,530	850
Change in operating assets and liabilities:			
Accounts receivable oil and gas sales	(66,865)	(11,826)	(9,651)
Accounts receivable JIB and other	(28,488)	(11,019)	(3,125)
Other current and noncurrent assets	(1,802)	(218)	(6,799)
Accounts payable	(4,350)	(646)	3,059
Accrued liabilities	75,903	27,931	5,977
Other	(290)	(368)	694
Net cash provided by operating activities	**$ 227,102**	**$ 137,249**	**$ 141,550**
CASH FLOWS FROM INVESTING ACTIVITIES:			
Investment in property and equipment	(573,734)	(422,332)	(242,619)
Investment in acquired property	(620,112)	(351,276)	
Net cash used in investing activities	**$ (1,193,846)**	**$ (773,608)**	**$ (242,619)**
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	1,041,450	744,667	145,200
Repayment of long-term borrowings	(34,300)	(285,467)	
Proceeds from issuance of mandatorily redeemable convertible preferred units		65,000	
Repayment of mandatorily redeemable convertible preferred units		(65,000)	
Proceeds from sale of common stock, net of initial public offering expenses of $6.4 million		213,569	
Deferred financing costs	(25,457)	(24,876)	(863)
Acquisition of treasury stock	(664)		
Cash received for units, pre-IPO			2,870
Distributions to members			(50,572)
Other			(139)
Net cash provided by financing activities	**$ 981,029**	**$ 647,893**	**$ 96,496**
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**14,285**	**11,534**	**(4,573)**
Cash and cash equivalents, beginning of period	**$ 18,878**	**$ 7,344**	**$ 11,917**

Cash and cash equivalents, end of period	**$**	**33,163**	**$**	**18,878**	**$**	**7,344**

SUPPLEMENTAL INFORMATION:						
Non-cash transactions investments in property and equipment accrued not paid	$	106,500	$	87,812	$	61,590
Non-cash components of Eagle Property Acquisition Purchase Price:						
Preferred stock issued for property				291,956		
Deferred tax liability assumed		(727)		26,712		
Asset retirement obligation assumed				2,662		
Accrual for additional consideration		(941)		1,500		
Non-cash components of Anadarko Basin Acquisition Purchase Price:						
Asset retirement obligations assumed		6,296				
Accrual for miscellaneous liabilities assumed		3,030				
Cash paid for interest, net of capitalized interest of $32.2 million, $11.2 million and $2.6 million, respectively		72,085				1,594
Tax attributes contributed at IPO reorganization date by shareholding entities				33,888		
Reclassification of share-based compensation to members' equity						6,924

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

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements

1. Organization and Business

Midstates Petroleum Company, Inc., through its wholly-owned subsidiary Midstates Petroleum Company LLC, engages in the business of drilling for, and production of, oil, natural gas and natural gas liquids. 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 ("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, 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 Petroleum Company LLC became a wholly-owned subsidiary of Midstates Petroleum Company, Inc. and Midstates Petroleum Holdings LLC ceased to exist as a separate entity. The terms "the Company," "we," "us," "our," and similar terms 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. The term "Holdings LLC" refers solely to Midstates Petroleum Holdings LLC prior to the corporate reorganization.

On April 25, 2012, the Company completed its initial public offering of common stock pursuant to a registration statement on Form S-1 (File 333-177966), as amended and declared effective by the SEC on April 19, 2012. Pursuant to the registration statement, the Company registered the offer and sale of 27,600,000 shares of $0.01 par value common stock, which included 6,000,000 shares of stock sold by the selling shareholders and 3,600,000 shares of common stock sold by the selling stockholders pursuant to an option granted to the underwriters to cover over-allotments. The Company's sale of the shares in its initial public offering closed on April 25, 2012 and its initial public offering terminated upon completion of the closing.

The proceeds of the Company's 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 $21.5 million and the net proceeds to the selling stockholders of $117.3 million, the Company 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 the Company). The Company used $67.1 million of the net proceeds to redeem convertible preferred units in Holdings LLC, including interest and other charges, and $99.0 million to pay down a portion of the borrowings under its revolving credit facility. The Company used the remaining $47.5 million to fund the execution of its growth strategy through its drilling program. The Company 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 granted to the underwriters, First Reserve Midstates Interholding LP and its affiliates owned approximately 41.4% of the Company's outstanding common stock.

On October 1, 2012, the Company closed on the acquisition of all of Eagle Energy Production, LLC's producing properties as well as its developed and undeveloped acreage primarily in the Mississippian Lime liquids play in Oklahoma and Kansas for $325 million in cash and 325,000 shares of the Company's Series A Preferred Stock with an initial liquidation preference value of $1,000 per share (the "Eagle Property Acquisition"). The Company funded the cash portion of the Eagle Property Acquisition purchase price with a portion of the net proceeds from the private placement of

MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

1. Organization and Business (Continued)

$600 million in aggregate principal amount of 10.75% senior unsecured notes due 2020, which also closed on October 1, 2012 ("2020 Senior Notes").

On May 31, 2013, the Company closed on the acquisition of producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma from Panther Energy Company, LLC and its partners for approximately $618 million in cash (the "Anadarko Basin Acquisition"), before customary post-closing adjustments. The Company funded the purchase price with a portion of the net proceeds from the private placement of $700 million in aggregate principal amount of 9.25% senior unsecured notes due 2021, which also closed on May 31, 2013 ("2021 Senior Notes").

Subsequent to the closing of the Eagle Property Acquisition and the Anadarko Basin Acquisition, the Company has oil and gas operations and properties in Louisiana, Oklahoma, Texas and Kansas. At December 31, 2013, the Company operated oil and natural gas properties as one reportable segment engaged in the exploration, development and production of oil, natural gas liquids and natural gas. The Company's management evaluated performance based on one reportable segment as there were not significantly different economic or operational environments within its oil and natural gas properties.

All pro forma and per share information presented in the accompanying consolidated financial statements have been adjusted to reflect the effects of the Company's initial public offering.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements of the Company have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC") and have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP").

All intercompany transactions have been eliminated in consolidation. The consolidated financial statements as of and for the year ended December 31, 2013 include the results from the Anadarko Basin Acquisition beginning May 31, 2013. The consolidated financial statements as of and for the year ended December 31, 2012 include the results from the Eagle Property Acquisition beginning October 1, 2012.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Significant estimates include, but are not limited to, the amount of recoverable oil and natural gas reserves; future cash flows from oil and natural gas properties; the fair value of commodity derivative contracts; the fair value of share-based compensation; and the valuation of future asset retirement obligations.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

2. Summary of Significant Accounting Policies (Continued)

Cash and Cash Equivalents

The Company considers all short-term investments with an original maturity of three months or less to be cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are stated at the historical carrying amount net of allowance for uncollectible accounts. The carrying amount of the Company's accounts receivable approximate fair value because of the short-term nature of the instruments. The Company accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any reserve may be reasonably estimated. As of December 31, 2013 and 2012, the Company had no allowance for doubtful accounts.

Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, receivables, payables, debt, and commodity derivative contracts. Commodity derivative contracts are recorded at fair value (see Note 3). Based upon recent amendments to the Company's Credit Facility, the Company believes the carrying amount of the related floating-rate debt approximates fair value due to the variable nature of the interest rate and the current financing terms available to the Company. The carrying amount of the Company's other financial instruments approximate fair value because of the short-term nature of the items or variable pricing. See fair value discussion of Senior Notes and Series A Preferred Shares issued in October 2012 in Notes 8 and 10, respectively.

Derivative financial instruments are recorded in the 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 in "Losses on commodity derivative contracts net." The related cash flow impact is reflected within cash flows from operating activities.

Other Noncurrent Assets

At December 31, 2013, other noncurrent assets consisted of $44.7 million in deferred financing costs, $9.7 million in field inventory, and $0.2 million in other noncurrent assets. At December 31, 2012, other noncurrent assets consisted of $25.2 million in deferred financing costs and $0.2 million in other noncurrent assets. The increase in deferred financing costs is the result of approximately $19.3 million in deferred financing costs incurred during 2013 with the issuance of the 2021 Senior Notes.

Property and Equipment

Oil and Gas Properties

The Company uses the full-cost method of accounting for its exploration and development activities. Under this method of accounting, the cost of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds from the sale or

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

2. Summary of Significant Accounting Policies (Continued)

disposition of oil and gas properties are accounted for as a reduction to capitalized costs unless a significant portion of the Company's reserve quantities are sold that results in a significant alteration of the relationship between capitalized costs and remaining proved reserves, in which case a gain or loss is generally recognized in income.

Unevaluated Property

Oil and gas unevaluated properties and properties under development include costs that are not being depleted or amortized. These costs represent investments in unproved properties. The Company excludes these costs until proved reserves are found, until it is determined that the costs are impaired or until major development projects are placed in service, at which time the costs are moved into oil and natural gas properties subject to amortization. All unproved property costs are reviewed at least annually to determine if impairment has occurred.

Oil and Gas Reserves

Proved oil, NGLs and natural gas reserves utilized in the preparation of the consolidated financial statements are estimated in accordance with the rules established by the SEC and the Financial Accounting Standards Board (FASB), which require that reserve estimates be prepared under existing economic and operating conditions using a 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. The Company depletes its oil and gas properties using the units-of-production method. Capitalized costs of oil and natural gas properties subject to amortization are depleted over proved reserves. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

Impairment of Oil and Gas Properties/Ceiling Test

The Company performs a full-cost ceiling test on 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 received by the Company as of the first trading day of each month over the preceding twelve months (such prices are 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 expense in the accompanying consolidated statements of operations. For the year ended December 31, 2013,

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

2. Summary of Significant Accounting Policies (Continued)

capitalized costs exceeded the ceiling and an impairment of oil and gas properties of $319.6 million, after tax, was recorded.

The most significant factors affecting the impairment related to the transfer of unevaluated property costs to the full cost pool during 2013 and negative reserve revisions in our Gulf Coast area. During 2013, we transferred $61.2 million of Gulf Coast unevaluated property costs to the full cost pool based upon our lack of future plans for further evaluation or development of those leases, and $168.4 million of Mississippian unevaluated property costs attributable to leases that expired during 2013 or that we currently intend to allow to expire in 2014. The negative reserve revisions in our Gulf Coast area were mainly attributable to variability in well performance, our decision during the second quarter to halt further development in our West Gordon field and unfavorable cost revisions. See Note 5.

Depreciation, Depletion, and Amortization (DD&A)

DD&A of oil and gas properties is calculated using the Units of Production Method (UOP). The UOP calculation, in its simplest terms, multiplies the percentage of estimated proved reserves produced by the cost of those reserves. The result is to recognize expense at the same pace that the reserves are estimated to be depleting. The amortization base in the UOP calculation includes the sum of proved property costs net of accumulated DD&A, estimated future development costs (future costs to access and develop proved reserves) and asset retirement costs that are not already included in oil and gas property, less related salvage value.

Capitalized Interest

Interest from external borrowings is capitalized on unevaluated properties using the weighted-average cost of outstanding borrowings until the project is substantially complete and ready for its intended use, which for oil and gas assets is at the first production from the field. Capitalized interest is depleted over the useful lives of the assets in the same manner as the depletion of the underlying assets. The Company paid cash interest of $104.3 million, $7.2 million, and $4.2 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Other Property and Equipment

Other property and equipment consists of vehicles, furniture and fixtures, and computer hardware and software and are carried at cost. Depreciation is provided principally using the straight-line method over the estimated useful lives of the assets, which primarily range from three to seven years. Maintenance and repairs are charged to expense as incurred, while renewals and betterments are capitalized.

Accrued Liabilities

Accrued liabilities at December 31, 2013 consisted of $87.2 million in oil and gas capital expenditures, $64.4 million in accrued revenue and royalty distributions, $21.3 million in accrued interest, $8.3 million in accrued lease operating and workover expenses, $4.4 million in accrued taxes, and $18.8 million in other accrued liabilities. At December 31, 2012, the balance consisted of $69.0 million in oil and gas capital expenditures, $16.2 million in accrued interest, and $13.4 million in other accrued liabilities.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

2. Summary of Significant Accounting Policies (Continued)

Asset Retirement Obligations

The legal obligations associated with the retirement of long-lived assets are recognized at estimated fair value at the time that the obligation is incurred.

Oil and gas producing companies incur such a liability upon acquiring or drilling a well. The Company estimates the fair value of an asset retirement obligation in the period in which the obligation is incurred and can be reliably measured. The corresponding asset retirement cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, any adjustment is recorded in the full cost pool. See Note 7.

Share-Based 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, net of amounts capitalized to oil and gas properties, in "General and administrative expense" in our consolidated statements of operations. See Note 10.

Revenue Recognition

Oil, NGLs and natural gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred and collection of the revenues is reasonably assured. Cash received relating to future revenues is deferred and recognized when all revenue recognition criteria are met.

The Company follows the sales method of accounting for oil and gas revenues, whereby revenue is recognized for all oil and gas sold to purchasers regardless of whether the sales are proportionate to the Company's ownership interest in the property. Production imbalances are recognized as a liability to the extent an imbalance on a specific property exceeds the Company's share of remaining proved oil and gas reserves. The Company had no significant imbalances at December 31, 2013 or 2012.

Acquisition and Transaction Costs

Acquisition related costs are expensed as incurred and as services are received. Such costs include finders' fees; advisory, legal, accounting, valuation and other professional and consulting fees; and acquisition related general and administrative costs. Costs incurred in 2013 relate to the Anadarko Basin Acquisition and costs incurred in 2012 relate to the Eagle Property Acquisition. See Note 6.

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or liabilities are settled. Deferred

MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

2. Summary of Significant Accounting Policies (Continued)

income taxes also include tax credits and net operating losses that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted tax rates.

The Company accounts for uncertainty in income taxes for tax positions taken or expected to be taken in a tax return. Only tax positions that meet the more-than-likely-than-not recognition threshold are recognized.

Prior to its corporate reorganization (See Note 1), the Company was a limited liability company and not subject to federal income tax or state income tax (in most states). Accordingly, no provision for federal or state income taxes was recorded prior to the corporate reorganization as the Company's equity holders were responsible for income tax on the Company's profits. In connection with the closing of the Company's initial public offering, the Company merged into a corporation and became subject to federal and state income taxes. The Company's book and tax basis in assets and liabilities differed at the time of the corporate reorganization due primarily to different cost recovery periods utilized for book and tax purposes for the Company's oil and natural gas properties. See Note 11.

Earnings (Loss) Per Share

Basic earnings (loss) per common share is calculated by dividing net income available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted earnings (loss) per common share is calculated by dividing net income available to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options (if any) using the treasury method, as well as the Company's Series A Preferred Stock using the if-converted method. In the computation of diluted earnings per share, excess tax benefits that would be created upon the assumed vesting of unvested restricted shares or the assumed exercise of stock options (i.e. hypothetical excess tax benefits) are included in the assumed proceeds component of the treasury share method to the extent that such excess tax benefits are more likely than not to be realized. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

Recent Accounting Pronouncements

The Company reviewed recently issued accounting pronouncements that became effective during the twelve months ended December 31, 2013, and determined that none would have a material impact on the Company's consolidated financial statements with the exception of the adoption of ASU 2011-11, "*Disclosures About Offsetting Assets and Liabilities*", which the Company adopted on January 1, 2013 and that applies to the disclosures regarding commodity derivative contracts discussed in Note 4.

Correction of the 2012 Net Deferred Tax Liability

In the third quarter of 2013, the Company determined that its 2012 accounting for the tax impacts of the merger of certain entities that occurred in connection with the Company's initial public offering was in error. The Company identified that certain tax attributes acquired from the merged entities were not properly identified. Because the tax attributes were acquired as a result of a merger of entities under common control, the impacts of these tax attributes should have been recorded through equity at the time the Company became a taxable entity.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

2. Summary of Significant Accounting Policies (Continued)

To correct the 2012 tax error, the Company has restated the accompanying Consolidated Balance Sheet and the Consolidated Statement of Changes in Stockholders'/Members Equity as of December 31, 2012. There was no impact to the Consolidated Statements of Operations or the Consolidated Statement of Cash Flows for the year ended December 31, 2012. The impact of the correction is shown in the table below (in thousands):

	December 31, 2012	
Balance Sheet	As Previously Reported	As Restated
Deferred income taxes	$ 190,625	$ 156,737
Total long-term liabilities	905,002	871,114
Additional paid-in-capital	830,003	863,891
Total stockholders' equity	643,581	677,469

3. Fair Value Measurements of Financial Instruments

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further divided into the following fair value input hierarchy:

Level 1 Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2 Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are commodity derivative contracts with fair values based on inputs from actively quoted markets. The Company uses a discounted cash flow approach to estimate the fair values of its commodity derivative contracts, utilizing commodity futures price strips for the underlying commodities provided by a reputable third-party.

Level 3 Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability.

Assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Derivative Instruments Commodity derivative contracts reflected in the consolidated balance sheets are recorded at estimated fair value. At December 31, 2013 and 2012, all of the Company's commodity

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

3. Fair Value Measurements of Financial Instruments (Continued)

derivative contracts were with seven and five bank counterparties, respectively, and are classified as Level 2.

	Fair Value Measurements at December 31, 2013			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Commodity derivative NGL swaps	$	$ 469	$	$ 469
Commodity derivative gas swaps		488		488
Commodity derivative oil collars		64		64
Commodity derivative gas collars		751		751
Commodity derivative differential swaps		806		806
Total assets	**$**	**$ 2,578**	**$**	**$ 2,578**
Liabilities:				
Commodity derivative oil swaps	$	$ 32,209	$	$ 32,209
Commodity derivative NGL swaps		74		74
Commodity derivative gas swaps		809		809
Commodity derivative oil collars		272		272
Commodity derivative gas collars		26		26
Total liabilities	**$**	**$ 33,390**	**$**	**$ 33,390**

	Fair Value Measurements at December 31, 2012			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Commodity derivative oil swaps	$	$ 16,133	$	$ 16,133
Commodity derivative NGL swaps		2,353		2,353
Commodity derivative oil collars		428		428
Commodity derivative gas collars		2,026		2,026

Commodity derivative differential swaps		2,661		2,661
Total assets	**$**	**$ 23,601**	**$**	**$ 23,601**
Liabilities:				
Commodity derivative oil swaps	$	$ 15,091	$	$ 15,091
Commodity derivative NGL swaps		458		458
Commodity derivative oil collars		287		287
Commodity derivative gas collars		185		185
Commodity derivative differential swaps		11,693		11,693
Total liabilities	**$**	**$ 27,714**	**$**	**$ 27,714**

MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

3. Fair Value Measurements of Financial Instruments (Continued)

Derivative instruments listed above are presented gross and include collars and swaps that are carried at fair value. The Company records the net change in the fair value of these positions in "Losses on commodity derivative contracts net" in the Company's consolidated statements of operations. See Note 4 for additional information on the Company's derivative instruments and balance sheet presentation.

4. Risk Management and Derivative Instruments

The Company is exposed to fluctuations in crude oil, NGLs and natural gas prices. The Company believes it is prudent to manage the variability in cash flows by entering into derivative financial instruments to economically hedge a portion of its crude oil, NGLs and natural gas production. The Company utilizes various types of derivative financial instruments, including swaps, collars and options, to manage fluctuations in cash flows resulting from changes in commodity prices. These derivative contracts are placed with major financial institutions that the Company believes are minimal credit risks. The oil, NGLs and gas reference prices, upon which the commodity derivative contracts are based, reflect various market indices that management believes have a high degree of historical correlation with actual prices received by the Company for its oil, NGLs and natural gas production.

Inherent in the Company's portfolio of commodity derivative contracts are certain business risks, including market risk and credit risk. Market risk is the risk that the price of the commodity will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the Company's counterparty to a contract. The Company does not require collateral from its counterparties but does attempt to minimize its credit risk associated with derivative instruments by entering into derivative instruments only with counterparties that are large financial institutions, which management believes present minimal credit risk. In addition, to mitigate its risk of loss due to default, the Company has entered into agreements with its counterparties on its derivative instruments that allow the Company to offset its asset position with its liability position in the event of default by the counterparty. Due to the netting arrangements, had the Company's counterparties failed to perform under existing commodity derivative contracts, the maximum loss at December 31, 2013 would have been approximately $0.7 million.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

4. Risk Management and Derivative Instruments (Continued)

Commodity Derivative Contracts

As of December 31, 2013, the Company had the following open commodity positions:

	Hedged Volume	Weighted-Average Fixed Price
Oil (Bbls):		
WTI Swaps 2014	4,344,450	$88.76
WTI Swaps 2015	1,820,000	$86.55
WTI Collars 2014	164,400	$88.49 - $97.94
WTI to LLS Basis Differential Swaps 2014(1)	501,000	$5.35
NGL (Bbls):		
NGL Swaps 2014	151,500	$62.16
Natural Gas (MMBtu):		
Swaps 2014(2)	17,885,000	$4.17
Swaps 2015	18,250,000	$4.13
Collars 2014(3)	1,685,004	$3.99 - $5.09

(1) The Company enters into swap arrangements intended to fix the positive differential between the Louisiana Light Sweet ("LLS") pricing and West Texas Intermediate ("NYMEX WTI") pricing.

(2) Includes 1,519,000 MMBtu that priced in the fourth quarter of 2013, but had not cash settled as of December 31, 2013.

(3) Includes 64,667 MMBtu that priced in the fourth quarter of 2013, but had not cash settled as of December 31, 2013.

Balance Sheet Presentation

The following table summarizes the gross fair value of derivative instruments by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

4. Risk Management and Derivative Instruments (Continued)

and qualify for net presentation in the Company's consolidated balance sheets at December, 2013 and 2012, respectively (in thousands):

Type	Balance Sheet Location(1)	December 31, 2013	December 31, 2012
Oil Swaps	Derivative financial instruments Current Assets	$	$ 16,004
Oil Swaps	Derivative financial instruments Non-Current Assets		129
Oil Swaps	Derivative financial instruments Current Liabilities	(28,871)	(11,485)
Oil Swaps	Derivative financial instruments Non-Current Liabilities	(3,338)	(3,606)
NGL Swaps	Derivative financial instruments Current Assets	469	1,624
NGL Swaps	Derivative financial instruments Non-Current Assets		729
NGL Swaps	Derivative financial instruments Current Liabilities	(74)	(336)
NGL Swaps	Derivative financial instruments Non-Current Liabilities		(122)
Gas Swaps	Derivative financial instruments Current Assets	469	
Gas Swaps	Derivative financial instruments Non-Current Assets	19	
Gas Swaps	Derivative financial instruments Current Liabilities	(496)	
Gas Swaps	Derivative financial instruments Non-Current Liabilities	(313)	
Oil Collars	Derivative financial instruments Current Assets	64	221
Oil Collars	Derivative financial instruments Non-Current Assets		207
Oil Collars	Derivative financial instruments Current Liabilities	(272)	(238)
Oil Collars	Derivative financial instruments Non-Current Liabilities		(49)
Gas Collars	Derivative financial instruments Current Assets	751	1,129
Gas Collars	Derivative financial instruments Non-Current Assets		897
Gas Collars	Derivative financial instruments Current Liabilities	(26)	(112)
Gas Collars	Derivative financial instruments Non-Current Liabilities		(73)
Basis Differential Swaps	Derivative financial instruments Current Assets	806	2,625
Basis Differential Swaps	Derivative financial instruments Non-Current Assets		36
Basis Differential Swaps	Derivative financial instruments Current Liabilities		(11,319)
Basis Differential Swaps	Derivative financial instruments Non-Current Liabilities		(374)

Total derivative fair value at period end	**$ (30,812)**	**$ (4,113)**

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(1) The fair values of commodity derivative instruments reported in the Company's consolidated balance sheets are subject to netting arrangements and qualify for net presentation. The following table summarizes the location and fair value amounts of all derivative instruments in the consolidated balance sheets, as well as the gross recognized derivative assets, liabilities and amounts offset in the consolidated balance sheets at December 31, 2013 and 2012, respectively (in thousands):

		December 31, 2013		
Not Designated as ASC 815 Hedges:	**Balance Sheet Classification**	**Gross Recognized Assets/ Liabilities**	**Gross Amounts Offset**	**Net Recognized Fair Value Assets/ Liabilities**
Derivative assets:				
Commodity contracts	Derivative financial instruments current	$ 2,559	$ 1,859	$ 700
Commodity contracts	Derivative financial instruments noncurrent	19		19
		$ 2,578	**$ 1,859**	**$ 719**
Derivative liabilities:				
Commodity contracts	Derivative financial instruments current	$ 29,739	$ 1,859	$ 27,880
Commodity contracts	Derivative financial instruments noncurrent	3,651		3,651
		$ 33,390	**$ 1,859**	**$ 31,531**

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

4. Risk Management and Derivative Instruments (Continued)

Not Designated as ASC 815 Hedges:	Balance Sheet Classification	December 31, 2012 Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Derivative financial instruments current	$ 21,603	$ 15,908	$ 5,695
Commodity contracts	Derivative financial instruments noncurrent	1,998	281	1,717
		$ 23,601	**$ 16,189**	**$ 7,412**
Derivative liabilities:				
Commodity contracts	Derivative financial instruments current	$ 23,490	$ 15,908	$ 7,582
Commodity contracts	Derivative financial instruments noncurrent	4,224	281	3,943
		$ 27,714	**$ 16,189**	**$ 11,525**

Gains/Losses on Commodity Derivative Contracts

The Company does not designate its commodity derivative contracts as hedging instruments for financial reporting purposes. Accordingly, commodity derivative contracts are marked-to-market each quarter with the change in fair value during the periodic reporting period recognized currently as a gain or loss in "Losses on commodity derivative contracts net" within revenues in the audited consolidated statements of operations. Realized gains and losses represent the actual settlements under commodity derivative contracts that require making a payment to or receiving a payment from the counterparty, as well as any deferred premiums payable to the counterparty upon contract settlement. During the year ended December 31, 2012, the Company paid deferred premiums of $3.3 million related to put options covering a total of 549,000 barrels of crude oil, respectively. No such payments for deferred premiums were made during 2013.

The following table presents realized net losses and unrealized net (losses) gains recorded by the Company in "Losses on commodity derivative contracts net" related to the change in fair value of the commodity derivative instruments for the periods presented:

	For the Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Realized net losses	$ (17,585)	$ (15,825)	$ (16,733)
Unrealized net (losses) gains	(26,699)	4,667	11,889

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

5. Property and Equipment

The Company's property and equipment as of December 31, 2013 and 2012 was as follows (in thousands):

	December 31, 2013	December 31, 2012
	(in thousands)	
Oil and gas properties, on the basis of full-cost accounting:		
Proved properties	$ 2,817,062	$ 1,522,723
Unevaluated properties	243,599	313,941
Other property and equipment	11,113	5,038
Less accumulated depreciation, depletion, amortization and impairment	(976,880)	(274,294)
Net property and equipment	**$ 2,094,894**	**$ 1,567,408**

For the years ended December 31, 2013, 2012 and 2011, depletion expense related to oil and gas properties was $248.2 million, $125.1 million and $91.4 million, respectively and $28.42, $34.17 and $33.40 per barrel of oil equivalent ("Boe"), respectively. For the years ended December 31, 2013, 2012 and 2011, depreciation expense related to other property and equipment was $2.2 million, $0.5 million and $0.3 million, respectively.

For the years ended December 31, 2013, 2012 and 2011, interest capitalized to unevaluated properties was $32.2 million, $11.2 million and $2.6 million, respectively. For the years ended December 31, 2013 and 2012, the Company capitalized $8.4 million and $1.5 million, respectively, of internal costs to oil and gas properties, including $1.4 million and $0.2 million, respectively, of qualifying share based compensation expense (see Note 10).

6. Acquisition of Oil and Gas Properties

Anadarko Basin Acquisition May 2013

On May 31, 2013, the Company closed on the acquisition of producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma from Panther Energy Company, LLC and its partners for approximately $618 million in cash (before customary post-closing adjustments). The Company funded the purchase price of the Anadarko Basin Acquisition with a portion of the net proceeds from the private placement of $700 million in aggregate principal amount of 9.25% senior unsecured notes due 2021, which also closed on May 31, 2013.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

6. Acquisition of Oil and Gas Properties (Continued)

The transaction was accounted for using the acquisition method of accounting which requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The final determination of fair value for certain assets and liabilities remains preliminary and will be completed after post-closing purchase price adjustments are finalized no later than one year from the acquisition date.

The following table summarizes (in thousands) the preliminary estimate of the assets acquired and liabilities assumed in the acquisition. The final determination of the certain assets and liabilities will be completed as soon as the post-closing purchase price adjustments are finalized. These amounts will be finalized as soon as practicable, but no later than one year from the acquisition date.

	Anadarko Basin Acquisition
Oil and gas properties	
Proved	$ 418,287
Unevaluated	207,789
Total assets acquired	**$ 626,076**
Asset retirement obligations	6,296
Total liabilities assumed	**$ 6,296**
Net assets acquired	**$ 619,780**

The fair values of oil and natural gas properties and asset requirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) oil and gas reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; and (v) market based weighted average cost of capital. Significant inputs to the valuation of asset retirement obligations include estimates of: (i) the timing of future plugging and abandonment activities; (ii) future plugging and abandonment costs; and (iii) market based weighted average cost of capital. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

Eagle Property Acquisition October 2012

On October 1, 2012, the Company closed on the Eagle Property Acquisition. The assets acquired include certain interests in producing oil and natural gas assets and unevaluated leasehold acreage in Oklahoma and Kansas and related hedging instruments. The aggregate purchase price, before adjustments for expenses incurred and revenue received by Eagle from June 1, 2012 through the closing date and other customary post-closing purchase price adjustments, consisted of (a) $325 million in cash and (b) 325,000 shares of Series A Preferred Stock with an initial liquidation preference of $1,000/share. 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.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

6. Acquisition of Oil and Gas Properties (Continued)

The transaction was accounted for using the acquisition method of accounting . The fair value of, and the allocation to, the assets acquired and liabilities assumed in the Eagle Property Acquisition has been finalized and is shown in the following table (in thousands):

	Eagle Property Acquisition
Oil and gas properties:	
Proved	$ 419,549
Unevaluated	244,236
Commodity derivative contracts	8,453
Total assets acquired	**$ 672,238**
Asset retirement obligations	2,662
Deferred income tax liabilities	25,985
Commodity derivative contracts	
Total liabilities assumed	**$ 28,647**
Net assets acquired	**$ 643,591**

The finalized balances in the table above include immaterial changes to the amounts originally allocated to oil and gas properties and deferred income tax liabilities. These changes were required to reflect the final consideration paid after adjustments for certain post-closing purchase price amounts.

Other Property Acquisitions

On April 1, 2013, the Company exercised preference rights and acquired additional acreage and producing wells in its Gulf Coast region for $3.4 million.

Actual and Pro Forma Impact of Acquisitions unaudited

Revenues attributable to the Anadarko Basin Acquisition included in the Company's consolidated statements of operations for the year ended December 31, 2013 were $104.7 million. Revenues attributable to the Eagle Property Acquisition, included in the Company's consolidated statements of operations for the year ended December 31, 2012 were $28.4 million.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

6. Acquisition of Oil and Gas Properties (Continued)

The following table presents unaudited pro forma information for the Company as if the Eagle Property Acquisition occurred on January 1, 2011 and the Anadarko Basin Acquisition occurred on January 1, 2012:

	For the Year Ended December 31,		
	2013(1)	**2012(2)**	**2011(3)**
Revenues and other	$ 539,562	$ 490,241	$ 287,119
Net income (loss)	(340,400)	(129,885)	21,066
Preferred stock dividends	(15,589)	(26,000)	(26,000)
Net loss attributable to common shareholders	$ (355,989)	$ (155,885)	$ (4,934)
Net loss per common share basic and diluted	$ (5.41)	$ (2.60)	N/A

(1) Includes the effect of the Anadarko Basin Acquisition, as the Eagle Property Acquisition was included in the historical results for this period.

(2) Includes the effect of the Eagle Property Acquisition and the Anadarko Basin Acquisition.

(3) Includes the effect of the Eagle Property Acquisition.

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Eagle Property Acquisition and the Anadarko Basin Acquisition and are factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the Company's consolidated results of operations actually would have been had the Eagle Property Acquisition been completed on January 1, 2011 and if the Anadarko Basin Acquisition had been completed on January 1, 2012. In addition, the unaudited pro forma consolidated results do not purport to project the future results of operations for the combined Company.

Acquisition and Transaction Expenses

For the year ended December 31, 2013, acquisition and transaction costs are costs the Company has incurred as a result of the Anadarko Basin Acquisition and include advisory, legal, accounting, valuation and other professional and consulting fees; and general and administrative costs. For the year ended December 31, 2013, the Company recorded $11.8 million of such expenses.

For the year ended December 31, 2012, 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 acquisition related general and administrative costs. For the year ended December 31, 2012, the Company recorded $14.9 million of such expenses.

7. Asset Retirement Obligations

For the Company, asset retirement obligations represent the future abandonment costs of tangible assets, such as wells, service assets and other facilities. The fair value of the asset retirement obligation at inception is capitalized as part of the carrying amount of the related long-lived assets. Asset retirement obligations approximated $26.3 million and $15.2 million as of December 31, 2013 and 2012,

MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

7. Asset Retirement Obligations (Continued)

respectively. The liability has been accreted to its present value as of December 31, 2013 and 2012. The Company evaluated its wells and determined a range of abandonment dates through 2071. At December 31, 2013, all asset retirement obligations represent long-term liabilities and are classified as such.

The following table details the change in the asset retirement obligations for the years ended December 31, 2013, 2012 and 2011, respectively (in thousands):

	Year ended December 31,		
	2013	2012	2011
Asset retirement obligations at beginning of year	**$ 15,245**	**$ 7,627**	**$ 2,859**
Liabilities incurred	2,535	3,044	1,294
Liabilities assumed in Anadarko Basin Acquisition	6,296		
Liablities assumed in Eagle Property Acquisition		2,662	
Revisions	858	1,189	3,196
Liabilities settled	(61)		(56)
Current period accretion expense	1,435	723	334
Asset retirement obligations at end of year	**$ 26,308**	**$ 15,245**	**$ 7,627**

Revisions during the year ended December 31, 2013 were due to an increase in estimated future abandonment costs based upon higher oilfield service pricing. Revisions during the year ended December 31, 2012 were due to an increase in estimated future abandonment costs for our Gulf Coast wells based upon higher oilfield service pricing and a change in the Company's approach to site remediation based upon expected environmental and regulatory requirements.

8. Long-Term Debt

The Company's long-term debt as of December 31, 2013 and 2012 is as follows:

	At December 31,	
	2013	2012
	(in thousands)	
Revolving credit facility, due 2018	$ 401,150	$ 94,000
Senior notes, due 2020	600,000	600,000
Senior notes, due 2021	700,000	
Long-term debt	**$ 1,701,150**	**$ 694,000**

Reserve-based Credit Facility

As of December 31, 2013, the Company's credit facility consisted of a $750 million senior revolving credit facility (the "Credit Facility") with a borrowing base of $500 million, as recently redetermined on September 26, 2013, when the borrowing base was increased from $425 million. At December 31, 2013, outstanding letters of credit obligations total $0.2 million.

The Credit Facility matures on May 31, 2018 and borrowings thereunder are secured by substantially all of the Company's oil and natural gas properties and currently bear interest at LIBOR

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

8. Long-Term Debt (Continued)

plus an applicable margin, depending upon the Company's borrowing base utilization, between 1.75% and 2.75% per annum. At December 31, 2013 and December 31, 2012, the weighted average interest rate was 2.5% and 2.5%, respectively.

In addition to interest expense, the 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 Credit Facility is subject to semiannual redeterminations in April and October and up to one additional time per six month period following each scheduled borrowing base redetermination, as may be requested by the Company 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 is October 1, 2014, assuming the financing discussed in Note 15 closes as planned.

Under the terms of the Credit Facility, the Company is 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. The Company is 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.

On September 26, 2013, the Company entered into the Assignment and Fourth Amendment to the Second Amended and Restated Credit Agreement among the Company, as parent, Midstates Sub, as borrower, SunTrust Bank as administrative agent, and the other lenders and parties party thereto (the "Fourth Amendment").

The Fourth Amendment amended the Credit Facility to provide that the Company's ratio of total net indebtedness to EBITDA for the trailing four fiscal quarter period ending on the last day of such fiscal quarter cannot exceed (i) 4.75:1.0, for the fiscal quarters ending December 31, 2013 and March 31, 2014, (ii) 4.50:1.0, for the fiscal quarters ending June 30, 2014, (iii) 4.25:1.0, for the fiscal quarters ending September 30, 2014 and December 31, 2014, and (iv) 4.00:1.0, for the fiscal quarter ending March 31, 2015 and each fiscal quarter thereafter. The Company also agreed to pay a one-time fee of 0.50% to each lender on the portion of their commitment to the borrowing base under the Fourth Amendment in excess of their commitment prior to the Fourth Amendment, and a one-time fee of 0.10% to each lender on the lesser of such lenders commitment immediately prior to, or after giving effect to, the Fourth Amendment.

The Credit Facility contains financial covenants, in addition to the maximum ratio of debt to EBITDA discussed above, which, among other things, set 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, 2013, the Company was in compliance with the minimum current ratio and the ratio of debt to EBITDA covenants as set forth in the Credit Facility. The Company's current ratio at December 31, 2013 was 1.3 to 1.0. At December 31, 2013, the Company's ratio of debt to EBITDA was 4.4 to 1.0.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

8. Long-Term Debt (Continued)

Based upon the recent amendments to the Credit Facility, the Company believes its carrying amount at December 31, 2013 approximates its fair value (Level 2) due to the variable nature of the applicable interest rate and current financing terms available to the Company.

2020 Senior Notes

On October 1, 2012, the Company issued $600 million in aggregate principal amount of 10.75% senior notes due 2020 (the "2020 Outstanding Notes") in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act of 1933, as amended (the "Securities Act"). On October 29, 2013, substantially all of the 2020 Outstanding Notes were exchanged for an equal principal amount of registered 10.75% senior subordinated notes due 2020 pursuant to an effective registration statement on Form S-4 filed on August 30, 2013 under the Securities Act (the "2020 Exchange Notes"). The 2020 Exchange Notes are identical to the 2020 Outstanding Notes except that the 2020 Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Form 10-K, the term "2020 Senior Notes" refers to both the 2020 Outstanding Notes and the 2020 Exchange Notes. The 2020 Senior Notes were co-issued on a joint and several basis by the Company and its wholly owned subsidiary, Midstates Sub. The Company does not have any operations or independent assets other than its 100% ownership interest in Midstates Sub and there are no other subsidiaries of the Company. The 2020 Senior Notes Indenture does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans to the Company or limit the ability of the Company to advance loans to Midstates Sub.

At any time prior to October 1, 2015, the Company may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2020 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 2020 Senior Notes, plus any accrued and unpaid interest up to the redemption date. In addition, at any time before October 1, 2016, the Company may redeem all or a part of the 2020 Senior Notes at a redemption price equal to 100% of the principal amount of 2020 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, the Company may redeem all or a part of the 2020 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 2020 Senior Notes redeemed, up to, the redemption date.

The Indenture contains covenants that, among other things, restrict the Company's 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 the Company's affiliates; (vii) consolidate, merge or sell substantially all of the Company's assets; (viii) prepay, redeem or repurchase certain debt; (ix) alter the business the Company conducts and (x) enter into agreements restricting the ability of the Company's current and any future subsidiaries to pay dividends.

Upon the occurrence of certain change of control events, as defined in the Indenture, each holder of the 2020 Senior Notes will have the right to require that the Company repurchase all or a portion of

MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

8. Long-Term Debt (Continued)

such holder's 2020 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.

The estimated fair value of the 2020 Senior Notes was $648.0 million as of December 31, 2013 (Level 2 in the fair value measurement hierarchy based on the limited trading volume on the secondary market), based on quoted market prices for these same debt securities. The effective annual interest rate for the 2020 Senior Notes was approximately 11.1% for the years ended December 31, 2013 and 2012.

2021 Senior Notes

On May 31, 2013, the Company issued $700 million in aggregate principal amount of 9.25% senior notes due 2021 (the "2021 Outstanding Notes") in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act. On October 29, 2013, all of the 2021 Outstanding Notes were exchanged for an equal principal amount of registered 9.25% senior subordinated notes due 2021 pursuant to an effective registration statement on Form S-4 filed on August 30, 2013 under the Securities Act (the "2021 Exchange Notes"). The 2021 Exchange Notes are identical to the 2021 Outstanding Notes except that the 2021 Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Form 10-K, the term "2021 Senior Notes" refers to both the 2021 Outstanding Notes and the 2021 Exchange Notes. The proceeds from the offering of $700 million (net of the initial purchasers' discount and related offering expenses) were used to fund the Anadarko Basin Acquisition and the related expenses, to pay the expenses related to an amendment to the Company's revolving credit facility, to repay $34.3 million in outstanding borrowings under the Company's Credit Facility, and for general corporate purposes.

The 2021 Senior Notes rank pari passu in right of payment with the 2020 Senior Notes.

The 2021 Senior Notes were co-issued on a joint and several basis by the Company and its wholly owned subsidiary, Midstates Sub. The Company does not have any operations or independent assets other than its 100% ownership interest in Midstates Sub and there are no other subsidiaries of the Company. The 2021 Senior Notes indenture does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans to the Company or limit the ability of the Company to advance loans to Midstates Sub.

On or prior to May 31, 2014, the Company may redeem up to $100.0 million of aggregate principal amount of the 2021 Senior Notes with the net cash proceeds from any Equity Offerings (as such term is defined in the 2021 Senior Notes Indenture) at a redemption price equal to 103% of the principal amount plus accrued and unpaid interest.

Prior to June 1, 2016, the Company may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes (less the amount of 2021 Senior Notes redeemed pursuant to the preceding paragraph) with the net proceeds of any Equity Offerings at a redemption price of 109.25% of the principal amount of the 2021 Senior Notes redeemed, plus any accrued and unpaid interest, if any, up to the redemption date. In addition, at any time before June 1, 2016, the Company may redeem all or a part of the 2021 Senior Notes at a redemption price equal to 100% of the principal amount of the 2021 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

MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

8. Long-Term Debt (Continued)

(as defined in the 2021 Senior Notes Indenture), if any, up to, the redemption date. On or after October 1, 2016, the Company may redeem all or a part of the 2021 Senior Notes at varying redemption prices (expressed as percentages of principal amount) set forth in the 2021 Senior Notes Indenture plus accrued and unpaid interest and Additional Interest (as defined in the 2021 Senior Notes Indenture), if any, on the 2021 Senior Notes redeemed, up to, the redemption date.

The terms of the covenants and change in control provisions in the 2021 Senior Notes Indenture are substantially identical to those of the 2020 Senior Notes discussed above.

The estimated fair value of the 2021 Senior Notes was $724.5 million as of December 31, 2013 (Level 2 in the fair value measurement hierarchy based on the limited trading volume on the secondary market), based on quoted market prices for these same debt securities. The effective annual interest rate for the 2021 Senior Notes was approximately 9.5% for the year ended December 31, 2013.

9. 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 of Directors) 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, the Company used $67.1 million of the proceeds from its initial public offering to redeem the Preferred Units in full, including interest and other charges. As such, at December 31, 2012, the Preferred Units are no longer outstanding. The Company recorded $2.1 million related to interest expense associated with these Preferred Units for the year ended December 31, 2012. There was no related interest expense for the year ended December 31, 2013.

10. Equity and Share-Based Compensation

Common and Preferred Shares

At December 31, 2011, Holdings LLC had 256,742 common units issued and outstanding. On April 24, 2012, in connection with the Company's initial public offering, a corporate reorganization occurred and each common unit of Holdings LLC was converted into approximately 185.5 common shares of the Company and as a result, the Company issued 47,634,353 shares of its common stock.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

10. Equity and Share-Based Compensation (Continued)

On April 25, 2012, the Company completed its initial public offering of common stock pursuant to a registration statement on Form S-1 (File 333-177966), as amended and declared effective by the SEC on April 19, 2012. Pursuant to the registration statement, the Company registered the offer and sale of 27,600,000 shares of $0.01 par value common stock, which included 6,000,000 shares of stock sold by the selling shareholders and 3,600,000 shares of common stock sold by the selling stockholders pursuant to an option granted to the underwriters to cover over-allotments.

After the corporate reorganization and the completion of its initial public offering discussed above, the Company is authorized to issue up to a total of 300,000,000 shares of its common stock with a par value of $0.01 per share, and 50,000,000 shares of its preferred stock with a par value of $0.01 per share. Holders of the Company's common shares are entitled to one vote for each share held of record on all matters submitted to a vote of stockholders and to receive ratably in proportion to the shares of common stock held by them any dividends declared from time to time by the board of directors. The common shares have no preferences or rights of conversion, exchange, pre-exemption or other subscription rights.

With respect to preferred shares, the Company is authorized, without further stockholder approval, to establish and issue from time to time one or more classes or series of preferred stock with such powers, preferences, rights, qualifications, limitations and restrictions as determined by its board of directors.

Series A Preferred Stock

In connection with the Eagle Property Acquisition, on September 28, 2012, the Company designated 325,000 shares of Series A Mandatorily Convertible Preferred Stock (the "Series A Preferred Stock") with an initial liquidation preference of $1,000 per share and an 8% per annum dividend, payable semiannually at the Company's option in cash or through an increase in the liquidation preference. The Series A Preferred Shares are convertible after October 1, 2013, in whole but not in part and at the option of the holders of a majority of the outstanding shares of Series A Preferred Stock, into a number shares of the Company's common stock calculated by dividing the then-current liquidation preference by the conversion price of $13.50 per share and, if not previously converted, are mandatorily convertible at September 30, 2015 into shares of the Company's common stock at a conversion price no greater than $13.50 per share and no less than $11.00 per share, with the ultimate conversion price dependent upon the volume weighted average price of the Company's common stock during the 15 trading days immediately prior to September 30, 2015. The Series A Preferred Stock was issued on October 1, 2012.

On March 30, 2013, the Company elected to pay the $13 million semi-annual dividend due on that date through an increase in the Series A Preferred Stock liquidation preference to $1,040. As a result, the Company will be obligated to issue between 962,963 and 1,181,818 additional shares of common stock upon conversion of the Series A Preferred Stock, with the ultimate number of shares dependent upon the conversion price then in effect as described above.

On September 30, 2013, the Company elected to pay the $13.5 million semi-annual dividend due on that date through an increase in the Series A Preferred Stock liquidation preference to $1,082. As a result, the Company will be obligated to issue between 1,001,481 and 1,229,091 additional shares of common stock upon conversion of the Series A Preferred Stock, with the ultimate number of shares dependent upon the conversion price then in effect as discussed above.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

10. Equity and Share-Based Compensation (Continued)

For the three months ended December 31, 2013, the $6.3 million Series A Preferred Stock dividend was based upon the estimated fair value of 639,127 common shares that would have been issued had the notional dividend amount of $7.0 million been converted into common shares at a conversion price of $11.00 per share.

For the twelve months ended December 31, 2013, the $15.6 million Series A Preferred Stock dividend was based upon the estimated fair value of 2,459,127 common shares that would have been issued had the notional dividend amounts for the year of $27.1 million been converted into common shares at a conversion price of $11.00 per share.

The following table demonstrates the number of shares to be issued upon conversion through December 31, 2013 at the respective conversion rates based upon the current liquidation preference:

	Conversion at $13.50/share	Conversion at $11.00/share
Number of Common Shares Issuable Upon Conversion	26,077,807	32,004,582

Share Activity

The following table summarizes changes in the number of outstanding shares since January 1, 2011:

	Number of Shares		
	Series A Preferred Stock	Common Stock	Treasury Stock
Share count as of January 1, 2011			
Share count as of December 31, 2011			
Issuance of common stock in pre IPO reorganization		47,634,353	
Proceeds from the sale of common stock to public		18,000,000	
Issuance of preferred stock as consideration in Eagle Property Acquisition			
Share based compensation grants of restricted stock		1,029,509	
Forfeitures of restricted stock		(44,151)	
Share count as of December 31, 2012	**325,000**	**66,619,711**	
Grants of restricted stock		2,840,241	
Forfeitures of restricted stock		(534,207)	
Acquisition of treasury stock			(118,702)
Share count as of December 31, 2013	**325,000**	**68,925,745**	**(118,702)**

At December 31, 2013, the Company had 68,925,745 and 68,807,043 shares of its common stock issued and outstanding, respectively, and 325,000 shares of Series A Preferred Stock issued and outstanding.

MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

10. Equity and Share-Based Compensation (Continued)

Share-Based Compensation, pre Initial Public Offering

During the year ended December 31, 2011, certain restricted and unrestricted shares in Petroleum Inc., through which Holdings LLC's founders, members of management and certain employees previously held their equity interests, certain unrestricted units in Holdings LLC, and certain units in Midstates Incentive Holdings, LLC ("Midstates Incentive") had been issued to employees of Holdings LLC.

Additionally, in March 2011, Holdings LLC's Chief Executive Officer, in connection with the commencement of his employment, purchased 17.3 shares of common stock of Petroleum Inc. and contemporaneously received a grant of 24.6 shares of common stock in Petroleum Inc. that vested as described further below. No other shares or units were issued during the 2011 period. The Company determined the grant date fair value of the share based award to be $80,013 per Petroleum Inc. share ($3.4 million in aggregate), or after taking into account the corporate reorganization attributable to the initial public offering completed on April 25, 2012, $4.26 per share of the Company's common stock. The Company recognized stock compensation based upon the grant date fair value and immediately expensed the difference between the grant date fair value and the price paid for the purchased shares of Petroleum Inc., as well as additional compensation expense related to the liability accounting for the Company's share-based awards discussed below.

Prior to December 5, 2011, due to certain rights to call shares and units in Holdings LLC for cash, Holdings LLC's share-based payments awarded to employees were accounted for as liability awards. As such, Holdings LLC calculated the fair value of the share-based awards on a quarterly basis using estimated market value and the total fair value of the awards was recorded within "Other long-term liabilities" in Holding LLC's consolidated balance sheets. Any change in the fair value of the liability awards was recorded as share-based compensation expense within "General and administrative expense" in Holdings LLC's consolidated statements of operations, which was the same line item as cash compensation paid to the same employees.

Historically, Holdings LLC's determination of the fair value of each of the units was affected by: (i) Holdings LLC's risk adjusted proved, possible, and probable reserves; (ii) internal assessment of long-term commodity prices; (iii) current values of Holdings LLC's non-oil and gas assets and liabilities; and (iv) a number of complex and subjective variables. Although the fair value of the share-based payments is determined in accordance with GAAP, that value may not be indicative of the fair value observed in a market transaction between a willing buyer and a willing seller.

Effective as of November 22, 2011, the Board of Directors of Petroleum Inc. accelerated the vesting of all restricted stock in Petroleum Inc. The vesting resulted in the recognition of previously unrecognized share-based compensation expense at the estimated fair market value of the restricted stock held by employees at November 22, 2011. Petroleum Inc. determined the fair market value of Petroleum Inc.'s common stock based on management's estimates.

On December 5, 2011, Employment Agreements with employees of Midstates Petroleum Company LLC, a Stockholders' Agreement by and among stockholders in Petroleum Inc. and a Unitholders' Agreement by and among the members of Holdings LLC were either terminated or amended such that the rights within those agreements to call shares in Petroleum Inc. and units in Holdings LLC for cash no longer required Holdings LLC's share-based payments awarded to employees to be accounted for as liability awards. As a result the Company transitioned as of December 5, 2011 from liability accounting to equity accounting for the Company's share-based compensation plans and accordingly, the Company no longer recognized changes in the estimated fair value of outstanding share-based awards in the statements of operations.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

10. Equity and Share-Based Compensation (Continued)

Restricted Shares.

Restricted shares in Petroleum Inc. were awarded at no cost to the recipient with a vesting period that commenced on the grant date and terminated on the fifth anniversary or upon certain changes in control of Holdings LLC, including but not limited to mergers, acquisitions, or a public offering.

As a result of the vesting on November 22, 2011, as discussed above, there is no unrecognized compensation cost and as a result of the corporate reorganization in April 2012, each share of Petroleum Inc. was converted into 18,762 shares of the Company's common stock. As a result, there are no outstanding restricted shares in Petroleum Inc. as of December 31, 2013.

Unrestricted Shares and Units.

Unrestricted shares in Petroleum Inc. and units of Holdings LLC were either purchased by the recipient on the grant date and were fully vested upon purchase, or represented restricted shares which vested. For shares of Petroleum Inc. and units of Holdings LLC purchased, any difference between the recipient's purchase price and the grant date fair value was recognized as compensation expense on the grant date. As a result of the corporate reorganization in April 2012, each share of Petroleum, Inc. and each unit of Holdings LLC were converted into 18,762 and 185.5 shares respectively, of the Company's common stock. As a result, at December 31, 2013, there are no Petroleum, Inc. shares or Holdings LLC units outstanding.

Incentive Units.

At December 31, 2013, 1,513 incentive units were issued and outstanding. In connection with the corporate reorganization that occurred immediately prior to our initial public offering, these incentive units held in the Company were contributed to FR Midstates Interholding, LP ("FRMI") in exchange for incentive units in FRMI. Holders of FRMI incentive units will receive, out of proceeds otherwise distributable to FRMI, a percentage interest in the amounts distributed to FRMI in excess of certain multiples of FRMI's aggregate capital contributions and investment expenses ("FRMI Profits"). Although any future payments to the incentive unit holders will be made out of the proceeds otherwise distributable to FRMI and not by the Company, the Company will be required to record a non-cash compensation charge in the period any payment is made related to the FRMI incentive units. To date, no compensation expense related to the incentive units has been recognized by the Company, as any payout under the incentive units is not considered probable, and thus, the amount of FRMI Profits, if any, cannot be determined.

Share-based Compensation, Post-Initial Public Offering

2012 Long Term Incentive Plan.

The Company established the 2012 Long Term Incentive Plan (the "2012 LTIP") and filed a Form S-8 with the SEC, registering 6,563,435 shares for future issuance under the terms of the 2012 LTIP. The 2012 LTIP provides a means for the Company to attract and retain employees, directors and consultants, and a method whereby employees, directors and consultants of the Company who contribute to its success can acquire and maintain stock ownership or awards, the value of which is tied to the performance of the Company, thereby strengthening their concern for the welfare of the Company and their desire to remain employed.

The 2012 LTIP provides for the granting of Options (Incentive and other), Restricted Stock Awards, Restricted Stock Units, Stock Appreciation Rights, Dividend Equivalents, Bonus Stock, Other Stock-Based Awards, Annual Incentive Awards, Performance Awards, or any combination of the

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

10. Equity and Share-Based Compensation (Continued)

foregoing (the "Awards"). Subject to certain limitations as defined in the 2012 LTIP, the terms of each Award are as determined by the Compensation Committee of the Board of Directors. A total of 6,563,435 common share Awards are authorized for issuance under the 2012 LTIP and shares of stock subject to an Award that expire, or are canceled, forfeited, exchanged, settled in cash or otherwise terminated, will again be available for future Awards under the 2012 LTIP.

Non-vested Stock Awards.

Subsequent to the completion of the Company's initial public offering and pursuant to the 2012 LTIP, through December 31, 2013 the Company had 2,963,672 shares of restricted common stock to directors, management and employees outstanding. Shares granted under the LTIP generally vest ratably over a period of three years (one-third on each anniversary of the grant), however, beginning in 2013, shares granted under the 2012 LTIP to directors are subject to one-year cliff vesting.

The fair value of restricted stock grants is based on the value of the Company's common stock on the date of grant. Compensation expense is recognized ratably over the requisite three year service period.

The following table summarizes the Company's non-vested share award activity for the years ended December 31, 2013 and 2012:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2011		**$**
Granted	1,029,509	$ 12.63
Vested		$
Forfeited	(44,151)	$ 12.99
Non-vested shares outstanding at December 31, 2012	**985,358**	**$ 12.61**
Granted	2,840,241	$ 6.82
Vested	(327,720)	$ 12.62
Forfeited	(534,207)	$ 8.65
Non-vested shares outstanding at December 31, 2013	**2,963,672**	**$ 7.78**

Unrecognized expense as of December 31, 2013 for all outstanding restricted stock awards, adjusted for estimated forfeitures, was $16.3 million and will be recognized over a weighted average period of 2.08 years.

At December 31, 2013, 3,272,043 shares remain available for issuance under the terms of the 2012 LTIP.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

10. Equity and Share-Based Compensation (Continued)

The following table summarizes share-based compensation costs (net of amounts capitalized to oil and gas properties) recognized as general and administrative expense by the Company for the periods presented (in thousands):

	For the Years Ended December 31,		
	2013	2012	2011
Restricted and unrestricted Petroleum Inc. shares and Holdings LLC units	$	$	$ 53,744
Incentive units			
2012 LTIP restricted shares	5,713	2,459	
Total share-based compensation expense	**$ 5,713**	**$ 2,459**	**$ 53,744**

For the years ended December 31, 2013 and 2012, the Company capitalized $1.4 million and $0.2 million, respectively, of qualifying share-based compensation costs to oil and gas properties.

11. Income Taxes

Prior to its corporate reorganization (See Note 1), the Company was a limited liability company and not subject to federal income tax or state income tax (in most states). Accordingly, no provision for federal or state income taxes was recorded prior to the corporate reorganization as the Company's equity holders were responsible for income tax on the Company's profits. In connection with the closing of the Company's initial public offering, the Company merged into a corporation and became subject to federal and state income taxes. The Company's book and tax basis in assets and liabilities differed at the time of the corporate reorganization due primarily to different cost recovery methodology utilized for book and tax purposes for the Company's oil and natural gas properties. In the quarter ended June 30, 2012, the Company recorded a one-time charge to income tax expense of $149.5 million to recognize this deferred tax liability related to the Company's change in tax status caused by the initial public offering.

The Company incurred a tax net operating loss ("NOL") in the current year due principally to the ability to expense certain intangible drilling and development costs under current law. There is no tax refund available to the Company, nor is there any current income tax payable. In light of the impairment of oil and gas properties, Management has recorded a $45.7 million valuation allowance against the Company's federal and State of Louisiana NOLs, as management does not believe that it is more-likely-than-not that this portion of the Company's NOLs are realizable. Management believes that the balance of the Company's NOLs are realizable only to the extent of future taxable income primarily related to the excess of book carrying value of properties over their respective tax bases. No other sources of future taxable income are considered in this judgment.

The Company's NOLs were incurred in the tax years 2012 and 2013, and U.S. federal and State of Oklahoma NOLs will generally be available for use through the tax years 2032 and 2033, respectively, and its State of Louisiana NOLs are generally available through 2027 and 2028, respectively. The State of Texas currently has no NOL carryover provision. The Company believes that Section 382 of the Internal Revenue Code of 1986, as amended, which relates to tax attribute limitations upon the 50% or greater change of ownership of an entity during any three-year look back period, will not have an adverse effect on future NOL usage.

On September 13, 2013, the US Treasury and IRS issued final Tangible Property Regulations ("TPR") under IRC Section 162 and IRC Section 263(a). The regulations are not effective until tax

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

11. Income Taxes (Continued)

years beginning on or after January 1, 2014; however, certain portions may require an accounting method change on a retroactive basis, thus requiring a IRC Section 481(a) adjustment related to fixed and real asset deferred taxes. The accounting rules under ASC 740 treat the release of the regulations as a change in tax law as of the date of issuance and require the Company to determine whether there will be an impact on its financial statements for the period ended December 31, 2013. Any such impact of the final tangible property regulations would affect temporary deferred taxes only and result in a balance sheet reclassification within non-current deferred taxes. The Company has analyzed the expected impact of the TPR on the Company and concluded that the expected impact is minimal. The Company will continue to monitor the impact of any future changes to the TPR on the Company prospectively.

As of December 31, 2013, the Company has not recorded a reserve for any uncertain tax positions. No income tax payments are expected in the upcoming four quarterly reporting periods.

	Year Ended December 31,	
	2013	**2012(1)**
Current		
United States	$	$
State		
Total current		
Deferred		
United States	(130,906)	137,496
State	(15,623)	20,390
Total deferred	(146,529)	157,886
Total income tax provision (benefit)	**$ (146,529)**	**$ 157,886**

(1) For the 2011 comparable period, the calculation is not applicable as the Company was not a taxable entity until April 25, 2012.

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements (Continued)

11. Income Taxes (Continued)

The Company's estimated income tax expense differs from the amount derived by applying the statutory federal rate to pretax income principally due the effect of the following items (in thousands):

	Year Ended December 31,	
	2013	**2012(1)**
Income before taxes	$ (490,514)	$ 7,789
Statutory rate	35%	35%
Income tax expense computed at statutory rate	$ (171,680)	$ 2,726
Reconciling items:		
Non-deductible pre-IPO loss		4,561
State income taxes, net of federal tax benefit	(10,886)	1,053
Change in valuation allowance	45,688	
Change in state rate	(10,500)	
Other, net	849	57
Change in tax status(2)		149,489
Tax provision (benefit)	**$ (146,529)**	**$ 157,886**

(1) For the 2011 comparable period, the calculation is not applicable as the Company was not a taxable entity until April 25, 2012.

(2) The change in tax status for the year ended December 31, 2012 is split between federal of $130.2 million and state of $19.3 million.

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for