GOODRICH PETROLEUM CORP
Form 10-K
March 30, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number: 001-12719

GOODRICH PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	76-0466193
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
801 Louisiana, Suite 700 Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(Registrant's telephone number, including area code) (713) 780-9494

Securities Registered Pursuant to Section 12(b) of the Act:

(Title of Each Class)	(Name of Each Exchange)
Common Stock, par value $0.20 per share	OTC Marketplace
Depositary Shares, Each Representing 1/1000 Interest in a Share of 9.75% Series D Cumulative Preferred Stock, par value $1.00 per share	OTC Marketplace
Depositary Shares, Each Representing 1/1000 Interest in a Share of 10.00% Series C Cumulative Preferred Stock, par value $1.00 per share	OTC Marketplace

Securities Registered Pursuant to Section 12(g) of the Act:

5.375% Series B Cumulative Convertible Preferred Stock, par value $1.00 per share

Depositary Shares, Each Representing 1/1000 Interest of 10.00% Series E Cumulative Convertible Preferred Stock, par value $1.00 per share

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

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 ¨ No x

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 x No ¨

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 x No ¨

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 of this Form 10-K or any amendment to this Form 10-K. ¨

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

Large accelerated filer	¨	Accelerated filer	x
Non-accelerated filer	¨	Smaller reporting company	¨

Indicate by check mark whether the Registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ¨ No x

The aggregate market value of Common Stock, par value $0.20 per share, held by non-affiliates (based upon the closing sales price on the New York Stock Exchange on June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter) was approximately $99.2 million. The number of shares of the registrant's common stock outstanding as of March 23, 2016 was 78,063,640.

Documents Incorporated By Reference:

Certain information called for in Items 10, 11, 12, 13 and 14 of Part III is incorporated by reference to the registrant's definitive proxy statement for its annual meeting of stockholders, or will be included in an amendment to this Annual Report on Form 10-K.

GOODRICH PETROLEUM CORPORATION

ANNUAL REPORT ON FORM 10-K

FOR THE FISCAL YEAR ENDED

December 31, 2015

PART I

Items 1. and 2. Business and Properties
General

Goodrich Petroleum Corporation, a Delaware corporation (together with its subsidiary, "we," "our," or "the Company") formed in 1995, is an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas on properties primarily in (i) Southwest Mississippi and Southeast Louisiana which includes the Tuscaloosa Marine Shale Trend ("TMS"), (ii) Northwest Louisiana and East Texas, which includes the Haynesville Shale Trend, and (iii) South Texas, which includes the Eagle Ford Shale Trend. We own interests in 193 producing oil and natural gas wells located in 43 fields in eight states. At December 31, 2015, we had estimated proved reserves of approximately 9.1 MMBoe, comprised of 31.9 Bcf of natural gas and 3.8 MMBbls of oil and condensate.

We operate as one segment as each of our operating areas have similar economic characteristics and each meet the criteria for aggregation as defined by accounting standards related to disclosures about segments of an enterprise.

Liquidity and Ability to Continue as a Going Concern

As discussed under "Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources," continued low oil and natural gas prices during 2015 and into 2016 have had a significant adverse impact on our business, and, as a result of our financial condition, substantial doubt exists that we will be able to continue as a going concern.

As of March 29, 2016, the total outstanding principal amount of our debt obligations was $439.2 million, consisting of the following:

- $40.0 million under the Second Amended and Restated Credit Agreement between us and Wells Fargo and certain lenders dated May 5, 2009, as amended (the "Senior Credit Facility");
- $100.0 million of our 8.0% Second Lien Senior Secured Notes due 2018 (the "8.0% Second Lien Notes");
- $75.0 million of our 8.875% Second Lien Senior Secured Notes due 2018 (the "8.875% Second Lien Notes");
- $116.8 million of our 8.875% Senior Notes due 2019 (the "2019 Notes");
- $0.4 million of our 3.25% Convertible Senior Notes due 2026 (the "2026 Notes");
- $6.7 million of our 5.0% Convertible Senior Notes due 2029 (the "2029 Notes");
- $94.2 million of our 5.0% Convertible Senior Notes due 2032 (the "2032 Notes"); and
- $6.1 million of our 5.0% Convertible Exchange Senior Notes due 2032 (the "2032 Exchange Notes").

In addition, we have outstanding four separate classes of preferred stock with an aggregate liquidation preference of $273.5 million.

As a result of the continued low commodity price environment, our cash flow from operations has substantially declined and the price of our common stock has declined significantly. On January 13, 2016, the New York Stock Exchange (the "NYSE") formally commenced delisting procedures for our common stock due to our abnormally low trading price. On January 21, 2016, the NYSE filed a Form 25 with the Securities and Exchange Commission (the "SEC"), notifying us of the removal of our common stock from listing.

We recently borrowed $10.0 million under the Senior Credit Facility, which represented substantially all of the remaining undrawn amount under the Senior Credit Facility. These funds are intended to be used for general corporate purposes. As a result of existing defaults under the Senior Credit Facility, we are unable to make any further draws on the Senior Credit Facility, unless the defaults are waived by the lenders.

We also recently announced that we were exercising our rights to a grace period with respect to (i) an aggregate $12.5 million in interest payments that were due on March 15, 2016 on our 2019 Notes, 8.0% Second Lien Notes and 8.875% Second Lien Notes and (ii) an aggregate $2.6 million in interest payments that are due on April 1, 2016 on our 2029 Notes, 2032 Notes and 2032 Exchange Notes. These grace periods permit us 30 days to make the interest payments before an event of default occurs under the respective indentures governing the notes. Despite the 30-day grace period and an event of default has not occurred, accounting principles generally accepted in the United States ("US GAAP") requires us to classify amounts outstanding under these notes and the Senior Credit Facility as current liabilities as of December 31, 2015.

The precipitous decline in oil and natural gas prices during 2015 and into 2016 has had a significant adverse impact on our business, and as a result of our financial condition, our registered independent public accountants have issued an opinion with an explanatory paragraph expressing substantial doubt as to our ability to continue as a "going concern." As a result, we are in default under the Senior Credit Facility as of the date hereof. As a result of the default, we are unable to make further draws on the Senior Credit Facility unless the default is waived by the lenders under our Senior Credit Facility. We are currently in discussions with the lenders under our Senior Credit Facility regarding a waiver of this requirement. If we do not obtain a waiver of this requirement within 15 days, an event of default will exist under the Senior Credit Facility and the lenders under the Senior Credit Facility will be able to accelerate the repayment of debt under the Senior Credit Facility. Furthermore, if we are unable to restructure our current obligations under our existing outstanding debt and preferred stock instruments, and address near-term liquidity needs, we may need to seek relief under the U.S. Bankruptcy Code. This relief may include: (i) seeking bankruptcy court approval for the sale or sales of some, most or substantially all of our assets pursuant to section 363(b) of the U.S. Bankruptcy Code and a subsequent liquidation of the remaining assets in the bankruptcy case; (ii) pursuing a plan of reorganization (where votes for the plan may be solicited from certain classes of creditors prior to a bankruptcy filing) that we would seek to confirm (or "cram down") despite any classes of creditors who reject or are deemed to have rejected such plan; or (iii) seeking another form of bankruptcy relief, all of which involve uncertainties, potential delays and litigation risks.

Under certain circumstances, it is also possible that our creditors may file an involuntary petition for bankruptcy against us. Please read "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" for further discussion. Also, for additional discussion of factors that may affect our ability to continue as a going concern and the potential consequences of our failure to do so, please see "Item 1A—Risk Factors."

Available Information

Our principal executive offices are located at 801 Louisiana Street, Suite 700, Houston, Texas 77002.

Our website address is http://www.goodrichpetroleum.com. We make available, free of charge through the Investor Relations portion of our website, our annual reports on Form 10-K, proxy statement, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission ("SEC"). Reports of beneficial ownership filed pursuant to Section 16(a) of the Exchange Act are also available on our website. Information contained on our website is not part of this report.

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the SEC under the Exchange Act. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any documents that we file with the SEC at http://www.sec.gov.

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

As used herein, the following terms have specific meanings as set forth below:

Bbls	Barrels of crude oil or other liquid hydrocarbons
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
Boe	Barrel of crude oil or other liquid hydrocarbons equivalent
MBbls	Thousand barrels of crude oil or other liquid hydrocarbons
Mboe	Thousand barrels of crude oil equivalent
Mcf	Thousand cubic feet of natural gas
Mcfe	Thousand cubic feet equivalent
MMBbls	Million barrels of crude oil or other liquid hydrocarbons
MMBtu	Million British thermal units
Mmcf	Million cubic feet of natural gas
Mmcfe	Million cubic feet equivalent
MMBoe	Million barrels of crude oil or other liquid hydrocarbons equivalent
NGL	Natural gas liquids
U.S.	United States

Crude oil and other liquid hydrocarbons are converted into cubic feet of natural gas equivalent based on six Mcf of natural gas to one barrel of crude oil or other liquid hydrocarbons.

Developed oil and natural gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or through installed extraction equipment and infrastructure operational at the time of the reserves estimates if the extraction is by means not involving a well.

Development well is a well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive.

Dry hole is an exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Economically producible as it relates to a resource, means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil-and-natural gas producing activities.

Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, a service well or a stratigraphic test well.

Farm-in or farm-out is an agreement whereby the owner of a working interest in an oil and natural gas lease or license assigns the working interest or a portion thereof to another party who desires to drill on the leased or licensed acreage. Generally, the assignee is required to drill one or more wells to earn its interest in the acreage. The assignor (the “farmor”) usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a “farm-in”, while the interest transferred by the assignor is a “farm-out”.

Field is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition. The SEC provides a complete definition of field in Rule 4-10 (a) (15).

Gross well or acre is a well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest.

Net well or acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions of whole numbers.

PV-10 is the pre-tax present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying the 12-month average price for the year and holding that price constant throughout the productive life of the reserves (except for consideration of price changes to the extent provided by contractual arrangements), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions). PV-10 is not a financial measure that is in accordance with US GAAP. The SEC methodology for computing the 12-month average price is discussed in the definition of “Proved reserves” below.

Productive well is an exploratory, development or extension well that is not a dry well.

Proved reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. 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. As used in this definition, “existing economic conditions” include prices and costs at which economic producibility from a reservoir is to be determined. The prices shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. The SEC provides a complete definition of proved reserves in Rule 4-10 (a) (22) of Regulation S-X.

Reasonable certainty means a high degree of confidence that the quantities will be recovered, if deterministic methods are used. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease. The deterministic method of estimating reserves or resources uses a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation. The probabilistic method of estimation of reserves or resources uses the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) to generate a full range of possible outcomes and their associated probabilities of occurrence.

Reserves are 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. In addition, there must exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.

Undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can 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 the specific circumstances, justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Working interest is the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover is a series of operations on a producing well to restore or increase production.

Oil and Natural Gas Operations and Properties

Overview. As of December 31, 2015, nearly all of our proved oil and natural gas reserves were located in Louisiana, Texas and Mississippi. We spent substantially all of our 2015 capital expenditures of $85.5 million in these areas, with $73.6 million, or 86%, spent on the TMS, $10.2 million, or 12% spent on the Haynesville Shale Trend and $1.6 million, or 2%, spent on the Eagle Ford Shale Trend. Our total capital expenditures, including accrued costs for services performed during 2015, consisted of $79.8 million for drilling and completion costs, $4.3 million for leasehold acquisitions and extensions and $1.4 million for facilities, infrastructure and equipment.

Beginning in the second half of 2014, commodity prices, particularly oil, began to decline sharply. The decline became precipitous late in the fourth quarter of 2014 and into 2015. The duration and significant magnitude of this price decline has materially and adversely impacted our results of operations and led to substantial changes in our operating and drilling programs for the second half of 2015. As a result, during 2015, we focused on managing our balance sheet to reduce leverage and preserve liquidity during this low commodity price environment.

The table below details our acreage positions, average working interest and producing wells as of December 31, 2015.

Field or Area	Acreage As of December 31, 2015 Gross	Net	Average Producing Well Working Interest		Producing Wells at December 31, 2015
Tuscaloosa Marine Shale Trend	358,527	271,985	65	%	44
Haynesville Shale Trend	54,869	26,581	37	%	93
Eagle Ford Shale Trend	36,209	16,668	—	%	—
Other	33,125	11,679	39	%	56

Tuscaloosa Marine Shale Trend

As of December 31, 2015, we have acquired approximately 359,000 gross (272,000 net) lease acres in the TMS, an emerging oil shale play in Southwest Mississippi and Southeast Louisiana. During 2015, we conducted drilling operations on 5 gross (3.9 net) wells and added 7 gross (5.7 net) wells to production in the TMS.

Haynesville Shale Trend

As of December 31, 2015, we have acquired or farmed-in leases totaling approximately 55,000 gross (27,000 net) acres in the Haynesville Shale. During 2015, we added 1 gross (1 net) well to production in the Angelina River Trend portion of our acreage position. Our Haynesville Shale Trend drilling activities are located in leasehold areas in East Texas and Northwest Louisiana.

Eagle Ford Shale Trend

As of December 31, 2015, we have acquired or farmed-in leases totaling approximately 36,000 gross (17,000 net) lease acres. As part of our efforts in 2015 to reduce leverage and preserve liquidity, we sold all of our proved reserves in the Eagle Ford Shale Trend and a portion of the associated leasehold. We retained 17,000 net acres of undeveloped acreage in the Eagle Ford Shale Trend. We closed the Eagle Ford Shale Trend sale on September 4, 2015.

Other

As of December 31, 2015, we maintained ownership interests in acreage and/or wells in several additional fields, including the Longwood field in Caddo Parish, Louisiana and the Garfield Unit in Kalkaska County, Michigan.

See “Item 7—Management’s Discussion and Analysis of Financial Condition and Results of Operations” in this Annual Report on Form 10-K for additional information on our recent operations in the TMS, Haynesville Shale Trend and Eagle Ford Shale Trend.

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Oil and Natural Gas Reserves

The following tables set forth summary information with respect to our proved reserves as of December 31, 2015 and 2014, as estimated by Netherland, Sewell & Associates, Inc. ("NSAI") and by Ryder Scott Company ("RSC") our independent reserve engineers. Approximately 58% and 42% of the proved reserves estimates shown herein at December 31, 2015 have been independently prepared by NSAI and RSC, respectively. NSAI prepared the estimates on all our proved reserves as of December 31, 2015 on properties other than those located in the TMS. RSC prepared the estimate of proved reserves as of December 31, 2015 for our TMS properties. Copies of the summary reserve reports of NSAI and RSC as of December 31, 2015 are included as exhibits to this Annual Report on Form 10-K. For additional information see Supplemental Information "Oil and Natural Gas Producing Activities (Unaudited)" to our consolidated financial statements in "Item 8—Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Proved undeveloped reserves were not included in our December 31, 2015 reserve estimates as the sustained decline in oil and natural gas prices has raised substantial doubt about our ability to continue as a going concern and our ability to adequately finance the development of proved undeveloped reserves in the future.

	Proved Reserves at December 31, 2015			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls) (1)	3,184	650	—	3,834
Natural Gas (Mmcf)	29,633	2,218	—	31,851
Barrel of Oil Equivalent (MBoe) (2)	8,122	1,020	—	9,142
Estimated Future Net Cash Flows				$94,811
PV-10 (3)				$69,895
Discounted Future Income Taxes				(—)
Standardized Measure of Discounted Net Cash Flows (3)				$69,895

	Proved Reserves at December 31, 2014			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls) (1)	9,457	634	16,977	27,068
NGL (MBbls) (4) (5)	624	4	447	1,075
Natural Gas (Mmcf)	58,111	2,597	44,124	104,832
Barrel of Oil Equivalent (MBoe) (2)	19,766	1,071	24,778	45,615
Estimated Future Net Cash Flows				$1,328,750
PV-10 (3)				$650,584
Discounted Future Income Taxes				(5,848)
Standardized Measure of Discounted Net Cash Flows (3)				$644,736

(1) Includes condensate.
(2) Based on ratio of six Mcf of natural gas per Bbl of oil and per Bbl of NGLs.
(3) PV-10 represents the discounted future net cash flows attributable to our proved oil and natural gas reserves before income tax, discounted at 10%. PV-10 of our total year-end proved reserves is considered a non-US GAAP financial measure as defined by the SEC. We believe that the presentation of the PV-10 is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. We further believe investors and creditors use our PV-10 as a basis for comparison of the relative size and value of our reserves to other companies. See the reconciliation of our PV-10 to the standardized measure of discounted future net cash flows in the table above.
(4) NGL reserves for 2014 included TMS and Eagle Ford Shale Trend fields, with 99% of the NGL reserves coming from our Eagle Ford Shale Trend.

(5) Our production and sales volumes are accounted for and disclosed based on the wet gas stream at the point of sale. We report no NGL production, as NGLs are processed after the point of sale. However, we share and receive the pricing benefit of the revenue stream of the gas through the processing. We believe that presenting NGLs separately from natural gas and oil in our reserve report provides more information for our investors. The presentation of NGLs as a separate commodity more accurately presents to investors our economic interest in those NGLs separated, produced and sold from the wet gas streams (which we realize through our sharing in the revenue stream attributable to the processed NGLs). These commodities have separate pricing that is monitored in the marketplace.

The following table presents our reserves by targeted geologic formation in MBoe.

	December 31, 2015			
Area	Proved Developed	Proved Undeveloped	Proved Reserves	% of Total
Tuscaloosa Marine Shale Trend	3,820	—	3,820	42 %
Haynesville Shale Trend	5,259	—	5,259	57 %
Other	63	—	63	1 %
Total	9,142	—	9,142	100 %

Reserve engineering is a subjective process of estimating underground accumulations of crude oil, condensate and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may differ from those assumed in these estimates. Therefore, the PV-10 amounts shown above should not be construed as the current market value of the oil and natural gas reserves attributable to our properties.

In accordance with the guidelines of the SEC, our independent reserve engineers' estimates of future net revenues from our estimated proved reserves, and the PV-10 and standardized measure thereof, were determined to be economically producible under existing economic conditions, which requires the use of the 12-month average price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price for the period of January 2015 through December 2015, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For reserves at December 31, 2015, the average twelve month prices used were $2.58 per MMBtu of natural gas and $50.28 per Bbl of crude. These prices do not include the impact of hedging transactions, nor do they include the adjustments that are made for applicable transportation and quality differentials, and price differentials between natural gas liquids and oil, which are deducted from or added to the index prices on a well by well basis in estimating our proved reserves and related future net revenues.

Our proved reserve information as of December 31, 2015 included in this Annual Report on Form 10-K was estimated by our independent petroleum engineers, NSAI and RSC, in accordance with petroleum engineering and evaluation principles and definitions and guidelines set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Natural Gas Reserve Information promulgated by the Society of Petroleum Engineers. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Natural Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our principal engineer has over 30 years of experience in the oil and natural gas industry, including over 25 years as a reserve evaluator, trainer or manager. Further professional qualifications of our principal engineer include a degree in petroleum engineering, extensive internal and external reserve training, and experience in asset evaluation and management. In addition, the principal engineer is an active participant in professional industry groups and has been a member of the Society of Petroleum Engineers for over 30 years.

Our estimates of proved reserves are made by NSAI and RSC, as our independent petroleum engineers. Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria is provided to them. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

We consider providing independent fully engineered third-party estimates of reserves from nationally reputable petroleum engineering firms, such as NSAI and RSC, to be the best control in ensuring compliance with Rule 4-10 of Regulation S-X for reserve estimates.

While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a preliminary copy of the NSAI and RSC reserve reports are reviewed by our senior management with representatives of NSAI and RSC and our internal technical staff. Additionally, our senior management reviews and approves any internally estimated significant changes to our proved reserves semi-annually.

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. To achieve reasonable certainty, NSAI and RSC 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, well logs, geologic maps, available downhole and production data, seismic data and well test data.

Our total proved reserves at December 31, 2015, as estimated by NSAI and RSC, were 9.1 MMBoe, consisting of 31.9 Bcf of natural gas and 3.8 MMBbls of oil and condensate. In 2015 we added approximately 2.3 MMBoe related to our drilling activities in the TMS and Haynesville Shale Trend. We had negative revisions of approximately 26.1 MMBoe, divestitures of 9.9 MMBoe and produced 2.7 MMBoe in 2015. The vast majority of our negative revisions related to the removal of 24.8 MMBoe of proved undeveloped reserves out of the proved category.

We did not report any proved undeveloped reserves at December 31, 2015. We had negative revisions of 24.8 MMBoe and we did not develop any of our total proved undeveloped reserves booked as of December 31, 2014.

Productive Wells

The following table sets forth the number of productive wells in which we maintain ownership interests as of December 31, 2015:

	Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Tuscaloosa Marine Shale Trend:						
Southeast Louisiana	20	14	—	—	20	14
Southwest Mississippi	24	15	—	—	24	15
Haynesville Shale Trend:						
East Texas	—	—	8	6	8	6
Northwest Louisiana	—	—	85	28	85	28
Other	10	1	46	20	56	21
Total Productive Wells	54	30	139	54	193	84

(1) Royalty and overriding interest wells that have immaterial values are excluded from the above table. As of December 31, 2015, only three wells with royalty-only and overriding interests-only are included.
(2) Net working interest.

Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline connections. A gross well is a well in which we maintain an ownership interest, while a net well is deemed to exist when the sum of the fractional working interests owned by us equals one. Wells that are completed in more than one producing horizon are counted as one well. Of the gross wells reported above, four wells had completions in multiple producing horizons.

Acreage

The following table summarizes our gross and net developed and undeveloped acreage under lease as of December 31, 2015. Acreage in which our interest is limited to a royalty or overriding royalty interest is excluded from the table.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Tuscaloosa Marine Shale Trend:						
Southwest Mississippi	22,223	16,075	86,613	59,528	108,836	75,603
Southeast Louisiana	28,509	19,177	221,182	177,205	249,691	196,382
Haynesville Shale Trend:						
East Texas	12,950	7,334	4,125	3,552	17,075	10,886
Northwest Louisiana	37,794	15,695	—	—	37,794	15,695
Eagle Ford Shale Trend:						
South Texas	—	—	36,209	16,668	36,209	16,668
Other	28,488	10,992	4,637	687	33,125	11,679
Total	129,964	69,273	352,766	257,640	482,730	326,913

Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to the extent that would permit the production of commercial quantities of oil or natural gas, regardless of whether or not such acreage contains proved reserves. As is customary in the oil and natural gas industry, we can retain our interest in undeveloped acreage by drilling activity that establishes commercial production sufficient to maintain the leases or by payment of delay rentals during the remaining primary term of such a lease. The oil and natural gas leases in which we have an interest are for varying primary terms; however, most of our developed lease acreage is beyond the primary term and is held so long as oil or natural gas is produced.

Lease Expirations

We have undeveloped lease acreage, excluding optioned acreage, that will expire during the next four years, unless the leases are converted into producing units or extended prior to lease expiration. All costs related to the leased acreage below have been written-off as of December 31, 2015. The following table sets forth the lease expirations as of December 31, 2015:

Year	Net Acreage
2016	113,320
2017	38,924
2018	18,108
2019	826

Operator Activities

We operate a majority of our producing properties by value, and will generally seek to become the operator of record on properties we drill or acquire. Chesapeake Energy Corporation ("Chesapeake") continues to operate our jointly owned Northwest Louisiana acreage in the Haynesville Shale.

Drilling Activities

The following table sets forth our drilling activities for the last three years. As denoted in the following table, “gross” wells refer to wells in which a working interest is owned, while a “net” well is deemed to exist when the sum of the fractional working interests we own in gross wells equals one.

	Year Ended December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	8	6.7	19	13.0	14	9.3
Non-Productive	—	—	—	—	—	—
Total	8	6.7	19	13.0	14	9.3
Exploratory Wells:						
Productive	—	—	4	3.2	8	4.1
Non-Productive	—	—	—	—	—	—
Total	—	—	4	3.2	8	4.1
Total Wells:						
Productive	8	6.7	23	16.2	22	13.4
Non-Productive	—	—	—	—	—	—
Total	8	6.7	23	16.2	22	13.4

At December 31, 2015, we had 2 gross (1.7 net) development wells waiting to be completed.

Net Production, Unit Prices and Costs

The following table presents certain information with respect to oil and natural gas production attributable to our interests in all of our properties (including two fields which have attributed more than 15% of our total proved reserves as of December 31, 2015), the revenue derived from the sale of such production, average sales prices received and average production costs during each of the years in the three-year period ended December 31, 2015. See “Item 6—Selected Financial Data” and “Item 8—Financial Statements and Supplementary Data” of this Form 10-K for disclosure of revenues, profits and total assets for the years ended December 31, 2015, 2014 and 2013.

	Sales Volumes			Average Sales Prices (1)				Average
	Natural Gas Mmcf	Oil & Condensate MBbls	Total Boe	Natural Gas Mcf	Oil & Condensate Per Bbl	Total Per Boe	% of Total Revenue	Production Cost (2) Per Boe
For Year 2015:								
TMS	—	883	883	$—	$ 49.60	$49.60	55 %	$ 8.14
Haynesville Shale Trend	7,018	—	1,170	1.67	—	10.05	15 %	2.33
Eagle Ford Shale Trend (3)	776	453	584	2.39	46.30	39.21	29 %	8.23
Other	190	—	30	3.58	—	21.47	1 %	27.30

Total	7,984	1,336	2,667	$1.79	$ 48.50	$29.65	100	%	$ 5.82
For Year 2014:									
TMS	—	738	738	$—	$ 90.55	$90.55	32	%	$ 6.41
Haynesville Shale Trend	10,176	1	1,697	3.08	86.36	18.48	15	%	2.62
Eagle Ford Shale Trend (3)	1,321	928	1,148	5.70	89.69	79.86	44	%	9.71
Other	3,483	25	606	5.01	90.83	34.32	9	%	15.00
Total	14,980	1,692	4,189	$3.75	$ 90.08	$49.79	100	%	$ 7.05
For Year 2013:									
TMS	—	165	165	$—	$ 105.29	$105.29	9	%	$ 6.12
Haynesville Shale Trend	14,406	1	2,401	3.00	100.05	18.06	22	%	2.40
Eagle Ford Shale Trend (3)	1,129	1,132	1,320	5.66	101.56	91.92	61	%	9.66
Other	4,225	40	745	3.44	98.26	22.20	8	%	6.42
Total	19,760	1,338	4,631	$3.35	$ 101.96	$43.74	100	%	$ 5.88

(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem and severance taxes.
(3) We sold our Eagle Ford Shale Trend proved reserves and a portion of the associated leasehold on September 4, 2015.

Oil and Natural Gas Marketing and Major Customers

Marketing. Our natural gas production is sold under spot or market-sensitive contracts to various natural gas purchasers on short-term contracts. Our oil production is sold to various purchasers under short-term rollover agreements based on current market prices.

Customers. Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. The revenues compared to our total oil and natural gas revenues from the top purchasers for the years ended December 31, 2015, 2014 and 2013 are as follows:

	Year Ended December 31,		
	2015	2014	2013
BP Energy Company	31%	46 %	64 %
Genesis Crude Oil LP	26%	11 %	7 %
Sunoco, Inc.	17%	5 %	—

Competition

The oil and natural gas industry is highly competitive. Major and independent oil and natural gas companies, drilling and production acquisition programs and individual producers and operators are active bidders for desirable oil and natural gas properties, as well as the equipment and labor required to operate those properties. Many competitors have financial resources substantially greater than ours, and staffs and facilities substantially larger than us.

Employees

At March 23, 2016, we had 51 full-time employees in our Houston administrative office and our one field office, none of whom is represented by any labor union. We regularly use the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well-site supervision, permitting and environmental assessment. Independent contractors usually perform field and on-site production operation services for us, including gauging, maintenance, dispatching, inspection, and well testing.

Regulations

The availability of a ready market for any oil and natural gas production depends upon numerous factors beyond our control. These factors include regulation of oil and natural gas production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be “shut-in” because of an oversupply of natural gas or the lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment.

Environmental and Occupational Health and Safety Matters

General

Our operations are subject to stringent and complex federal, regional, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. Compliance with these laws and regulations may require the acquisition of permits before drilling or other related activity commences, restrict the type, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling and production activities on certain lands lying within wilderness, wetlands and other protected areas, impose specific health and safety criteria addressing worker protection, and impose substantial liabilities for pollution arising from drilling and production operations. Environmental laws and regulations also impose certain plugging and abandonment and site reclamation requirements. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that may limit or prohibit some or all of our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, the trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and, any changes in environmental laws and regulations that result in more stringent and costly well construction, drilling, waste management or completion activities or waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our business. While we believe that we are in substantial compliance with current applicable federal and state environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations or financial condition, there is no assurance that we will be able to remain in compliance in the future with such existing or any new laws and regulations or that such future compliance will not have a material adverse effect on our business and operating results. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future.

The following is a summary of the more significant existing environmental laws to which our business operations are subject and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

Hazardous Substances and Wastes

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended (“CERCLA”), also known as the “Superfund” law and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred, and companies that disposed or arranged for the disposal of hazardous substances released at the site. Under CERCLA, these persons may be subject to joint and several, strict liabilities for remediation cost at the site, natural resource damages and for the costs of certain health studies. Additionally, it is not uncommon for neighboring landowners and other third parties to file tort claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. We generate materials in the course of our operations that are regulated as hazardous substances.

We also may incur liability under the Resource Conservation and Recovery Act, as amended (“RCRA”), and comparable state statutes that impose stringent requirements related to the handling and disposal of non-hazardous and hazardous wastes. Wastes, including drilling fluids and produced water, generated in the exploration or production of oil and natural gas are exempt from classification as hazardous wastes under RCRA. Proposals have been made from time to time to eliminate this exemption, which, if adopted, would cause some of these wastes to be regulated under the more rigorous RCRA hazardous waste standards. A loss of this RCRA exemption could result in increased costs to us and the oil and gas industry in general to manage and dispose of generated wastes. Moreover, some ordinary industrial wastes which we generate, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous wastes if they have hazardous characteristics.

We currently own or lease, and in the past have owned or leased, properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes and petroleum hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties whose treatment and disposal of hazardous substances, wastes and petroleum hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to undertake costly site investigations, remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges and Subsurface Injections

The Federal Water Pollution Control Act, as amended, (“Clean Water Act”), and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into state and federal waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the U.S. Environmental Protection Agency (“EPA”) or an analogous state agency. Spill prevention, control and countermeasure (“SPCC”) plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. In September 2015, new EPA and U.S. Army Corps of Engineers (the “Corps”) rules defining the scope of the EPA’s and the Corps’ jurisdiction became effective. To the extent the rule expands the scope of the CWA’s jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of CWA programs, and implementation of the rule has been stayed pending resolution of the court challenge. The process for obtaining permits has the potential to delay the development of natural gas and oil projects. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In addition, the Oil Pollution Act of 1990, as amended ("OPA"), imposes a variety of requirements related to the prevention of oil spills into navigable waters as well as liabilities for oil cleanup costs, natural resource damages and a variety of public and private damages that may result from such oil spills.

The disposal of oil and natural gas wastes into underground injection wells are subject to the federal Safe Drinking Water Act, as amended ("SDWA"), and analogous state laws. The SDWA's Underground Injection Control Program establishes requirements for permitting, testing, monitoring, recordkeeping and reporting of injection well activities as well as a prohibition against the migration of fluid containing any contaminants into underground sources of drinking water. State programs may have analogous permitting and operational requirements. In response to concerns related to increased seismic activity in the vicinity of injection wells, regulators in some states are considering additional requirements related to seismic safety. For example, the Texas Railroad Commission ("RRC") adopted new oil and gas permit rules in October 2014 for wells used to dispose of saltwater and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to conduct continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position. In addition, any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for property damages and personal injury.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing. For example, the EPA has taken the following actions and issued: guidance under the SDWA for hydraulic fracturing activities involving the use of diesel fuel; final regulations under the federal Clean Air Act governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; an advanced notice of proposed rulemaking in March 2014 under the Toxic Substances Control Act that would require companies to disclose information regarding the chemicals used in hydraulic fracturing; and proposed rules in April 2015 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision has not yet been issued.

Various state and federal agencies are studying the potential environmental impacts of hydraulic fracturing. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and, in June 2015, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources, which concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. The draft report is expected to be finalized after a public comment period and a formal review by the EPA's Science Advisory Board. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These or future studies could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Louisiana and Texas, 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. Moreover, some states and local governments have enacted laws or regulations limiting hydraulic fracturing within their borders or prohibiting the activity altogether. In the event that 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.

Air Emissions

The CAA and comparable state laws, regulate emissions of various air pollutants from many sources in the United States, including crude oil and natural gas production activities through air emissions standards, construction and operating programs and the imposition of other compliance requirements. These laws and any implementing 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. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations. 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 October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, in 2012, the EPA issued federal regulations requiring the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. Compliance with these requirements could increase our costs of development and production significantly.

Climate Change

Certain scientific studies have found that emissions of carbon dioxide, methane and other "greenhouse gases" are contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA determined that greenhouse gases present an endangerment to public health and the environment and has issued regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from a variety of sources in the United States, including certain onshore oil and natural gas production facilities, on an annual basis. More recently, in December 2015, the EPA finalized rules that added new sources to the scope of the GHG monitoring and reporting rule. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. These changes to EPA's GHG emissions reporting rule could result in increased compliance costs. Also, in August 2015, the EPA announced proposed rules that would establish new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities, as part of an overall effort to reduce methane emissions by up to 45 percent by 2025. These new and proposed rules could result in increased compliance costs for our business.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through regional greenhouse gas cap and trade programs. The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases 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 greenhouse gases 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 greenhouse gases 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. Such climatic events could have an adverse effect on our financial condition and results of operations.

Endangered Species

The Federal Endangered Species Act, as amended (“ESA”), and analogous state laws restrict activities that could have an adverse effect on threatened or endangered species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Some of our operations may be located in or near areas that are designated as habitat for endangered or threatened species. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. Moreover, as a result of a court settlement the U.S. Fish and Wildlife Service is required to make a determination on listing of numerous species as endangered or threatened under the ESA before the completion of the agency's 2017 fiscal year. The presence of protected species or the designation of previously unidentified endangered or threatened species could impair our ability to timely complete well drilling and development and could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee Health and Safety

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended, ("OSHA"), and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act, as amended, and implementing regulations and similar state statutes and regulations require that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local governmental authorities and citizens.

Other Laws and Regulations

State statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. In addition, there are state statutes, rules and regulations governing conservation matters, including the unitization or pooling of oil and natural gas properties, establishment of maximum rates of production from oil and natural gas wells and the spacing, plugging and abandonment of such wells. Such statutes and regulations may limit the rate at which oil and natural gas could otherwise be produced from our properties and may restrict the number of wells that may be drilled on a particular lease or in a particular field.

Item 1A. Risk Factors

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

The Company has made in this report, and may from time to time otherwise make in other public filings, press releases and discussions with Company management, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended concerning the Company's operations, economic performance and financial condition. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and natural gas properties, marketing and midstream activities, and also include those statements accompanied by or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends,' "estimates," "projects," "predicts," "target," "goal," "plans," "objective," "potential," "should," or similar expressions or variat such expressions that convey the uncertainty of future events or outcomes. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. The Company has based these forward-looking statements on its current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by the Company in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate under the circumstances. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made; the Company undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, the following risk and uncertainties:

- the market prices of oil and natural gas;
- failure to consummate the Recapitalization Plan (as described in Part II below) or otherwise address our near-term liquidity needs, at which time we may not be able to make our interest payments on our unsecured notes and second lien notes beginning in March 2016 and are likely to need to seek protection under chapter 11 of the U.S. Bankruptcy Code;
- our ability to comply with the financial covenants in our debt instruments and our available liquidity even if the Recapitalization Plan is successfully implemented, particularly if oil and natural gas prices remain depressed;
- volatility in the commodity-futures market;
- financial market conditions and availability of capital;

- future cash flows, credit availability and borrowings;
- sources of funding for exploration and development;
- our financial condition;
- our ability to repay our debt;
- the securities, capital or credit markets;
- planned capital expenditures;
- future drilling activity;
- uncertainties about the estimated quantities of our oil and natural gas reserves;
- production;
- hedging arrangements;
- litigation matters;
- pursuit of potential future acquisition opportunities;
- general economic conditions, either nationally or in the jurisdictions in which we are doing business;
- legislative or regulatory changes, including retroactive royalty or production tax regimes, hydraulic-fracturing regulation, drilling and permitting regulations, derivatives reform, changes in state and federal corporate taxes, environmental regulation, environmental risks and liability under federal, state and foreign and local environmental laws and regulations;
- the creditworthiness of our financial counterparties and operation partners; and
- other factors discussed below and elsewhere in this Annual Report on Form 10-K and in our other public filings, press releases and discussions with our management.

Oil prices and natural gas prices have declined substantially from historical highs and may remain depressed for the foreseeable future. Oil and natural gas prices are volatile; a sustained decrease in the price of oil or natural gas would adversely impact our business.

Our success depends on the market prices of oil and natural gas. These market prices tend to fluctuate significantly in response to factors beyond our control. The prices we receive for our crude oil production are based on global market conditions. The general pace of global economic growth, the continued instability in the Middle East and other oil and natural gas producing regions and actions of the Organization of Petroleum Exporting Countries, as well as other economic, political, and environmental factors will continue to affect world supply and prices. Domestic natural gas prices fluctuate significantly in response to numerous factors including U.S. economic conditions, weather patterns, other factors affecting demand such as substitute fuels, the impact of drilling levels on crude oil and natural gas supply, and the environmental and access issues that limit future drilling activities for the industry.

Natural gas and crude oil prices are extremely volatile. High and low spot prices for New York Mercantile Exchange (“NYMEX”) West Texas Intermediate crude oil and NYMEX Henry Hub natural gas between February 2015 and the date of this annual report were as follows:

	2015 - 2016	
	High	Low
West Texas Intermediate crude oil price range per barrel	$61.36	$26.19

Henry Hub natural gas price range per MMBtu	3.27	1.49

Average oil and natural gas prices varied substantially during the past few years. Any actual or anticipated reduction in natural gas and crude oil prices may further depress the level of exploration, drilling and production activity. We expect that commodity prices will continue to fluctuate significantly in the future.

Changes in commodity prices significantly affect our capital resources, liquidity and expected operating results. These lower prices, coupled with the slow recovery in financial markets that has significantly limited and increased the cost of capital, have compelled most oil and natural gas producers, including us, to reduce the level of exploration, drilling and production activity. This will have a significant effect on our capital resources, liquidity and expected operating results. Any sustained reductions in oil and natural gas prices will directly affect our revenues and can indirectly impact expected production by changing the amount of funds available to us to reinvest in exploration and development activities. Further reductions in oil and natural gas prices could also reduce the quantities of reserves that are commercially recoverable. A reduction in our reserves could have other adverse consequences including a possible downward redetermination of the availability of borrowings under the Senior Credit Facility, which would restrict our liquidity. Additionally, further or continued declines in prices could result in additional non-cash charges to earnings due to impairment write-downs. Any such write down could have a material adverse effect on our results of operations in the period taken.

Our future revenues are dependent on the ability to successfully complete drilling activity.

Drilling and exploration are the main methods we utilize to replace our reserves. However, drilling and exploration operations may not result in any increases in reserves for various reasons. Exploration activities involve numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- reductions in oil and natural gas prices;
- inadequate capital resources;
- limitations in the market for oil and natural gas;
- lack of acceptable prospective acreage;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- unavailability or high cost of drilling rigs, equipment or labor;
- title problems;
- compliance with governmental regulations;
- mechanical difficulties; and
- risks associated with horizontal drilling.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain.

In addition, while lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically, higher oil and natural gas prices generally increase the demand for drilling rigs, equipment and crews and can lead to shortages of, and increased costs for, such drilling equipment, services and personnel. Such shortages could restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could adversely affect our ability to increase our reserves and production and reduce our revenues.

A sustained depression of oil and natural gas prices can continue to affect our ability to obtain funding, obtain funding on acceptable terms or obtain funding under our current credit facility. This may hinder or prevent us from meeting our future capital needs.

The current low commodity price environment has had a significant, adverse impact on us. As of December 31, 2015, we had $470.6 million in indebtedness and declining cash flows from operations due to the decline in oil and natural gas prices and the roll off of our crude oil hedging arrangements. Our ability to service our debt, including the unsecured notes and second lien notes, and fund our operations is at risk in a sustained continuation of the current commodity price environment. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. If funding is not available as needed, or is available only on more expensive or otherwise unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations.

Due to our substantial liquidity concerns, we may be unable to continue as a going concern.

Our existing and future debt agreements could create issues as interest payments become due and the debt matures that will threaten our ability to continue as a going concern. For example, absent any action with respect to the repayment or refinancing of our existing indebtedness or any waivers or amendments to the agreements governing our existing indebtedness, our Senior Credit Facility will mature on February 24, 2017. As of the date of this filing, total lender commitments under our Senior Credit Facility are $40.3 million on which we had $27.0 million drawn on December 31, 2015 under the Senior Credit Facility. Additionally, the borrowing base under our Senior Credit Facility is subject to at least semi-annual redetermination on April 1 and October 1, and as a result, availability thereunder, could be reduced and advances in excess of the new availability would need to be repaid. The next semi-annual redetermination of the borrowing base is scheduled for April 1, 2016. We also have substantial interest payments due on our unsecured notes and second lien notes beginning in March 2016. If we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in the debt agreements governing our indebtedness, an event of default could result, which would permit acceleration of such debt and which could result in an event of default under and an acceleration of our other debt and would permit our secured lenders to foreclose on any of our assets securing such debt. Any accelerated debt would become immediately due and payable. While we will attempt to take appropriate mitigating actions to refinance any indebtedness prior to its maturity or otherwise extend the maturity dates, and to cure any potential defaults, there is no assurance that any particular actions with respect to refinancing existing indebtedness, extending the maturity of existing indebtedness or curing potential defaults in our existing and future debt agreements will be sufficient. The uncertainty associated with our ability to repay our outstanding debt obligations as they become due raises substantial doubt about our ability to continue as a going concern.

The report of our independent registered public accounting firm that accompanies our audited consolidated financial statements for the year ended December 31, 2015 contains an explanatory paragraph regarding the substantial doubt about our ability to continue as a going concern. As a result, we are in default under our Senior Credit Facility.

Our Senior Credit Facility requires that our annual financial statements include a report from our independent registered public accounting firm with an unqualified opinion without an explanatory paragraph as to going concern. The report of our independent registered public accounting firm that accompanies our audited consolidated financial statements for the year ended December 31, 2015 contains an explanatory paragraph regarding the substantial doubt about our ability to continue as a going concern. Per the terms of our agreement, we are in default under our Senior Credit Facility. As a result of the default, we are unable to make further draws on the Senior Credit Facility unless the default is waived by the lenders under our Senior Credit Facility. We are currently in discussions with the lenders under our Senior Credit Facility regarding a waiver of this requirement. If we do not obtain a waiver of this requirement within 15 days, an event of default will exist under the Senior Credit Facility and the lenders under the Senior Credit Facility will be able to accelerate the repayment of debt under the Senior Credit Facility. Any acceleration of our debt obligations under the Senior Credit Facility would result in a potential foreclosure on the collateral securing the Senior Credit Facility and would trigger cross-default provisions under our other financing agreements.

If we are unable to complete the Recapitalization Plan and address our near-term liquidity needs, we may not be able to make our interest payments on our unsecured notes and second lien notes, at which time we are likely to need to seek relief under the U.S. Bankruptcy Code. If we seek bankruptcy relief, we expect that our common stockholders, preferred stockholders and general unsecured creditors would likely receive little or no consideration for their securities.

We believe that the substantial reduction in our cash interest expense contemplated by the Recapitalization Plan is critical to our continuing viability. We were not able to make our interest payments on our unsecured notes and second lien notes on March 15, 2016 and elected to exercise our right to a 30-day grace period for the interest payments due on both March 15, 2016 and April 1, 2016. If we are unable to complete the Recapitalization Plan and address our near-term liquidity needs, we will likely not be able to make these interest payments and we are likely to need to seek relief under the U.S. Bankruptcy Code. A chapter 11 case would have a significant impact on our business. It is impossible for us to predict with certainty the amount of time needed in order to complete an in-court restructuring. If we seek to implement a plan of reorganization under the U.S. Bankruptcy Code, we will need to negotiate agreements with our constituent parties regarding the terms of such plan and such negotiations could take a significant amount of time. A lengthy chapter 11 case would involve significant additional professional fees and expenses and divert the attention of management from operation of the business, as well as create concerns for customers, employees and vendors. There is a risk, due to uncertainty about the future, that (i) employees could be distracted from performance of their duties or attracted to other career opportunities; (ii) our ability to enter into new contracts or to renew existing contracts and compete for new business may be adversely affected; and (iii) we may not be able to obtain the necessary financing to sustain us during the chapter 11 case.

In addition, to successfully complete a restructuring under the U.S. Bankruptcy Code, we would require debtor-in-possession financing, the most likely source of which would be our existing lenders. If we were unable to obtain financing in a bankruptcy case or any such financing was insufficient to fund operations pending the completion of a restructuring, there would be substantial doubt that we could complete a restructuring.

Furthermore, assuming we are able to develop a plan of reorganization, we may not receive the requisite acceptances to confirm such a plan and, even if the requisite acceptances of the plan are received, the Bankruptcy Court may not confirm the plan. If we are unable to develop a plan of reorganization that can be accepted and confirmed, or if the Bankruptcy Court otherwise finds that it would be in the best interest of creditors, or if we are unable to obtain appropriate financing, our chapter 11 case may be converted to a case under chapter 7 of the U. S. Bankruptcy Code, pursuant to which a trustee would be appointed or elected to liquidate our assets for distribution in accordance with the priorities established by the U.S. Bankruptcy Code.

As a result of the foregoing, if we seek bankruptcy relief, we expect that holders of our common stock, preferred stock and unsecured senior notes would likely receive little or no consideration for their securities. In particular, we believe that liquidation under chapter 7 of the U.S. Bankruptcy Code would likely result in no distributions being made to our shareholders or to our general unsecured creditors.

Even if we are able to complete the Recapitalization Plan, we may still be unsuccessful in our operating plan, particularly if oil and natural gas prices do not recover. If we are not successful in executing our current plan for operations, we may need to seek relief under the U.S. Bankruptcy Code notwithstanding the success of the Recapitalization Plan. If we seek bankruptcy relief, we expect that holders of our common stock, preferred stock and any unsecured notes that remain outstanding would likely receive little or no consideration.

Even if the Recapitalization Plan is successful, but oil and natural gas prices do not recover or if we are not able to execute our current plan for operations, then we may need to seek relief under the U.S. Bankruptcy Code notwithstanding the completion of the Recapitalization Plan. If we were to seek relief under the U.S. Bankruptcy Code notwithstanding the completion of the Recapitalization Plan, we expect that the holders of our shares of our common stock and any unsecured notes or preferred stock remaining outstanding after the Exchange Offers would likely receive little or no consideration for their securities.

Our substantial indebtedness, liquidity issues and the potential for restructuring transactions, including the Recapitalization Plan, may impact our business, financial condition and operations.

Due to our substantial indebtedness, liquidity issues and the potential for restructuring transactions, including the Recapitalization Plan, there is risk that, among other things:

- third parties' confidence in our ability to explore and produce oil and natural gas could erode, which could impact our ability to execute on our business strategy;

- it may become more difficult to retain, attract or replace key employees;
- employees could be distracted from performance of their duties or attracted to other career opportunities; and
- our suppliers, hedge counterparties, vendors and service providers could renegotiate the terms of our arrangements, terminate their relationship with us or require financial assurances from us.

The occurrence of certain of these events has already negatively affected our business and may continue to have a material adverse effect on our business, results of operations and financial condition.

We may be unable to maintain compliance with certain financial ratio covenants of our outstanding indebtedness which could result in an event of default that, if not cured or waived, would have a material adverse effect on our business, financial condition and results of operations.

Our Senior Credit Facility contains customary restrictions, including covenants limiting our ability to incur additional debt, grant liens, make investments, consolidate, merge or acquire other businesses, sell assets, pay dividends and other distributions and enter into transactions with affiliates. We also are required to meet specified financial ratios under the terms of our Senior Credit Facility. As of December 31, 2015, we were not in compliance with all the financial covenants of our Senior Credit Facility and did not receive a waiver from our lenders; furthermore, without the restructuring of our current obligations under our existing outstanding debt and preferred stock instruments, we anticipate that we will violate the First Lien Debt to EBITDAX financial covenant ratio under the Senior Credit Facility at the end of the third quarter of 2016. Such failures to comply with the conditions and covenants in our Senior Credit Facility that is not waived by our lenders or otherwise cured could lead to a termination of our Senior Credit Facility and acceleration of all amounts due under our Senior Credit Facility and trigger cross-default provisions under other financing agreements. These restrictions may make it difficult for us to successfully execute our business strategy or to compete in our industry with companies not similarly restricted. These restrictions may also limit our ability to obtain future financings to withstand a downturn in our business or the economy in general. We may also be prevented from taking advantage of business opportunities that arise. The Senior Credit Facility matures on February 24, 2017. Any replacement credit facility may have more restrictive covenants or provide us with less borrowing capacity.

The consummation of the Unsecured Notes Exchange Offers and Second Lien Exchange Offers in connection with the Recapitalization Plan could result in significant federal income tax liabilities for us.

The consummation of the Unsecured Notes Exchange Offers and Second Lien Exchange Offers in connection with the Recapitalization Plan is expected to trigger a substantial amount of taxable income from the cancellation of indebtedness. While we anticipate being able to offset this income with current and prior net operating losses, under certain circumstances the amount of taxable income or alternative minimum taxable income could exceed the net operating losses available to offset such income in which case the consummation of the Unsecured Notes Exchange Offers and Second Lien Exchange Offers could result in our having significant federal income tax liabilities.

The price of our common stock has been volatile recently. This volatility may affect the price at which you could sell your common stock.

The market price for our common stock has varied between a high of $4.71 and a low of $0.05 between February 2015 and February 2016, respectively. This volatility may affect the price at which you can sell your common stock, and the sale of substantial amounts of our common stock could adversely affect the price of our common stock. Our stock price may continue to be volatile and subject to significant price and volume fluctuations in response to market and other factors, which may include:

- general market conditions, including fluctuations in commodity prices;
- our operating and financial performance and prospects;
- our ability to continue as a going concern;
- quarterly variations in the rate of growth of our financial indicators, such as production, reserves;
- revenues, net income and earnings per share;
- changes in production, reserves, revenue or earnings estimates or publication of research reports by analysts;
- speculation in the press or investment community; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

Our common stock has been delisted by the NY SE

As a result of a precipitous decline in our stock price, on January 13, 2016, the NYSE formally commenced delisting procedures for our common stock due to our abnormally low trading price. On January 21, 2016, the NYSE filed a Form 25 with the SEC, notifying our removal from listing.

The delisting of our common stock has had an adverse effect on the market liquidity of our common stock and, as a result, the market price for our common stock could become more volatile. If we are unable to become re-listed on a national securities exchange and increase the market value per share of our common stock, it may be difficult to attract the interest of analysts, institutional investors, investment funds and brokers.

There may be future sales or other dilution of our equity, which may adversely affect the market price of our common stock.

We are not restricted from issuing additional common stock, including securities that are convertible into or exchangeable for, or that represent a right to receive, common stock. Any issuance of additional shares of our common stock or convertible securities, including outstanding options, or otherwise will dilute the ownership interest of our common stockholders. Sales of a substantial number of shares of our common stock or other equity-related securities in the public market could depress the market price of our common stock and impair our ability to raise capital through the sale of additional equity securities. We cannot predict the effect that future sales of our common stock or other equity-related securities would have on the market price of our common stock.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve report. These differences may be material.

The proved oil and natural gas reserve information included in this report are estimates. These estimates are based on reports prepared by NSAI and RSC, our independent reserve engineers, and were calculated using the unweighted average of first-day-of-the-month oil and natural gas prices in 2015. The prices we receive for our production may be lower than those upon which our reserve estimates are based. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing wells;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and natural gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil and natural gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material. The discounted future net cash flows included in this document should not be considered as the current market value of the estimated oil and natural gas reserves attributable to our properties. As required by the SEC, the standardized measure of discounted future net cash flows from proved reserves are generally based on 12-month average prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- supply and demand for oil and natural gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, which is required by the SEC to be used to calculate discounted future net cash flows for reporting purposes, and which we use in calculating our PV-10, is not necessarily 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.

Our operations are subject to governmental risks that may impact our operations.

Our operations have been, and at times in the future may be, affected by political developments and are subject to complex federal, state, tribal, local and other laws and regulations such as restrictions on production, permitting and changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies or price gathering-rate controls. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, tribal and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws, including tax laws, and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

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

Our oil and natural gas exploration and production operations are subject to stringent and complex federal, regional, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of permits, including drilling permits, before conducting regulated activities; plugging and abandonment and site reclamation requirements; the restriction of types, quantities and concentration of materials that can be released into the environment; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition 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 as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict, joint and several liabilities for the removal or remediation of previously released materials or property contamination. Failure to comply with environmental laws and regulations may result in the assessment of civil and criminal fines and penalties, the revocation of permits or the issuance of injunctions restricting or prohibiting our operations in certain areas. Moreover, private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. Changes in environmental laws and regulations occur frequently and the clear trend is to place increasingly stringent limitations on activities that may affect the environment. Any changes in legal requirements related to the protection of the environment could result in more stringent or costly well drilling, construction, completion or water management activities, or waste control, handling, storage, transport, disposal or cleanup requirements. Such changes could also require us to make significant expenditures to attain and maintain compliance, and also have the potential to reduce demand for the oil and gas we produce and may otherwise have a material adverse effect on 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.

Federal, state and local legislative and regu