GOODRICH PETROLEUM CORP
Form 10-K
March 02, 2015

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, 2014

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:

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

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

Series B 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	x	Accelerated filer	¨
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 (Common Stock), held by non-affiliates (based upon the closing sales price on the New York Stock Exchange on June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter) was approximately $963.5 million. The number of shares of the registrant's common stock outstanding as of February 26, 2015 was 45,109,912.

Documents Incorporated By Reference:

Portions of Goodrich Petroleum Corporation's definitive Proxy Statement, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2014, are incorporated by reference in Part III of this Form 10-K.

GOODRICH PETROLEUM CORPORATION

ANNUAL REPORT ON FORM 10-K

FOR THE FISCAL YEAR ENDED

December 31, 2014

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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) South Texas, which includes the Eagle Ford Shale Trend, and (iii) Northwest Louisiana and East Texas, which includes the Haynesville Shale. Due to the depressed natural gas price environment, we are concentrating the vast majority of our development efforts on existing leased acreage within formations that are prospective for oil. We own interests in 260 producing oil and natural gas wells located in 43 fields in eight states. At December 31, 2014, we had estimated proved reserves of approximately 273.7 Bcfe, comprised of 104.8 Bcf of natural gas, 1.0 MMBbls of NGLs and 27.1 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.

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 equivalent
MBbls	Thousand barrels of crude oil or other liquid hydrocarbons

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.

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).

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 accounting principles generally accepted in the United States ("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.

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.

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.

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.

Oil and Natural Gas Operations and Properties

Overview. As of December 31, 2014, nearly all of our proved oil and natural gas reserves were located in Louisiana, Texas and Mississippi. We spent substantially all of our 2014 capital expenditures of $333.3 million in these areas, with $263.0 million, or 79%, spent on the TMS, $52.6 million, or 16%, spent on the Eagle Ford Shale Trend, and $16.2 million, or 5% spent on the Haynesville Shale Trend. Our total capital expenditures, including accrued costs for services performed during 2014 consist of $305.5 million for drilling and completion costs, $23.2 million for leasehold acquisitions and extensions, $4.2 million for facilities, infrastructure and equipment and $0.4 million for asset retirement obligation.

The table below details our acreage positions, average working interest and producing wells as of December 31, 2014.

Field or Area	Acreage As of December 31, 2014 Gross	Net	Average Producing Well Working Interest	Producing Wells at December 31, 2014
Tuscaloosa Marine Shale Trend	460,660	327,495	63%	34
Eagle Ford Shale Trend	44,370	29,914	67%	79
Haynesville Shale Trend	66,664	37,424	39%	90
Other	33,125	11,667	47%	57

Tuscaloosa Marine Shale Trend

As of December 31, 2014, we have acquired approximately 460,700 gross (327,500 net) lease acres in the Tuscaloosa Marine Shale Trend, an emerging oil shale play in Southwest Mississippi and Southeast Louisiana. During 2014, we conducted drilling operations on 22 gross (16 net) wells and added 17 gross (12 net) wells to production in the TMS.

Eagle Ford Shale Trend

As of December 31, 2014, we have acquired or farmed-in leases totaling approximately 44,400 gross (29,900 net) lease acres. In 2010, we began development and production activity in the Eagle Ford Shale and Buda Lime formations (“Eagle Ford Shale Trend”) in La Salle and Frio Counties located in South Texas. During 2014, we conducted drilling operations on 6 gross (4 net) wells in the Eagle Ford Shale Trend.

Haynesville Shale Trend

As of December 31, 2014, we have acquired or farmed-in leases totaling approximately 66,700 gross (37,400 net) acres in the Haynesville Shale. During 2014, we conducted drilling operations on 1 gross (1 net) well in the Angelina River Trend portion of our acreage position. Our Haynesville Shale drilling activities are located in leasehold areas in East Texas and Northwest Louisiana.

Other

As of December 31, 2014, we maintained ownership interests in acreage and/or wells in several additional fields, including the Midway field in San Patricio County, Texas 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 and plans for 2015 in the Tuscaloosa Marine Shale Trend, Eagle Ford Shale and Haynesville Shale Trends.

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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, 2014 and 2013, as estimated by Netherland, Sewell & Associates, Inc. ("NSAI") and by Ryder Scott Company ("RSC") our independent reserve engineers. Approximately 35% and 65% of the proved reserves estimates shown herein at December 31, 2014 have been independently prepared by NSAI and RSC, respectively. NSAI prepared the estimates on all our proved reserves as of December 31, 2014 on properties other than in the TMS and the Eagle Ford Shale Trend areas. RSC prepared the estimate of proved reserves as of December 31, 2014 for our TMS and Eagle Ford Shall Trend areas. Copies of the summary reserve reports of NSAI and RSC as of December 31, 2014 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 Part II Item 8 of this Annual Report on Form 10-K.

	Proved Reserves at December 31, 2014			
	Developed	Developed		
	Producing	Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls) (1)	9,457	634	16,977	27,068
NGL (MBbls) (2) (3)	624	4	447	1,075
Natural Gas (Mmcf)	58,111	2,597	44,124	104,832
Natural Gas Equivalent (Mmcfe) (4)	118,595	6,424	148,670	273,689
Estimated Future Net Cash Flows				$1,328,750
PV-10 (5)				$650,584
Discounted Future Income Taxes				(5,848)
Standardized Measure of Discounted Net Cash Flows (5)				$644,736

	Proved Reserves at December 31, 2013			
	Developed	Developed		
	Producing	Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls) (1)	7,738	5	6,335	14,078
NGL (MBbls) (2) (3)	2,264	93	3,996	6,353
Natural Gas (Mmcf)	112,682	4,502	212,432	329,616
Natural Gas Equivalent (Mmcfe) (4)	172,695	5,091	274,417	452,203
Estimated Future Net Cash Flows				$1,067,708
PV-10 (5)				$472,268
Discounted Future Income Taxes				(4,121)
Standardized Measure of Discounted Net Cash Flows (5)				$468,147

(1) Includes condensate.
(2) NGL reserves for 2014 include TMS and Eagle Ford Shale Trend fields and in 2013 included TMS, Eagle Ford Shale Trend, West Brachfield, North Minden and Beckville fields.
(3) 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.
(4) Based on ratio of six Mcf of natural gas per Bbl of oil and per Bbl of NGLs.

(5) 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.

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

	December 31, 2014			
	Proved	Proved	Proved	% of
Area	Developed	Undeveloped	Reserves	Total
Tuscaloosa Marine Shale Trend	31,796	83,536	115,332	42 %
Eagle Ford Shale Trend	37,135	25,254	62,389	23 %
Haynesville Shale Trend	54,049	39,880	93,929	34 %
Other	2,039	—	2,039	1 %
Total	125,019	148,670	273,689	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 2014 through December 2014, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For reserves at December 31, 2014, the average twelve month prices used were $4.35 per MMBtu of natural gas, $94.99 per Bbl of crude oil/condensate and $44.84 per Bbl of natural gas liquids. 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, 2014 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, 2014, as estimated by NSAI and RSC, were 273.7 Bcfe, consisting of 104.8 Bcf of natural gas, 1.0 MMBbls of NGLs and 27.1 MMBbls of oil and condensate. In 2014 we added approximately 91.6 Bcfe related to the TMS and 8.8 Bcfe related to the Eagle Ford Shale Trend. We had negative revisions of approximately 116.3 Bcfe, divestitures of 135.8 Bcfe and produced 26.8 Bcfe in 2014. The vast majority of our negative revisions related to transfers of 103.1 Bcfe of proved undeveloped cases out of the proved category.

Our proved undeveloped reserves at December 31, 2014 were 148.7 Bcfe or 54.3% of our total proved reserves, consisting of 44.1 Bcf of natural gas, 0.4 MMBbls of NGLs and 17.0 MMBbls of oil and condensate. In 2014, we added approximately 3.9 Bcfe related to the Eagle Ford Shale Trend and 63.6 Bcfe related to the TMS. We had negative revisions of 91.7 Bcfe and we developed approximately 3.2 Bcfe, or 1.2% of our total proved undeveloped reserves booked as of December 31, 2013 through the drilling of 3 gross (2.3 net) development wells at an aggregate capital cost of approximately $37.5 million. Of the proved undeveloped reserves in our December 31, 2014 reserve reports, none have remained undeveloped for more than five years since the date of initial booking as proved undeveloped reserves and none are scheduled for commencement of development on a date more than five years from the date the reserves were initially booked as proved undeveloped.

Productive Wells

The following table sets forth the number of productive wells in which we maintain ownership interests as of December 31, 2014:

	Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Southeast Louisiana (3)	14	10	—	—	14	10
Southwest Mississippi (3)	20	11	—	—	20	11
South Texas	79	53	—	—	79	53
East Texas	1	—	8	5	9	5

Northwest Louisiana	—	—	112	46	112	46
Other	12	3	14	—	26	3
Total Productive Wells	126	77	134	51	260	128

(1) Royalty and overriding interest wells that have immaterial values are excluded from the above table. As of December 31, 2014, only three wells with royalty-only and overriding interests-only are included.
(2) Net working interest.
(3) Tuscaloosa Marine Shale producing wells.

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, 2014. 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
Southwest Mississippi	17,055	11,300	96,084	64,738	113,139	76,038
Southeast Louisiana	23,025	15,273	324,496	236,184	347,521	251,457
South Texas	11,456	7,804	32,915	22,110	44,371	29,914
East Texas	37,653	13,017	20,936	15,355	58,589	28,372
Northwest Louisiana	39,087	20,515	—	—	39,087	20,515
Other	2,103	195	9	9	2,112	204
Total	130,379	68,104	474,440	338,396	604,819	406,500

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 natural gas or oil, 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 natural gas or oil is produced.

Lease Expirations

Our undeveloped lease acreage, excluding optioned acreage, will expire during the next four years, unless the leases are converted into producing units or extended prior to lease expiration. The following table sets forth the lease expirations as of December 31, 2014:

Year	Net Acreage
2015	74,390
2016	124,430
2017	45,925
2018	14,321

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,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	19	13.0	14	9.3	40	25.3
Non-Productive	—	—	—	—	—	—
Total	19	13.0	14	9.3	40	25.3
Exploratory Wells:						
Productive	4	3.2	8	4.1	5	1.0
Non-Productive	—	—	—	—	1	0.8
Total	4	3.2	8	4.1	6	1.8
Total Wells:						
Productive	23	16.2	22	13.4	45	26.3
Non-Productive	—	—	—	—	1	0.8
Total	23	16.2	22	13.4	46	27.1

At December 31, 2014, we had 6 gross (4.5 net) development wells and 1 gross (1 net) exploration wells in progress of being drilled or 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, 2014), 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, 2014. See Item 8 of this Form 10-K for disclosure of revenues, profits and total assets for the years ended December 31, 2014, 2013 and 2012.

	Sales Volumes			Average Sales Prices (1)				Average
	Natural Gas	Oil & Condensate	Total	Natural Gas	Oil & Condensate	Total Per	% of Total	Production Cost (2)
	Mmcf	MBbls	Mmcfe	Mcf	Per Bbl	Mcfe	Revenue	Per Mcfe
For Year 2014								
TMS	—	738	4,426	$-	$ 90.55	$15.09	32%	$ 1.07
Eagle Ford Shale Trend	1,321	928	6,888	5.70	89.69	13.31	44%	1.63
Haynesville Shale Trend	10,176	1	10,179	3.08	86.36	3.08	15%	0.44

Other	3,483	26	3,638	5.01	90.83	5.72	9%	2.50
Total	14,980	1,693	25,131	$3.75	$ 90.08	$8.30	100%	$ 1.17
For Year 2013								
TMS	—	165	990	$-	$ 105.29	$17.58	9%	$ 1.02
Eagle Ford Shale Trend	1,129	1,132	7,919	5.66	101.56	15.32	61%	1.61
Haynesville Shale Trend	14,406	1	14,409	3.00	100.05	3.01	22%	0.40
Other	4,225	40	4,467	3.44	98.26	3.70	8%	1.07
Total	19,760	1,338	27,785	$3.35	$ 101.96	$7.29	100%	$ 0.98
For Year 2012								
Haynesville Shale Trend	15,395	1	15,401	$2.20	$ 97.28	$2.20	19%	$ 0.27
Eagle Ford Shale Trend	1,142	960	6,902	4.26	100.01	14.64	55%	0.81
Other	8,307	134	9,112	4.06	99.26	5.25	26%	1.41
Total	24,844	1,095	31,415	$2.86	$ 99.91	$5.75	100%	$ 0.83

(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem and severance taxes.

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, 2014, 2013 and 2012 are as follows:

	Year Ended December 31,		
	2014	2013	2012
BP Energy Company	46%	64%	34%
Genesis Crude Oil LP	11%	7%	—
Flint Hill Resources, LLC	—	—	15%

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 February 26, 2015, we had 105 full-time employees in our Houston administrative office and our two field offices, none of whom is represented by any labor union. We closed our Shreveport office on December 31, 2013. 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. Pipelines are subject to the jurisdiction of various federal, state and local agencies as well.

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. 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.

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. There exists an exclusion under RCRA from the definition of hazardous wastes for drilling fluids, produced waters and certain other wastes generated in the exploration, development or production of oil and natural gas, efforts have been made from time to time to remove this exclusion such that those wastes would be regulated under the more rigorous RCRA hazardous waste standards. A loss of this RCRA exclusion could result in increased costs to us and the oil and gas industry in general to manage and dispose of generated wastes.

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 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. 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 hydrocarbons, particularly natural gas from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuel and issued guidance in February 2014 related to such activities. Moreover, the EPA has promulgated rules under the federal Clean Air Act ("CAA") requiring operators to use "green completions" to capture the emission of volatile organic compounds from well completion activities involving the use of hydraulic fracturing. The rules also regulate emissions from new or modified compressors, dehydrators, storage tanks, and other production equipment. Also, the EPA issued an advanced notice of proposed rulemaking under the Toxic Substances Control Act in May 2014 seeking comment on potential rules that would require companies to disclose the chemical additives used in their hydraulic fracturing fluids.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft report expected to be issued for peer review and comment sometime in the first half of 2015. The EPA has also announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities sometime in the first half of 2015. These results of studies could spur initiatives to further regulate hydraulic fracturing under the SDWA 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, the EPA has promulgated rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants

(“NESHAP”) programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all “other” fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare. However, the “other” wells must use reduced emission completions, also known as “green completions,” with or without combustion devices. 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, which costs could be significant.

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 specified large greenhouse gas emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis. Recently, the EPA finalized modifications to its GHG reporting rules that would require covered entities to report emissions on an individual GHG basis. In addition, the EPA has proposed a rule that would expand the agency’s reporting requirements to cover emissions from completions and workovers of hydraulically fractured oil wells. Also, the Obama Administration is expected to propose a series of new regulations on the oil and gas industry in 2015, including federal standards limiting methane emissions. 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:

- planned capital expenditures;
- future drilling activity;
- our financial condition;
- business strategy including the our ability to successfully transition to more liquids-focused operations;
- the market prices of oil and natural gas;
- volatility in the commodity-futures market;
- uncertainties about the estimated quantities of oil and natural gas reserves;
- financial market conditions and availability of capital;
- production;
- hedging arrangements;
- future cash flows and borrowings;

- litigation matters;
- pursuit of potential future acquisition opportunities;
- sources of funding for exploration and development;
- 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;
- the securities, capital or credit markets;
- our ability to repay our debt; 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.

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 2014. 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.

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 will depend 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. For example, spot prices for New York Mercantile Exchange ("NYMEX") West Texas Intermediate crude-oil ranged from a high of $107.95 per barrel to a low of $53.45 per barrel during 2014. Spot prices for NYMEX Henry Hub natural gas ranged from a high of $8.15 per million British thermal units (MMBtu) to a low of $2.99 per MMBtu during 2014. Furthermore, oil prices experienced a significant decline during the fourth quarter of 2014 with NYMEX West Texas Intermediate crude-oil spot prices declining from $91.02 per barrel in October 2014 to $53.45 in December 2014. Crude-oil spot prices continued their decline through January 2015 down to $44.08 per barrel.

Average oil and natural gas prices varied substantially during the past few years. Any actual or anticipated reduction in natural gas and crude oil and 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. Our average realized prices for natural gas increased slightly in 2014 but still remain below average historical prices. 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 Second Amended and Restated Credit Agreement between the Company and Wells Fargo and certain lenders dated May 5, 2009, as amended (the "Senior Credit Facility"), which would restrict our liquidity. Additionally, further or continued declines in prices could result in 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 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; 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 regulatory initiatives relating to hydraulic fracturing as well as government reviews of such activity could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuel and issued guidance in February 2014 related to such activities. Moreover, the EPA has promulgated rules under the federal Clean Air Act requiring operators to use "green completions" to capture the emission of volatile organic compounds from well completion activities involving the use of hydraulic fracturing. The rules also regulate emissions from new or modified compressors, dehydrators, storage tanks, and other production equipment. Also, the EPA issued an advanced notice of proposed rulemaking under the Toxic Substances Control Act in May 2014 seeking comment on potential rules that would require companies to disclose the chemical additives used in their hydraulic fracturing fluids.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft report expected to be issued for peer review and comment sometime in the first half of 2015. The EPA has also announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities sometime in the first half of 2015. These results of studies could spur initiatives to further regulate hydraulic fracturing under the SDWA 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.

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

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 specified large greenhouse gas emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis. Recently, the EPA finalized modifications to its GHG reporting rules that would require covered entities to report emissions on an individual GHG basis. In addition, the EPA has proposed a rule that would expand the agency’s reporting requirements to cover emissions from completions and workovers of hydraulically fractured oil wells. Also, the Obama Administration is expected to propose a series of new regulations on the oil and gas industry in 2015, including federal standards limiting methane emissions. 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.

We have incurred losses from operations and may continue to do so in the future.

We incurred losses from operations of $354.8 million, $36.3 million, $63.7 million, $17.1 million and $280.4 million for the years ended December 31, 2014, 2013, 2012, 2011 and 2010, respectively. Our development of and participation of drilling locations has required and will continue to require substantial capital expenditures. The uncertainty and risks described in this report may impede our ability to economically acquire and develop oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows provided by operating activities in the future.

Our 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:

- lack of acceptable prospective acreage;
- inadequate capital resources;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- unavailability or high cost of drilling rigs, equipment or labor;
- reductions in oil and natural gas prices;
- limitations in the market for oil and natural gas;
- 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 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.

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.

We have limited experience drilling wells on our Tuscaloosa Marine Shale trend acreage, which has a limited operational history and is subject to more uncertainties than our drilling program in more established formations.

We, along with other operators, have begun drilling wells in the Tuscaloosa Marine Shale trend only recently. Accordingly, we have limited information on which we can determine optimum drilling and completion strategies, or estimate production decline rates or recoverable reserves from drilling on our acreage in this trend. Our drilling plans with respect to the Tuscaloosa Marine Shale trend are flexible and depend on a number of factors, including the extent to which our initial wells in the trend are commercially successful.

A substantial portion of our near term capital investments will be concentrated in the development of the recently acquired acreage in the Tuscaloosa Marine Shale.

We intend to devote a substantial portion of our near term capital expenditures on drilling and completion activity (including facilities and infrastructure) in the Tuscaloosa Marine Shale. The results of these investments may not prove as attractive as we anticipate, and the concentration of such funding and activity in the Tuscaloosa Marine Shale will divert those resources from use to further develop our other properties. There can be no assurance that these investments will generate any specific return on investment.

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

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

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could impact liquidity and reduce cash available to us for capital expenditures; therefore reducing our ability to execute hedges to reduce risk and protect cash flow. The proposed margin rules are not yet final, and therefore the impact of those provisions on us is uncertain at this time.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, or reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations on us is uncertain.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of proposed legislation.

Legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively impact the value of an investment in our common stock.

Our use of oil and natural gas price hedging contracts may limit future revenues from price increases and result in significant fluctuations in our net income.

We use hedging transactions with respect to a portion of our oil and natural gas production to achieve more predictable cash flow and to reduce our exposure to price fluctuations. While the use of hedging transactions limits the downside risk of price declines, their use may also limit future revenues from price increases. We hedged approximately 77% (approximately 73% of natural gas production and approximately 82% of oil production) of our total production volumes for the year ended December 31, 2014.

Our results of operations may be negatively impacted by our commodity derivative instruments and fixed price forward sales contracts in the future and these instruments may limit any benefit we would receive from increases in the prices for oil and natural gas. For the year ended December 31, 2014 we received cash receipts to settle our derivative contracts totaling $3.4 million, while we paid $3.8 million to settle our derivative contracts for the year ended December 31, 2013. At December 31, 2014, we had a net asset derivative position of $46.9 million related to our derivative contracts compared to a net asset derivative position of $0.9 million at December 31, 2013. The ultimate settlement amount of these derivative contract positions is dependent on future commodity prices.

We account for our oil and natural gas derivatives using fair value accounting standards. Each derivative is recorded on the balance sheet as an asset or liability at its fair value. Additionally, changes in a derivative’s fair value are recognized currently in earnings unless specific hedge accounting criteria are met at the time the derivative contract is executed. We have elected not to apply hedge accounting treatment to our swaps and, as such, all changes in the fair value of these instruments are recognized in earnings. Our fixed price physical contracts qualify for the normal purchase and normal sale exception. Contracts that qualify for this treatment do not require mark-to-market accounting treatment.

In the future, we will continue to be exposed to volatility in earnings resulting from changes in the fair value of our derivative instruments. See Note 8-“Derivative Activities” in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.

Because our operations require significant capital expenditures, we may not have the funds available to replace reserves, maintain production or maintain interests in our properties.

We must make a substantial amount of capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. Historically, we have paid for these expenditures with cash from operating activities, proceeds from debt and equity financings and asset sales. Our revenues or cash flows could be reduced because of lower oil and natural gas prices or for other reasons. If our revenues or cash flows decrease, we may not have the funds available to replace reserves or maintain production at current levels. If this occurs, our production will decline over time. Other sources of financing may not be available to us if our cash flows from operations are not sufficient to fund our capital expenditure requirements. 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. Where we are not the majority owner or operator of an oil and natural gas property, we may have no control over the timing or amount of capital expenditures associated with the particular property. If we cannot fund such capital expenditures, our interests in some properties may be reduced or forfeited.

If we are unable to replace reserves, we may not be able to sustain production at present levels.

Our future success depends largely upon our ability to find, acquire or develop additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves will decline over time. In addition, approximately 54% of our total estimated proved reserves by volume at December 31, 2014, were undeveloped. By their nature, estimates of proved undeveloped reserves and timing of their production are less certain particularly because we may chose not to develop such reserves on anticipated schedules in future adverse oil or natural gas price environments. Recovery of such reserves will require significant capital expenditures and successful drilling operations. The lack of availability of sufficient capital to fund such future operations could materially hinder or delay our replacement of produced reserves. We may not be able to successfully find and produce reserves economically in the future. In addition, we may not be able to acquire proved reserves at acceptable costs.

We may incur substantial impairment writedowns.

If management's estimates of the recoverable proved reserves on a property are revised downward or if oil and natural gas prices decline, we may be required to record additional non-cash impairment writedowns in the future, which would result in a negative impact to our financial position. Furthermore, any sustained decline in oil and natural gas prices may require us to make further impairments. We review our proved oil and natural gas properties for impairment on a depletable unit basis when circumstances suggest there is a need for such a review. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and natural gas prices to the estimated future production of oil and natural gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineers' estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis.

Fair value is estimated to be the present value of expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future cash flows and fair value. For the years ended December 31, 2014 and 2013, we recorded impairments related to oil and natural gas properties of $331.9 million and zero, respectively.

Management's assumptions used in calculating oil and natural gas reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, impacting our net income or loss and our basis in the related asset. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property's fair value. Additionally, as management's views related to future prices change, the change will affect the estimate of future net cash flows and the fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment.

A majority of our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, making us vulnerable to risks associated with operating in one geographic area.

Essentially all of our estimated proved reserves at December 31, 2014, and all our production during 2014 were associated with our Louisiana, Texas and Mississippi properties which include the Tuscaloosa Marine Shale, Haynesville Shale and Eagle Ford Shale Trends. Accordingly, if the level of production from these properties substantially declines or is otherwise subject to a disruption in our operations resulting from operational problems, government intervention (including potential regulation or limitation of the use of high pressure fracture stimulation techniques in these formations) or natural disasters, it could have a material adverse effect on our overall production level and our revenue.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. For example, Chesapeake operates certain properties in the Haynesville Shale. We have less ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them versus those fields in which we are the operator. Our dependence on the operator and other working interest owners for these projects and our reduced influence or ability to control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital and lead to unexpected future costs.

Our ability to sell natural gas and receive market prices for our natural gas may be adversely affected by pipeline and gathering system capacity constraints and various transportation interruptions.

We operate primarily in (i) Southwest Mississippi and Southeast Louisiana which includes the Tuscaloosa Marine Shale, (ii) South Texas, which includes the Eagle Ford Shale Trend and (iii) Northwest Louisiana and East Texas, which includes the Haynesville Shale Trend. A number of companies are currently operating in the Haynesville Shale and Eagle Ford Shale. If drilling in these areas continues to be successful, the amount of natural gas being produced could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in this region. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for Northwest Louisiana and East Texas may not occur or may be substantially delayed for lack of financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our natural gas to interstate pipelines. In such an event, we might have to shut in our wells awaiting a pipeline connection or capacity or sell natural gas production at significantly lower prices than those quoted on New York Mercantile Exchange (NYMEX) or that we currently project, which would adversely affect our results of operations.

A portion of our oil and natural gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

Our debt instruments impose restrictions on us that may affect our ability to successfully operate our business.

We have in place a $600 million Senior Credit Facility with a borrowing base of $230 million on which we had $121.0 million drawn on December 31, 2014. The 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, 2014, we were in compliance with all the financial covenants of our Senior Credit Facility. 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. 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.

We may be unable to identify liabilities associated with the properties that we acquire or obtain protection from sellers against them.

The acquisition of properties requires us to assess a number of factors, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well, facility or pipeline. We cannot necessarily observe structural and environmental problems, such as pipeline corrosion or subsurface groundwater contamination, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities relating to the acquired assets and indemnities are unlikely to cover liabilities relating to the time periods after closing. We may be required to assume any risk relating to the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. The incurrence of an unexpected liability could have a material adverse effect on our financial position and results of operations.

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 loss of, or material nonpayment or nonperformance by, any one or more of these customers could materially adversely affect our financial condition, results of operations and cash flows.

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. Revenues from the largest of these sources as a percent of oil and natural gas revenues for the year ended December 31, 2014, 2013 and 2012 were 57%, 71% and 49%, respectively. Some of our customers may have material financial and liquidity issues or may, as a result of operational incidents or other events, be disproportionately affected as compared to larger, better-capitalized companies. Any material nonpayment or nonperformance by any of our key customers could have a material adverse effect on our financial condition, results of operations and cash flows. We expect our exposure to concentrated risk of non-payment or non-performance to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our revenue.

Customer credit risks could result in losses.

Our exposure to non-payment or non-performance by our customers and counterparties presents a credit risk. Generally, non-payment or non-performance results from a customer's or counterparty's inability to satisfy obligations. We monitor the creditworthiness of our customers and counterparties and established credit limits according to our credit policies and guidelines, but cannot assure that any losses will be consistent with our expectations. Furthermore, the concentration of our customers in the energy industry may impact our overall exposure to credit risk as customers may be similarly affected by prolonged changes in economic and industry conditions. The revenues compared to our total oil and natural gas revenues from the top purchasers for the years ended December 31, 2014, 2013 and 2012 are as follows:

	Year Ended December 31,		
	2014	2013	2012
BP Energy Company	46%	64%	34%
Genesis Crude Oil LP	11%	7%	—
Flint Hill Resources, LLC	—	—	15%

Competition in the oil and natural gas industry is intense, and we are smaller and have a more limited operating history than some of our competitors.

We compete with major and independent oil and natural gas companies for property acquisitions. We also compete for the equipment and labor required to operate and to develop these properties. Some of our competitors have substantially greater financial and other resources than us. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for oil and natural gas properties and may be able to define, evaluate, bid for and acquire a greater number of properties than we can. Our ability to acquire additional properties and develop new and existing properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Our success depends on our management team and other key personnel, the loss of any of whom could disrupt our business operations.

Our success will depend on our ability to retain and attract experienced engineers, geoscientists and other professional staff. We depend to a large extent on the efforts, technical expertise and continued employment of these personnel and members of our management team. If a significant number of them resign or become unable to continue in their present role and if they are not adequately replaced, our business operations could be adversely affected.

The oil and natural gas exploration and production business involves many uncertainties, economic risks and operating risks that can prevent us from realizing profits and can cause substantial losses.

The nature of the oil and natural gas exploration and production business involves certain operating hazards such as:

- well blowouts;
- cratering;
- explosions;
- uncontrollable flows of oil, natural gas, brine or well fluids;
- fires;
- formations with abnormal pressures;
- shortages of, or delays in, obtaining water for hydraulic fracturing operations;
- environmental hazards such as crude oil spills;

- natural gas leaks;
- pipeline and tank ruptures;
- unauthorized discharges of brine, well stimulation and completion fluids or toxic gases into the environment;
- encountering naturally occurring radioactive materials;
- other pollution; and
- other hazards and risks.

Any of these operating hazards could result in substantial losses to us. As a result, substantial liabilities to third parties or governmental entities may be incurred. The payment of these amounts could reduce or eliminate the funds available for exploration, development or acquisitions. These reductions in funds could result in a loss of our properties. Additionally, some of our oil and natural gas operations are located in areas that are subject to weather disturbances such as hurricanes. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position and results of operations. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future. A loss in connection with our oil and natural gas properties could have a materially adverse effect on our financial position and results of operations to the extent that the insurance coverage provided under our policies cover only a portion of any such loss.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

A discussion of our current legal proceedings is set forth in Note 9—“Commitments and Contingencies” in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.

Item 4. Mine Safety Disclosures

Not Applicable.

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PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Price of Our Common Stock

Our common stock is traded on the New York Stock Exchange ("NYSE") under the symbol "GDP".

At February 26, 2015, the number of holders of record of our common stock was 1,087 and 45,109,912 shares were outstanding. High and low sales prices for our common stock for each quarter during 2014 and 2013 as reported on the NYSE were as follows:

	2014		2013	
	High	Low	High	Low
First Quarter	$18.81	$11.80	$16.18	$8.68
Second Quarter	30.52	15.36	16.00	11.16
Third Quarter	27.95	14.09	27.65	12.18
Fourth Quarter	14.85	2.96	28.55	15.66

Dividends

We have neither declared nor paid any cash dividends on our common stock and do not anticipate declaring any dividends in the foreseeable future. We expect to retain our cash for the operation and expansion of our business, including exploration, development and production activities. In addition, our senior bank credit facility contains restrictions on the payment of dividends to the holders of common stock. For additional information, see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Issuer Repurchases of Equity Securities

We made no open market repurchases of our common stock for the year ended December 31, 2014.

For information on securities authorized for issuance under our equity compensation plans, see Item 12. "Security Ownership of Certain Beneficial Owners and Management".

Unregistered Sales of Equity Securities

None that have not been previously reported by us on a Current Report on Form 8-K.

Performance

The following performance graph and related information shall not be deemed “soliciting material” or to be “filed” with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the company specifically incorporates it by reference into such filing.

The following graph compares the cumulative five-year total return to stockholders on our common stock relative to the cumulative total returns of the S&P 500 Index and the Russell 2000 Index. An investment of $100 is assumed to have been made in our common stock and the indexes on December 31, 2009 and its relative performance is tracked through December 31, 2014.

Item 6. Selected Financial Data

The following table sets forth our selected financial data and other operating information. The selected consolidated financial data in the table are derived from our consolidated financial statements. This data should be read in conjunction with the consolidated financial statements, related notes and other financial information included herein.

	Summary Financial Information				
	2014	2013	2012	2011	2010
	(In thousands, except per share amounts)				
Revenues:					
Oil and natural gas revenues	$208,544	$202,557	$180,543	$200,456	$148,031
Other	9	738	302	613	302
	208,553	203,295	180,845	201,069	148,333
Operating Expenses:					
Lease operating expense	29,525	27,293	25,938	21,490	26,306
Production and other taxes	9,905	9,812	8,115	5,450	3,627
Transportation and processing	9,070	10,498	13,900	12,974	9,856
Depreciation, depletion and amortization	135,716	135,357	141,222	131,811	105,913
Exploration	6,206	22,774	23,122	8,289	10,152
Impairment	331,931	—	47,818	8,111	234,887
General and administrative	33,728	34,069	28,930	29,799	30,918
Loss (gain) on sale of assets	3,499	(107)	(44,606)	(236)	2,824
Other	3,793	(91)	91	448	4,268
	563,373	239,605	244,530	218,136	428,751
Operating loss	(354,820)	(36,310)	(63,685)	(17,067)	(280,418)
Other income (expense):					
Interest expense	(47,829)	(51,187)	(52,403)	(49,351)	(37,179)
Interest income and other	90	101	4	59	117
Gain (loss) on derivatives not designated as hedges	49,423	(702)	31,882	34,539	55,275
Gain (loss) on extinguishment of debt	—	(7,088)	—	62	—
	1,684	(58,876)	(20,517)	(14,691)	18,213
Loss before income taxes	(353,136)	(95,186)	(84,202)	(31,758)	(262,205)
Income tax benefit	—	—	—	—	85
Net loss	(353,136)	(95,186)	(84,202)	(31,758)	(262,120)
Preferred stock dividends	29,722	18,604	6,047	6,047	6,047
Net loss applicable to common stock	$(382,858)	$(113,790)	$(90,249)	$(37,805)	$(268,167)
PER COMMON SHARE					
Net loss applicable to common stock—basic	$(8.62)	$(2.99)	$(2.48)	$(1.05)	$(7.47)
Net loss applicable to common stock—diluted	$(8.62)	$(2.99)	$(2.48)	$(1.05)	$(7.47)
Weighted average common shares outstanding—basic	44,402	38,098	36,390	36,124	35,921
Weighted average common shares outstanding—diluted	44,402	38,098	36,390	36,124	35,921
Balance Sheet Data:					
Total assets	$722,138	$974,213	$768,385	$862,103	$664,577
Total long-term debt	568,625	435,866	568,671	566,126	179,171
Stockholders' equity	(15,774)	356,523	60,245	143,700	183,972

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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read together with the Consolidated Financial Statements and the Notes to Consolidated Financial Statements, which are included in this Annual Report on Form 10-K in Item 8, and the information set forth in Risk Factors under Item 1A.

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of properties primarily in (i) Southwest Mississippi and Southeast Louisiana, which includes the Tuscaloosa Marine Shale ("TMS"), (ii) South Texas, which includes the Eagle Ford Shale Trend, and (iii) Northwest Louisiana and East Texas, which includes the Haynesville Shale Trend.

We seek to increase shareholder value by growing our oil and natural gas reserves, production revenues and operating cash flow. In our opinion, on a long term basis, growth in oil and natural gas reserves and production on a cost-effective basis are the most important indicators of performance success for an independent oil and natural gas company.

Management strives to increase our oil and natural gas reserves, production and cash flow through exploration and development activities. We develop an annual capital expenditure budget, which is reviewed and approved by our board of directors on a quarterly basis and revised throughout the year as circumstances warrant. We take into consideration our projected operating cash flow and externally available sources of financing, such as bank debt, asset divestures, issuance of debt and equity securities and strategic joint-ventures, when establishing our capital expenditure budget.

We place primary emphasis on our cash flow from operating activities ("operating cash flow") in managing our business. Management considers operating cash flow a more important indicator of our financial success than other traditional performance measures such as net income because operating cash flow considers only the cash expenses incurred during the period and excludes the non-cash impact of unrealized hedging gains (losses), non-cash general and administrative expenses and impairments.

Our revenues and operating cash flow depend on the successful development of our inventory of capital projects with available capital, the volume and timing of our production, as well as commodity prices for oil and natural gas. Such pricing factors are largely beyond our control; however, we employ commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our earnings and operating cash flow.

Business Strategy

Our business strategy is to provide long-term growth in reserves and cash flow on a cost-effective basis. We focus on maximizing our return on capital employed and adding reserve value through the timely development of our TMS, Eagle Ford Shale Trend and Haynesville Shale Trend acreage. We regularly evaluate possible acquisitions of prospective acreage and oil and natural gas drilling opportunities.

Several of the key elements of our business strategy are the following:

- Develop our core position in the TMS. We seek to maximize the value of our existing assets by developing and exploiting our properties with the lowest risk and the highest potential rate of return. In the current commodity price environment, we intend to focus the development of our core acreage position through drilling in the TMS.
- Maintain oil production. During the past three years, we have concentrated on increasing our crude oil production and reserves by investing and drilling in the TMS and Eagle Ford Shale Trend. However, we intend to keep oil

production relatively flat over the next year as we monitor the crude oil markets, return to growth when markets improve and focus drilling in the TMS. We will continue to evaluate our capital allocation to oil and natural gas drilling as market conditions dictate.

- Maintain our acreage position in shale plays. As of December 31, 2014, we held approximately 327,000 net acres in the TMS in Southeastern Louisiana and Southwestern Mississippi. We continue to concentrate our efforts in areas where we can apply our technical expertise and where we have significant operational control or experience. To leverage our extensive regional knowledge base, we seek to acquire leasehold acreage with significant drilling potential in areas that exhibit characteristics similar to our existing properties. We continually strive to rationalize our portfolio of properties by selling non-core properties in an effort to redeploy capital to exploitation, development and exploration projects that offer a potentially higher overall return.

- Focus on maximizing cash flow margins and conserving capital. We intend to maximize operating cash flow by focusing on higher-margin oil development in the TMS and working with service providers to reduce costs in the TMS. In the current commodity price environment, our TMS assets offer rates of return on capital invested and cash flow margins more favorable than our natural gas assets. In January 2015, we announced a reduced capital expenditure budget of $90 to $110 million for 2015.
- Enhance financial flexibility. As of December 31, 2014, we had a borrowing base of $230 million under our $600 million Second Amended and Restated Credit Agreement (including all amendments, the "Senior Credit Facility"), on which we had $121 million drawn. On February 26, 2015 we entered into a definitive agreement to issue $100 million of second lien senior secured notes, which will be used to pay down the amount drawn on our Senior Credit Facility. Our borrowing base was reduced to $200 million on February 26, 2015 and will be further reduced to $150 million on the earlier of April 1, 2015 or the funding of the $100 million second lien senior secured notes. We have historically funded growth through operating cash flow, debt, equity and equity-linked security issuances, divestments of non-core assets and entering into strategic joint ventures. In addition, we may divest our Eagle Ford Shale assets if market conditions improve and will continue to seek a joint venture partner to share in the cost to develop our acreage in the TMS. We also actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, including fixed price swaps, swaptions and costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy.

2014 Highlights

- Our annual oil production increased to 40% of our equivalent production in 2014 from 29% in 2013 and we achieved average daily oil production volume growth of 26% for the year, with production volumes growing from an average of 3,665 barrels of oil per day in 2013 to 4,635 barrels of oil per day in 2014.
- We ended the year with estimated proved reserves of approximately 274 Bcfe (approximately 105 Bcf of natural gas, 1 MMBbls of NGL and 27 MMBbls of oil and condensate), with a PV-10 of $651 million and a standardized measure of $644.7 million, approximately 46% of which is proved developed.

- We conducted drilling operations on 29 gross (21 net) wells in 2014, including 22 gross (16 net) wells in the TMS and 6 gross (4 net) Eagle Ford Shale Trend wells in South Texas. We added 23 gross (16 net) wells to production in 2014, of which 17 gross (12 net) were in the TMS, and 6 gross (4 net) were in the Eagle Ford Shale Trend.

- Our crude oil reserves grew to 59% of our total reserves as of December 31, 2014 compared to 19% for the year ended 2013. Our PV-10 also grew 38% to $651 million at December 31, 2014 compared to $472 million at December 31, 2013.

Tuscaloosa Marine Shale Trend

We held approximately 461,000 gross (327,000 net) acres in the TMS as of December 31, 2014. Our acreage is located in Southeastern Louisiana and Southwestern Mississippi. Since December 31, 2013, we have added approximately 46,000 gross (21,000 net) acres in the trend.

During 2014, we conducted drilling operations on approximately 22 gross (16 net), TMS wells. As of December 31, 2014, we had 4 gross (3.5 net) TMS wells drilled and waiting on completion. Our net production volumes from our TMS wells represented approximately 18% of our total equivalent production on a Mcfe basis and approximately 44% of our total oil production for the year ended December 31, 2014. During 2014, we spent $263.0 million in the Tuscaloosa Marine Shale Trend, which included $22.8 million for leasehold costs. We plan on spending approximately 91% to 93% of our total 2015 capital budget in the TMS.

Eagle Ford Shale Trend

We entered into the Eagle Ford Shale Trend in April 2010, with our leasehold position located in La Salle and Frio counties, Texas. We held approximately 44,000 gross (30,000 net) acres as of December 31, 2014, all of which are either producing from or prospective for the Eagle Ford Shale Trend. During 2014, we conducted drilling operations on approximately 6 gross (4 net) Eagle Ford Shale Trend wells. During the year ended December 31, 2014, we spent $52.5 million on drilling and completion, leasehold and infrastructure capital expenditures in the Eagle Ford Shale Trend. Our net production volumes from our Eagle Ford Shale Trend wells represented approximately 27% of our total equivalent production on a Mcfe basis and approximately 55% of our total oil production for 2014.

Haynesville Shale Trend

Our relatively low risk development acreage in this trend is primarily centered in and around Angelina and Nacogdoches counties, Texas and DeSoto and Caddo parishes, Louisiana. We hold approximately 67,000 gross (37,000 net) acres as of December 31, 2014 producing from or prospective for the Haynesville Shale. Our net production volumes from our Haynesville Shale wells aggregated approximately 41% of our total oil and natural gas production for the year.

Core Haynesville Shale

Our core Haynesville Shale acreage is primarily concentrated in the Bethany-Longstreet and Greenwood-Waskom fields in Caddo and DeSoto Parishes in Northwest Louisiana. Our core Haynesville Shale drilling activity includes both operated and non-operated drilling in and around our core acreage positions in Northwest Louisiana. We currently hold approximately 32,000 gross (14,000 net) acres as of December 31, 2014.

Shelby Trough / Angelina River Trend

We operate all of our acreage in this area, which is primarily located in Nacogdoches, Angelina and Shelby counties, Texas. We held approximately 29,000 gross (22,000 net) acres as of December 31, 2014.

Results of Operations

For the year ended December 31, 2014, we reported net loss applicable to common stock of $382.9 million, or $8.62 per share (basic and diluted), on operating revenues of $208.5 million. This compares to net loss applicable to common stock of $113.8 million, or $2.99 per share (basic and diluted), for the year ended December 31, 2013 and net loss applicable to common stock of $90.2 million, or $2.48 per share (basic and diluted), for the year ended December 31, 2012. The largest change in net loss from 2013 to 2014 is the $331.9 million impairment expense recorded in 2014.

The following table reflects our summary operating information for the periods presented in thousands except for price and volume data. Because of normal production declines, increased or decreased drilling activity and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as indicative of future results.

	Year End December 31,				Year End December 31,			
Summary Operating Information:	2014	2013	Variance		2013	2012	Variance	
Revenues:								
Natural gas	$56,140	$66,180	$(10,040)	(15%)	$66,180	$71,136	$(4,956)	(7%)
Oil and condensate	152,404	136,377	16,027	12%	136,377	109,407	26,970	25%
Natural gas, oil and condensate	208,544	202,557	5,987	3%	202,557	180,543	22,014	12%
Operating revenues	208,553	203,295	5,258	3%	203,295	180,845	22,450	12%
Operating expenses	563,373	239,605	323,768	135%	239,605	244,530	(4,925)	(2%)
Operating loss	(354,820)	(36,310)	(318,510)	877%	(36,310)	(63,685)	27,375	(43%)
Net loss applicable to common stock	(382,858)	(113,790)	(269,068)	236%	(113,790)	(90,249)	(23,541)	26%

Net Production:								
Natural gas (Mmcf)	14,980	19,760	(4,780)	(24%)	19,760	24,844	(5,084)	(20%)
Oil and condensate (MBbls)	1,692	1,338	354	26%	1,338	1,095	243	22%
Total (Mmcfe)	25,131	27,785	(2,654)	(10%)	27,785	31,415	(3,630)	(12%)
Average daily production (Mcfe/d)	68,853	76,124	(7,271)	(10%)	76,124	85,832	(9,708)	(11%)
Average Realized Sales Price Per Unit:								
Natural gas (per Mcf)	$3.75	$3.35	0.40	12%	$3.35	$2.86	$0.49	17%
Natural gas (per Mcf) including the effect of realized gains/losses on derivatives	4.03	3.38	0.65	19%	3.38	5.50	(2.12)	(39%)
Oil and condensate (per Bbl)	90.08	101.96	(11.88)	(12%)	101.96	99.91	2.05	2%
Oil and condensate (per Bbl) including the effect of realized gains/losses on derivatives	89.61	98.70	(9.09)	(9%)	98.70	106.98	(8.28)	(8%)
Average realized price (per Mcfe)	8.30	7.29	1.01	14%	7.29	5.75	1.54	27%

Oil and Natural Gas Revenue

Our natural gas, oil and condensate revenues increased in 2014 compared to 2013 reflecting an increase in oil and condensate production and an increase in our average realized sales prices for natural gas, partially offset by a decline in our average realized sales prices for oil and condensate and a reduction in natural gas production. The increases in oil production and natural gas realized sales prices compared to 2013 contributed approximately $39.8 million to the increase in natural gas, oil and condensate revenue, which was partially offset by $33.8 million due to decreased natural gas production and a decline in our average realized sales prices for oil and condensate compared to 2013.

The difference between our average realized prices inclusive of net cash derivative settlements in the years ended December 31, 2014 and 2013 relates to our oil and natural gas swap contracts. During 2014, we had derivative contracts covering 30,000 MMBtus per day at an average floor price of $4.76 per MMBtu and during the full year of 2013 we had derivative contracts covering 10,000 MMBtus per day at a floor price of $4.18 per MMBtu. During 2014, we had an average of 3,800 Bbls per day hedged at an average fixed price of $93.65 per Bbl. During 2013, we had 3,626 Bbls per day hedged at an average fixed price of $94.65 per Bbl.

Natural gas, oil and condensate revenues increased in 2013 compared to 2012 reflecting an increase in oil and condensate production and an increase in our average realized sales prices, not including the effects of derivatives, partially offset by a decline in natural gas production. The increases in oil production and realized sales prices compared to 2012 contributed approximately $39.1 million to the increase in natural gas, oil and condensate revenue, which were partially offset by $17.1 million due to decreased natural gas production compared to 2012. During 2013, we focused on increasing oil production, which we were able to sell at a more favorable relative price than natural gas. In 2013, 67% of our natural gas, oil and condensate revenue was attributable to oil compared to 61% in 2012.

The difference between our average realized prices inclusive of net cash derivative settlements in the years ended December 31, 2013 and 2012 relates to our oil and natural gas swap contracts. During 2013, we had derivative contracts covering 10,000 MMBtus per day only for the fourth quarter of 2013 at a floor price of $4.18 per MMBtu and during the full year of 2012 we had derivative contracts covering 60,000 MMBtus per day at a floor price of $5.78 per MMBtu. During 2013, we had derivative contracts covering an average of 3,626 Bbls per day at an average fixed price of $94.65 per Bbl. During 2012, we had derivative contracts covering 3,500 Bbls per day at an average fixed price of $100.12 per Bbl.

Operating Expenses

Our operating expenses in 2014 increased by $323.8 million primarily as a result of recognizing $331.9 million of asset impairment expense and a $3.5 million loss on the sale of assets. When excluding these items from the operating expenses in both 2014 and 2013, the adjusted operating expense of $227.9 million in 2014 decreased 5%, or $11.7 million, from the adjusted operating expense of $239.7 million in 2013. This decrease in operating expense is driven by decreased exploration expense.

Our operating expenses in 2013 includes $4.4 million of dry hole expense and lease expirations of $11.5 million. When eliminating these items from the operating expenses in both 2013 and 2012, the adjusted operating expense of $223.7 million in 2013 decreased 3%, or $8.0 million, from adjusted operating expense of $231.7 million in 2012. This decrease in operating expenses is driven by decreased depreciation, depletion and amortization ("DD&A") expense.

	Year Ended December 31,			Year Ended December 31,		
(in thousands)	2014	2013	Variance	2013	2012	Variance

Lease operating expenses	$29,525	$27,293	$2,232	8 %	$27,293	$25,938	$1,355	5 %
Production and other taxes	9,905	9,812	93	1 %	9,812	8,115	1,697	21 %
Transportation and processing	9,070	10,498	(1,428)	(14)%	10,498	13,900	(3,402)	(24%)
Exploration	6,206	22,774	(16,568)	(73)%	22,774	23,122	(348)	(2 %)

	Year Ended December 31,				Year Ended December 31,			
Per Mcfe	2014	2013	Variance		2013	2012	Variance	
Lease operating expenses	$1.17	$0.98	$0.19	20 %	$0.98	$0.83	$0.15	18 %
Production and other taxes	0.39	0.35	0.04	11 %	0.35	0.26	0.09	35 %
Transportation and processing	0.36	0.38	(0.02)	(5)%	0.38	0.44	(0.06)	(14%)
Exploration	0.25	0.82	(0.57)	(70)%	0.82	0.74	0.08	11 %

Lease Operating Expense

Our lease operating expense (“LOE”) during 2014 included an expense of $4.3 million in workover costs which added $0.17 per Mcfe to LOE. Our LOE during 2013 included $6.0 million in workover costs which added $0.22 per Mcfe to LOE. LOE excluding workover expense increased in 2014 compared to 2013. The majority of the increase, or $3.7 million, was associated with the wells we purchased in August 2013 and wells we brought online in the TMS. Our LOE will generally trend higher as we add more oil wells to our well count which carry higher operating costs than natural gas wells. Oil contributed approximately 40% to our equivalent production volumes in 2014 compared to 29% in 2013.

Our LOE during 2013 included an expense of $6.0 million in workover costs, which added $0.22 per Mcfe to LOE. Our LOE during 2012 included $4.3 million in workover costs, which added $0.13 per Mcfe to LOE. LOE excluding workover expense decreased in 2013 compared to 2012. The absence of $2.1 million in LOE for the South Henderson Field, which we sold in late September 2012, was partially offset by increased expense related to oil production. Our LOE will generally trend higher as we add more oil wells to our well count, which carry higher operating costs than natural gas wells. Oil contributed 29% to our equivalent production volumes in 2013 compared to 21% in 2012.

Production and Other Taxes

Our production and other taxes for the year 2014 included production tax of $6.2 million and ad valorem tax of $3.7 million. Production and other taxes increased slightly in 2014 due to an increase in ad valorem taxes associated with new TMS and Eagle Ford Shale Trend wells offset by lower production taxes. The decrease in production tax for the year ended 2014 is associated with lower oil production from our Eagle Ford Shale wells and lower tax rates on the TMS wells drilled in the state of Mississippi after July 1, 2013. The State of Mississippi has enacted an exemption from the existing 6% severance tax for horizontal wells drilled after July 1, 2013 with production commencing before July 1, 2018, which will be partially offset by a 1.3% local severance tax on such wells. The exemption is applicable until the earlier of (i) 30 months from the date of first sale of production or (ii) until payout of the well cost is achieved. The State of Louisiana has also enacted an exemption from the existing 12.5% severance tax for horizontal wells with production commencing after July 31, 1994. The exemption is applicable until the earlier of (i) 24 months from the date of first sale of production or (ii) until payout of the well cost is achieved. The net revenues from our wells drilled in our TMS acreage in Southwestern Mississippi and Southeast Louisiana have been favorably impacted by these exemptions.

Our production and other taxes for the year 2013 included production tax of $7.4 million and ad valorem tax of $2.4 million. We did not earn any tax credits in 2013 attributed to Tight Gas Sands (“TGS”) credits for our wells in the State of Texas. Production and other taxes for the year 2012 include production tax of $5.6 million and ad valorem tax of $2.5 million. Production tax in 2012 is net of $1.6 million of tax credits attributed to TGS credits.

Transportation and Processing

Transportation and processing expense decreased in 2014 compared to 2013 due to lower operated natural gas production in 2014, as our natural gas production incurs substantially all of our transportation and processing cost.

The sale of the South Henderson Field in September 2012, which contributed $2.3 million of expense in 2012, and overall lower natural gas production decreased our transportation and processing expense in 2013 compared to 2012.

Exploration

The decrease in exploration expenses in 2014 compared to 2013 was attributable primarily to lower lease amortization costs primarily associated with expiring leases in our Eagle Ford Shale Trend acreage of $10.2 million, lower seismic costs of $1.5 million and lower dry hole costs of $4.4 million.

Exploration expense decreased slightly in 2013 from 2012. Dry hole cost declined $8.4 million as we suspended operations on the Denkmann 33H-1 and expensed $12.8 million of the well cost in 2012. We opted not to drill a new well utilizing the existing well bore and expensed the remaining well costs of $4.4 million in 2013. Lease amortization in 2013 increased $7.8 million from $5.9 million in 2012 to $13.7 million in 2013, which mostly offsets the decrease in dry hole cost. Lease amortization in 2013 included lease expiration expense. As part of our ongoing review of capital allocation, we elected not to renew certain expiring leases in non-core Eagle Ford Shale Trend acreage resulting in $11.1 million lease expiration expense.

	Year Ended December 31,				Year Ended December 31,			
(in thousands)	2014	2013	Variance		2013	2012	Variance	
Depreciation, depletion & amortization	$135,716	$135,357	$359	0 %	$135,357	$141,222	$(5,865)	(4 %)
Impairment	331,931	—	331,931	100%	—	47,818	(47,818)	(100%)
General & administrative	33,728	34,069	(341)	(1)%	34,069	28,930	5,139	18 %
(Gain) loss on sale of assets	3,499	(107)	3,606	NM	(107)	(44,606)	44,499	(100%)

	Year Ended December 31,				Year Ended December 31,			
Per Mcfe	2014	2013	Variance		2013	2012	Variance	
Depreciation, depletion & amortization	$5.40	$4.87	$0.53	11 %	$4.87	$4.50	$0.37	8 %
Impairment	$13.21	—	$13.21	100%	—	1.52	(1.52)	(100%)
General & administrative	$1.34	1.23	$0.11	9 %	1.23	0.92	0.31	34 %
(Gain) loss on sale of assets	$0.14	—	$0.14	NM	—	(1.42)	1.42	(100%)

NM – Not meaningful.

Depreciation, Depletion & Amortization (“DD&A”)

DD&A expense for 2014 was slightly higher than 2013. The increase in production volumes and DD&A rates associated with the continued development of the TMS was offset by lower DD&A rates in our Eagle Ford Shale Trend properties. TMS production increased to 18% of total production volumes in 2014 compared to 4% of total production volumes in 2013.

DD&A expense for 2013 decreased as compared to 2012 despite an increase in the DD&A rate between the periods. The decrease in DD&A expense resulted from lower 2013 production volumes. We calculated DD&A rates for the second half of 2013 using our mid-year reserve reports as of June 30, 2013. Our mid-year reserve report as of June 30, 2013 reflected additional proved reserves as a result of our activity in our Eagle Ford Shale Trend properties and drilling cost reductions, which partially offset the DD&A rate increase for the second half of 2013 and for 2013 overall.

Impairment

We recorded impairment expense of $331.9 million for the year ended December 31, 2014. The majority of the impairment expense, or $244.8 million, was recorded during the fourth quarter of 2014 and was related to our Eagle Ford Shale Trend properties.The impairment was driven by declining crude oil prices. In addition, we recorded $85.3 million of impairment expense during the third quarter of 2014 for properties that were sold in December 2014. We did not record impairment expense in 2013.

We recorded impairment expense of $47.8 million in the year ended December 31, 2012, $44.4 million of which related to our Angelina River trend field and was a result of declining natural gas prices. We calculated the fair value of our oil and natural gas properties based on a natural gas five year average futures strip price of $4.17 per Mcf.

General and Administrative Expense (“G&A”)

Although the rate per Mcfe increased, G&A expense decreased slightly in 2014 compared to 2013. Lower compensation expense and restructuring costs were partially offset by increased share based compensation. The higher rate per Mcfe reflects decreased natural gas production in 2014.

Share based compensation expense, which is a non-cash item, totaled $9.6 million, a $1.9 million increase over 2013 share based compensation expense. The increase in share based compensation reflects higher amortization expense associated with restricted stock awards to key employees.

G&A expense increased in 2013 compared to 2012. The increase reflects higher compensation expense, increased share based compensation and the restructuring cost of approximately $1.2 million associated with closing our Shreveport office. The consolidation of our administrative offices in Houston is expected to create operational efficiencies, but will not materially change our future G&A expenses.

Share based compensation expense, which is a non-cash item, amounted to $7.7 million in 2013 compared to $6.9 million in 2012. The increase in share based compensation reflects a restricted stock awarded to certain key employees in June 2012, which was amortized for the full year in 2013.

(Gain) loss on Sale of Assets

We recorded a $3.5 million loss on the sale of our interests in the Beckville, North Minden and West Brachfield fields located in Panola and Rusk Counties, Texas in 2014.

We recorded a gain of $44.6 million in the year ended December 31, 2012 representing the sale of our interest in three non-core properties, which included the sale of our South Henderson field in East Texas for a gain of $44.0 million.

Other Income (Expense)

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Other Income (Expense):			
Interest expense	$(47,829)	$(51,187)	$(52,403)
Interest income and other	90	101	4
Gain (loss) on derivatives not designated as hedges	49,423	(702)	31,882
Loss on extinguishment of debt	—	(7,088)	—
Income tax benefit (expense)	—	—	—
Average funded borrowings adjusted for debt discount	554,095	552,935	606,801
Average funded borrowings	559,616	567,494	631,129

Interest Expense

Our interest expense decreased in 2014 compared to 2013 as a result the reduction in our effective interest rate due to the exchange of our 5.0% Convertible Senior Notes due 2029 (the “2029 Notes) for our 5.0% Convertible Senior Notes due 2032 (the “2032 Notes”) that occurred in the second half of 2013. Also impacting the decline of interest expense was the Company repurchasing $45.1 million of the 2029 Notes on October 1, 2014. Non-cash interest of $10 million is included in the interest expense reported for the year 2014.

Our interest expense decreased in 2013 compared to 2012 as a result of the lower average level of outstanding debt in 2013. The lower average level of debt resulted from the repayment of the amounts due under our Senior Credit Facility with proceeds from our equity offerings. Non-cash interest of $12.7 million is included in the interest expense reported for the year 2013.

Gain (loss) on Derivatives Not Designated as Hedges

We produce and sell oil and natural gas into a market where prices are historically volatile. We enter into swap contracts, swaptions or other derivative agreements from time to time to manage our exposure to commodity price risk for a portion of our production.

Gain on derivatives not designated as hedges was $49.4 million for 2014. The gain includes $46.0 million representing the change in the fair value of our oil and natural gas derivative contracts and net cash receipts of $3.4 million on the settlement of our oil and natural gas derivatives. The change in fair value of our derivative contracts consisted of a $50.4 million gain on our oil derivatives and a $4.4 million loss on our natural gas derivatives. The increase in fair value of our oil derivatives reflects the decrease in futures prices for the period.

Loss on derivatives not designated as hedges was $0.7 million for 2013. The loss includes net cash settlement payments of $3.8 million and an increase in the fair value of our oil and natural gas derivative contracts of $3.1 million. The increase in fair value of our derivative contracts reflects the lower average futures strip prices at December 31, 2012 as compared to December 31, 2013 in addition to the expiration of the oil swaption contract.

Gain on derivatives not designated as hedges was $31.9 million for 2012. The gain includes net cash receipts of $73.2 million on our natural gas derivatives and a loss of $41.3 million representing the change in fair value of our oil and natural gas commodity contracts. The decrease in fair value reflects the higher average futures strip prices at December 31, 2011 as compared to December 31, 2012.

We will continue to be exposed to volatility in earnings resulting from changes in the fair value of our commodity contracts when we do not designate these contracts as hedges.

Loss on Extinguishment of Debt

On August 26, 2013 we exchanged half of our outstanding 2029 Notes for new 2032 Notes. We retired $109.25 million of outstanding 2029 Notes with a carrying value of $102.6 million and expensed unamortized debt issuance cost of $0.5 million, offset by $10.1 million attributable to the fair value of the equity portion of the 2029 Notes. The 2032 Notes had a fair value of $117.0 million, which resulted in a loss on extinguishment of debt of $4.8 million.

On October 1, 2013, we exchanged $57.4 million of our 2029 Notes for $57.0 million of new 2032 Notes. We retired the 2029 Notes with a carrying of $54.3 million and expensed unamortized debt issuance cost of $0.3 million, offset by $9.9 million attributable to the fair value of the equity portion of the 2029 Notes. The 2032 Notes had a fair value of $66.2 million, which resulted in a loss of on extinguishment of debt of $2.3 million.

Income Tax Benefit

We recorded no income tax benefit for the years 2014, 2013 and 2012. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2009 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed and as a result, we continue to maintain a full valuation allowance for our net deferred asset as of December 31, 2014.

Adjusted EBITDAX

Adjusted EBITDAX is a supplemental non-US GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as earnings before interest expense, income tax, DD&A, exploration expense, stock compensation expense and impairment of oil and gas properties. In calculating Adjusted EBITDAX, gains/losses on derivatives, less net cash received or paid in settlement of commodity derivatives are excluded from Adjusted EBITDAX. Other excluded items include Interest income and other, Gain/loss on sale of assets, Gain/loss on early extinguishment of debt and other expense. Adjusted EBITDAX is not a measure of net income (loss) as determined by US GAAP. Adjusted EBITDAX should not be considered an alternative to net income, as defined by US GAAP. The following table presents a reconciliation of the non-US GAAP measure of Adjusted EBITDAX to the US GAAP measure of net income (loss), its most directly comparable measure presented in accordance with US GAAP.

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Net loss (US GAAP)	$(353,136)	$(95,186)	$(84,202)
Depreciation, depletion and amortization	135,716	135,357	141,222
Exploration Expense	6,206	22,774	23,122
Impairment	331,931	—	47,818
Loss on extinguishment of debt	—	7,088	—
Stock based compensation	9,555	7,680	6,903
Interest expense	47,829	51,187	52,403
(Gain) loss on derivatives not designated as hedges	(49,423)	702	(31,882)
Net cash received (paid) in settlement of derivative instruments	3,417	(3,786)	73,160
Other items (1)	7,202	(299)	(44,519)
Adjusted EBITDAX	$139,297	$125,517	$184,025

(1) Other items include interest income and other, gain/loss on sale of assets, income taxes and other expense.

Management believes Adjusted EBITDAX is a good financial indicator of our ability to internally generate operating funds.

Management believes that this non-US GAAP financial measure provides useful information to investors because it is monitored and used by our management and widely used by professional research analysts in the valuation and investment recommendations of companies within the oil and gas exploration and production industry. Our computations of Adjusted EBITDAX may not be comparable to other similarly totaled measures of other companies.

LIQUIDITY AND CAPITAL RESOURCES

Overview Our primary sources of cash during 2014 were from cash on hand, cash flow from operating activities, borrowings under our Senior Credit Facility and proceeds from the sale of our non-core assets. We used cash in 2014 to fund our capital spending program, pay down debt, pay interest on outstanding debt, and pay preferred stock dividends. Our primary sources of cash during 2013 were from cash on hand, cash flow from operating activities, borrowings under our Senior Credit Facility, proceeds from our Series C and D Preferred Stock and our common stock offerings. We used cash in 2013 to fund our capital spending program and the TMS acreage acquisition, pay down debt, pay interest on outstanding debt, and pay preferred stock dividends. Our primary sources of cash during 2012 were from cash on hand, cash flow from operating activities, borrowings under our Senior Credit Facility and proceeds from sale of assets. We primarily used cash in 2012 to fund our capital spending program, pay interest on outstanding debt and pay preferred stock dividends.

We have in place a $600 million Senior Credit Facility, entered into with a syndicate of U.S. and international lenders. As of December 31, 2014, we had a $230.0 million borrowing base with $121.0 million in outstanding borrowings. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations occur on a semi-annual basis on April 1 and October 1. We were in compliance with existing covenants under the Senior Credit Facility at December 31, 2014.

The Thirteenth Amendment to our Senior Credit Facility, which became effective on February 26, 2015, includes the following key elements:

- reduces our borrowing base to $200 million on February 26, 2015;
- on the earlier of April 1, 2015 or the funding of the $100 million second lien senior secured notes, our borrowing base will be reduced to $150 million;
- the next redetermination of our borrowing base will occur on October 1, 2015;
- extends the maturity date of the Senior Credit Facility to February 24, 2017;
- eliminates our current Total Debt to EBITDAX covenant and replaces it with a Maximum Secured Debt to EBITDAX covenant of 2.50x. Maximum Secured Debt is defined as first and second lien debt only; and
- revises our Minimum Interest Coverage Ratio to 2.00x.

On February 26, 2015 we entered into a definitive agreement to issue an aggregate principal amount of $100 million of second lien senior secured notes that will mature in 2018. The proceeds of the note issuance will be used to pay down the amount drawn on our Senior Credit Facility.

Outlook

Our total capital expenditures for 2015 are expected to be approximately $90 to $110 million, with flexibility to increase or decrease based on the movement of commodity prices. We plan to spend approximately $80 to $100 million on drilling and completion cost and $10 million on leasehold and infrastructure costs. We plan to focus our 2015 drilling efforts in the TMS by allocating approximately 90% of our total capital budget, to the play. We believe that our expected level of operating cash flows and our borrowing capacity will be sufficient to fund our projected operational and capital programs for 2015.

In addition, to support 2015 cash flows, we entered into strategic derivative positions as of December 31, 2014, covering approximately 70% of our anticipated oil and condensate sales volumes for 2015. See Note 8—"Derivative Activities" in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.

We continuously monitor our balance sheet and coordinate our capital program with our expected cash flows and scheduled debt repayments. We will continue to evaluate funding alternatives as needed.

Alternatives available to us may include:

- issuance of debt or equity securities;
- joint venture partnerships in our TMS, Eagle Ford Shale Trend, and/or core Haynesville Shale acreage;
- availability under our Senior Credit Facility; and
- sale of non-core assets.

The following section discusses significant sources and uses of cash for the three-year period ending December 31, 2014. Forward-looking information related to our liquidity and capital resources are discussed above in Outlook.

Capital Resources

We intend to fund our capital expenditure program, contractual commitments, including settlement of derivative contracts and future acquisitions with cash flows from our operations and borrowings under our Senior Credit Facility. In the future, as we have done on several occasions over the last few years, we may also access public markets to issue additional debt and/or equity securities enter into joint ventures or sell non-core assets.

Our primary sources of cash during 2014 were from cash on hand, cash flow from operating activities, borrowings under our Senior Credit Facility and proceeds from the sale of non-core assets.

Our primary sources of cash during 2013 were from cash on hand, cash flow from operating activities, borrowings under our Senior Credit Facility and the proceeds from our underwritten public offerings of $110 million of our 10% Series C Preferred Stock (the “Series C Preferred Stock”), $130 million of our 9.75% Series D Preferred Stock (the “Series D Preferred Stock”) and 6,900,000 shares of our common stock.

Our primary sources of cash during 2012 were from cash on hand, cash flow from operating activities, borrowings under our Senior Credit Facility and proceeds from the sale of assets.

The table below summarizes the sources of cash during 2014, 2013 and 2012:

	Year Ended December 31,			Year Ended December 31,		
Cash flow statement information:	2014	2013	Variance	2013	2012	Variance
	(In thousands)					
Net Cash:						
Provided by operating activities	$121,733	$71,405	$50,328	$71,405	$173,789	$(102,384)
Used in investing activities	(268,422)	(250,654)	(17,768)	(250,654)	(161,494)	(89,160)

Provided by (used) financing activities	97,477	227,281	(129,804)	227,281	(14,454)	241,735
Increase (decrease) in cash and cash equivalents	$(49,212)	$48,032	$(97,244)	$48,032	$(2,159)	$50,191

At December 31, 2014, we had a working capital deficit of $79.4 million and long-term debt, net of debt discount, of $568.6 million.

Cash Flows

Year ended December 31, 2014 Compared to Year ended December 31, 2013

Operating activities: Production from our wells, the price of oil and natural gas and operating costs represent the main drivers of our cash flow from operations. Changes in working capital also impact cash flows. Net cash provided by operating activities for 2014 totaled $121.7 million, up $50.3 million from 2013. The two main drivers for the increase include operating revenues and changes in working capital. Operating revenues increased $6.0 million in 2014 compared to 2013 reflecting the increase in oil production volumes and higher average realized natural gas sales prices. The $38.2 million change in working capital, from $12.7 million negative working capital in 2013 to $25.5 million positive working capital in 2014, results from timing of drilling and completion activity for each respective year-end.

Investing activities: Net cash used in investing activities was $268.4 million for the year ended December 31, 2014, compared to $250.7 million for the year ended December 31, 2013. While we booked capital expenditures of approximately $332.9 million in