GOODRICH PETROLEUM CORP
Form 10-K
February 22, 2013
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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, 2012

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	**(I.R.S. Employer**

incorporation or organization)	**Identification No.)**
801 Louisiana, Suite 700	
Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

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

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

Common Stock, par value $0.20 per share	New York Stock Exchange
(Title of Class)	***(Name of Exchange)***

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

Series B Preferred Stock, $1.00 par value

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

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

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

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

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

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

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨ Small 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, 2012, the last business day of the registrant s most recently completed second fiscal quarter) was approximately $359.7 million. The number of shares of the registrant s common stock outstanding as of February 18, 2013 was 36,759,232.

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, 2012, are incorporated by reference in Part III of this Form 10-K.

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GOODRICH PETROLEUM CORPORATION

ANNUAL REPORT ON FORM 10-K

FOR THE FISCAL YEAR ENDED

December 31, 2012

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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) South Texas, which includes the Eagle Ford Shale Trend, (ii) Northwest Louisiana and East Texas, which includes the Haynesville Shale and Cotton Valley Taylor Sand and (iii) Southwest Mississippi and Southeast Louisiana which includes the Tuscaloosa Marine Shale. In the current 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. In addition, we continue to aggressively pursue the evaluation and acquisition of prospective acreage and oil and natural gas drilling opportunities outside of our existing leased acreage. We own working interests in 392 producing oil and natural gas wells located in 32 fields in eight states. At December 31, 2012, we had estimated proved reserves of approximately 333.1 Bcfe, comprised of 254.0 Bcf of natural gas, 5.1 MMBbls of natural gas liquids (NGLs) and 8.1 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, 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 (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*.

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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
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
SEC	United States Securities and Exchange Commission
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

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developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions). PV-10 is not a Generally Accepted Accounting Principles (GAAP) financial measure.

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 geosciences 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 regulation 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 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 reconditions. 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 geosciences (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 geosciences, 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 geosciences 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.

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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.

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Oil and Natural Gas Operations and Properties

Overview. As of December 31, 2012, nearly all of our proved oil and natural gas reserves were located in Louisiana, Texas and Mississippi. We spent substantially all of our 2012 capital expenditures of $250.7 million in these areas, with $173.5 million, or 69%, spent on the Eagle Ford Shale Trend, $48.7 million, or 19%, on the Tuscaloosa Marine Shale and $26.8 million, or 11%, spent on the Haynesville Shale Trend. Our total capital expenditures, including accrued costs for services performed during 2012, consist of $221.3 million for drilling and completion costs, $22.3 million for leasehold acquisitions, $5.7 million for facilities, infrastructure and equipment and $1.4 million for geological and geophysical costs.

The table below details our acreage positions, average working interest and producing wells as of December 31, 2012.

Field or Area	Acreage As of December 31, 2012 Gross	Net	Average Working Interest	Producing Wells at December 31, 2012
Eagle Ford Shale Trend	53,515	38,582	72%	51
Cotton Valley Taylor Sand	43,185	38,339	93%	5
Haynesville Shale Trend	122,555	78,860	46%	78
Tuscaloosa Marine Shale	158,214	134,244	84%	2
Other	32,029	6,831	39%	256

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Eagle Ford Shale Trend

As of December 31, 2012, we have acquired or farmed-in leases totaling approximately 53,500 gross (38,600 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 2012, we drilled 33 gross (22 net) oil wells.

Tuscaloosa Marine Shale

As of December 31, 2012, we have acquired approximately 158,200 gross (134,200 net) lease acres in the Tuscaloosa Marine Shale Trend, an emerging oil shale play in East Feliciana, West Feliciana, St. Helena, Concordia and Washington parishes in Southeast Louisiana and Wilkinson, Pike and Amite Counties in Southwest Mississippi. During 2012, we conducted drilling operations on six gross (two net) and added to production two gross (0.5 net) Tuscaloosa Marine Shale wells. One gross (0.8 net) drilling well resulted in a mechanical failure in which operations have been suspended.

Haynesville Shale Trend

As of December 31, 2012, we have acquired or farmed-in leases totaling approximately 122,600 gross (78,900 net) acres in the Haynesville Shale. During 2012, we drilled and completed six gross (three net) successful Haynesville Shale wells. Our Haynesville Shale drilling activities are located in five primary leasehold areas in East Texas and Northwest Louisiana.

In December 2010, we sold a significant amount of our shallow rights in fields in East Texas and Northwest Louisiana, but retained ownership of all the deep rights including the Haynesville and Bossier Shale formations. The sale resulted in net proceeds of $64.9 million, after normal closing adjustments.

Cotton Valley Taylor Sand

As of December 31, 2012, we have acquired or farmed-in leases totaling approximately 43,200 gross (38,300 net) lease acres in the Cotton Valley Taylor Sand Trend. During 2012, we drilled and completed one gross (0.5 net) well, with a 100% success rate.

Other

As of December 31, 2012, 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.

On September 28, 2012, we closed the sale of certain non-core natural gas properties in the South Henderson field in the Cotton Valley Taylor Sand Trend to Memorial Resource Development, L.L.C. The total consideration paid for these assets was $95 million and we recognized a gain on the sale of assets of $44.0 million. The sale was effective as of July 1, 2012.

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 2013 in the Haynesville Shale, Eagle Ford Shale and Tuscaloosa Marine 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, 2012 and 2011, as estimated by Netherland, Sewell & Associates, Inc. (NSAI), our independent reserve engineers. A copy of their summary reserve report for 2012 is included as an exhibit 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, 2012			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls) (1)	3,549	1,058	3,453	8,060
NGL (MBbls) (5) (6)	1,674	166	3,289	5,129
Natural Gas (Mmcf)	100,949	18,722	134,310	253,981
Natural Gas Equivalent (Mmcfe) (2)	132,284	26,068	174,764	333,116
Estimated Future Net Cash Flows				$ 675,529
PV-10 (3)				$ 359,094
Discounted Future Income Taxes				(1,645)
Standardized Measure of Discounted Net Cash Flows (3)				$ 357,449

	Proved Reserves at December 31, 2011			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls) (1)	2,329	222	3,151	5,702
NGL (MBbls) (4) (6)	3,854	127	3,833	7,814
Natural Gas (Mmcf) (4)	152,066	17,277	239,364	408,707
Natural Gas Equivalent (Mmcfe) (2)	189,161	19,377	281,267	489,805
Estimated Future Net Cash Flows				$ 1,049,967
PV-10 (3)				$ 452,009
Discounted Future Income Taxes				(4,039)
Standardized Measure of Discounted Net Cash Flows (3)				$ 447,970

(1) Includes condensate.

(2) Based on ratio of six Mcf of natural gas per Bbl of oil and per Bbl of NGLs.

(3) PV-10 represents the discounted future net cash flows attributable to our proved oil and natural gas reserves before income tax, discounted at 10%. PV-10 of our total year-end proved reserves is considered a non-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. Our standardized

measure of discounted future net cash flows of proved reserves, or standardized measure, as of December 31, 2012 was $357.4 million. See the reconciliation of our PV-10 to the standardized measure of discounted future net cash flows in the table above.

(4) Reserves were recast for 2011 to break out NGLs from our natural gas in our Eagle Ford Shale Trend, West Brachfield, South Henderson, Minden and Beckville fields.

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(5) NGL reserves for 2012 include our Eagle Ford Shale Trend, West Brachfield, Minden and Beckville fields but not South Henderson as it was sold in September 2012.

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

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

	December 31, 2012			
Area	**Proved Developed**	**Proved Undeveloped**	**Proved Reserves**	**% of Total**
Haynesville Shale Trend	84,231	65,812	150,043	45%
Cotton Valley Taylor Sand Trend	8,609	87,989	96,598	29%
Eagle Ford Shale Trend	30,991	20,434	51,425	16%
Tuscaloosa Marine Shale Trend	516	529	1,045	
Other	34,005		34,005	10%
Total	158,352	174,764	333,116	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 2012 through December 2012, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For reserves at December 31, 2012, the average twelve month prices used were $2.76 per MMBtu of natural gas and $91.21 per Bbl of crude oil/condensate. 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, 2012 included in this Annual Report on Form 10-K was estimated by our independent petroleum consultant, NSAI, 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.

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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, 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 estimate of reserves from a nationally reputable petroleum engineering firm, such as NSAI, 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 reserve report is reviewed by our senior management with representatives of NSAI 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 geosciences 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 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, 2012, as estimated by NSAI, were 333.1 Bcfe, consisting of 254.0 Bcf of natural gas, 5.1 MMBbls of NGLs and 8.1 MMBbls of oil and condensate. In 2012 we added approximately 2.1 Bcfe related to the Haynesville Shale Trend and Cotton Valley Taylor Sand Trend, 29.1 Bcfe related to the Eagle Ford Shale Trend and 1.2 Bcfe in other areas. We had negative revisions of approximately 120.8 Bcfe, sale of minerals of 36.1 Bcfe and produced 32.2 Bcfe in 2012. The vast majority of our negative revisions related to the loss of proved undeveloped natural gas reserves reflecting low natural gas prices for the year ended December 31, 2012 at an average Henry Hub spot price of $2.76 per MMBtu.

Our proved undeveloped reserves at December 31, 2012 were 174.8 Bcfe or 52% of our total proved reserves, consisting of 134.3 Bcf of natural gas, 3.3 MMBbls of NGLs and 3.5 MMBbls of oil and condensate. In 2012 we added approximately 14.0 Bcfe related to the Eagle Ford Shale Trend and 0.5 Bcfe related to the Tuscaloosa Marine Shale Trend. We had negative revisions of 103.7 Bcfe and we developed approximately 17.4 Bcfe, or 6% of our total proved undeveloped reserves booked as of December 31, 2011 through the drilling of 16 gross (10 net) development wells at an aggregate capital cost of approximately $73.2 million. Of the proved undeveloped reserves in our December 31, 2012 reserve report, 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.

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Productive Wells

The following table sets forth the number of productive wells in which we maintain ownership interests as of December 31, 2012:

	Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
South Texas	51	34			51	34
East Texas	1		207	194	208	194
Northwest Louisiana			105	44	105	44
Other	14	4	14		28	4
Total Productive Wells	66	38	326	238	392	276

(1) Royalty and overriding interest wells that have immaterial values are excluded from the above table. As of December 31, 2012, only three wells with royalty-only and overriding interests-only are included.
(2) Net working interest.

Productive wells consist of producing wells and wells capable of production, including natural gas 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, 51 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, 2012. 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
South Texas	14,199	10,460	39,316	28,123	53,515	38,583
East Texas	80,556	50,832	32,471	22,948	113,027	73,780
Northwest Louisiana	38,412	22,167	3,025	1,752	41,437	23,919
Southeast Louisiana			72,050	71,880	72,050	71,880
Southwest Mississippi	490	387	85,674	61,977	86,164	62,364
Other	2,135	227	9	9	2,144	236
Total	135,792	84,073	232,545	186,689	368,337	270,762

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.

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The following table sets forth the lease expirations as of December 31, 2012:

Year	Net Acreage
2013	10,847
2014	38,252
2015	14,008
2016	6,119

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,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	40	25.3	46	24.1	44	18.9
Non-Productive						
Total	40	25.3	46	24.1	44	18.9
Exploratory Wells:						
Productive	5	1.0	1	0.7	3	2.3
Non-Productive	1	0.8				
Total	6	1.8	1	0.7	3	2.3
Total Wells:						
Productive	45	26.3	47	24.8	47	21.2
Non-Productive	1	0.8				
Total	46	27.1	47	24.8	47	21.2

At December 31, 2012, we had 20 gross (10 net) development wells and two gross (0.6 net) exploration wells in progress of being drilled or completed.

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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 each of the two fields which have attributed more than 15% of our total proved reserves as of December 31, 2012), 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, 2012.

	Sales Volumes			Average Sales Prices (1)			Average
	Natural Gas Mmcf	Oil & Condensate MBbls	Total Mmcfe	Natural Gas Mcf	Oil & Condensate Per Bbl	Total Per Mcfe	Production Cost (2) Per Mcfe
For Year 2012							
Haynesville Shale Trend	15,395	1	15,401	$ 2.20	$ 97.28	$ 2.20	$ 0.27
Cotton Valley Taylor Sand	3,715	68	4,123	4.27	99.92	5.66	0.33
Eagle Ford Shale Trend	1,142	960	6,902	4.26	100.01	14.64	0.81
Other	4,592	66	4,989	3.78	98.43	4.79	2.75
Total	24,844	1,095	31,415	$ 2.86	$ 99.91	$ 5.75	$ 0.83
For Year 2011							
Haynesville Shale Trend	24,753	1	24,760	$ 3.57	$ 94.80	$ 3.57	$ 0.18
Cotton Valley Taylor Sand	5,008	104	5,634	4.43	93.38	5.74	0.21
Eagle Ford Shale Trend	838	464	3,624	5.16	90.22	12.89	0.76
Other	5,568	75	6,011	4.80	94.60	5.69	2.11
Total	36,167	644	40,029	$ 3.92	$ 91.34	$ 5.01	$ 0.54
For Year 2010							
Haynesville Shale Trend	17,295	1	17,300	$ 3.83	$ 64.00	$ 3.83	$ 0.15
Cotton Valley Taylor Sand	2,386	24	2,529	4.38	62.17	4.72	0.16
Eagle Ford Shale Trend	131	39	368	3.53	68.26	8.49	0.62
Other	13,003	86	13,519	4.56	84.53	4.93	1.70
Total	32,815	150	33,716	$ 4.16	$ 76.59	$ 4.39	$ 0.78

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

In addition, three of our fields, the Bethany Longstreet, Beckville and the Eagle Ford Shale Trend fields each account for more than 15% of our estimated proved reserves as of December 31, 2012. The table below provides production volume data for each of the fields for the years presented:

	Sales volumes		
	Natural Gas (Mmcf)	Oil & Condensate (MBbls)	Total (Mmcfe)
For Year 2012			
Bethany Longstreet	8,852		8,852

Beckville	3,208	21	3,337
Eagle Ford Shale Trend	1,142	960	6,902
For Year 2011			
Bethany Longstreet	14,962		14,962
Beckville	4,372	30	4,551
Eagle Ford Shale Trend	838	464	3,624
For Year 2010			
Bethany Longstreet	10,398	2	10,412
Beckville	6,259	37	6,483
Eagle Ford Shale Trend	131	39	368

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For a discussion of comparative changes in our sales volumes, revenues and operating expenses for the three years ended December 31, 2012, see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operation Results of Operations.

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. Revenues from the largest of these sources as a percent of oil and natural gas revenues for the year ended December 31, 2012 were as follows:

	2012
BP Energy Company	34%
Flint Hill Resources, LLC	15%
OGO Marketing LLC	5%

Competition

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

Employees

At February 18, 2013, we had 112 full-time employees in our two administrative offices and two field offices, none of whom is represented by any labor union. We regularly use the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well-site supervision, permitting and environmental assessment. Independent contractors usually perform field and on-site production operation services for us, including gauging, maintenance, dispatching, inspection, and well testing.

Regulations

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

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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 costs 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 solid wastes. While 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 as hazardous wastes and therefore subject to more rigorous RCRA standards. Notwithstanding the continued effectiveness of this RCRA exclusion, these exploration, development and production wastes remain subject to regulation by the EPA and state environmental agencies as non-hazardous solid 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 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.

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. Under Part C of the SDWA, the EPA established the Underground Injection Control Program, which 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. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for property damages and personal injury.

Hydraulic Fracturing

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

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

Air Emissions

The federal Clean Air Act, as amended (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 regulations. 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, on August 16, 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all other fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare after October 15, 2012. However, the other wells must use reduced emission completions, also known as green completions, with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2013. Compliance with these requirements could increase our costs of development and production, which costs could be significant

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Climate Change Based on findings by the EPA in December 2009 that emissions of carbon dioxide, methane, and other greenhouse gases (GHGs) present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the earth s atmosphere and other climatic changes, the EPA has adopted regulations under existing provisions of the CAA. The EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, including, among others, certain onshore and offshore oil and natural gas production facilities, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has from time to time considered legislation to reduce emissions of GHGs that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production interests and 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. 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 settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing more than 250 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. We believe that we are in substantial compliance with all applicable laws relating to worker health and safety.

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.

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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 and Section 21E of the Securities Exchange Act of 1934 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 variations on 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;*
- *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;

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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, our independent reserve engineers, and were calculated using the unweighted average of first-day-of-the-month oil and natural gas prices in 2012. These prices will change and may be lower at the time of production than those prices that prevailed during 2012. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

historical production from the area compared with production from other similar producing wells;

the assumed effects of regulations by governmental agencies;

assumptions concerning future oil and natural gas prices; and

assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

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

the quantities of oil and natural gas that are ultimately recovered;

the production and operating costs incurred;

the amount and timing of future development expenditures; and future oil and natural gas sales prices.

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

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

In addition, the 10% discount factor, which is required by the SEC to be used to calculate discounted future net cash flows for reporting purposes, and which we use in calculating our PV-10, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

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

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

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

Our oil and natural gas exploration and production operations are subject to stringent and complex federal, regional, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of permits, including drilling permits, before conducting regulated activities; 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. 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 any changes that result in more stringent or costly well drilling, construction, completion or water management activities, or waste control, handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our 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, but due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, the EPA has

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asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel. In addition, 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. 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.

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 and EPA expects to issue a final report by 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

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.

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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.

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 and its maintenance of production constraints, 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. 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. Realized prices for natural gas decreased slightly in 2012 and are lower when compared with average prices in prior years. 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 our 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 writedown could have a material adverse effect on our results of operations in the period taken.

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.

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, establishes 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. In its rulemaking under the Dodd-Frank Act, the CFTC issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions are exempt from these position limits. The position-limits rule was vacated by the U.S. District Court for the District of Colombia in September 2012 and the CFTC recently stated that it will appeal the District Court s decision. The CFTC also finalized other regulations, including critical rulemakings on the definition of swap, swap dealer, and major swap participant. Some regulations, however, remain to be finalized and it is not possible at this time to predict when this will be accomplished. Depending on our classification and the particular nature of our derivative activities, the Dodd-Frank Act and regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with certain derivative activities. The Dodd-Frank Act and regulations may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. 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.

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 91% (approximately 88% of natural gas production and approximately 100% of oil production) of our total production volumes for the year ended December 31, 2012.

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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.

	December 31,		
Oil and Natural Gas Derivatives (in thousands)	**2012**	**2011**	**2010**
Realized gain on oil and natural gas derivatives	$ 73,160	$ 31,305	$ 24,590
Unrealized gain (loss) on oil and natural gas derivatives	(41,278)	3,234	30,706
Total gain on oil and natural gas derivatives	$ 31,882	$ 34,539	$ 55,296

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 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 52% of our total estimated proved reserves by volume at December 31, 2012, 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.

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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, 2012, 2011 and 2010, we recorded impairments related to oil and natural gas properties of $47.8 million, $8.1 million and $234.9 million, 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, 2012, and all our production during 2012 were associated with our Louisiana, Texas and Mississippi properties which include the Tuscaloosa Marine Shale, Haynesville Shale, Cotton Valley Taylor Sand and Eagle Ford Shale Trend. 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.

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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) South Texas, which includes the Eagle Ford Shale Trend, (ii) Northwest Louisiana and East Texas, which includes the Haynesville Shale and Cotton Valley Taylor Sand and (iii) Southwest Mississippi and Southeast Louisiana which includes the Tuscaloosa Marine Shale. 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.

Our Senior Credit Facility contains customary restrictions, including covenants limiting our ability to incur additional debt, grant liens, make investments, consolidate, merge or acquire other businesses, sell assets, pay dividends and other distributions and enter into transactions with affiliates. We also are required to meet specified financial ratios under the terms of our Senior Credit Facility. As of December 31, 2012, 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 July 1, 2014, which maturity is subject to automatic extension to February 25, 2016, if, prior to maturity, we prepay or escrow certain proceeds sufficient to prepay our $218.5 million 5% Convertible Senior Notes due 2029. 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.

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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;
- unauthorize discharges of brine, well stimulation and completion fluids or toxic gases into the environment;
- encountering naturally occuring 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 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 18, 2013, the number of holders of record of our common stock was 1,268 and 36,759,232 shares outstanding. High and low closing sales prices for our common stock for each quarter during 2012 and 2011 as reported on the NYSE were as follows:

	2012		2011	
	High	Low	High	Low
First Quarter	$ 20.04	$ 14.06	$ 23.04	$ 18.17
Second Quarter	19.49	12.29	22.47	17.54
Third Quarter	15.12	10.86	20.73	11.82
Fourth Quarter	13.68	7.95	17.52	10.77

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, 2012. When an employee s restricted stock shares vest, the company (at the option of the employee) generally withholds an amount of shares necessary to cover that employees minimum payroll tax withholding obligation. The company then remits the withholding amount to the appropriate tax authority and subsequently retires the shares. During 2012, we withheld 99,827 shares of common stock from issuance in this manner and paid $0.9 million to the appropriate tax authority as minimum withholding.

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

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.

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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, 2007 and its relative performance is tracked through December 31, 2012.

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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				
	2012	2011	2010	2009	2008
	(In thousands, except per share amounts)				
Revenues:					
Oil and natural gas revenues	$ 180,543	$ 200,456	$ 148,031	$ 110,784	$ 215,369
Other	302	613	302	(358)	682
	180,845	201,069	148,333	110,426	216,051
Operating Expenses:					
Lease operating expense	25,938	21,490	26,306	30,188	31,950
Production and other taxes	8,115	5,450	3,627	4,317	7,542
Transportation and processing	13,900	12,974	9,856	9,459	8,645
Depreciation, depletion and amortization	141,222	131,811	105,913	160,361	107,123
Exploration	23,122	8,289	10,152	9,292	8,404
Impairment	47,818	8,111	234,887	208,905	28,582
General and administrative	28,930	29,799	30,918	27,923	24,254
Loss (gain) on sale of assets	(44,606)	(236)	2,824	(297)	(145,876)
Other	91	448	4,268		
	244,530	218,136	428,751	450,148	70,624
Operating income (loss)	(63,685)	(17,067)	(280,418)	(339,722)	145,427
Other income (expense):					
Interest expense	(52,403)	(49,351)	(37,179)	(26,148)	(22,410)
Interest income and other	4	59	117	458	1,682
Gain on derivatives not designated as hedges	31,882	34,539	55,275	47,115	51,547
Gain on early extinguishment of debt		62			
	(20,517)	(14,691)	18,213	21,425	30,819
Income (loss) before income taxes	(84,202)	(31,758)	(262,205)	(318,297)	176,246
Income tax (expense) benefit			85	67,311	(54,472)
Net income (loss)	(84,202)	(31,758)	(262,120)	(250,986)	121,774
Preferred stock dividends	6,047	6,047	6,047	6,047	6,047
Net income (loss) applicable to common stock	$ (90,249)	$ (37,805)	$ (268,167)	$ (257,033)	$ 115,727
PER COMMON SHARE					
Net income (loss) applicable to common stock basic	$ (2.48)	$ (1.05)	$ (7.47)	$ (7.17)	$ 3.42
Net income (loss) applicable to common stock diluted	$ (2.48)	$ (1.05)	$ (7.47)	$ (7.17)	$ 3.23
Weighted average common shares outstanding basic	36,390	36,124	35,921	35,866	33,806
Weighted average common shares outstanding diluted	36,390	36,124	35,921	35,866	40,397
Balance Sheet Data:					

Total assets	$ 768,385	$ 862,103	$ 664,577	$ 860,274	$ 1,038,287
Total long-term debt	568,671	566,126	179,171	330,147	226,723
Stockholders equity	60,245	143,700	183,972	445,385	665,348

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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) South Texas, which includes the Eagle Ford Shale Trend, (ii) Northwest Louisiana and East Texas, which includes the Haynesville Shale, Bossier Shale and Cotton Valley Trends and (iii) Southwest Mississippi and Southeast Louisiana which includes the Tuscaloosa Marine Shale.

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, 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 on a cost-effective basis. We focus on maximizing our return on capital employed and adding reserve value through the timely development of our Eagle Ford Shale Trend, Haynesville Shale, Cotton Valley Taylor Sand and Tuscaloosa Marine Shale 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 existing property base. 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. We intend to develop our multi-year inventory of drilling locations on our acreage in the Eagle Ford Shale Trend, Haynesville Shale, Cotton Valley Taylor Sands and Tuscaloosa Marine Shale in order to develop our oil and natural gas reserves.

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Increase our oil production. During the past several years we have changed our strategy by concentrating on increasing our crude oil production and reserves rather than natural gas by investing and drilling in the Eagle Ford Shale Trend and, more recently, Tuscaloosa Marine Shale. We intend to take advantage of the current favorable sales price of oil compared to the relative sales price of natural gas, and continue to grow our oil production as a percentage of total production.

Expand acreage position in emerging shale plays. As of December 31, 2012, we have acquired approximately 135,000 net acres in the Tuscaloosa Marine Shale Trend 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 similar characteristics to our existing properties. We continually strive to rationalize our portfolio of properties by selling marginal 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. We intend to maximize operating cash flow by focusing on higher-margin oil development in the Eagle Ford Shale Trend and the Tuscaloosa Marine Shale. In the current commodity price environment, our Eagle Ford Shale Trend and the Tuscaloosa Marine Shale assets offer more attractive cash flow margins than our natural gas assets.

Maintain financial flexibility. As of December 31, 2012, we had a borrowing base of $210 million under our $600 million Senior Credit Facility, of which $95 million was outstanding. We have historically funded growth through cash flow from operations, debt, equity and equity-linked security issuances, divestments of non-core assets and entering into strategic joint ventures. We 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 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.

2012 Overview

We increased our annual oil production from 10% in 2011 to 21% of our equivalent production in 2012 and achieved average daily oil production volume growth of 70% for the year, with production volumes growing from an average of 1,763 barrels of oil per day in 2011 to 2,992 barrels of oil per day in 2012.

We ended the year with estimated proved reserves of approximately 333.1 Bcfe (approximately 254.0 Bcf of natural gas, 5.1 MMBbls of NGL and 8.1 MMBbls of oil and condensate), with a PV-10 of $359.1 million and a standardized measure of $357.4 million, approximately 48% of which is proved developed.

We conducted drilling operations on 33 gross (22 net) wells in the Eagle Ford Shale Trend and added 26 gross (17 net) wells to production in 2012.

We conducted drilling operations on six gross (three net) wells in the Haynesville Shale Trend. Two gross (0.5 net) wells were added to production in 2012. As of December 31, 2012, we had 13 gross (six net) wells drilled but awaiting completion in the Haynesville Shale Trend.

We conducted drilling operations on six gross (two net) wells, in the Tuscaloosa Marine Shale Trend and added two gross (0.5 net) wells to production in 2012.

Eagle Ford Shale Trend

During 2012, we continued drilling operations on our acreage in the 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 hold approximately 53,500 gross (38,600 net) acres as of December 31, 2012, all of which are either producing from or prospective for the Eagle Ford Shale Trend. During 2012, we conducted drilling operations on approximately 33 gross (22 net) Eagle Ford Shale Trend wells. In 2013, we plan to spend approximately $115-137 million, representing approximately 58-78% of our 2013 capital budget, on 24-28 gross wells in the Eagle Ford Shale Trend.

Tuscaloosa Marine Shale Trend

We hold approximately 158,200 gross (134,200 net) acres in the Tuscaloosa Marine Shale Trend as of December 31, 2012. Our acreage is located in East Feliciana, West Feliciana, St Helena, Concordia and Washington Parishes in Southeastern Louisiana and Wilkinson, Pike and Amite counties in Southwestern Mississippi. Since December 31, 2011, we have added approximately 56,400 gross (54,000 net) acres in the trend. In December 2011, we participated in our first non-operated drilling well in the Tuscaloosa Marine Shale. During 2012, we conducted drilling operations on approximately six gross (two net) Tuscaloosa Marine Shale wells. One gross (0.8 net) drilling well resulted in a mechanical failure in which operations have been suspended.

On February 6, 2013, we announced results of our first operated well, the Crosby 12H-1 well in which we own a 50% working interest. The well had an initial 24-hour production rate of approximately 1,130 BOE per day, comprised of 1,050 barrels of oil and 469 Mcf of gas per day. In 2013, we plan to spend approximately $50 million, representing 28.5% of our 2013 capital budget, on six to ten gross wells in the Tuscaloosa Marine Shale Trend.

Haynesville Shale Trend

Our relatively low risk development drilling program in this trend is primarily centered in and around Rusk, Panola, Angelina and Nacogdoches counties, Texas and DeSoto and Caddo parishes, Louisiana. We hold approximately 122,600 gross (78,900 net) acres as of December 31, 2012 producing from or prospective for the Haynesville Shale. As of year-end 2012, we conducted drilling operations on a cumulative total of six gross (three net) wells in the trend with a 100% success rate. Two gross (0.5 net) wells were added to production. Our net production volumes from our Haynesville Shale wells aggregated approximately 42,000 Mcfe per day in 2012, or approximately 49% of our total oil and natural gas production for the year. Our 2013 capital expenditure budget includes plans to conduct completion operations on 13 gross (six net) Haynesville Shale horizontal wells which were previously drilled.

Core Haynesville Shale

Our core Haynesville Shale drilling program 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 (15,600 net) acres as of December 31, 2012. Our net production volumes from our core Haynesville Shale wells totaled approximately 34,200 Mcfe per day in 2012, or approximately 40% of our total production for the year. In 2013, we estimate that we will spend approximately $18 million of completion costs associated with previously drilled wells in our core Haynesville Shale area.

Shelby Trough / Angelina River Trend

During the second half of 2010, we spud our first Haynesville and Bossier Shale wells in the Shelby Trough/Angelina River Trend area. We operate all of our drilling activities in this area, which is primarily located in Nacogdoches, Angelina and Shelby counties, Texas. We currently hold approximately 39,200 gross (28,300 net) acres as of December 31, 2012. Our net production volumes from our Shelby Trough wells totaled approximately 4,300 Mcfe per day in 2012, or approximately 5% of our total production for the year. In 2013, we estimate that we will spend approximately $4 million on completion costs associated with a previously drilled well in the Shelby Trough/Angelina River Trend area.

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Results of Operations

For the year ended December 31, 2012, we reported net loss applicable to common stock of $90.2 million, or $2.48 per share (basic and diluted), on operating revenues of $180.8 million. This compares to net loss applicable to common stock of $37.8 million, or $1.05 per share (basic and diluted), for the year ended December 31, 2011 and net loss applicable to common stock of $268.2 million, or $7.47 per share (basic and diluted), for the year ended December 31, 2010.

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:	**2012**	**2011**	**Variance**		**2011**	**2010**	**Variance**	
Revenues:								
Natural gas	$ 71,136	$ 141,665	$ (70,529)	(50%)	$ 141,665	$ 136,527	$ 5,138	4%
Oil and condensate	109,407	58,791	50,616	86%	58,791	11,504	47,287	411%
Natural gas, oil and condensate	180,543	200,456	(19,913)	(10%)	200,456	148,031	52,425	35%
Operating revenues	180,845	201,069	(20,224)	10%	201,069	148,333	52,736	36%
Operating expenses	244,530	218,136	26,394	12%	218,136	428,751	(210,615)	(49%)
Operating loss	(63,685)	(17,067)	(46,618)	(273%)	(17,067)	(280,418)	263,351	94%
Net loss applicable to common stock	(90,249)	(37,805)	(52,444)	(139%)	(37,805)	(268,167)	230,362	86%
Net Production:								
Natural gas (Mmcf)	24,844	36,167	(11,323)	(31%)	36,167	32,815	3,352	10%
Oil and condensate (MBbls)	1,095	644	451	70%	644	150	494	329%
Total (Mmcfe)	31,415	40,029	(8,614)	(22%)	40,029	33,716	6,313	19%
Average daily production (Mcfe/d)	85,832	109,669	(23,837)	(22%)	109,669	92,373	17,296	19%
Average Realized Sales Price Per Unit:								
Natural gas (per Mcf)	$ 2.86	$ 3.92	$ (1.06)	(27%)	$ 3.92	$ 4.16	$ (0.24)	(6%)
Natural gas (per Mcf) including the effect of realized gains/losses on derivatives	5.50	4.70	0.80	17%	4.70	4.91	(0.21)	(4%)
Oil and condensate (per Bbl)	99.91	91.34	8.57	9%	91.34	76.59	14.75	19%
Oil and condensate (per Bbl) including the effect of realized gains/losses on derivatives	106.98	96.23	10.75	11%	96.23	76.59	19.64	26%
Average realized price (per Mcfe)	5.75	5.01	0.74	15%	5.01	4.39	0.62	14%

Oil and Natural Gas Revenue

Our oil and natural gas revenues decreased in 2012 compared to 2011 reflecting a decrease in production, partially offset by a net increase in average realized sales price. The decrease in net production compared to 2011 contributed approximately $49.5 million to the decrease in oil and natural gas revenue partially offset by the increase in average realized sales price compared to 2011 of approximately $29.6 million. We continued to focus on drilling oil wells in 2012 resulting in a corresponding decline in our natural gas production. The average realized sales price increase of 15% in 2012 was led by the increased oil production. In response to depressed natural gas prices, we will continue to focus our resources on increasing oil production, which we are currently able to sell at a more favorable relative price. During 2012, 61% of our oil and natural gas revenue was attributable to oil revenue compared to 29% in 2011.

The difference between our average realized prices inclusive of the hedge realizations in the year ended December 31, 2012 and 2011 periods relates to our natural gas and oil swap contracts. During 2012, we had 60,000 MMBtus per day hedged at a floor price of $5.78 per MMBtu and during 2011 we had 40,000 MMBtus per day hedged at a floor price of $6.00 per MMBtu. During 2012, we had 3,500 Bbls per day hedged at an average fixed price of $100.12 per Bbl and during 2011 we had 2,000 Bbls per day hedged at an average fixed price of $100.20 per Bbl.

Our oil and natural gas revenues increased in 2011 compared to 2010. The increase in average realized sales price compared to 2010 contributed approximately $20.8 million to the increase in oil and natural gas revenue while the net production increase compared to 2010 contributed approximately $31.6 million to the increase in oil and natural gas revenue. Our average realized sales price was $5.01 per Mcfe in 2011 compared to $4.39 per Mcfe in 2010. Sales prices are dictated by the market. We increased production by the continued development of our Haynesville Shale and Eagle Ford Shale Trend assets. The drilling and completion of 28 wells in Northwest Louisiana and East Texas, 20 of which were in the Haynesville Shale, resulted in the continued trend of annual natural gas production growth for us. The drilling of 20 South Texas wells, all of which were in the Eagle Ford Shale Trend, increased our oil production.

The difference between our average realized prices inclusive of the hedge realizations in the year ended December 31, 2011 and 2010 periods relates to our natural gas collars and basis swap contracts. During 2011, we had 40,000 MMBtus per day hedged at a floor price of $6.00 per MMBtu and during 2010 we had 50,000 MMBtus per day hedged at a floor price of $6.00 per MMBtu and 50,000 MMBtus per day hedged in our basis swaps. During 2011, we had 2,500 Bbls per day hedged at an average fixed price of $100.20 per Bbl and we did not have any oil hedges during 2010.

Operating Expenses

Our operating expenses in 2012 include a $47.8 million asset impairment, $12.8 million dry hole expense, other expense of $0.1 million and a gain on the sale of assets of $44.6 million. Eliminating these items from the operating expenses in both 2012 and 2011, the adjusted operating expense of $228.4 million in 2012 increased 9%, or $18.6 million, from adjusted operating expense of $209.8 million in 2011. This increase in operating expenses is driven by increased depreciation, depletion and amortization (DD&A) expense.

Our operating expenses in 2011 include an $8.1 million asset impairment, other expense of $0.4 million and a gain on the sale of assets of $0.2 million. Eliminating these items from the operating expenses in both 2011 and 2010, the adjusted operating expense of $209.8 million in 2011 increased 12%, or $23.8 million, from adjusted operating expense of $186.8 million in 2010. This increase in operating expenses is driven by increased DD&A expense.

	Year Ended December 31,				Year Ended December 31,			
(in thousands)	**2012**	**2011**	**Variance**		**2011**	**2010**	**Variance**	
Lease operating expenses	$ 25,938	$ 21,490	$ 4,448	21%	$ 21,490	$ 26,306	$ (4,816)	(18%)
Production and other taxes	8,115	5,450	2,665	49%	5,450	3,627	1,823	50%
Transportation and processing	13,900	12,974	926	7%	12,974	9,856	3,118	32%
Exploration	23,122	8,289	14,833	179%	8,289	10,152	(1,863)	(18%)

	Year Ended December 31,				Year Ended December 31,			
Per Mcfe	**2012**	**2011**	**Variance**		**2011**	**2010**	**Variance**	
Lease operating expenses	$ 0.83	$ 0.54	$ 0.29	54%	$ 0.54	$ 0.78	$ (0.24)	(31%)
Production and other taxes	0.26	0.14	0.12	86%	0.14	0.11	0.03	27%
Transportation and processing	0.44	0.32	0.12	38%	0.32	0.29	0.03	10%
Exploration	0.74	0.21	0.53	252%	0.21	0.30	(0.09)	(30%)

Lease Operating Expense

Our lease operating expense (LOE) during 2012 included an expense of $4.3 million in workover costs which added $0.13 per Mcfe to unit expense. Our LOE is trending higher as we add more oil wells to our well count which carry higher operating costs than natural gas wells. Oil contributed 21% to our production volumes in 2012 compared to only 10% in 2011.

Our LOE for the year 2011 decreased overall and on a per unit basis from 2010. The overall cost decrease is a result of our sale in December 2010 of certain of our high cost non-core natural gas properties and a greater percentage of our production volumes coming from our Haynesville Shale wells which carry a lower LOE per unit of production. On a per unit basis, LOE decreased for the year 2011 compared to the year 2010 as a result of cost reductions, an increase in production volumes and an increasing portion of our production coming from the lower production cost Haynesville Shale wells.

Production and Other Taxes

Our 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 Tight Gas Sands (TGS) credits for our wells in the State of Texas. Production and other taxes for the year 2011 include production tax of $3.9 million and ad valorem tax of $1.6 million. Production tax in 2011 is net of $1.4 million of tax credits attributed to TGS credits for our wells in the State of Texas. The higher production tax for 2012 compared to 2011 is attributable to the increasing portion of our production coming from the Eagle Ford Shale oil wells which are not exempt from Texas severance tax and the expiration of the Louisiana tax exemption on certain of our horizontal natural gas wells.

The TGS tax credits allow for reduced and in many cases the complete elimination of severance taxes in the State of Texas for qualifying wells for up to ten years of production. We only accrue for such credits once we have been notified of the State s approval. The Louisiana horizontal wells are eligible for a two year severance tax exemption from the date of first production or until payout of qualified costs, whichever is first.

Our ad valorem taxes increased $0.9 million to $2.5 million in 2012 from $1.6 million in 2011. Ad valorem tax is assessed on the value of properties as of the first day of the year and is highly influenced by commodity prices for the prior several months. The increase is attributed to the assessment of our new Eagle Ford Shale oil wells.

Our production and other taxes for the year 2011 include production tax of $3.9 million and ad valorem tax of $1.6 million. Production tax in 2011 is net of $1.4 million of tax credits attributed to TGS credits for our wells in the State of Texas. During the year 2010, production and other taxes included production tax of $1.1 million and ad valorem tax of $2.5 million. Production tax in 2010 is net of $1.6 million of tax credits attributed to TGS credits for our wells in the State of Texas and $0.4 million severance tax relief related to the horizontal wells we have drilled in the State of Louisiana. The higher production tax for 2011 compared to 2010 is attributable to the increasing portion of our production coming from the Eagle Ford Shale oil wells which are not exempt from Texas severance tax.

Our ad valorem taxes decreased $0.9 million to $1.6 million in 2011 from $2.5 million in 2010. Ad valorem tax is assessed on the value of properties as of the first day of the year and is highly influenced by commodity prices for the prior several months. The number of properties we owned decreased from January 1, 2010 to January 1, 2011 and the assessed values for our properties were lower year-to-year driven by decreased commodity prices.

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Transportation and Processing

Our transportation and processing expense increased in 2012 compared to 2011. The increase in expense is partially a result of higher gathering costs related to our gas production from the Eagle Ford Shale Trend wells but more predominately related to the renegotiation of certain natural gas gathering and processing contracts. In return for paying higher gathering and processing fees, as compared to gas production from our Haynesville Shale wells, we are receiving higher pricing due to the existence of natural gas liquids in our natural gas thereby increasing our revenues.

Our transportation and processing expense increased in 2011 compared to 2010. The increase in expense is primarily a result of higher transportation costs related to our new natural gas production from the Eagle Ford Shale Trend wells offset by the cost savings from the sale of non-core properties in December 2010.

Exploration

The increase in exploration expenses in 2012 compared to 2011 is attributable primarily to $ 12.8 million in dry hole expense related to the Denkmann 33H-1 well drilled on our Tuscaloosa Marine Shale acreage. Drilling operations on the well have been suspended due to mechanical failure. Exploration expense for 2012 also includes $5.9 million of amortization of leasehold costs.

The decrease in exploration expenses in 2011 compared to 2010 is attributable primarily to a $0.8 million decrease in exploration labor costs and a $0.6 million decrease in seismic costs. Exploration expense for 2011 includes $5.5 million of amortization of leasehold costs.

	Year Ended December 31,				Year Ended December 31,			
(in thousands)	**2012**	**2011**	**Variance**		**2011**	**2010**	**Variance**	
Depreciation, depletion & amortization	$ 141,222	$ 131,811	$ 9,411	7%	$ 131,811	$ 105,913	$ 25,898	24%
Impairment	47,818	8,111	39,707	490%	8,111	234,887	(226,776)	(97%)
General & administrative	28,930	29,799	(869)	(3%)	29,799	30,918	(1,119)	(4%)
Loss (gain) on sale of assets	(44,606)	(236)	(44,370)	NM	(236)	2,824	(3,060)	(108%)
Other	91	448	(357)	(80%)	448	4,268	(3,820)	(90%)

	Year Ended December 31,				Year Ended December 31,			
Per Mcfe	**2012**	**2011**	**Variance**		**2011**	**2010**	**Variance**	
Depreciation, depletion & amortization	$ 4.50	$ 3.29	$ 1.21	37%	$ 3.29	$ 3.14	$ 0.15	5%
Impairment	1.52	0.20	1.32	660%	0.20	6.97	(6.77)	(97%)
General & administrative	0.92	0.74	0.18	24%	0.74	0.92	(0.18)	(20%)
Loss (gain) on sale of assets	(1.42)	(0.01)	(1.41)	NM	(0.01)	0.08	(0.09)	(113%)
Other		0.01	(0.01)	(100%)	0.01	0.13	(0.12)	(92%)

NM Not meaningful.

Depreciation, Depletion & Amortization

Our DD&A expense increased in 2012 from 2011 as a result of higher production and more production coming from operating areas with higher DD&A rates, such as our Eagle Ford Shale Trend oil properties. The average DD&A rate increased 37% while production decreased 22% year-to-year.

We calculated the first six months of 2012 DD&A rates using the December 31, 2011 reserves prepared by NSAI. Proved developed reserves increased 9% from 191.9 Bcfe at December 31, 2010 to 208.5 Bcfe at December 31, 2011. We calculated the last six months of 2012 DD&A rates using the June 30, 2012 mid-year reserves prepared by internal reserve engineers. Proved developed reserves at June 30, 2012 were 191.9 Bcfe, an 8% decrease from the reserves at December 31, 2011.

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Our DD&A expense increased in 2011 from 2010 as a result of higher production and more production coming from operating areas with higher DD&A rates, such as our Eagle Ford Shale Trend oil properties. The average DD&A rate increased 5% while production increased 19% year-to-year.

We calculated the first six months of 2011 DD&A rates using the December 31, 2010 reserves prepared by NSAI. Proved developed reserves increased 16% from 165.5 Bcfe at December 31, 2009 to 191.9 Bcfe at December 31, 2010. We calculated the last six months of 2011 DD&A rates using the June 30, 2011 mid-year reserves prepared by internal reserve engineers. Proved developed reserves at June 30, 2011 were 216.8 Bcfe, a 13% increase over the reserves at December 31, 2010.

While our internal, mid-year reserve reports were prepared in accordance with existing SEC guidelines, they should not be construed as a fully independent reserve report.

Impairment

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 is 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 MMcf. If natural gas prices decline further we expect to have further impairments.

We recorded impairment expense of $8.1 million on four fields for the year ended December 31, 2011. The majority is related to our non-core Beckville field due to falling natural gas prices.

We recorded impairment expense of $234.9 million on several fields for the year ended December 31, 2010, related primarily to a decreasing projected natural gas price environment resulting in the write down of the carrying values of certain non-core assets. In addition to lower commodity prices, the impairment was a result of our change in forward looking development plans, which will focus on the Eagle Ford Shale Trend, core Haynesville Shale in Northwest Louisiana and the Angelina River Trend of the Shelby Trough.

General and Administrative Expense

Our general and administrative (G&A) expense decreased in 2012 compared to 2011. Salaries and payroll taxes were lower in 2012 as a result of the timing of filling open positions, partially offset by increased stock compensation for a one time issuance to key personnel. Also contributing to the decrease was the expiration of a previous incentive program for certain employees based on stock price performance. Share based compensation expense, which is a non-cash item, amounted to $6.9 million in 2012 compared to $6.5 million in 2011. G&A on a per unit basis increased to $0.92 per Mcfe from $0.74 per Mcfe as a result of the 22% decrease in production volume in 2012 compared to 2011.

Our G&A expense decreased in 2011 compared to 2010. The decrease relates primarily to the partial refund and final settlement of a Louisiana franchise tax payment made under protest in 2007, decreases in stock based compensation and consulting cost. Share based compensation expense, which is a non-cash item, amounted to $6.5 million in 2011 compared to $7.6 million in 2010. G&A on a per unit basis decreased to

$0.74 per Mcfe from $0.92 per Mcfe as a result of the 19% increase in production volume in 2011 compared to 2010.

Gain on Sale of Assets

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.

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We recorded a gain of $0.2 million on the sale on non-core oil and natural gas properties in the year ended December 31, 2011 and a loss of $2.8 million on the sale of assets in the year ended December, 31, 2010.

Other

We recorded a $4.3 million expense in 2010 related to a lawsuit concerning additional oil and natural gas bonus payments. In 2011, a money judgment of $4.4 million, including interest, was paid to the opposing party in the lawsuit consequently another $0.1 million was recorded in 2011 as a result of the settlement. We accrued an additional $0.3 million in 2011 representing potential settlements on two other minor litigation actions for a total of $0.4 million as of December 31, 2011.

A discussion of these legal proceedings is set forth in *Note 9 Commitment and Contingencies in the Notes to the Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

Other Income (Expense)

	Year Ended December 31,		
	2012	2011	2010
		(In thousands)	
Other Income (Expense):			
Interest expense	$ (52,403)	$ (49,351)	$ (37,179)
Interest income and other	4	59	117
Gain on derivatives not designated as hedges	31,882	34,539	55,275
Gain on extinguishment of debt		62	
Income tax benefit (expense)			85
Average funded borrowings adjusted for debt discount	606,801	508,323	379,582
Average funded borrowings	631,129	543,688	400,405

Interest Expense

Our interest expense increased in 2012 compared to 2011 as a result of the higher average level of outstanding debt in the current year. The higher average level of debt resulted from increased borrowings under our Senior Credit Facility. Non-cash interest of $12.8 million is included in the interest expense reported for the year 2012.

Our interest expense increased in 2011 compared to 2010 as a result of the higher average level of outstanding debt in 2011. The higher average level of debt resulted from the issuance of our $275 million 8.875% Senior Notes due 2019 (the 2019 Notes). Non-cash interest of $14.4 million is included in the interest expense reported in 2011.

Interest Income and Other

We invested the proceeds from the 5% convertible senior note offering in September 2009 in money market funds and time deposits with certain acceptable institutions, subject to our Short Term Investment Policy. We used the invested proceeds throughout 2010 and 2009 to fund our capital program. The income earned on these investments during 2011 and 2010 is reflected in the Interest income line.

Gain on Derivatives Not Designated as Hedges

We produce and sell oil and natural gas into a market where selling prices are historically volatile. For example, on November 7, 2012 the Henry Hub natural gas spot price reached a high of $3.77 per MMBtu, but the price was down to $1.82 per MMBtu at April 20, 2012. 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.

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Gain on derivatives not designated as hedges was $31.9 million for 2012. The gain includes a realized gain of $73.2 million on our natural gas derivatives and an unrealized loss of $41.3 million for the change in fair value of our oil and natural gas commodity contracts. The unrealized gain reflects the lower average futures strip prices from December 31, 2011 as compared to December 31, 2012.

Gain on derivatives not designated as hedges was $34.5 million for 2011. The gain includes a realized gain of $31.3 million on our natural gas derivatives and an unrealized gain of $3.2 million for the change in fair value of our oil and natural gas commodity contracts. The unrealized gain reflects the lower average futures strip prices from December 31, 2010 as compared to December 31, 2011.

Gain on derivatives not designated as hedges was $55.3 million for 2010. The gain includes a realized gain of $24.6 million on our natural gas derivatives and an unrealized gain of $30.7 million for the change in fair value of our oil and natural gas commodity contracts. The unrealized gain reflects the lower average futures strip prices from December 31, 2009 as compared to December 31, 2010.

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.

Income Tax Benefit

We recorded no income tax benefit for the years 2012 and 2011. 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, 2012.

We recorded a small tax benefit of less than $0.1 million in 2010, which reflects the monetization of our alternative minimum tax credit. We recorded no income tax benefit for 2010.

Adjusted EBITDAX (1)

	Year Ended December 31,		
	2012	**2011**	**2010**
		(In thousands)	
Net Income (GAAP)	$ (84,202)	$ (31,758)	$ (262,120)
Exploration Expense	23,122	8,289	10,152
Depreciation, depletion and amortization	141,222	131,811	105,913
Impairment	47,818	8,111	234,887
Stock compensation expense	6,903	6,495	7,554
Interest expense	52,403	49,351	37,179
Unrealized (gain)/loss on derivatives not designated as hedges	41,278	(3,234)	(31,794)
Other items (2)	(44,519)	91	6,890
Adjusted EBITDAX	$ 184,025	$ 169,156	$ 108,661

(1) Adjusted EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense and impairment of oil and gas properties. In calculating EBITDAX for this purpose, earnings include realized gains (losses) from derivatives but exclude unrealized gains (losses) from derivatives. Other excluded items include Interest income and other, Gain on sale of assets, Gain on early extinguishment of debt and other expense. As defined in our Senior Credit Facility.

(2) Other items include interest income and other, (gain) loss on sale of assets, gain on extinguishment of debt, income taxes and other expense.

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Management believes adjusted EBITDAX is a good financial indicator of our ability to internally generate operating funds. Adjusted EBITDAX should not be considered an alternative to net income, as defined by GAAP. Management believes that this non-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.

LIQUIDITY AND CAPITAL RESOURCES

Outlook

Our total capital expenditures for 2013 are expected to be between $175 million and $200 million, exclusive of acquisitions other than lease acreage additions in our core areas. We plan on spending between $160 million and $175 million on drilling and completion cost and $15 million on leasehold and infrastructure costs. We will concentrate on developing our oil assets in 2013 by allocating approximately 85% of our drilling and completion budget to oil directed activity. Oil directed activity will be concentrated in the Eagle Ford Shale and the Tuscaloosa Marine Shale trends. We plan on spending $22 million in 2013 on gas directed activity in the completion of 13 gross (6 net) Haynesville Shale wells that have been previously drilled. Our primary emphasis will be on managing near-term growth opportunities. We believe that our expected level of operating cash flows, cash on hand as of December 31, 2012, and our borrowing base will be sufficient to fund our projected operational and capital programs for 2013. However, if capital expenditures exceed operating cash flow and cash on hand, funds would likely be supplemented as needed through short-term borrowings under senior credit facility or through the issuance of debt or equity.

As we continue to increase our oil production in 2013, we expect that our overall operating expenses will increase as a result of the higher DD&A rates associated with oil wells compared to our natural gas wells.

In addition, to support 2013 cash flows, we entered into strategic derivative positions as of December 31, 2012, covering approximately 75% of our anticipated oil and condensate sales volumes for 2013. 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 leverage position and coordinate our capital program with our expected cash flows and repayment of our projected debt. We will continue to evaluate funding alternatives as needed.

Alternatives available to us include:

- sale of non-core assets;
- joint venture partnerships in our Tuscaloosa Marine Shale, Eagle Ford Shale Trend, and/or core Haynesville Shale acreage;
- availability under our Senior Credit Facility; and

issuance of debt or equity securities.

Our next borrowing base redetermination is currently scheduled for April 2013. At December 31, 2012, our borrowing base under our Senior Credit Facility is $210 million with $95 million outstanding. Our borrowing base is typically reviewed twice annually by our bank group using their price deck applied to our most recent reserve report, in this case as of December 31, 2012.

On January 22, 2013 we filed a universal shelf registration statement that, once declared effective by the SEC, will provide us with the ability to make registered offerings of various equity or debt securities to the public of up to an aggregate amount of $500 million. We anticipate conducting a public offering before our $218.5 million 5% senior convertible notes due 2029 become putable on October 1, 2014, however, we can make no assurances that we would be able to access the capital market on terms that are acceptable to us. Any amounts outstanding on the 2029 notes will be characterized as a current liability in the fourth quarter of 2013. Similarly, if the 2029 notes are not redeemed prior to June 30, 2013, any amount outstanding under the Senior Credit facility with a maturity date of July 1, 2014 will be characterized as a current liability in the third quarter of 2013.

Overview

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. We primarily used cash 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 2011 were from cash on hand, cash flow from operating activities, available borrowings under our Senior Credit Facility and our issuance in March 2011 of $275 million of our 2019 Notes. We primarily used cash to fund our capital spending program, retire debt and pay preferred stock dividends. Our primary sources of cash during 2010 were from cash on hand, cash flow from operating activities and proceeds from divestitures. In 2010, we primarily used cash to fund our capital spending program, 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, 2012, we had a $210 million borrowing base with $95 million outstanding. On February 25, 2011, we entered into a Fourth Amendment to the Senior Credit Facility. The Fourth Amendment became effective upon the closing of the issuance and sale of our 2019 Notes, which occurred on March 2, 2011, and the placement of $175 million of net proceeds in an escrow account which was used for the redemption of $174.6 million of our $3.25% Convertible Senior Notes due 2026 (the 2026 Notes). We were in compliance with existing covenants, as amended, at December 31, 2012. The Senior Credit Facility matures on July 1, 2014 subject to automatic extension to February 25, 2016, if, prior to maturity, we prepay or escrow certain proceeds sufficient to prepay our $218.5 million 5% Convertible Senior Notes due 2029 (the 2029 Notes).

The following section discusses significant sources and uses of cash for the three-year period ending December 31, 2012. Forward-looking information related to our liquidity and capital resources are discussed in *Outlook* that follows.

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.

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.

Our primary sources of cash during 2011 were from cash on hand, cash flow from operating activities, available borrowings under our Senior Credit Facility and our issuance of the 2019 Notes.

Primary sources of cash during 2010 were cash flow from operating activities and the sale of assets.

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The table below summarizes the sources of cash during 2012, 2011 and 2010:

Cash flow statement information:	Year Ended December 31, 2012	Year Ended December 31, 2011	Variance	Year Ended December 31, 2011	Year Ended December 31, 2010	Variance
	(In thousands)					
Net Cash:						
Provided by operating activities	$ 173,789	$ 136,340	$ 37,449	$ 136,340	$ 100,432	$ 35,908
Used in investing activities	(161,494)	(335,064)	173,570	(335,064)	(200,080)	(134,984)
Provided by (used) financing activities	(14,454)	184,283	(198,737)	184,283	(7,680)	191,963
Increase (decrease) in cash and cash equivalents	$ (2,159)	$ (14,441)	$ 12,282	$ (14,441)	$ (107,328)	$ 92,887

At December 31, 2012, we had a working capital deficit of $79.3 million and long-term debt, net of debt discount, of $568.7 million.

Cash Flows

Year ended December 31, 2012 Compared to Year Ended December 31, 2011

Operating activities. Production from our wells, the price of oil and natural gas and operating costs represent the main drivers behind our cash flow from operations. Changes in working capital also impact cash flows. Net cash provided by operating activities increased $37.4 million in 2012. Derivative settlements of $41.8 million and working capital savings of $22.9 million increased operating cash offset by a $13.3 million decreased related to oil and natural gas revenue year over year with (i) a 22% decrease in total production offset by (ii) growth in oil volumes as a percentage of total volumes from 10% in 2011 to 21% in 2012, and (iii) a 15% increase in the average realized sales price from $5.01 to $5.75 per Mcfe. Operating costs increase related to increased cost of producing oil reduced cash by $9.4 million in 2012 as compared to 2011. Decreases to cash flow in 2012 also include (i) $4.6 million in additional cash interest paid in 2012 as we replaced $175 million of our 3.25% Convertible Senior Notes due 2026 with $275 million of our 8.875% 2019 Notes.

Investing activities. Net cash used in investing activities was $161.5 million for the year ended December 31, 2012, compared to $335.1 million for 2011. While we booked capital expenditures of approximately $252.0 million in 2012, we paid out cash amounts totaling $252.4 million in 2012, with differences being attributed to approximately $19.2 million in drilling and completion costs which were accrued at December 31, 2012 and non-cash asset retirement obligation additions of $2.7 million offset by $22.3 million in drilling and completion cost accrued at December 31, 2011 and paid in 2012. Net cash used in investing activities was offset by the receipt of $90.9 million of cash proceeds from the sale of fixed assets in 2012.

We drilled 46 gross wells in 2012 compared to 47 gross wells in 2011. Of the $252.4 million cash spent in 2012, $220.8 million was for drilling and completion activities (of which $20.8 million related to 2011 wells); $22.3 million was for leasehold acquisition, $5.2 million for facilities and infrastructure, $3.5 million for capital workovers and $0.6 million for furniture, fixtures and equipment. Of the $335.2 million cash spent in 2011, $299.9 million was for drilling and completion activities (of which $29.8 million related to 2010 wells); $22.7 million was for leasehold acquisition, $9.2 million for facilities and infrastructure, $2.8 million for capital workovers and $0.6 million for furniture, fixtures and equipment.

Financing activities. The net cash provided by financing activities for 2012 consisted primarily of net payments under our Senior Credit Facility of $7.5 million and preferred stock dividends of $6.1 million. We had $95.0 million of borrowings outstanding under our Senior Credit Facility as of December 31, 2012. In 2011, the cash provided by financing activities consisted primarily of proceeds from the issuance of $275 million of the 2019 Notes and net borrowings under our Senior Credit Facility of $102.5 million.

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

Operating activities. Production from our wells, the price of oil and natural gas and operating costs represent the main drivers behind our cash flow from operations. Changes in working capital also impact cash flows. Net cash provided by operating activities increased $35.9 million in 2011. Cash received related to oil and natural gas revenue increased $47.2 million year over year with (i) a 19% increase in total production, (ii) growth in oil volumes as a percentage of total volumes from 3% in 2010 to 10% in 2011, and (iii) a 14% increase in the average realized sales price from $4.39 to $5.01 per Mcfe. Operating costs savings of $7.9 million in 2011 as compared to 2010 and $7.9 million in additional realized cash settlements on our derivative contracts were also additive to cash flow from operations. Offsetting decreases to cash flow in 2011 include (i) $17.2 million in additional cash interest paid in 2011 as we replaced $175 million of our 3.25% Convertible Senior Notes due 2026 with $275 million of our 8.875% 2019 Notes and (ii) $9.9 million in working capital changes.

Net cash used in investing activities was $335.1 million for the year ended December 31, 2011, compared to $200.1 million for 2010. While we booked capital expenditures of approximately $330.2 million in 2011, we paid out cash amounts totaling $335.2 million in 2011, with the difference being attributed to approximately $22.3 million in drilling and completion costs which were accrued at December 31, 2011, non-cash asset retirement obligation additions of $2.1 million and geophysical and geological cost of $0.6 million offset by $30.0 million in drilling and completion cost accrued at December 31, 2010 and paid in 2011. Net cash used in investing activities was offset by the receipt of $0.2 million of cash proceeds from the sale of fixed assets in 2011.

We drilled 47 gross wells in 2011 compared to 46 gross wells in 2010. Of the $335.2 million cash spent in 2011, $299.9 million was for drilling and completion activities (of which $29.8 million related to 2010 wells); $22.7 million was for leasehold acquisition, $9.2 million for facilities and infrastructure, $2.8 million for capital workovers and $0.6 million for furniture, fixtures and equipment. Of the $265.0 million cash spent in 2010, approximately $227.6 million was for drilling and completion activities (of which $13.8 million related to 2009 wells); $33.7 million was for leasehold acquisition, $0.6 million for facilities and infrastructure, $2.3 million for capital workovers, and $0.8 million for furniture, fixtures and equipment.

Financing activities. The net cash provided by financing activities for 2011 consisted primarily of proceeds from the issuance of $275 million of the 2019 Notes and net borrowings under our Senior Credit Facility of $102.5 million, partially offset by the redemption of a portion of our 2026 Notes totaling $176.4 million, financing cost on the issuance of the 2019 Notes of $9.3 million and preferred stock dividends of $6.0 million. We had $102.5 million borrowings outstanding under our Senior Credit Facility as of December 31, 2011. In 2010 we had no issuances of debt or equity and the cash used in financing activities was primarily the dividend paid on preferred stock.

Debt consisted of the following balances as of the dates indicated (in thousands):

	December 31, 2012			December 31, 2011		
	Principal	Carrying Amount	Fair Value (1)	Principal	Carrying Amount	Fair Value (1)
Senior Credit Facility	$ 95,000	$ 95,000	$ 95,000	$ 102,500	$ 102,500	$ 102,500
3.25% Convertible Senior Notes due 2026	429	429	429	429	429	429
5.0% Convertible Senior Notes due 2029 (2)	218,500	198,242	204,975	218,500	188,197	201,785
8.875% Senior Notes due 2019	275,000	275,000	261,250	275,000	275,000	243,898
Total debt	$ 588,929	$ 568,671	$ 561,654	$ 596,429	$ 566,126	$ 548,612

(1) The carrying amount for the Senior Credit Facility represents fair value because the variable interest rates are reflective of current market conditions and the carrying amount of the 3.25% Convertible Senior Notes due 2026 represents fair value because the last transacted activity was at par; otherwise, fair value was obtained by direct market quotes within Level 1 of the fair value hierarchy.

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(2) The debt discount is amortized using the effective interest rate method based upon an original five year term through October 1, 2014. The debt discount was $20.3 million and $30.3 million as of December 31, 2012 and December 31, 2011, respectively.

The following table summarizes the total interest expense (contractual interest expense, amortization of debt discount and financing costs) and the effective interest rate on the liability component of the debt (amounts in thousands, except effective interest rates):

	December 31, 2012		December 31, 2011		December 31, 2010	
	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate