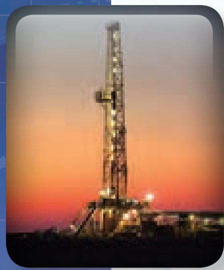
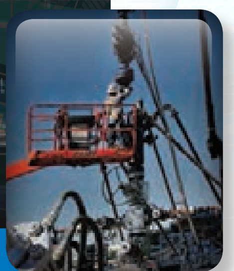




COMSTOCK RESOURCES

2014

2014 ANNUAL REPORT

Comstock Resources, Inc. is a growing independent energy company engaged in the acquisition, development, production and exploration of oil and natural gas properties. Our operations are primarily focused in Texas and Louisiana.

Financial Highlights

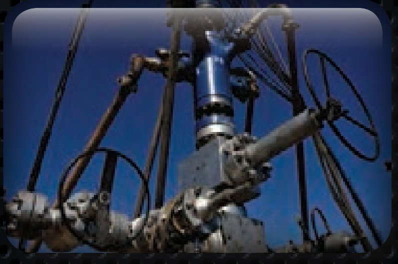
(in thousands except per share data)	2010	2011	2012	2013	2014
Oil and gas sales	$349,141	$434,367	$384,814	$420,290	$555,231
Income (loss) from continuing operations	($19,586)	($33,472)	($103,079)	($106,723)	($57,111)
Net income (loss)	($19,586)	($33,472)	($100,060)	$41,029	($57,111)
Per Share - Income (loss) from continuing operations	($0.43)	($0.73)	($2.22)	($2.22)	($1.24)
Per Share - Net income (loss)	($0.43)	($0.73)	($2.16)	$0.85	($1.24)
Cash flow from continuing operations	$219,746	$298,088	$233,598	$249,306	$391,522
Total assets	$1,964,214	$2,642,598	$2,569,897	$2,139,398	$2,274,337
Total debt	$513,372	$1,196,908	$1,324,383	$798,700	$1,070,445
Stockholders' equity	$1,068,531	$1,037,625	$933,534	$952,005	$870,272

Operational Highlights

	2010	2011	2012	2013	2014
Capital expenditures (000)	$545,650	$694,207	$348,179	$480,873	$588,614
Net producing wells	854.0	903.2	863.4	821.8	869.7
Natural gas production (MMcf per day)	189	248	223	153	109
Oil production (Barrels per day)	1,958	2,297	4,897	6,339	11,816
Equivalent units (MMcfe per day)	201	262	253	191	180
Proved gas reserves (Bcf)	1,026	1,081	437	453	495
Proved oil reserves (MBbls)	4,219	13,234	18,899	21,976	20,854
Proved reserves (Bcfe)	1,051	1,160	551	585	620

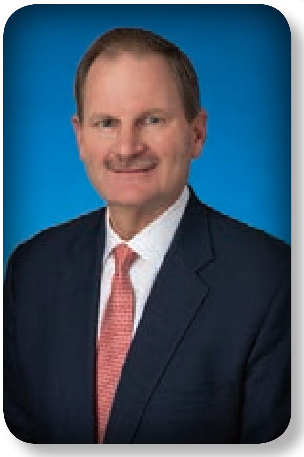
MAJOR PROPERTIES

	2014 Reserves		2014 Production	
	Total (Bcfe)	% of Total	Total (MMcfe/D)	% of Total
East Texas / North Louisiana	384.7	62%	86.0	48%
South Texas	221.2	36%	89.6	50%
Other Regions	14.5	2%	4.3	2%
	620.4	100%	179.9	100%

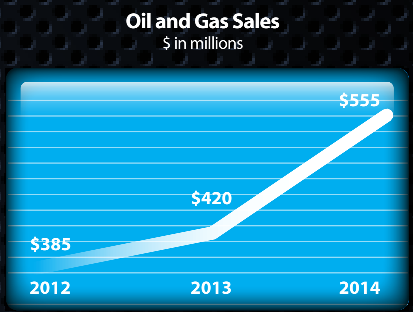


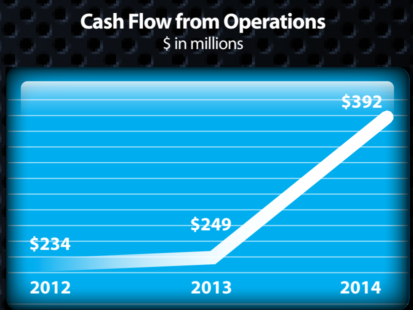
To our stockholders:

In 2014 we were able to accomplish many of our goals which were centered around building up our oil operations. Our successful drilling program in our Eagleville field in South Texas allowed us to increase our oil production by 86%. We also invested in new oil opportunities in the East Texas expansion of the Eagle Ford shale and in the emerging Tuscaloosa Marine shale. The growth in oil production caused our oil & gas sales to increase by 32% over 2013 and our cash flow from operations grew 57% in 2014. Unfortunately the bottom fell out of oil prices in the fourth quarter, but the progress we made to build up our oil operations will serve us well when oil prices rebound.



Advances in completion technology that we have applied to the oil shales offer the potential for improved returns from our largest asset, our properties in the Haynesville and Bossier shales in East Texas and North Louisiana. We plan to focus on natural gas again in 2015.





2014 Financial Results

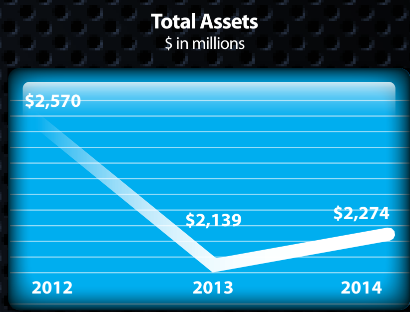
We reported a net loss of $57 million, or $1.24 per share, for 2014 as compared to net income of $41 million or 85¢ per share for 2013. Of the 2013 net income, $148 million, or $3.07 per share, was attributable to the sale of our West Texas operations in May 2013, which resulted in a gain of $230 million ($149 million after tax). The loss from continuing operations for 2013 was $107 million, or $2.22 per share. Our 2014 financial results also included certain unusual items, the largest of which were impairments of oil and gas properties and unevaluated leases and exploratory dry hole costs totaling $80 million. Excluding unusual items, the net loss in 2014 would have been $5 million (12¢ per share).

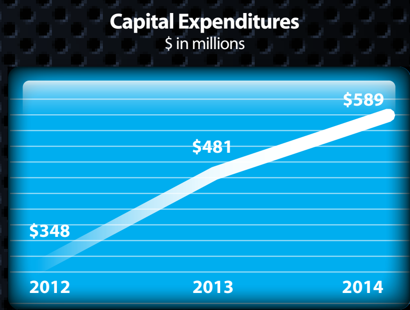
In 2014, our oil and gas sales increased 32% as growth in our oil production and improved natural gas prices offset the decrease in our natural gas production. We generated operating cash flow of $392 million in 2014 which was 57% higher than 2013's operating cash flow of $249 million. With the growth in oil production, our operating costs increased 15% in 2014 to $97 million as compared to $85 million in 2013 and our depreciation, depletion and amortization increased 12% in 2014

to $378 million as compared to $337 million in 2013. Even with the increase in oil production, we were able to reduce certain of our other costs in 2014. Our general and administrative expenses in 2014 decreased 7% to $32 million as compared to $35 million in 2013. Our exploration costs decreased in 2014 to $19 million as compared to $33 million in 2013, and our interest expense decreased 20% in 2014 to $59 million in 2014 as compared to $73 million in 2013. The decrease in interest expense was due to the debt that we retired in 2013 following the sale of our West Texas properties.

Drilling Program

During 2014, we spent $490 million on development and exploration activities and $98 million on acreage and acquisition costs. We drilled 80 horizontal oil wells (54.7 net) and one natural gas well (0.2 net). We drilled 68 successful South Texas Eagle Ford wells and put 91 wells on production. In our new East Texas Eagle Ford shale play we drilled 11 wells with 10 being successful. We placed six of those wells on production and have eight more to be completed in 2015. We drilled our first well on our 82,000 net acres in the Tuscaloosa Marine shale. Our Eagle Ford shale horizontal well



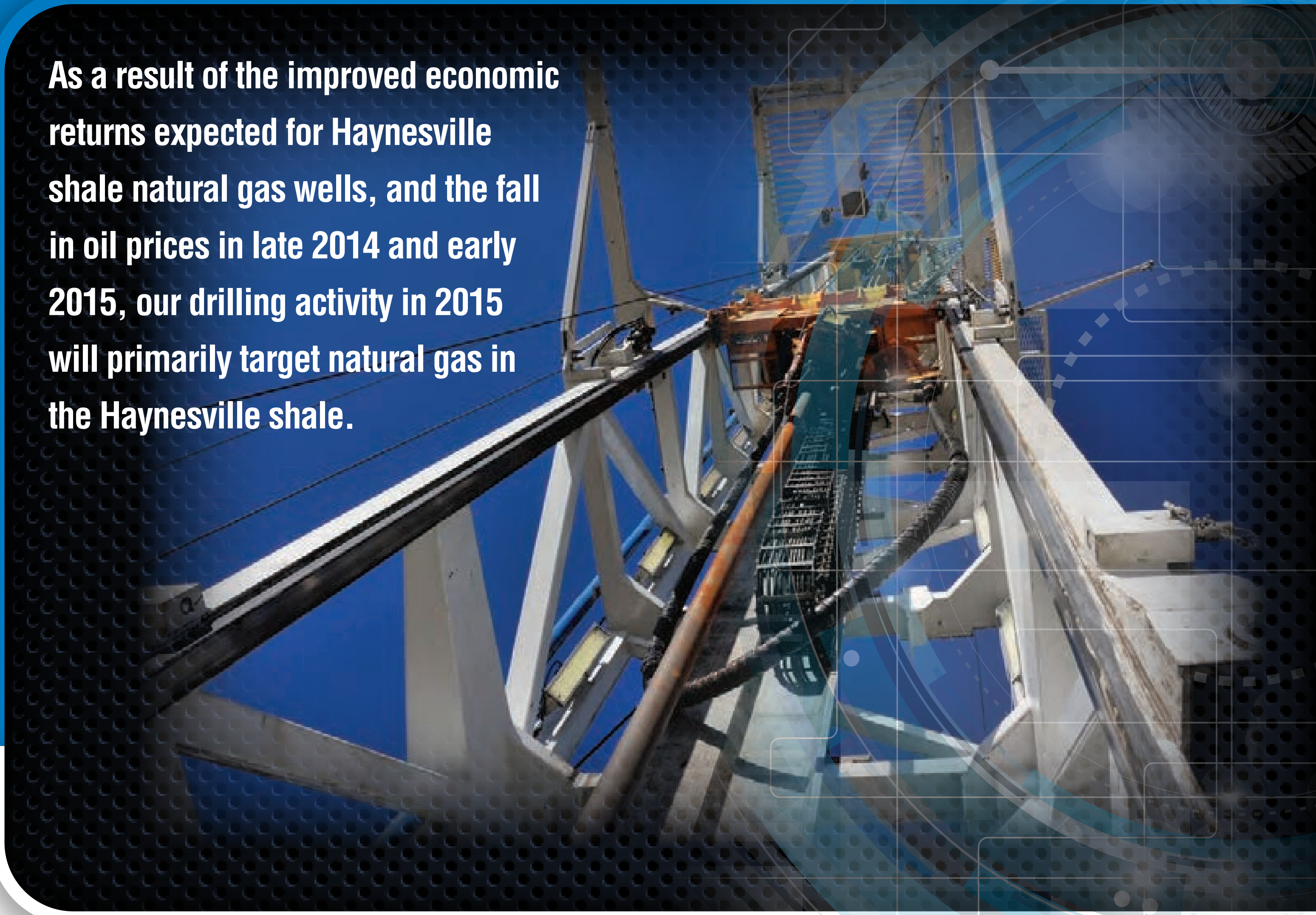


drilling program in our Eagleville field in South Texas was the primary driver of the growth in our oil production and proved oil reserves in 2014. Our drilling program in the Eagle Ford shale added 5.1 million barrels of oil and 5 Bcf of natural gas or 5.9 million barrels of oil equivalent to proved reserves in 2014.

South Texas Region

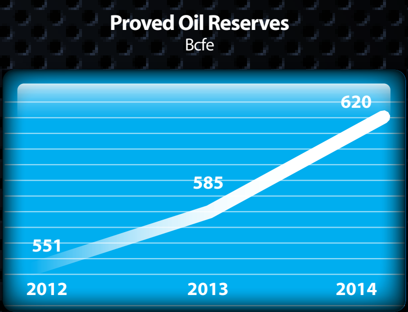
In our South Texas region we have 36.9 million barrels of oil equivalent reserves which are 36% of our total reserves. 55% of our reserves in this region are oil. We have 55,000 net acres in our South Texas region that are in the oil window of the Eagle Ford shale play. This region accounted for 97% of our oil production at 11,500 barrels of oil per day and 19% of our natural gas production at 20 MMcf per day. Our oil production in the region increased 89% as a result of our drilling Eagle Ford shale wells. Natural gas production in this region increased by 3% in 2014 with the associated natural gas from the Eagle Ford shale wells. We spent $463 million in 2014 to drill 79 (53.7 net) horizontal Eagle Ford shale wells. We completed 88 Eagle Ford shale wells which had an average per well initial production rate of 737 barrels of oil equivalent per day.

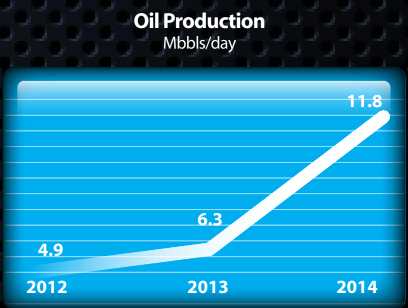
As a result of the improved economic returns expected for Haynesville shale natural gas wells, and the fall in oil prices in late 2014 and early 2015, our drilling activity in 2015 will primarily target natural gas in the Haynesville shale.



East Texas/North Louisiana Region

At the end of 2014, we had 385 Bcfe of our proved reserves (62%) in our East Texas/North Louisiana region. The properties in this region are essentially all natural gas. In response to the very low natural gas prices we discontinued drilling in this region in the first quarter of 2012 and drilled only two wells in this region in 2013. As a result our production from this region which averaged 86 MMcfe per day in 2014 declined by 34% from 2013. We currently have 69,000 net acres that we believe are prospective for Haynesville or Bossier shale development. We believe that our acreage has over 6 Tcfe of combined reserve potential for these two plays. Advances in completion technology since we last drilled wells in this region are expected to improve recoveries through longer horizontal lateral length and substantially larger well stimulation. As a result of the improved economic returns expected for Haynesville shale natural gas wells, and the fall in oil prices in late 2014 and early 2015, our drilling activity in 2015 will primarily target natural gas in the Haynesville shale.





Other Regions

We have 14 Bcfe in the San Juan basin, the Tuscaloosa Marine shale and in other areas. Our properties in the other regions accounted for 2% of our 2014 daily production at 4 MMcfe per day.

Outlook for 2015

With the severe drop in oil prices and weaker natural gas prices, we enter 2015 with our primary focus on preserving liquidity and protecting the Company's balance sheet. The first step we took last December was to substantially reduce our oil directed drilling program. We released four operated drilling rigs that we had lined up for 2015. We decided to pursue a prudent natural gas drilling program in the Haynesville shale based on enhanced recovery from longer laterals and increased stimulation. We have mapped over 1,200 drilling locations on our acreage which have over 6 Tcf of reserve potential. This program will provide strong natural gas production growth in 2015. The new production is near the Gulf Coast market which has premium price realizations in comparison to most other basins in the country. We have put our

oil program on hold in the current low oil price environment. Once oil prices improve, we have 235 identified future operated Eagle Ford shale locations and 327 future operated Tuscaloosa Marine shale locations. We have one of the lowest overall cost structures in the industry, and we intend to maintain a low cost structure on-going. Lastly, we plan to safeguard our balance sheet in 2015 due to the oil and gas price uncertainty that we are currently experiencing. We will continue to evaluate our drilling activity and will reduce activity as needed to preserve our liquidity. We completed a $700 million bond offering in March 2015 to protect our current liquidity from potential reductions in borrowing availability from our bank group. The financing ensures that we have no debt maturities for the next three years and that we have adequate cash reserves to weather this storm of low prices.

The directors and management of Comstock want to thank the stockholders for their continued support.

M. Jay Allison

Chairman and Chief Executive Officer

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2014

OR

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

For the transition period from to

Commission File No. 001-03262

COMSTOCK RESOURCES, INC.

(Exact name of registrant as specified in its charter)

NEVADA	**94-1667468**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*

5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034

(Address of principal executive offices including zip code)

(972) 668-8800

(Registrant's telephone number and area code)

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

Common Stock, $.50 Par Value	**New York Stock Exchange**
(Title of class)	*(Name of exchange on which registered)*

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

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

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 ☑

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 ☑ 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 ☑ 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. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if smaller reporting company) Smaller reporting company ☐

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

The aggregate market value of the common stock held by non-affiliates of the registrant, based on the closing price of common stock on the New York Stock Exchange on June 30, 2014 (the last business day of the registrant's most recently completed second fiscal quarter), was $1.3 billion.

As of February 24, 2015, there were 47,626,557 shares of common stock of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement for the 2015 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

COMSTOCK RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2014

CONTENTS

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information contained in this report includes “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. These forward-looking statements are identified by their use of terms such as “expect,” “estimate,” “anticipate,” “project,” “plan,” “intend,” “believe” and similar terms. All statements, other than statements of historical facts, included in this report, are forward-looking statements, including statements mentioned under “Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” regarding:

- amount and timing of future production of oil and natural gas;
- amount, nature and timing of capital expenditures;
- the number of anticipated wells to be drilled after the date hereof;
- the availability of exploration and development opportunities;
- our financial or operating results;
- our cash flow and anticipated liquidity;
- operating costs including lease operating expenses, administrative costs and other expenses;
- finding and development costs;
- our business strategy; and
- other plans and objectives for future operations.

Any or all of our forward-looking statements in this report may turn out to be incorrect. They can be affected by a number of factors, including, among others:

- the risks described in “Risk Factors” and elsewhere in this report;
- the volatility of prices and supply of, and demand for, oil and natural gas;
- the timing and success of our drilling activities;
- the numerous uncertainties inherent in estimating quantities of oil and natural gas reserves and actual future production rates and associated costs;
- our ability to successfully identify, execute or effectively integrate future acquisitions;
- the usual hazards associated with the oil and natural gas industry, including fires, well blowouts, pipe failure, spills, explosions and other unforeseen hazards;
- our ability to effectively market our oil and natural gas;
- the availability of rigs, equipment, supplies and personnel;
- our ability to discover or acquire additional reserves;
- our ability to satisfy future capital requirements;
- changes in regulatory requirements;
- general economic conditions, status of the financial markets and competitive conditions;
- our ability to retain key members of our senior management and key employees; and
- hostilities in the Middle East and other sustained military campaigns and acts of terrorism or sabotage that impact the supply of crude oil and natural gas.

DEFINITIONS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report. Natural gas equivalents and crude oil equivalents are determined using the ratio of six Mcf to one barrel. All references to "us," "our," "we" or "Comstock" mean the registrant, Comstock Resources, Inc. and where applicable, its consolidated subsidiaries.

"Bbl" means a barrel of U.S. 42 gallons of oil.

"Bcf" means one billion cubic feet of natural gas.

"Bcfe" means one billion cubic feet of natural gas equivalent.

"BOE" means one barrel of oil equivalent.

"Btu" means British thermal unit, which is the quantity of heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

"Completion" means the installation of permanent equipment for the production of oil or gas.

"Condensate" means a hydrocarbon mixture that becomes liquid and separates from natural gas when the gas is produced and is similar to crude oil.

"Development well" means a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

"Dry hole" means a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Exploratory well" means a well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new productive reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

"GAAP" means generally accepted accounting principles in the United States of America.

"Gross" when used with respect to acres or wells, production or reserves refers to the total acres or wells in which we or another specified person has a working interest.

"MBbls" means one thousand barrels of oil.

"MBbls/d" means one thousand barrels of oil per day.

"Mcf" means one thousand cubic feet of natural gas.

"Mcfe" means one thousand cubic feet of natural gas equivalent.

"MMBbls" means one million barrels of oil.

"MMBOE" means one million barrels of oil equivalent.

"MMBtu" means one million British thermal units.

"MMcf" means one million cubic feet of natural gas.

“MMcf/d” means one million cubic feet of natural gas per day.

“MMcfe/d” means one million cubic feet of natural gas equivalent per day.

“MMcfe” means one million cubic feet of natural gas equivalent.

“Net” when used with respect to acres or wells, refers to gross acres of wells multiplied, in each case, by the percentage working interest owned by us.

“Net production” means production we own less royalties and production due others.

“Oil” means crude oil or condensate.

“Operator” means the individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

“PV 10 Value” means the present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with the Securities and Exchange Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. This amount is the same as the standardized measure of discounted future net cash flows related to proved oil and natural gas reserves except that it is determined without deducting future income taxes. Although PV 10 Value is not a financial measure calculated in accordance with GAAP, management believes that the presentation of PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. Because many factors that are unique to any given company affect the amount of estimated future income taxes, the use of a pre-tax measure is helpful to investors when comparing companies in our industry.

“Proved developed reserves” means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

“Proved developed non-producing” means reserves (i) expected to be recovered from zones capable of producing but which are shut-in because no market outlet exists at the present time or whose date of connection to a pipeline is uncertain or (ii) currently behind the pipe in existing wells, which are considered proved by virtue of successful testing or production of offsetting wells.

“Proved developed producing” means reserves expected to be recovered from currently producing zones under continuation of present operating methods. This category includes recently completed shut-in gas wells scheduled for connection to a pipeline in the near future.

“Proved reserves” means the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided by contractual arrangements.

“Proved undeveloped reserves” means 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 are limited to those drilling locations offsetting productive wells that are reasonably certain of production when drilled or where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

"Recompletion" means the completion for production of an existing well bore in another formation from which the well has been previously completed.

"Reserve life" means the calculation derived by dividing year-end reserves by total production in that year.

"Reserve replacement" means the calculation derived by dividing additions to reserves from acquisitions, extensions, discoveries and revisions of previous estimates in a year by total production in that year.

"Royalty" means an interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

"3-D seismic" means an advanced technology method of detecting accumulations of hydrocarbons identified by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

"Tcfe" means one trillion cubic feet of natural gas equivalent.

"Working interest" means an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. For example, the owner of a 100% working interest in a lease burdened only by a landowner's royalty of 12.5% would be required to pay 100% of the costs of a well but would be entitled to retain 87.5% of the production.

"Workover" means operations on a producing well to restore or increase production.

PART I

ITEMS 1 and 2. *BUSINESS AND PROPERTIES*

We are engaged in the acquisition, development, production and exploration of oil and natural gas. Our common stock is listed and traded on the New York Stock Exchange. In 2013, we divested all of our oil and gas properties in West Texas and, accordingly, the discussion which follows pertains solely to our continuing oil and gas operations.

Our oil and gas operations are concentrated in Texas and Louisiana. Our oil and natural gas properties are estimated to have proved reserves of 620 Bcfe with an estimated PV 10 Value of $1.1 billion as of December 31, 2014 and a standardized measure of discounted future net cash flows of $1.1 billion. Our proved oil and natural gas reserve base is 80% natural gas and 20% oil and was 68% developed as of December 31, 2014.

Our proved reserves at December 31, 2014 and our 2014 average daily production are summarized below:

	Proved Reserves at December 31, 2014				2014 Average Daily Production			
	Oil (MMBbls)	Natural Gas (Bcf)	Total (Bcfe)	% of Total	Oil (MBbls/d)	Natural Gas (MMcf/d)	Total (MMcfe/d)	% of Total
East Texas / North Louisiana	0.5	382.0	384.7	62.0%	0.2	84.7	86.0	47.8%
South Texas	20.1	100.5	221.2	35.7%	11.5	20.3	89.6	49.8%
Other Regions	0.3	12.8	14.5	2.3%	0.1	4.0	4.3	2.4%
Total	20.9	495.3	620.4	100.0%	11.8	109.0	179.9	100.0%

Strengths

High Quality Properties. Our operations are focused in two operating areas: East Texas/North Louisiana and South Texas. Our properties have an average reserve life of approximately 9.5 years and have extensive development and exploration potential. In recent years, we have focused our drilling activity primarily on oil projects in our South Texas region. Our Eagleville field includes 31,459 acres (23,547 net to us) located in the oil window of the Eagle Ford shale in South Texas. In 2014 73% of our drilling and completion expenditures were related to our Eagleville field development. We also have 35,322 acres (31,465 net to us) in the oil window of the Eagle Ford shale in or near Burleson County, Texas, where we spent 20% of our 2014 drilling and completion expenditures. In addition to our acreage in the Eagle Ford shale, we have 91,208 acres (82,468 net to us) in Mississippi and Louisiana that are prospective for development in the Tuscaloosa Marine shale. Our properties in the East Texas/North Louisiana region, which are primarily prospective for natural gas, include 81,294 acres (68,877 net to us) in the Haynesville or Bossier shale formations. Advances in completion technology since we last drilled wells in this region are expected to improve recoveries through longer horizontal lateral length and substantially larger well stimulation. As a result of the improved economic returns expected for Haynesville shale natural gas wells, and the fall in oil prices in late 2014 and early 2015, our drilling activity in 2015 will primarily target natural gas in the Haynesville shale.

Successful Exploration and Development Program. In 2014 we spent $587.8 million on exploration and development activities, of which $472.7 million was for drilling and completing wells. We drilled 81 wells (55.0 net to us) and completed 91 wells (61.3 net to us). We also spent $97.7 million in 2014 to acquire additional leasehold, $0.4 million to acquire seismic data and $10.3 million for recompletions, workovers, abandonment, and production facilities. In addition, we spent $6.7 million to release two drilling rigs before their contract termination dates. Of our 2014 capital expenditures, 98% was directed towards oil projects. Our drilling in 2014 increased our oil production by 86% from 2013's oil production and increased reserves in our oil properties by 6.2 MMBOE.

Efficient Operator. We operated 96% of our proved reserve base as of December 31, 2014. As operator we are better able to control operating costs, the timing and plans for future development, the level of drilling and lifting costs and the marketing of production. As an operator, we receive reimbursements for overhead from other working interest owners, which reduces our general and administrative expenses.

Successful Acquisitions. We have had significant growth over the years as a result of our acquisition activity. In recent years we have focused primarily on acquiring undrilled acreage rather than producing properties. We apply strict economic and reserve risk criteria in evaluating acquisitions. Since 1991, we have added 1.1 Tcfe of proved oil and natural gas reserves from 38 acquisitions of producing oil and gas properties at an average cost of $1.17 per Mcfe. Our application of strict economic and reserve risk criteria have enabled us to successfully evaluate and integrate acquisitions.

Business Strategy

Pursue Exploration Opportunities. Each year, we conduct exploration activities to grow our reserve base and to replace our production. While in recent years we have been focused on oil development, in 2015 we are shifting our focus back to natural gas development primarily due to advances in completion technology and the significant decline in oil prices that began in late 2014.

In 2014 our Eagleville field in South Texas was the primary focus of our drilling activity. From 2010 through 2014, we spent approximately $169.5 million leasing acreage in McMullen, Atascosa, Frio, La Salle, Karnes and Wilson Counties in South Texas, in the oil window of the Eagle Ford shale formation. In 2012 we entered into a joint venture arrangement to allow us to accelerate the development of this field. Our joint venture partner participates for a one-third interest in the wells that we drill in exchange for paying $25,000 per net acre that is earned by their participation. Through December 31, 2014, we have drilled 196 wells (138.2 net to us) in our Eagleville field including 68 wells (43.9 net to us) that were drilled in 2014. Our joint venture partner participated in 144 of these wells and contributed $86.0 million through December 31, 2014 for acreage and an additional $9.1 million to reimburse us for a portion of common production facilities. We have budgeted to spend $51.0 million in 2015, net of reimbursements from our joint venture partner, to complete four wells (2.2 net to us) that were drilled in 2014 and for production facilities and other capital projects.

We spent a total of $126.1 million in 2013 and 2014 to lease 35,322 acres (31,465 net to us) in or near Burleson County, Texas which are prospective for oil in the Eagle Ford shale formation. During 2014, we spent $98.1 million to drill 11 wells (9.9 net to us) on this acreage. In 2015 we have budgeted to spend $64.0 million to drill four wells (4.0 net to us), to complete four wells (3.8 net to us) that were drilled in 2014 and for production facilities and other capital projects.

Through the end of 2014 we spent $91.7 million to acquire 91,208 acres (82,468 net to us) in Louisiana and Mississippi which are prospective for oil in the Tuscaloosa Marine shale. During 2014 we drilled our first well on this acreage. We suspended development of this acreage in late 2014 due to the substantial decline in oil prices. We have budgeted $3.0 million to participate in one non-operated well and for production facilities and other capital projects in 2015.

We have 81,294 acres (68,877 net to us) in East Texas and North Louisiana with Haynesville or Bossier shale natural gas potential. We have restarted our gas focused drilling program in 2015 based on a new completion design that we believe will enhance the economics of new wells drilled on our Haynesville shale acreage. We have budgeted $185.0 million in 2015 to drill 14 horizontal natural gas wells (14.0 net to us) and to recomplete ten producing Haynesville shale gas wells.

Exploit Existing Reserves. We seek to maximize the value of our oil and gas properties by increasing production and recoverable reserves through development drilling and workover, recompletion and exploitation activities. We utilize advanced industry technology, including 3-D seismic data, horizontal drilling, enhanced logging tools, and formation stimulation techniques. We have budgeted $17.0 million in 2015 to refrac ten of our producing horizontal wells in the Haynesville shale. This pilot program being conducted in 2015 could provide support for a larger program to re-stimulate many of our 186 producing natural gas shale wells and may also have applicability to our 208 horizontal oil shale wells.

Maintain Flexible Capital Expenditure Budget. The timing of most of our capital expenditures is discretionary because we have not made any significant long-term capital expenditure commitments except for contracted drilling and completion services. We operate most of the drilling projects in which we participate. Consequently, we have a significant degree of flexibility to adjust the level of such expenditures according to market conditions. For 2015 we have two operated drilling rigs under contract for our Haynesville shale drilling program. The contacts expire in August and November 2015. The total early termination fees to release these two rigs as of February 28, 2015 would be approximately $8.0 million. We have budgeted to spend approximately $307.0 million in 2015 on our development and exploration projects and $10.0 million for lease acquisition activity.

Acquire High Quality Properties at Attractive Costs. Historically, we have had a successful track record of increasing our oil and natural gas reserves through opportunistic acquisitions. Since 1991, we have added 1.1 Tcfe of proved oil and natural gas reserves from 38 acquisitions of producing oil and gas properties at a total cost of $1.3 billion, or $1.17 per Mcfe. The acquisitions were acquired at an average of 67% of their PV 10 Value in the year the acquisitions were completed. In evaluating acquisitions, we apply strict economic and reserve risk criteria. We target properties in our core operating areas with established production and low operating costs that also have potential opportunities to increase production and reserves through exploration and exploitation activities. We also evaluate our existing properties and consider divesting of non-strategic assets when market conditions are favorable.

Primary Operating Areas

The following table summarizes the estimated proved oil and natural gas reserves for our fifteen largest field areas as of December 31, 2014:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)(1)	%	PV 10 Value(2) (000's)	%
East Texas / North Louisiana:						
Logansport	36	283,051	283,269	45.7%	$ 285,360	24.9%
Beckville	146	30,731	31,605	5.1%	44,305	3.9%
Toledo Bend	—	20,464	20,464	3.3%	26,852	2.3%
Waskom	67	11,755	12,155	2.0%	18,367	1.6%
Blocker	46	10,691	10,964	1.8%	14,535	1.3%
Mansfield	—	8,366	8,366	1.3%	8,510	0.7%
Douglass	1	3,528	3,535	0.6%	2,701	0.2%
Longwood	35	2,686	2,898	0.5%	4,561	0.4%
Other	117	10,735	11,439	1.7%	18,036	1.7%
	448	382,007	384,695	62.0%	423,227	37.0%
South Texas:						
Eagleville	16,282	14,716	112,405	18.1%	562,757	49.2%
Fandango	—	44,448	44,448	7.2%	43,117	3.8%
Giddings	3,749	3,873	26,369	4.3%	49,622	4.3%
Rosita	1	21,425	21,429	3.5%	12,746	1.1%
Javelina	36	6,624	6,839	1.1%	10,786	0.9%
Las Hermanitas	—	5,307	5,308	0.9%	5,716	0.5%
Other	46	4,144	4,422	0.6%	6,540	0.6%
	20,114	100,537	221,220	35.7%	691,284	60.4%
Other:						
San Juan Basin	7	2,524	2,569	0.4%	3,376	0.3%
Other	285	10,198	11,904	1.9%	26,384	2.3%
	292	12,722	14,473	2.3%	29,760	2.6%
Total	20,854	495,266	620,388	100.0%	1,144,271	100.0%
Discounted Future Income Taxes					(53,611)	
Standardized Measure of Discounted Future Cash Flows					$1,090,660	

(1) Oil is converted to natural gas equivalents by using a conversion factor of one barrel of oil for six Mcf of natural gas based upon the approximate relative energy content of oil to natural gas, which is not indicative of oil and natural gas prices.

(2) The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although it is a non-GAAP measure, we believe that the presentation of the PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves after income tax, discounted at 10%.

East Texas/North Louisiana Region

Approximately 62% or 384.7 Bcfe of our proved reserves are located in East Texas and North Louisiana where we own interests in 935 producing wells (574.1 net to us) in 28 field areas. We operate 648 of these wells. The largest of our fields in this region are the Logansport, Beckville, Toledo Bend, Waskom, Blocker, Mansfield, Douglass and Longwood fields. Production from this region averaged 85 MMcf of natural gas per day and 206 barrels of oil per day during 2014 or 86 MMcfe per day. Most of the reserves in this area produce from the upper Jurassic aged Haynesville or Bossier shale or Cotton Valley formations and the Cretaceous aged Travis Peak/Hosston formation. In 2014, we spent $1.4 million drilling one well (0.2 net to us), $2.2 million on workovers and recompletions and $0.6 million on leasing activity in this region. We plan to spend approximately $185.0 million in 2015 to drill 14 Haynesville/ Bossier shale natural gas wells (14.0 net to us) and to recomplete ten producing Haynesville shale wells.

Logansport

The Logansport field located in DeSoto Parish, Louisiana primarily produces from the Haynesville and Bossier shale formations at a depth of 11,100 to 11,500 feet and from multiple sands in the Cotton Valley and Hosston formations at an average depth of 8,000 feet. Our proved reserves of 283.3 Bcfe in the Logansport field represent approximately 46% of our proved reserves. We own interests in 245 wells (159.9 net to us) and operate 175 of these wells in this field. Our 2015 drilling program will be focused on drilling fourteen horizontal wells in Logansport targeting the Haynesville shale formation each with a planned lateral length of 7,500 feet. The lateral lengths are approximately 64% longer than Haynesville shale wells we have previously drilled and these wells will have substantially larger stimulation jobs.

Beckville

The Beckville field, located in Panola and Rusk Counties, Texas, has estimated proved reserves of 31.6 Bcfe which represents approximately 5% of our proved reserves. We operate 187 wells in this field and own interests in 76 additional wells for a total of 263 wells (156.3 net to us). The Beckville field produces primarily from the Cotton Valley formation at depths ranging from 9,000 to 10,000 feet. The field is also prospective for future Haynesville shale development.

Toledo Bend

The Toledo Bend field, located in DeSoto and Sabine Parishes in Louisiana, is productive in the Haynesville shale from 11,400 to 11,800 feet and in the Bossier shale from 10,880 to 11,300 feet. Our proved reserves of 20.5 Bcfe in the Toledo Bend field represent approximately 3% of our reserves. We own interests in 76 producing wells (39.3 net to us) and operate 41 of these wells in this field.

Waskom

The Waskom field, located in Harrison and Panola Counties in Texas, represents approximately 2% (12.2 Bcfe) of our proved reserves. We own interests in 60 wells in this field (36.8 net to us) and operate 45 wells in this field. The Waskom field produces from the Cotton Valley formation at depths ranging from 9,000 to 10,000 feet and from the Haynesville shale formation at depths of 10,800 to 10,900 feet.

Blocker

Our proved reserves of 11.0 Bcfe in the Blocker field located in Harrison County, Texas represent approximately 2% of our proved reserves. We own interests in 77 wells (71.0 net to us) and operate 71 of these wells. Most of this production is from the Cotton Valley formation between 8,600 and 10,150 feet and the Haynesville shale formation between 11,100 and 11,450 feet.

Mansfield

The Mansfield field is located in DeSoto Parish, Louisiana and produces from the Haynesville shale between 12,250 and 12,350 feet. We own interests in 17 wells (4.6 net to us) and operate 4 of these wells. Our proved reserves in this field of 8.4 Bcfe represent approximately 1% of our total reserves.

Douglass

The Douglass field is located in Nacogdoches County, Texas and is productive from stratigraphically trapped reservoirs in the Pettet Lime and Travis Peak formations. These reservoirs are found at depths from 9,200 to 10,300 feet. Our proved reserves of 3.5 Bcfe in the Douglass field represent less than 1% of our reserves. We own interests in 38 wells (24.9 net to us) and operate 32 of these wells.

Longwood

The Longwood field located in Harrison County, Texas primarily produces from stacked sandstone reservoirs of the Travis Peak and Cotton Valley formation at depths from approximately 6,000 to 10,000 feet. Our proved reserves of 2.9 Bcfe in the Longwood field represent less than 1% of our reserves. We own interests in 23 wells (18.7 net to us) and operate 20 of these wells.

South Texas Region

Approximately 36%, or 36.9 MMBOE (221.2 Bcfe), of our proved reserves are located in South Texas, where we own interests in 325 producing wells (212.0 net to us). We own interests in 14 field areas in the region, the largest of which are the Eagleville, Fandango, Giddings, Rosita, Javelina and Las Hermanitas fields. Net daily production rates from this region averaged 11,546 barrels of oil and 20 MMcf of natural gas during 2014 or 14,933 BOE per day. We spent $462.5 million in 2014 to drill 79 oil wells (53.7 net to us) targeting the Eagle Ford shale and for other development activity. We also spent $58.7 million in this region in 2014 to acquire acreage in or near Burleson County, Texas which is prospective in the Eagle Ford shale formation. We plan to spend approximately $115.0 million in 2015 to drill four horizontal wells, to complete eight wells that were drilled in 2014 and for production facilities and other capital projects.

Eagleville

We have 31,459 acres (23,547 net to us) in McMullen, Atascosa, Frio, La Salle, Karnes and Wilson Counties which comprise our Eagleville field. The Eagle Ford shale is found between 7,500 feet and 11,500 feet across our acreage position. At December 31, 2014 we had 188 wells (133.2 net to us) producing in the Eagleville field. Our proved reserves in this field are estimated to be 18.7 MMBOE (112.4 Bcfe) (87% oil) and represent 18% of our total proved reserves. We plan to spend approximately $51.0 million in 2015 to complete four wells (2.2 net to us) that were drilled in 2014 and for production facilities and other capital projects.

Fandango

We own interests in 18 wells (18.0 net to us) in the Fandango field located in Zapata County, Texas. We operate all of these wells which produce from the Wilcox formation at depths from approximately 13,000 to 18,000 feet. Our proved reserves of 44.5 Bcfe in this field represent approximately 7% of our total proved reserves.

Giddings

We have 35,322 acres (31,465 net to us) in Burleson County which comprise our Giddings field. The Eagle Ford shale is found between 8,500 feet and 12,200 feet across our acreage position. At December 31, 2014 we had seven wells (6.1 net to us) producing in the Giddings field. Our proved reserves in this field are estimated to be 4.4 MMBOE (26.4 Bcfe) (85% oil) and represent 4% of our total proved reserves. We plan to spend approximately $64.0 million in 2015 to drill four wells (4.0 net to us), to complete four wells (3.8 net to us) that were drilled in 2014 and for production facilities and other capital projects.

Rosita

We own interests in 24 wells (13.3 net to us) in the Rosita field, located in Duval County, Texas. We operate 23 of these wells which produce from the Wilcox formation at depths from approximately 9,300 to 17,000 feet. Our proved reserves of 21.4 Bcfe in this field represent approximately 4% of our total proved reserves.

Javelina

We own interests in and operate 17 wells (17.0 net to us) in the Javelina field in Hidalgo County in South Texas. These wells produce primarily from the Vicksburg formation at a depth of approximately 10,900 to 12,500 feet. Proved reserves attributable to our interests in the Javelina field are 6.8 Bcfe, which represents approximately 1% of our total proved reserves.

Las Hermanitas

We own interests in and operate 12 natural gas wells (12.0 net to us) in the Las Hermanitas field, located in Duval County, Texas. These wells produce from the Wilcox formation at depths from approximately 11,400 to 11,800 feet. Our proved reserves of 5.3 Bcfe in this field represent approximately 1% of our total proved reserves.

Other Regions

Approximately 2%, or 14.5 Bcfe, of our proved reserves are in other regions, primarily in New Mexico and the Mid-Continent region. We also have a large acreage position in Mississippi and Louisiana in the emerging Tuscaloosa Marine shale play. We own interests in 336 producing wells (83.6 net to us) in 15 fields within these regions. The field with the largest proved reserves is our San Juan Basin properties in New Mexico. Net daily production from our other regions during 2014 totaled 4 MMcf of natural gas and 64 barrels of oil or 4 MMcfe per day.

San Juan

Our San Juan Basin properties are located in the west-central portion of San Juan County, New Mexico. These wells produce from multiple sands of the Cretaceous Dakota formation and the Fruitland Coal seams. The Dakota is generally found at about 6,000 feet with the shallower Fruitland seams encountered at 2,500 to 3,000 feet. Our proved reserves of 2.6 Bcfe in the San Juan field represent less than 1% of our reserves. We own interests in 92 wells (14.0 net to us) in this field.

Tuscaloosa Marine Shale

We own 91,208 acres (82,468 net to us) in Louisiana and Mississippi which are prospective for oil in the Tuscaloosa Marine shale. The Tuscaloosa Marine shale is found between 11,400 feet and 13,400 feet across our acreage position. In 2014 we drilled one well (1.0 net to us). We plan to spend $3.0 million in 2015 to participate in one non-operated well and for production facilities and other capital projects on this acreage.

Major Property Acquisitions

As a result of our acquisitions of producing oil and gas properties, we have added 1.1 Tcfe of proved oil and natural gas reserves since 1991. Our five largest acquisitions include the following:

Delaware Basin Acquisition. In December 2011, we acquired certain oil and gas properties from Eagle Oil & Gas Co. and other third parties for $348.7 million. The properties acquired had estimated proved reserves of approximately 151.2 Bcfe and included approximately 65,000 exploratory acres (39,100 net to us). We divested of these properties in May 2014.

Shell Wilcox Acquisition. In December 2007, we completed the acquisition of certain oil and natural gas properties and related assets from SWEPI LP, an affiliate of Shell Oil Company for $160.1 million. The properties acquired had estimated proved reserves of approximately 70.1 Bcfe. Major fields acquired in the acquisition include the Fandango and Rosita fields.

Ensight Acquisition. In May 2005, we completed the acquisition of certain oil and natural gas properties and related assets from Ensight Energy Partners, L.P., Laurel Production, LLC, Fairfield Midstream Services, LLC and Ensight Energy Management, LLC (collectively, "Ensight") for $190.9 million. We also purchased additional interests in those properties from other owners for $10.9 million in July 2005. The properties acquired had estimated proved reserves of approximately 121.5 billion cubic feet of natural gas equivalent and included 312 active wells, of which 119 are operated by us. Major fields acquired include the Darco, Douglass, Cadeville, and Laurel fields. We divested of the Laurel field in 2010.

Bois d'Arc Acquisition. In December 1997, Comstock acquired working interests in certain producing offshore Louisiana oil and gas properties as well as interests in undeveloped offshore oil and natural gas leases for approximately $200.9 million from Bois d'Arc Resources and certain of its affiliates and working interest partners. We acquired interests in 43 wells (29.6 net to us) and eight separate production complexes located in the Gulf of Mexico offshore of Plaquemines and Terrebonne Parishes, Louisiana. The acquisition included interests in the Louisiana state and federal offshore areas of Main Pass Block 21, Ship Shoal Blocks 66, 67, 68 and 69 and South Pelto Block 1. The net proved reserves acquired in this acquisition were estimated at 14.3 MMBbls of oil and 29.4 Bcf of natural gas. We divested of these offshore properties in 2008.

Black Stone Acquisition. In May 1996, we acquired 100% of the capital stock of Black Stone Oil Company and interests in producing and undeveloped oil and gas properties located in South Texas for $100.4 million. We acquired interests in 19 wells (7.7 net to us) that were located in the Double A Wells field in Polk County, Texas and we became the operator of most of the wells in the field. The net proved reserves acquired in this acquisition were estimated at 5.9 MMBbls of oil and 100.4 Bcf of natural gas. We divested of these properties in 2012.

Oil and Natural Gas Reserves

The following table sets forth our estimated proved oil and natural gas reserves and the PV 10 Value as of December 31, 2014:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)	PV 10 Value (000's)
Proved Developed:				
Producing	15,275	268,061	359,712	$ 976,504
Non-producing	972	56,537	62,365	69,868
Total Proved Developed	16,247	324,598	422,077	1,046,372
Proved Undeveloped	4,607	170,668	198,311	97,899
Total Proved	20,854	495,266	620,388	1,144,271
Discounted Future Income Taxes				(53,611)
Standardized Measure of Discounted Future Net Cash Flows[1]				$1,090,660

(1) The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and natural gas reserves before income tax, discounted at 10%. Although it is a non-GAAP measure, we believe that the presentation of the PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves after income tax, discounted at 10%.

The following table sets forth our year end reserves as of December 31 for each of the last three fiscal years:

	2012		2013		2014	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved Developed	8,389	362,426	13,914	344,278	16,247	324,598
Proved Undeveloped	10,510	75,019	8,062	108,375	4,607	170,668
Total Proved Reserves	18,899	437,445	21,976	452,653	20,854	495,266

Proved reserves that are attributable to existing producing wells are primarily determined using decline curve analysis and rate transient analysis, which incorporates the principles of hydrocarbon flow. Proved reserves attributable to producing wells with limited production history and for undeveloped locations are estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. Technologies relied on to establish reasonable certainty of economic producibility include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available production data, seismic data and well test data.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

The average prices that we realized from sales of oil and natural gas and lifting costs including severance and ad valorem taxes and transportation costs, for each of the last three fiscal years were as follows:

	Year Ended December 31,		
	2012	2013	2014
Oil Price — $/Bbl	$101.09	$100.20	$ 90.37
Natural Gas Price — $/Mcf	$ 2.49	$ 3.38	$ 4.16
Lifting costs — $/Mcfe	$ 0.96	$ 1.22	$ 1.48

Prices used in determining quantities of oil and natural gas reserves and future cash inflows from oil and natural gas reserves represent the average first of the month prices received at the point of sale for the last twelve months. These prices have been adjusted from posted prices for both location and quality differences. The oil and natural gas prices used for reserves estimation were as follows:

Year	Oil Price (per Bbl)	Natural Gas Price (per Mcf)
2012	$101.75	$2.58
2013	$104.38	$3.37
2014	$ 92.55	$3.96

Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered, and they are scheduled to be drilled within five years of their initial inclusion as proved reserves, unless specific circumstances justify a longer time. In connection with estimating proved undeveloped reserves for our December 31, 2014 reserve report, reserves on undrilled acreage were limited to those that are reasonably certain of production when drilled where we can verify the continuity of the reservoir. Using empirical evidence, we utilize control points and sample sizes to show continuity in the reservoir. We reflect changes to undeveloped reserves that occur in the same field as revisions to the extent that proved undeveloped locations are revised due to changes in future development plans, including changes to proposed lateral lengths, development spacing and timing of development.

As of December 31, 2014, our proved undeveloped reserves included 4.6 MMBbls of oil and 170.7 Bcf of natural gas, for a total of 198.3 Bcfe of undeveloped reserves. All of our undeveloped oil reserves and 3 Bcf of natural gas of our proved undeveloped reserves were associated with our Eagle Ford shale properties in South and East Texas. The proved undeveloped reserves associated with our Haynesville and Bossier shale properties represented approximately 153 Bcf of our proved undeveloped natural gas reserves at December 31, 2014. The remaining proved undeveloped natural gas reserves are primarily associated with developing reserves in our Wilcox and Vicksburg reservoirs in South Texas. In 2014, we focused on drilling our oil properties. 51 of the Eagle Ford shale wells we drilled in 2014 resulted in conversions of proved undeveloped reserves to proved developed producing reserves at December 31, 2014. Our proved undeveloped oil reserves decreased by 3.5 MMBbls during 2014. This decrease was primarily due to converting 4.7 MMBbls of our proved undeveloped oil reserves to developed in 2014, new reserves additions of 2.6 MMBbls and price and other revisions which decreased our reserves by 1.4 MMBbls. Our proved undeveloped natural gas reserves increased by 62 Bcf at December 31, 2014 as compared with December 31, 2013. This increase was primarily related to proved undeveloped reserve additions of 76 Bcf of natural gas associated with our 2015 natural gas drilling program, which were partially offset by undeveloped reserves converted to developed reserves of 2 Bcf and price and other revisions which reduced our reserves by 12 Bcfe.

As of December 31, 2013, our proved undeveloped reserves included 8.1 MMBbls of oil and 108.4 Bcf of natural gas, for a total of 157 Bcfe of undeveloped reserves. All of our undeveloped oil reserves and 5 Bcf of natural gas were associated with our Eagle Ford shale properties in South Texas. The proved undeveloped natural gas reserves associated with our Haynesville and Bossier shale properties represented approximately 87 Bcf of our total natural gas proved undeveloped reserves at December 31, 2013. The remaining proved undeveloped reserves are primarily associated with developing reserves in our Wilcox and Vicksburg reservoirs in South Texas. In 2013, we focused on drilling oil wells due to the weak natural gas prices. 28 of the Eagleville wells we drilled in 2013 resulted in conversions of proved undeveloped reserves to proved developed producing reserves at December 31, 2013. Our oil proved undeveloped reserves decreased by 2.4 MMBbls during 2013. This decrease was primarily due to converting 3.0 MMBbls of our proved undeveloped oil reserves to developed in 2013 and new reserves additions of 0.6 MMBbls. Our natural gas proved undeveloped reserves increased by 33 Bcf during 2013. This increase was primarily related to the reserve additions of 36 Bcf of natural gas which were partially offset by undeveloped reserves converted to developed reserves of 3 Bcf.

The following table presents the changes in our estimated proved undeveloped oil and natural gas reserves for the years ended December 31, 2012, 2013 and 2014:

	Proved Undeveloped Reserves					
	2012		2013		2014	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Beginning Balance	6,735	534,017	10,510	75,019	8,062	108,375
Sales and Disposals	(3,143)	(16,125)	—	—	—	—
Extension & Discoveries	8,142	7,007	583	36,578	2,640	76,009
Conversions from undeveloped to developed	(1,341)	(1,095)	(3,060)	(2,930)	(4,676)	(2,053)
Price, Performance and Other Revisions	117	(448,785)	29	(292)	(1,419)	(11,663)
Total Change	3,775	(458,998)	(2,448)	33,356	(3,455)	62,293
Ending Balance	10,510	75,019	8,062	108,375	4,607	170,668

The timing, by year, when our proved undeveloped reserve quantities were estimated to be converted to proved developed reserves is as follows:

	Proved Undeveloped Reserves					
	2012		2013		2014	
Year ended December 31,	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
2013	2,205	11,832	—	—	—	—
2014	988	27,581	6,392	4,617	—	—
2015	845	17,624	1,328	369	375	43,659
2016	3,933	14,896	342	1,242	680	57,118
2017	2,539	3,086	—	56,129	1,475	25,924
2018	—	—	—	46,018	1,738	43,967
2019	—	—	—	—	339	—
Total	10,510	75,019	8,062	108,375	4,607	170,668

The following table presents the estimated timing of our estimated future development capital costs to be incurred for the years ended December 31, 2012, 2013 and 2014:

Year ended December 31,	Future Development Costs Total Proved Undeveloped Reserves		
	2012	2013	2014
		(in millions)	
2013	$ 73.6	—	$ —
2014	53.3	265.2	—
2015	91.8	70.6	69.6
2016	130.0	24.1	108.8
2017	104.7	98.1	113.5
2018	—	85.2	157.6
2019	—	—	13.5
Total	$453.4	$543.2	$463.0

The following table presents the changes in our estimated future development costs for the years ended December 31, 2013 and 2014:

	Haynesville/ Bossier Shale	Eagle Ford Shale	All Other Properties	Total
		(in millions)		
Total as of December 31, 2012	$ 83.9	$ 348.8	$20.7	$ 453.4
Development Costs Incurred	—	(105.7)	—	(105.7)
Additions and Revisions	68.2	114.5	12.8	195.5
Total Changes	68.2	8.8	12.8	89.8
Total as of December 31, 2013	152.1	357.6	33.5	543.2
Development Costs Incurred	—	(211.1)	—	(211.1)
Additions and Revisions	41.9	88.9	0.1	130.9
Total Changes	41.9	(122.2)	0.1	(80.2)
Total as of December 31, 2014	$194.0	$ 235.4	$33.6	$ 463.0

Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2014 of $463.0 million decreased by $80.2 million from our estimated future capital costs of $543.2 million as of December 31, 2013. We incurred approximately $211.1 million during 2014 to develop proved undeveloped reserves, all of which was in our Eagle Ford shale properties. Our oil focused future capital expenditures decreased by $122.2 million and our natural gas focused capital expenditures increased by $41.9 million. This change mainly reflects the significant amount of capital spending in 2014 on developing our proved undeveloped oil reserves, and our planned resumption of natural gas drilling beginning in 2015. The timing of the development of our proved undeveloped reserves considered current economic trends including our projections of future oil and natural gas prices.

Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2013 of $543.2 million increased by $89.8 million from our estimated future capital costs of $453.4 million as of December 31, 2012. During 2013, we incurred approximately $105.7 million to develop proved undeveloped reserves primarily in our Eagle Ford shale properties. Our oil focused future capital expenditures increased by $114.5 million and our natural gas focused capital expenditures increased by $68.2 million.

The estimates of our oil and natural gas reserves were determined by Lee Keeling and Associates, Inc. ("Lee Keeling"), an independent petroleum engineering firm. Lee Keeling has been providing consulting engineering and geological services for over fifty years. Lee Keeling's professional staff is comprised of qualified petroleum engineers who are experienced in all productive areas of the United States. The technical person responsible for review of our reserve estimates at Lee Keeling meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Lee Keeling does not own any interests in our properties and is not employed on a contingent fee basis.

We have established, and maintain, internal controls designed to provide reasonable assurance that the estimates of proved reserves are computed and reported in accordance with rules and regulations promulgated by the SEC. These internal controls include documented process workflows, employing qualified professional engineering and geological personnel, and on-going education for personnel involved in our reserves estimation process. Our internal audit function routinely tests our processes and controls. Inputs to our reserves estimation process, which we provide to Lee Keeling for use in their reserves evaluation, are based upon our historical results for production history, oil and natural gas prices, lifting and development costs, ownership interests and other required data. Our Reservoir Engineering Department, comprised of qualified petroleum engineers and technical support staff, works with our operating, accounting, land and marketing departments in order to accumulate the information required for the reserves estimation process. Our Vice President of Reservoir Engineering is the primary person in charge of overseeing our reserve estimates and our Reservoir Engineering Department. He has a BS Degree and a Masters Degree in Petroleum Engineering, is a Registered Professional Engineer and has over thirty-five years of experience in various technical roles within the oil and gas industry. During the reserves estimation process our petroleum engineers work with Lee Keeling to ensure that all data we provide is properly reflected in the final reserves estimates and they consult with Lee Keeling throughout the reserves estimation process on technical questions regarding the reserve estimates. We also regularly communicate with Lee Keeling throughout the year about our operations and the potential impact of operational changes and events on our reserve estimates.

We did not provide estimates of total proved oil and natural gas reserves during the years ended December 31, 2012, 2013 or 2014 to any federal authority or agency, other than the SEC.

Drilling Activity Summary

During the three-year period ended December 31, 2014, we drilled development and exploratory wells as set forth in the table below:

	2012		2013		2014	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	30	20.5	75	51.6	76	51.0
Gas	7	3.2	2	2.0	1	0.2
Dry	—	—	—	—	—	—
	37	23.7	77	53.6	77	51.2
Exploratory:						
Oil	—	—	—	—	3	2.8
Gas	—	—	—	—	—	—
Dry	—	—	—	—	1	1.0
	—	—	—	—	4	3.8
Total	37	23.7	77	53.6	81	55.0

In 2015 to the date of this report, we have drilled five wells (5.0 net to us) and we have three wells (1.9 net to us) in the process of being drilled.

Producing Well Summary

The following table sets forth the gross and net producing oil and natural gas wells in which we owned an interest at December 31, 2014:

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Arkansas	—	—	15	8.0
Kansas	—	—	8	4.4
Louisiana	17	4.7	441	248.1
Mississippi	1	1.0	—	—
New Mexico	1	—	91	14.0
Oklahoma	10	1.2	132	18.5
Texas	215	143.0	639	424.9
Wyoming	—	—	26	1.9
Total	244	149.9	1,352	719.8

We operate 962 of the 1,596 producing wells presented in the above table. As of December 31, 2014, we owned interests in 15 wells containing multiple completions, which means that a well is producing from more than one completed zone. Wells with more than one completion are reflected as one well in the table above.

Acreage

The following table summarizes our developed and undeveloped leasehold acreage at December 31, 2014, all of which is onshore in the continental United States. We have excluded acreage in which our interest is limited to a royalty or overriding royalty interest.

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Arkansas	1,280	684	—	—
Kansas	6,400	4,064	—	—
Louisiana	93,834	59,508	62,669	56,703
Mississippi	2,009	1,942	40,140	33,494
New Mexico	10,240	1,896	—	—
Oklahoma	38,080	5,707	—	—
Texas	117,682	72,246	37,174	31,575
Wyoming	13,440	927	—	—
Total	282,965	146,974	139,983	121,772

Our undeveloped acreage expires as follows:

Expires in 2015	18%
Expires in 2016	24%
Expires in 2017	53%
Thereafter	5%
	100%

Title to our oil and natural gas properties is subject to royalty, overriding royalty, carried and other similar interests and contractual arrangements customary in the oil and gas industry, liens incident to operating agreements and for current taxes not yet due and other minor encumbrances. All of our oil and natural gas properties are pledged as collateral under our bank credit facility. As is customary in the oil and gas industry, we are generally able to retain our ownership interest in undeveloped acreage by production of existing wells, by drilling activity which establishes commercial reserves sufficient to maintain the lease, by payment of delay rentals or by the exercise of contractual extension rights. We anticipate retaining ownership of a substantial amount of the acreage with primary terms expiring in 2015 through drilling activity or by extending the leases.

Markets and Customers

The market for our production of oil and natural gas depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil production is currently sold under short-term contracts with a duration of six months or less. The contracts require the purchasers to purchase the amount of oil production that is available at prices tied to the spot oil markets. Our natural gas production is primarily sold under contracts with various terms and priced on first of the month index prices or on daily spot market prices. Approximately 84.9% of our 2014 natural gas sales were priced utilizing first of the month index prices and approximately 15.1% were priced utilizing daily spot prices. BP Energy Company and its subsidiaries and Shell Oil Company and its subsidiaries accounted for 52.6% and 34.7%, respectively, of our total 2014 sales. The loss of either of these customers would not have a material adverse effect on us as there is an available market for our crude oil and natural gas production from other purchasers.

We have entered into longer term marketing arrangements to ensure that we have adequate transportation to get our natural gas production in North Louisiana to the markets. As an alternative to constructing our own gathering and treating facilities, we have entered into a variety of gathering and treating agreements with midstream companies to transport our natural gas to the long-haul natural gas pipelines. We have entered into certain agreements with a major natural gas marketing company to provide us with firm transportation for 55,000 MMBtus per day for our North Louisiana natural gas production on the long-haul pipelines. These agreements expire from 2015 to 2019. To the extent we are not able to deliver the contracted natural gas volumes, we may be responsible for the transportation costs. Our production available to deliver under these agreements in North Louisiana is expected to exceed the firm transportation arrangements we have in place. In addition, the marketing company managing the firm transportation is required to use reasonable efforts to supplement our deliveries should we have a shortfall during the term of the agreements.

Competition

The oil and gas industry is highly competitive. Competitors include major oil companies, other independent energy companies and individual producers and operators, many of which have financial resources, personnel and facilities substantially greater than we do. We face intense competition for the acquisition of oil and natural gas properties and leases for oil and gas exploration.

Regulation

General. Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulation, as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. The Federal Energy Regulatory Commission, or "FERC," regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938, or "NGA," and the Natural Gas Policy Act of 1978, or "NGPA." In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and nonprice controls affecting all "first sales" of natural gas, effective January 1, 1993, subject to the terms of any private contracts that may be in effect. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business. Under the provisions of the Energy Policy Act of 2005 (the "2005 Act"), the NGA has been amended to prohibit any form of market manipulation with the purchase or sale of natural gas, and the FERC has issued new regulations that are intended to increase natural gas pricing transparency. The 2005 Act has also significantly increased the penalties for violations of the NGA. The FERC has issued Order No. 704 et al. which requires a market participant to make an annual filing if it has sales or purchases equal to or greater than 2.2 million MMBtu in the reporting year to facilitate price transparency.

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. The FERC requires interstate pipelines to provide open-access transportation on a not unduly discriminatory basis for similarly situated shippers. The FERC frequently reviews and modifies its regulations regarding the transportation of natural gas, with the stated goal of fostering competition within the natural gas industry.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The Texas Railroad Commission has been changing its regulations governing transportation and gathering services provided by intrastate pipelines and gatherers. While the changes by these state regulators affect us only indirectly, they are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC or state regulators will take on these matters; however, we do not believe that we will be affected differently in any material respect than other natural gas producers with which we compete by any action taken.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach pursued by the FERC, Congress and state regulatory authorities will continue.

Federal leases. Some of our operations are located on federal oil and natural gas leases that are administered by the Bureau of Land Management ("BLM") of the United States Department of the Interior. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed Department of Interior and BLM regulations and orders that are subject to interpretation and change. These leases are also subject to certain regulations and orders promulgated by the Department of Interior's Bureau of Ocean Energy Management, Regulation & Enforcement ("BOEMRE"), through its Minerals Revenue Management Program, which is responsible for the management of revenues from both onshore and offshore leases.

Oil and natural gas liquids transportation rates. Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. The price received from the sale of these products may be affected by the cost of transporting the products to market.

The FERC's regulation of pipelines that transport crude oil, condensate and natural gas liquids under the Interstate Commerce Act is generally more light-handed than the FERC's regulation of natural gas pipelines under the NGA. FERC-regulated pipelines that transport crude oil, condensate and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates are permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates governed by the Interstate Commerce Act that allowed for an increase or decrease in the transportation rates. The FERC's regulations include a methodology for such pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The mandatory five year review in 2005 revised the methodology for this index to be based on Producer Price Index for Finished Goods (PPI-FG) plus 1.3 percent for the period July 1, 2006 through June 30, 2011. The mandatory five year review in 2012 revised the methodology for this index to be based on PPI-FG plus

2.65 percent for the period July 1, 2011 through June 30, 2016. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available.

With respect to intrastate crude oil, condensate and natural gas liquids pipelines subject to the jurisdiction of state agencies, such state regulation is generally less rigorous than the regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests. Complaints or protests have been infrequent and are usually resolved informally.

We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate or natural gas liquids pipelines will affect us in a way that materially differs from the way it affects other crude oil, condensate and natural gas liquids producers or marketers.

Environmental regulations. We are subject to stringent federal, state and local laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be released into the environment, the discharge and disposition of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup cost without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent pollution, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases our cost of doing business and consequently affects our profitability. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations. However, environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements or new regulatory schemes such as carbon "cap and trade" programs could have a material adverse effect upon our capital expenditures, earnings or competitive position, including the suspension or cessation of operations in affected areas. As such, there can be no assurance that material cost and liabilities will not be incurred in the future.

The Comprehensive Environmental Response, Compensation and Liability Act, or "CERCLA," imposes liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current or former 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. Under CERCLA, such persons may be subject to joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies. In addition, companies that incur liability frequently also confront third party claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment from a polluted site.

The Federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, or "RCRA," regulates the generation, transportation, storage, treatment and disposal of hazardous wastes and can require cleanup of hazardous waste disposal sites. RCRA currently excludes drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas from regulation as "hazardous waste." Disposal of such non-hazardous oil and natural gas exploration, development and production wastes usually are regulated by state law. Other wastes handled at exploration and production sites or used in the course of providing well services may not fall within this exclusion. Moreover, stricter standards for waste handling and disposal may be imposed on the oil and natural gas industry in the future. From time to time, legislation is proposed in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from RCRA's definition of "hazardous wastes," thereby potentially subjecting such wastes to more stringent handling, disposal and cleanup requirements. If such legislation were enacted, it could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted.

Our operations are also subject to the Clean Air Act, or "CAA," and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. On April 17, 2012, the U. S. Environmental Protection Agency or "EPA" promulgated new emission standards for the oil and gas industry. These rules require a nearly 95 percent reduction in volatile organic compounds ("VOCs") emitted from hydraulically fractured gas wells by January 1, 2015. This significant reduction in emissions is to be accomplished primarily through the use of "green completions" (i.e., capturing natural gas that currently escapes to the air). These rules also have notification and reporting requirements. On September 23, 2014, EPA revised the emission requirements for storage tanks emitting certain levels of VOCs requiring a 95% reduction of VOC emissions by April 15, 2014 and April 15, 2015 (depending upon the date of construction of the storage tank). On December 19, 2014, EPA finalized updates and clarifications to these emission standards for the oil and gas industry. We believe our operations comply in all material respects with these emission limitations. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

The Federal Water Pollution Control Act of 1972, as amended, or the "Clean Water Act," imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters, unless otherwise authorized. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the cost of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

The Federal Safe Drinking Water Act of 1974, as amended, requires EPA to develop minimum federal requirements for Underground Injection Control ("UIC") programs and other safeguards to protect public health by preventing injection wells from contaminating underground sources of drinking water. The UIC program does not regulate wells that are solely used for production. However, EPA has authority to regulate hydraulic fracturing when diesel fuels are used in fluids or propping agents. In February 2014, EPA issued new guidance on when UIC permitting requirements apply to fracking fluids containing diesel. We believe our operations will not be materially adversely affected by the new guidance, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

Federal regulators require certain owners or operators of facilities that store or otherwise handle oil to prepare and implement spill prevention, control, countermeasure and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") contains numerous requirements relating to the prevention and response to oil spills in the waters of the United States. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages relating to a spill. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities.

Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas, or "MPAs," in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future exploration and development projects and/or causing us to incur increased operating expenses.

Certain flora and fauna that have officially been classified as "threatened" or "endangered" are protected by the Endangered Species Act. This law prohibits any activities that could "take" a protected plant or animal or reduce or degrade its habitat area. If endangered species are located in an area we wish to develop, the work could be prohibited or delayed and/or expensive mitigation might be required.

Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the Oil Pollution Act, the Emergency Planning and Community Right to Know Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands and other protected areas and impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities. In addition, laws such as the National Environmental Policy Act and the Coastal Zone Management Act may make the process of obtaining certain permits more difficult or time consuming, resulting in increased costs and potential delays that could affect the viability or profitability of certain activities.

Certain statutes such as the Emergency Planning and Community Right to Know Act require the reporting of hazardous chemicals manufactured, processed, or otherwise used, which may lead to heightened scrutiny of the company's operations by regulatory agencies or the public. In 2012, the EPA adopted a new reporting requirement, the Petroleum and Natural Gas Systems Greenhouse Gas Reporting Rule (40 C.F.R. Part 98, Subpart W), which requires certain onshore petroleum and natural gas facilities to begin collecting data on their emissions of greenhouse gases ("GHGs") in January 2012, with the first annual reports of those emissions due on September 28, 2012. GHGs include gases such as methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas. Different GHGs have different global warming potentials with CO_2 having the lowest global warming potential, so emissions of GHGs are typically expressed in terms of CO_2 equivalents, or CO_2e. The rule applies to facilities that emit 25,000 metric tons of CO_2e or more per year, and requires onshore petroleum and natural gas operators to group all equipment under common ownership or control within a single hydrocarbon basin together when determining if the threshold is met. We have determined that these reporting requirements apply to us and we believe we have met all of the EPA required reporting deadlines and strive to ensure accurate and consistent emissions data reporting. Other EPA actions with respect to the reduction of greenhouse gases (such as EPA's Greenhouse Gas Endangerment Finding, and EPA's Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule) and various state actions have or could impose mandatory reductions in greenhouse gas emissions. We are unable to predict at this time how much the cost of compliance with any legislation or regulation of greenhouse gas emissions will be in future periods.

Such changes in environmental laws and regulations which result in more stringent and costly reporting, or waste handling, storage, transportation, disposal or cleanup activities, could materially affect companies operating in the energy industry. Adoption of new regulations further regulating emissions from oil and gas production could adversely affect our business, financial position, results of operations and prospects, as could the adoption of new laws or regulations which levy taxes or other costs on greenhouse gas emissions from other industries, which could result in changes to the consumption and demand for natural gas. We may also be assessed administrative, civil and/or criminal penalties if we fail to comply with any such new laws and regulations applicable to oil and natural gas production.

We maintain insurance against "sudden and accidental" occurrences, which may cover some, but not all, of the risks described above. Most significantly, the insurance we maintain will not cover the risks described above which occur over a sustained period of time. Further, there can be no assurance that such insurance will continue to be available to cover all such cost or that such insurance will be available at a cost that would justify its purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and results of operations.

Regulation of oil and natural gas exploration and production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits and drilling bonds for the drilling of wells, regulating the location of wells, the method of drilling and casing wells and the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing, plugging and abandonment of such wells. Some state statutes limit the rate at which oil and natural gas can be produced from our properties.

State regulation. Most states regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

Office and Operations Facilities

Our executive offices are located at 5300 Town and Country Blvd., Suite 500 in Frisco, Texas 75034 and our telephone number is (972) 668-8800. We lease office space in Frisco, Texas covering 66,382 square feet at a monthly rate of $124,466. This lease expires on December 31, 2021. We also own production offices and pipe yard facilities near Marshall, Pleasanton and Zapata, Texas and Logansport, Louisiana.

Employees

As of December 31, 2014, we had 139 employees and utilized contract employees for certain of our field operations. We consider our employee relations to be satisfactory.

Directors and Executive Officers

The following table sets forth certain information concerning our executive officers and directors.

Name	Position with Company	Age
M. Jay Allison	Chief Executive Officer and Chairman of the Board of Directors	59
Roland O. Burns	President, Chief Financial Officer, Secretary and Director	54
Mack D. Good[a]	Chief Operating Officer	64
D. Dale Gillette	Vice President of Legal and General Counsel	69
Michael D. McBurney	Vice President of Marketing	59
Daniel K. Presley	Vice President of Accounting, Controller and Treasurer	54
Russell W. Romoser	Vice President of Reservoir Engineering	63
LaRae L. Sanders	Vice President of Land	52
Richard D. Singer	Vice President of Financial Reporting	60
Blaine M. Stribling	Vice President of Corporate Development	44
Elizabeth B. Davis	Director	52
David K. Lockett	Director	60
Cecil E. Martin	Director	73
Frederic D. Sewell	Director	80
David W. Sledge	Director	58
Jim L. Turner	Director	69
Nancy E. Underwood	Director	63

(a) Effective March 2, 2015.

Executive Officers

A brief biography of each person who serves as a director or executive officer follows below.

M. Jay Allison has been a director since 1987, and our Chief Executive Officer since 1988. Mr. Allison was elected Chairman of the board of directors in 1997. From 1988 to 2013, Mr. Allison served as our President and before that he served as our Vice President and Secretary. From 1981 to 1987, he was a practicing oil and gas attorney with the firm of Lynch, Chappell & Alsup in Midland, Texas. Mr. Allison was Chairman of the Board of Directors of Bois d'Arc Energy, Inc. from the time of its formation in 2004 until its merger with Stone Energy Corporation in 2008. He received B.B.A., M.S. and J.D. degrees from Baylor University in 1978, 1980 and 1981, respectively. Mr. Allison also currently serves as a Director of Tidewater, Inc. and is on the Board of Regents for Baylor University.

Roland O. Burns has been our President since 2013, Chief Financial Officer since 1990, Secretary since 1991 and a director since 1999. Mr. Burns served as our Senior Vice President from 1994 to 2013 and Treasurer from 1990 to 2013. From 1982 to 1990, Mr. Burns was employed by the public accounting firm, Arthur Andersen. During his tenure with Arthur Andersen, Mr. Burns worked primarily in the firm's oil and gas audit practice. Mr. Burns was a director, Senior Vice President and the Chief Financial Officer of Bois d'Arc Energy, Inc. from the time of its formation in 2004 until its merger with Stone Energy Corporation in 2008. Mr. Burns received B.A. and M.A. degrees from the University of Mississippi in 1982 and is a Certified Public Accountant. Mr. Burns also served on the Board of Directors of the University of Mississippi Foundation and the Cotton Bowl Athletic Association.

Mack D. Good was named our Chief Operating Officer in February 2015. Mr. Good served as our Chief Operating Officer from 2004 until 2011, when he took early retirement. From 1997 until 2004 he served in various other management and engineering positions with us. From 1983 until 1997 Mr. Good was with Enserch Exploration, Inc., serving in various engineering and operations management positions. Mr. Good received a B.S. of Biology/Chemistry from Oklahoma State University in 1975 and a B.S. degree of Petroleum Engineering from the University of Tulsa in 1983.

D. Dale Gillette was named our General Counsel and Vice President of Legal in November 2014. He has been our General Counsel since 2006. From 2006 until November 2014, Mr. Gillette was also our Vice President of Land. Prior to joining us, Mr. Gillette practiced law extensively in the energy sector for 34 years, most recently as a partner with Gardere Wynne Sewell LLP, and before that with Locke Liddell & Sapp LLP (now known as Locke Lord LLP). During that time he represented independent exploration and production companies and large financial institutions in numerous oil and gas transactions. Mr. Gillette has also served as corporate counsel in the legal department of Mesa Petroleum Co. and in the legal department of Enserch Corp. Mr. Gillette holds B.A. and J.D. degrees from the University of Texas and is a member of the State Bar of Texas.

Michael D. McBurney was named our Vice President of Marketing in July 2013. Mr. McBurney has over 32 years of energy industry experience within the oil, natural gas, LNG, and power segments. For the past seven years Mr. McBurney worked for EXCO Resources, Inc., an independent exploration and production company where he was responsible for natural gas and natural gas liquids marketing. From 2000 to 2006, Mr. McBurney was with FPL Energy of Florida, where he was responsible for Fuel and Transportation logistics for large scale power generation facilities located throughout the U.S. Mr. McBurney received a B.B.A. in Finance from the University of North Texas in 1978.

Daniel K. Presley was named our Treasurer in 2013. Mr. Presley, who has been with us since 1989, also continues to serve as our Vice President of Accounting and Controller, positions he has had held since 1997 and 1991, respectively. Prior to joining us, Mr. Presley had six years of experience with several independent oil and gas companies including AmBrit Energy, Inc. Prior thereto, Mr. Presley spent two and one-half years with B.D.O. Seidman, a public accounting firm. Mr. Presley received a B.B.A. degree from Texas A & M University in 1983.

Russell W. Romoser has been our Vice President of Reservoir Engineering since 2012. Mr. Romoser has over 35 years of experience as a reservoir engineer both with industry and with a petroleum engineering consulting firm. Prior to joining us, Mr. Romoser served eleven years as the Acquisitions Engineering Manager for EXCO Resources, Inc. Mr. Romoser received a B.S. Degree in Petroleum Engineering in 1975 and a Masters Degree in Petroleum Engineering in 1976 from the University of Texas and is a Registered Professional Engineer in Oklahoma and Texas.

LaRae L. Sanders was named our Vice President of Land in November 2014. Ms. Sanders has been with us since 1995. She has served as Land Manager since 2007, and has been instrumental in all of our active development programs and major acquisitions. Prior to joining us, Ms. Sanders held positions with Bridge Oil Company and Kaiser-Francis Oil Company, as well as other independent exploration and production companies. Ms. Sanders is a Certified Professional Landman with 35 years of experience. She became the nation's first Certified Professional Lease and Title Analyst in 1990.

Richard D. Singer has been our Vice President of Financial Reporting since 2005. Mr. Singer has over 35 years of experience in financial accounting and reporting. Prior to joining us, Mr. Singer most recently served as an assistant controller for Holly Corporation from 2004 to 2005 and as assistant controller for Santa Fe International Corporation from 1988 to 2002. Mr. Singer received a B.S. degree from the Pennsylvania State University in 1976 and is a Certified Public Accountant.

Blaine M. Stribling has been our Vice President of Corporate Development since 2012. From 2007 to early 2012, Mr. Stribling served as our Asset & Corporate Development Manager. Prior to joining us, Mr. Stribling managed a development project team at Encana Oil & Gas from 2005 to 2007. Prior to 2005 he worked in various petroleum engineering operations management positions of increasing responsibility for several independent oil and gas exploration and development companies. Mr. Stribling received a B.S. Degree in Petroleum Engineering from the Colorado School of Mines.

Outside Directors

Elizabeth B. Davis has served as a director since May 2014. Dr. Davis is currently the President of Furman University. Dr. Davis was the Executive Vice President and Provost for Baylor University until July 2014, and served as Interim Provost from 2008 until 2010. Prior to her appointment as Provost, she was a professor of accounting in the Hankamer School of Business at Baylor University where she also served as associate dean for undergraduate programs and as acting chair for the Department of Accounting and Business Law. Prior to joining Baylor University, she worked for the public accounting firm Arthur Andersen from 1984 to 1987.

David K. Lockett has served as a director since 2001. Mr. Lockett was a Vice President with Dell Inc. and held executive management positions in several divisions within Dell from 1991 until his retirement from Dell in 2012. In November 2014, Mr. Lockett became President of Austex Fence & Deck in Austin, Texas. Between 2012 and 2014, Mr. Lockett, who has over 35 years of experience in the technology industry, provided consulting services to small and mid-size companies. Mr. Lockett was a director of Bois d'Arc Energy, Inc. from May 2005 until its merger with Stone Energy Corporation in August 2008.

Cecil E. Martin has served as a director since 1989 and is currently the chairman of our audit committee and our Lead Director. Mr. Martin is an independent commercial real estate investor who has primarily been managing his personal real estate investments since 1991. From 1973 to 1991, he also served as chairman of a public accounting firm in Richmond, Virginia. Mr. Martin was a director and chairman of the Audit Committee of Bois d'Arc Energy, Inc. from May 2005 until its merger with Stone Energy Corporation in August 2008. Mr. Martin also served on the board of directors of Crosstex Energy, Inc. and

Crosstex Energy, L.P. until their merger with EnLink Midstream and EnLink Midstream Partners LP, respectively, in March 2014. Mr. Martin currently serves on the board of directors of Garrison Capital, Inc. He served as chairman of the compensation committee at Crosstex Energy L.P. and currently serves as chairman of the audit committee at Garrison Capital, Inc. Mr. Martin is a Certified Public Accountant.

Frederic D. Sewell has served as a director since 2012. Mr. Sewell has extensive experience in the oil and gas industry, where he has had a distinguished career as an executive leader and a petroleum engineer. Mr. Sewell was the co-founder of Netherland, Sewell & Associates, Inc., a worldwide oil and gas consulting firm, where he served as the chairman and chief executive officer until his retirement in 2008. Mr. Sewell is presently the President and Chief Executive Officer of Sovereign Resources LLC, an exploration and production company that he founded.

David W. Sledge has served as a director since 1996. Mr. Sledge is the Chief Operating Officer of ProPetro Services, Inc. Mr. Sledge was President and Chief Operating Officer of Sledge Drilling Company until it was acquired by Basic Energy Services, Inc. in April 2007 and served as a Vice President of Basic Energy Services, Inc. from April 2007 to February 2009. He served as an area operations manager for Patterson-UTI Energy, Inc. from May 2004 until January 2006. From March 2009 through October 2011, and from October 1996 until May 2004, Mr. Sledge managed his personal investments in oil and gas exploration activities. Mr. Sledge was a director of Bois d'Arc Energy, Inc. from May 2005 until its merger with Stone Energy Corporation in August 2008. Mr. Sledge is a past director of the International Association of Drilling Contractors and is a past chairman of the Permian Basin chapter of this association.

Jim L. Turner has served as a director since May 2014. Mr. Turner currently serves as principal of JLT Beverages, L.P., a position he has held since 1996. Mr. Turner was also recently named the Chief Executive Officer of JLT Automotive, Inc. which owns and operates an automobile dealership in Texas. Mr. Turner served as President and Chief Executive Officer of Dr. Pepper/Seven Up Bottling Group, Inc., from its formation in 1999 through 2005, when he sold his interest in that company. Prior to that, Mr. Turner served as Owner/Chairman of the Board and Chief Executive Officer of the Turner Beverage Group, the largest privately owned independent bottler in the United States. Mr. Turner currently serves as a director for Dean Foods Company and Crown Holdings, Inc. He also serves as Vice Chairman and Chair-elect of the board of directors of Baylor Scott & White Health.

Nancy E. Underwood has served as a director since 2004. Ms. Underwood is owner and President of Underwood Financial Ltd., a position she has held since 1986, which is primarily engaged in real estate development. From 1981 until 1985, Ms. Underwood was on the Board of Directors of Richardson Bank and Trust, serving as the Vice Chairman of the Loan Committee. She started her career as an attorney at an Atlanta, Georgia based law firm before joining River Hill Development Corporation in 1981. Ms. Underwood serves on the Board of European Initiative Ministry and is a founding Advisory Board Member of the SMU Cox School of Business Women's Inner Circle. She is currently a member of Charter 100 which is comprised of the 100 most powerful women in Dallas.

Available Information

Our executive offices are located at 5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034. Our telephone number is (972) 668-8800. We file annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. 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. In addition, the SEC maintains a website that contains reports, proxy and information statements, and other information that is electronically filed with the SEC. The public can obtain any documents that we file with the SEC at www.sec.gov. We also make available free of charge on our website (www.comstockresources.com) our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we file such material with, or furnish it to, the SEC.

ITEM 1A. *RISK FACTORS*

You should carefully consider the following risk factors as well as the other information contained or incorporated by reference in this report, as these important factors, among others, could cause our actual results to differ from our expected or historical results. It is not possible to predict or identify all such factors. Consequently, you should not consider any such list to be a complete statement of all of our potential risks or uncertainties.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition, cash flow, liquidity or results of operations and our ability to meet our capital expenditure obligations and financial commitments and to implement our business strategy.

Our business is heavily dependent upon the prices of, and demand for, oil and natural gas. Historically, the prices for oil and natural gas have been volatile and are likely to remain volatile in the future. From June 30, 2014 through the date of this report, the New York Mercantile Exchange ("NYMEX") settled prices for oil and natural gas have decreased by approximately 50% and 37%, respectively.

The prices we receive for our oil and natural gas production are subject to wide fluctuations and depend on numerous factors beyond our control, including the following:

- the domestic and foreign supply of oil and natural gas;
- weather conditions;
- the price and quantity of imports of oil and natural gas;
- political conditions and events in other oil-producing and natural gas-producing countries, including embargoes, hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- domestic government regulation, legislation and policies;
- the level of global oil and natural gas inventories;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- overall economic conditions.

Lower oil and natural gas prices will adversely affect:

- our revenues, profitability and cash flow from operations;
- the value of our proved oil and natural gas reserves;
- the economic viability of certain of our drilling prospects;
- our borrowing capacity; and
- our ability to obtain additional capital.

Our debt service requirements could adversely affect our operations and limit our growth.

We had $1,070.4 million in debt as of December 31, 2014, and our ratio of total debt to total capitalization was approximately 55%.

Our outstanding debt will have important consequences, including, without limitation:

- a portion of our cash flow from operations will be required to make debt service payments;
- our ability to borrow additional amounts for capital expenditures (including acquisitions) or other purposes will be limited; and
- our debt could limit our ability to capitalize on significant business opportunities, our flexibility in planning for or reacting to changes in market conditions and our ability to withstand competitive pressures and economic downturns.

In addition, future acquisition or development activities may require us to alter our capitalization significantly. These changes in capitalization may significantly increase our debt. Moreover, our ability to meet our debt service obligations and to reduce our total debt will be dependent upon our future performance, which will be subject to general economic conditions and financial, business and other factors affecting our operations, many of which are beyond our control. If we are unable to generate sufficient cash flow from operations in the future to service our indebtedness and to meet other commitments, we will be required to adopt one or more alternatives, such as refinancing or restructuring our indebtedness, selling material assets or seeking to raise additional debt or equity capital. We cannot assure you that any of these actions could be effected on a timely basis or on satisfactory terms or that these actions would enable us to continue to satisfy our capital requirements.

Our bank credit facility contains a number of significant covenants. These covenants will limit our ability to, among other things:

- borrow additional money;
- merge, consolidate or dispose of assets;
- make certain types of investments;
- enter into transactions with our affiliates; and
- pay dividends.

Our failure to comply with any of these covenants could cause a default under our bank credit facility and the respective indentures governing our senior notes. A default, if not waived, could result in acceleration of our indebtedness, in which case the debt would become immediately due and payable. If this occurs, we may not be able to repay our debt or borrow sufficient funds to refinance it given the current status of the credit markets. Even if new financing is available, it may not be on terms that are acceptable to us. Complying with these covenants may cause us to take actions that we otherwise would not take or not take actions that we otherwise would take.

We pursue acquisitions as part of our growth strategy and there are risks in connection with acquisitions.

Our growth has been attributable in part to acquisitions of producing properties and companies. More recently we have been focused on acquiring acreage for our drilling program. We expect to continue to evaluate and, where appropriate, pursue acquisition opportunities on terms we consider favorable. However, we cannot assure you that suitable acquisition candidates will be identified in the future, or that we will be able to finance such acquisitions on favorable terms. In addition, we compete against other companies for acquisitions, and we cannot assure you that we will successfully acquire any material property interests. Further, we cannot assure you that future acquisitions by us will be integrated successfully into our operations or will increase our profits.

The successful acquisition of producing properties requires an assessment of numerous factors beyond our control, including, without limitation:

- recoverable reserves;
- exploration potential;
- future oil and natural gas prices;
- operating costs; and
- potential environmental and other liabilities.

In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. The resulting assessments are inexact and their accuracy uncertain, and such a review may not reveal all existing or potential problems, nor will it necessarily permit us to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is made.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may be substantially different in operating and geologic characteristics or geographic location than our existing properties. While our current operations are focused in Texas, Louisiana and Mississippi, we may pursue acquisitions or properties located in other geographic areas.

Our future production and revenues depend on our ability to replace our reserves.

Our future production and revenues depend upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we must continue our acquisition and drilling activities. We cannot assure you, however, that our acquisition and drilling activities will result in significant additional reserves or that we will have continuing success drilling productive wells at low finding and development costs. Furthermore, while our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return.

A prospect is a property in which we own an interest or have operating rights and that has what our geoscientists believe, based on available seismic and geological information, to be an indication of potential oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial additional evaluation and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. The analysis that we perform using data from other wells, more fully explored prospects and/or producing fields may not be useful in predicting the characteristics and potential reserves associated with our drilling prospects. If we drill additional unsuccessful wells, our drilling success rate may decline and we may not achieve our targeted rate of return.

Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our future success will depend on the success of our exploration and development activities. Exploration activities involve numerous risks, including the risk that no commercially productive natural gas or oil reserves will be discovered. In addition, these activities may be unsuccessful for many reasons, including weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells can hurt our efforts to replace production and reserves.

Our business involves a variety of operating risks, including:

- unusual or unexpected geological formations;
- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;
- natural disasters, such as hurricanes, tropical storms and other adverse weather conditions;
- pipe, cement, or pipeline failures;
- casing collapses;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If we experience any of these problems, well bores, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations.

We could also incur substantial losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

We operate in a highly competitive industry, and our failure to remain competitive with our competitors, many of which have greater resources than we do, could adversely affect our results of operations.

The oil and natural gas industry is highly competitive in the search for and development and acquisition of reserves. Our competitors often include companies that have greater financial and personnel resources than we do. These resources could allow those competitors to price their products and services more aggressively than we can, which could hurt our profitability. Moreover, our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to close transactions in a highly competitive environment.

If oil and natural gas prices decline further or remain low for an extended period of time, we may be required to further write-down the carrying values and/or the estimates of total reserves of our oil and natural gas properties, which would constitute a non-cash charge to earnings and adversely affect our results of operations.

Accounting rules applicable to us require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We may incur non-cash charges in the future, which could have a material adverse effect on our results of operations in the period taken. We may also reduce our estimates of the reserves that may be economically recovered, which could have the effect of reducing the total value of our reserves.

Our reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate depends on the quality of available data, production history and engineering and geological interpretation and judgment. Because all reserve estimates are to some degree imprecise, 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 prices may all differ materially from those assumed in these estimates. The information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves is only estimated and should not be construed as the current market value of the oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to proved properties included in the preceding year’s estimates. Such revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Any future downward revisions could adversely affect our financial condition, our borrowing ability, our future prospects and the value of our common stock.

As of December 31, 2014, 32% of our total proved reserves were undeveloped and 10% were developed non-producing. These reserves may not ultimately be developed or produced. Furthermore, not all of our undeveloped or developed non-producing reserves may be ultimately produced at the time periods we have planned, at the costs we have budgeted, or at all. As a result, we may not find commercially viable quantities of oil and natural gas, which in turn may result in a material adverse effect on our results of operations.

Some of our undeveloped leasehold acreage is subject to leases that will expire unless production is established on units containing the acreage.

Leases on oil and gas properties normally have a term of three to five years and will expire unless, prior to expiration of the lease term, production in paying quantities is established. If the leases expire and we are unable to renew them, we will lose the right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals.

If we are unsuccessful at marketing our oil and natural gas at commercially acceptable prices, our profitability will decline.

Our ability to market oil and natural gas at commercially acceptable prices depends on, among other factors, the following:

- the availability and capacity of gathering systems and pipelines;
- federal and state regulation of production and transportation;
- changes in supply and demand; and
- general economic conditions.

Our inability to respond appropriately to changes in these factors could negatively affect our profitability.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and processing facilities. Our ability to market our production depends in a substantial part on the availability and capacity of gathering systems, pipelines and processing facilities, in some cases owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of the inadequacy or unavailability of pipelines or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market.

We are subject to extensive governmental laws and regulations that may adversely affect the cost, manner or feasibility of doing business.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and natural gas, and operating safety. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may harm our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with governmental laws and regulations, such as:

- lease permit restrictions;

- drilling bonds and other financial responsibility requirements, such as plug and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- regulatory requirements; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well reclamation costs; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from various sources for use in our operations. In recent years South Texas has experienced the lowest inflows of water in recent history. As a result of this severe drought, some local water districts may begin restricting the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

Our operations may incur substantial liabilities to comply with environmental laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment and otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of one or more permits before drilling commences;
- impose limitations on where drilling can occur and/or requires mitigation before authorizing drilling in certain locations;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- require reporting of significant releases, and annual reporting of the nature and quantity of emissions, discharges and other releases into the environment;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in:

- the assessment of administrative, civil and criminal penalties;
- the incurrence of investigatory and/or remedial obligations; and
- the imposition of injunctive relief.

In June 2009 the United States House of Representatives passed the American Clean Energy and Security Act of 2009. A similar bill, the Clean Energy Jobs and American Power Act, introduced in the Senate, did not pass. Both bills contained the basic feature of establishing a "cap and trade" system for restricting greenhouse gas emissions in the United States. Under such a system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary over time to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. It appears that the prospects for a cap and trade system such as that proposed in these bills have dimmed significantly; however, the EPA has moved ahead with its efforts to regulate GHG emissions from certain sources by rule. The EPA issued Subpart W of the Final Mandatory Reporting of Greenhouse Gases Rule, which required petroleum and natural gas systems that emit 25,000 metric tons of CO_2e or more per year to begin collecting GHG emissions data under a new reporting system. We believe we have met all of the reporting requirements under these new regulations. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The EPA has adopted regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. States in which we operate may also require permits and reductions in GHG emissions. Since all of our oil and natural gas production is in the United States, these laws or regulations that have been or may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur substantial increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce. On January 14, 2015, the Obama Administration announced that, pursuant to the Administration's Climate Action Plan, the EPA will propose a rule to regulate methane and volatile organic compound emissions from new and modified oil and gas sources in the summer of 2015, with a final rule expected in 2016. The Administration's announcement also stated that other federal agencies, including the Bureau of Land Management, will impose new or more stringent regulations on the oil and gas sector that will have the effect of further reducing methane emissions. In 2010 the Bureau of Land Management began implementation of a proposed oil and gas leasing reform. The leasing reform requires, among other things, a more detailed environmental review prior to leasing oil and natural gas resources on federal lands, increased public engagement in the development of Master Leasing Plans prior to leasing areas where intensive new oil and gas development is anticipated, and a comprehensive parcel review process with greater public involvement in the identification of key environmental resource values before a parcel is leased. New leases would incorporate adaptive management stipulations, requiring lessees to monitor and respond to observed environmental impacts, possibly through the implementation of expensive new control measures or curtailment of operations, potentially reducing profitability. The leasing reform policy could have the effect of reducing the amount of new federal lands made available for lease, increasing the competition for and cost of available parcels.

On August 16, 2012, the EPA adopted final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. On September 23, 2014, the EPA revised the emission requirements for storage tanks emitting certain levels of VOCs requiring a 95% reduction of VOC emissions by April 15, 2014 and April 15, 2015 (depending on the date of construction of the storage tank). The court challenges to these rules have been abated while the EPA considers whether to revise the rules. Compliance with these requirements could increase our costs of development and production, though we do not expect these requirements to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly restrictions on emissions, and/or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to reach and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if our operations met previous standards in the industry at the time they were performed. Future environmental laws and regulations, including proposed legislation regulating climate change, may negatively impact our industry. The costs of compliance with these requirements may have an adverse impact on our financial condition, results of operations and cash flows.

Our hedging transactions could result in financial losses or could reduce our income. To the extent we have hedged a significant portion of our expected production and actual production is lower than we expected or the costs of goods and services increase, our profitability would be adversely affected.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and gas, we have entered into and may in the future enter into hedging transactions for certain of our expected oil and natural gas production. These transactions could result in both realized and unrealized hedging losses.

The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. For example, the derivative instruments we utilize are primarily based on NYMEX futures prices, which may differ significantly from the actual crude oil and gas prices we realize in our operations. Furthermore, we have adopted a policy that requires, and our revolving credit facility also requires, that we enter into derivative transactions related to only a portion of our expected production volumes and, as a result, we will continue to have direct commodity price exposure on the portion of our production volumes not covered by these derivative financial instruments.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions. If our actual future production is higher than we estimated, we will have greater commodity price exposure than we intended. If our actual future production is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution in our profitability and liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

In addition, our hedging transactions are subject to the following risks:

- we may be limited in receiving the full benefit of increases in oil and gas prices as a result of these transactions;
- a counterparty may not perform its obligation under the applicable derivative financial instrument or may seek bankruptcy protection;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

The enactment of derivatives legislation and regulation 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.

In 2010, new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"), was enacted that established federal oversight regulation of over-the-counter derivatives market and entities, such as us, that participate in that market. Dodd-Frank requires the Commodities Futures Trading Commission, or CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. The final rules adopted under Dodd-Frank identify the types of products and the classes of market participants subject to regulation and will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption from such requirements). In addition, new regulations may require us to comply with margin requirements, although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result, it is not possible at this time to predict with certainty the full effects of Dodd-Frank and CFTC rules on us or the timing of such effects. Dodd-Frank 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. Dodd-Frank and associated regulations could significantly increase the cost of derivative contracts from additional recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity. Dodd-Frank could also materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that 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 Dodd-Frank and associated regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, Dodd-Frank 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 Dodd-Frank is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as restrict our access to our oil and gas reserves.

Hydraulic fracturing is an essential and common practice that is used to stimulate production of oil and natural gas from dense subsurface rock formations such as shale and tight sands. We routinely apply hydraulic fracturing techniques in completing our wells. The process involves the injection of water, sand and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the oil or natural gas to flow to the wellbore. The use of hydraulic fracturing is necessary to produce commercial quantities of oil and natural gas from many reservoirs including the Haynesville shale, Bossier shale, Eagle Ford shale, Tuscaloosa Marine shale, Cotton Valley and other tight natural gas and oil reservoirs. Substantially all of our proved oil and gas reserves that are currently not producing and our undeveloped acreage require hydraulic fracturing to be productive. All of the wells currently being drilled by us utilize hydraulic fracturing in their completion. We estimate we will incur approximately $113.0 million for hydraulic fracturing services in connection with our 2015 drilling and completion program.

The use of hydraulic fracturing in our well completion activities could expose us to liability for negative environmental effects that might occur. Although we have not had any incidents related to hydraulic fracturing operations that we believe have caused any negative environmental effects, we have established operating procedures to respond and report any unexpected fluid discharge which might occur during our operations, including plans to remediate any spills that might occur. In the event that we were to suffer a loss related to hydraulic fracturing operations, our insurance coverage will be net of a deductible per occurrence and our ability to recover costs will be limited to a total aggregate policy limit of $26.0 million, which may or may not be sufficient to pay the full amount of our losses incurred.

Drilling and completion activities are typically regulated by state oil and natural gas commissions. Our drilling and completion activities are conducted primarily in Louisiana and Texas. Texas adopted a law in June 2012 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic-fracturing process. Several proposals are before the United States Congress that, if implemented, would subject the process of hydraulic fracturing to regulation under the Safe Drinking Water Act. At the direction of Congress, the EPA is currently conducting an extensive, multi-year study into the potential effects of hydraulic fracturing on underground sources of drinking water, and the results of that study have the potential to impact the likelihood or scope of future legislation or regulation.

Potential changes to US federal tax regulations, if passed, could have an adverse effect on us.

The United States Congress continues to consider imposing new taxes and repealing many tax incentives and deductions that are currently used by independent oil and gas producers. Such changes include, but are not limited to:

- the repeal of the percentage depletion allowance for oil and gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- an elimination of the deduction for U.S. oil and gas production activities;
- an extension of the amortization period for certain geological and geophysical expenditures; and
- implementation of a fee on non-producing leases located on federal lands.

It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation containing these or similar changes in U.S. federal income tax law could eliminate or defer certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such changes could negatively affect our financial condition and results of operations. A reduction in operating cash flow could require us to reduce our drilling activities. Since none of these proposals have yet been included in new legislation, we do not know the ultimate impact they may have on our business.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure or we were subject to cyberspace breaches or attacks, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material effect on our business.

Our business could be negatively impacted by security threats, including cyber-security threats and other disruptions.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Cyber-security attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities, essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

We are exposed to the credit risk of our customers and counterparties, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Our credit procedures and policies may not be adequate to fully eliminate customer and counterparty credit risk. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers' and counterparties' creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write-down or write-off doubtful accounts. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Substantial exploration and development activities could require significant outside capital, which could dilute the value of our common shares and restrict our activities. Also, we may not be able to obtain needed capital or financing on satisfactory terms, which could lead to a limitation of our future business opportunities and a decline in our oil and natural gas reserves.

We expect to expend substantial capital in the acquisition of, exploration for and development of oil and natural gas reserves. In order to finance these activities, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of non-strategic assets or other means. The issuance of additional equity securities could have a dilutive effect on the value of our common shares, and may not be possible on terms acceptable to us given the current volatility in the financial markets. The issuance of additional debt would require that a portion of our cash flow from operations be used for the payment of interest on our debt, thereby reducing our ability to use our cash flow to fund working capital, capital expenditures, acquisitions, dividends and general corporate requirements, which could place us at a competitive disadvantage relative to other competitors. Additionally, if our revenues decrease as a result of lower oil or natural gas prices, operating difficulties or declines in reserves, our ability to obtain the capital necessary to undertake or complete future exploration and development programs and to pursue other opportunities may be limited, which could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could result in a decline in our oil and natural gas reserves.

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

Our industry has experienced a shortage of drilling rigs, equipment, supplies and qualified personnel in prior years as the result of higher demand for these services. Shortages of drilling rigs, equipment or supplies or qualified personnel in the areas in which we operate could delay or restrict our exploration and development operations, which in turn could adversely affect our financial condition and results of operations because of our concentration in those areas.

We depend on our key personnel and the loss of any of these individuals could have a material adverse effect on our operations.

We believe that the success of our business strategy and our ability to operate profitably depend on the continued employment of M. Jay Allison, our Chief Executive Officer, and Roland O. Burns, our President and Chief Financial Officer, and a limited number of other senior management personnel. Loss of the services of Mr. Allison, Mr. Burns or any of those other individuals could have a material adverse effect on our operations.

Our insurance coverage may not be sufficient or may not be available to cover some liabilities or losses that we may incur.

If we suffer a significant accident or other loss, our insurance coverage will be net of our deductibles and may not be sufficient to pay the full current market value or current replacement value of our lost investment, which could result in a material adverse impact on our operations and financial condition. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Because third party drilling contractors are used to drill our wells, we may not realize the full benefit of workers' compensation laws in dealing with their employees. In addition, some risks, including pollution and environmental risks, generally are not fully insurable.

Provisions of our articles of incorporation, bylaws and Nevada law will make it more difficult to effect a change in control of us, which could adversely affect the price of our common stock.

Nevada corporate law and our articles of incorporation and bylaws contain provisions that could delay, defer or prevent a change in control of us. These provisions include:

- allowing for authorized but unissued shares of common and preferred stock;
- a classified board of directors;
- requiring special stockholder meetings to be called only by our chairman of the board, our chief executive officer, a majority of the board or the holders of at least 10% of our outstanding stock entitled to vote at a special meeting;
- requiring removal of directors by a supermajority stockholder vote;
- prohibiting cumulative voting in the election of directors; and
- Nevada control share laws that may limit voting rights in shares representing a controlling interest in us.

These provisions could make an acquisition of us by means of a tender offer or proxy contest or removal of our incumbent directors more difficult. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 3. *LEGAL PROCEEDINGS*

We are not a party to any legal proceedings which management believes will have a material adverse effect on our consolidated results of operations or financial condition.

ITEM 4. *MINE SAFETY DISCLOSURES*

Not applicable.

PART II

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

Our common stock is listed for trading on the New York Stock Exchange under the symbol "CRK." The following table sets forth, on a per share basis for the periods indicated, the high and low sales prices by calendar quarter for the periods indicated as reported by the New York Stock Exchange.

		High	Low
2013 —	First Quarter	$18.86	$12.83
	Second Quarter	$18.22	$14.11
	Third Quarter	$18.42	$14.21
	Fourth Quarter	$18.91	$15.83
2014 —	First Quarter	$23.15	$16.22
	Second Quarter	$29.15	$22.42
	Third Quarter	$29.49	$18.30
	Fourth Quarter	$18.80	$ 5.01

As of February 24, 2015, we had 47,626,557 shares of common stock outstanding, which were held by 261 holders of record and approximately 36,000 beneficial owners who maintain their shares in "street name" accounts.

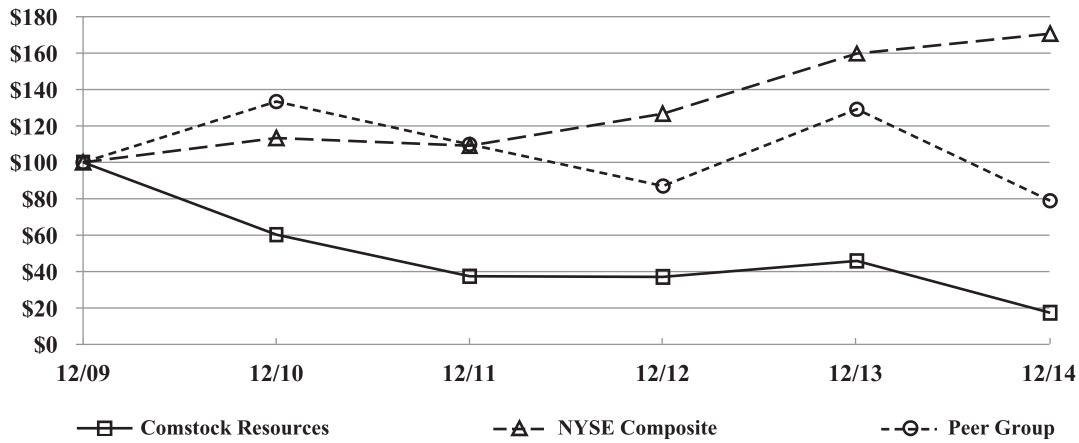
We paid a quarterly cash dividend on our common stock in 2014, resulting in total dividends paid of $23.8 million. On February 13, 2015 we announced that the dividend was being temporarily suspended until oil and natural gas prices improve. Any future determination as to the payment of dividends will depend upon the results of our operations, capital requirements, our financial condition and such other factors as our board of directors may deem relevant.

Stockholder Return Performance

A peer group of companies is used by our compensation committee to benchmark our executives' compensation and to determine total stockholder return performance for purposes of vesting of performance share units granted to executives under our 2009 Long-term Incentive Plan. In 2014, the compensation committee approved our current peer group, which consists of Approach Resources. Inc., Bill Barrett Corporation, Carrizo Oil & Gas Inc., Cimarex Energy Co., Forest Oil Corp., Kodiak Oil and Gas Corp., Laredo Petroleum Holdings Inc., Oasis Petroleum Inc., PDC Energy Inc., Quicksilver Resources Inc., Rosetta Resources Inc., SM Energy, Inc., Stone Energy Corporation, Swift Energy Co., and Ultra Petroleum Corp. Beginning in 2015, Forest Oil Corp., Kodiak Oil and Gas Corp. and Quicksilver Resources Inc. were removed from the peer group.

The following graph compares the yearly percentage change in the cumulative total stockholder return on our common stock during the five years ended December 31, 2014 with the cumulative return on the New York Stock Exchange Index and the cumulative return for our peer group. The graph assumes that $100.00 was invested on the last trading day of 2009, and that dividends, if any, were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN(1)(2)
Among Comstock Resources, the NYSE Composite Index, and Our Peer Group



(1) $100 invested on December 31, 2009 in stock or index, including reinvestment of dividends, fiscal year ending December 31.
(2) The data contained in the above graph is deemed to be furnished and not filed pursuant to Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section.

Total Return Analysis	As of December 31, 2009	2010	2011	2012	2013	2014
Comstock Resources	$100.00	$ 60.54	$ 37.71	$ 37.27	$ 46.15	$ 17.75
NYSE Composite	$100.00	$113.39	$109.04	$126.47	$159.71	$170.49
Peer Group	$100.00	$133.22	$109.86	$ 87.09	$129.13	$ 79.18

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

In May 2013, our Board of Directors approved an open market share repurchase plan which allows us to repurchase up to $100.0 million of our common stock on the open market. All purchases executed to date have been through open market transactions. There is no expiration date associated with the authorization to repurchase our securities. All repurchased shares have been cancelled. The following table summarizes the purchases of our common stock during the three months ended December 31, 2014:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
				(in thousands)
December 2014	1,000,000	$8.09	1,000,000	$82,682
Total	1,000,000	$8.09	1,000,000	$82,682

ITEM 6. *SELECTED FINANCIAL DATA*

The historical financial data presented in the table below as of and for each of the years in the five-year period ended December 31, 2014 are derived from our consolidated financial statements. The financial results are not necessarily indicative of our future operations or future financial results. The data presented below should be read in conjunction with our consolidated financial statements and the notes thereto and "Management's Discussion and Analysis of Financial Condition and Results of Operations." During 2013, we divested all of our interests in our West Texas operations. Accordingly, we have adjusted the presentation of selected financial data to reflect these operations on a discontinued basis.

Statement of Operations Data:

	Year Ended December 31,				
	2010	2011	2012	2013	2014
	(In thousands, except per share data)				
Revenues:					
Oil sales	$ 48,848	$ 80,244	$ 181,163	$ 231,837	$ 389,770
Natural gas sales	300,293	354,123	203,651	188,453	165,461
Total oil and gas sales	349,141	434,367	384,814	420,290	555,231
Gain on sales of oil and gas properties	—	—	24,271	—	—
Total revenues	349,141	434,367	409,085	420,290	555,231
Operating expenses:					
Production taxes	9,894	3,670	11,727	14,524	23,797
Gathering and transportation	17,256	28,491	26,265	17,245	12,897
Lease operating(1)	53,525	46,552	51,248	52,844	60,283
Exploration	2,605	10,148	61,449	33,423	19,403
Depreciation, depletion and amortization	213,809	290,776	343,858	337,134	378,275
General and administrative, net	37,200	35,172	33,798	34,767	32,379
Impairment of oil and gas properties	224	60,817	25,368	652	60,268
Loss on sales of oil and gas properties	26,632	57	—	2,033	—
Total operating expenses	361,145	475,683	553,713	492,622	587,302
Operating loss	(12,004)	(41,316)	(144,628)	(72,332)	(32,071)
Other income (expenses):					
Gain on sale of marketable securities	16,529	35,118	26,621	7,877	—
Gain (loss) on derivative financial instruments	—	—	21,256	(8,388)	8,175
Loss on early extinguishment of debt	—	(1,096)	—	(17,854)	—
Other income	499	790	944	1,059	727
Interest expense	(29,456)	(41,592)	(57,906)	(73,242)	(58,631)
Total other income (expenses)	(12,428)	(6,780)	(9,085)	(90,548)	(49,729)
Loss from continuing operations before income taxes	(24,432)	(48,096)	(153,713)	(162,880)	(81,800)
Benefit from income taxes	4,846	14,624	50,634	56,157	24,689
Loss from continuing operations	(19,586)	(33,472)	(103,079)	(106,723)	(57,111)
Income from discontinued operations, net of income taxes	—	—	3,019	147,752	—
Net income (loss)	$ (19,586)	$ (33,472)	$(100,060)	$ 41,029	$ (57,111)
Basic net income (loss) per share:					
Loss from continuing operations	$ (0.43)	$ (0.73)	$ (2.22)	$ (2.22)	$ (1.24)
Income from discontinued operations	—	—	0.06	3.07	—
Net Income (loss)	$ (0.43)	$ (0.73)	$ (2.16)	$ 0.85	$ (1.24)
Diluted net income (loss) per share:					
Loss from continuing operations	$ (0.43)	$ (0.73)	$ (2.22)	$ (2.22)	$ (1.24)
Income from discontinued operations	—	—	0.06	3.07	—
Net Income (loss)	$ (0.43)	$ (0.73)	$ (2.16)	$ 0.85	$ (1.24)
Dividends per common share	$ —	$ —	$ —	$ 0.375	$ 0.500
Weighted average shares outstanding:					
Basic	45,561	45,997	46,422	46,553	46,547
Diluted(2)	45,561	45,997	46,422	46,553	46,547

(1) Includes ad valorem taxes.
(2) Basic and diluted weighted average shares are the same due to the net loss from continuing operations.

Balance Sheet Data:

	As of December 31,				
	2010	2011	2012	2013	2014
			(In thousands)		
Cash and cash equivalents	$ 1,732	$ 8,460	$ 4,471	$ 2,967	$ 2,071
Property and equipment, net	1,816,248	2,155,568	1,958,687	2,066,735	2,198,169
Total assets	1,964,214	2,642,598	2,569,897	2,139,398	2,274,337
Total debt	513,372	1,196,908	1,324,383	798,700	1,070,445
Stockholders' equity	1,068,531	1,037,625	933,534	952,005	870,272

Cash Flow Data:

	Year Ended December 31,				
	2010	2011	2012	2013	2014
			(In thousands)		
Cash flows provided by operating activities from continuing operations	$ 311,662	$ 275,433	$ 219,721	$ 268,994	$ 400,984
Cash flows used for investing activities from continuing operations	(440,473)	(597,809)	(205,393)	(408,678)	(634,787)
Cash flows provided by (used for) financing activities from continuing operations	40,071	673,381	117,502	(576,140)	232,907
Cash flows provided by (used for) operating activities of discontinued operations	—	—	42,508	(7,715)	—
Cash flows provided by (used for) investing activities of discontinued operations	—	(344,277)	(178,327)	722,035	—

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

The following discussion and analysis should be read in conjunction with our selected historical consolidated financial data and our accompanying consolidated financial statements and the notes to those financial statements included elsewhere in this report. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this report, particularly in "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements."

Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas in the United States. We own interests in 1,596 producing oil and natural gas wells (869.7 net to us) and we operate 962 of these wells. In managing our business, we are concerned primarily with maximizing return on our stockholders' equity. To accomplish this goal, we focus on profitably increasing our oil and natural gas reserves and production.

In 2011, we acquired an undeveloped acreage position and some producing oil wells in Gaines and Reeves Counties in West Texas. We operated these properties, which we designated as our West Texas region, through May 2013 when we sold all of these properties for total proceeds of $823.1 million. Accordingly, we are presenting our West Texas operations as discontinued operations in our financial statements for all periods presented. Unless indicated otherwise, the amounts in the accompanying tables and discussion relate to our continuing operations.

Our growth is driven primarily by acquisition, development and exploration activities. In 2014 our growth in production and proved reserves was primarily driven by our successful oil focused drilling activities. Under our current drilling budget, we plan to spend approximately $317.0 million in 2015 for development and exploration activities, which will primarily be focused on natural gas projects and completing oil projects that were started in 2014. We plan to drill 18 horizontal wells (18.0 net to us) in 2015, of which 14 natural gas wells (14.0 net to us) will be drilled in our Haynesville/Bossier field and four oil wells (4.0 net to us) will be drilled in our Giddings field. However, we could increase or decrease the number of wells that we drill depending on oil and natural gas prices. We do not specifically budget for acquisitions as the timing and size of acquisitions are not predictable.

We use the successful efforts method of accounting, which allows only for the capitalization of costs associated with developing proven oil and natural gas properties as well as exploration costs associated with successful exploration activities. Accordingly, our exploration costs consist of costs we incur to acquire and reprocess 3-D seismic data, impairments of our unevaluated leasehold where we were not successful in discovering reserves and the costs of unsuccessful exploratory wells that we drill.

We generally sell our oil and natural gas at current market prices at the point our wells connect to third party purchaser pipelines. We have entered into certain transportation and treating agreements with midstream and pipeline companies to transport a substantial portion of our natural gas production in North Louisiana to long-haul gas pipelines. We market our products several different ways depending upon a number of factors, including the availability of purchasers for the product, the availability and cost of pipelines near our wells, market prices, pipeline constraints and operational flexibility. Accordingly, our revenues are heavily dependent upon the prices of, and demand for, oil and natural gas. Oil and natural gas prices have historically been volatile and are likely to remain volatile in the future.

Our operating costs are generally comprised of several components, including costs of field personnel, insurance, repair and maintenance costs, production supplies, fuel used in operations, transportation costs, workover expenses and state production and ad valorem taxes.

Like all oil and natural gas exploration and production companies, we face the constant challenge of replacing our reserves. Although in the past we have offset the effect of declining production rates from existing properties through successful acquisition and drilling efforts, there can be no assurance that we will be able to continue to offset production declines or maintain production at current rates through future acquisitions or drilling activity. Our future growth will depend on our ability to continue to add new reserves in excess of production.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and natural gas, and operating safety. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may have an adverse effect on our business, results of operations and financial condition. Applicable environmental regulations require us to remove our equipment after production has ceased, to plug and abandon our wells and to remediate any environmental damage our operations may have caused. The present value of the estimated future costs to plug and abandon our oil and gas wells and to dismantle and remove our production facilities is included in our reserve for future abandonment costs, which was $14.9 million as of December 31, 2014.

Recently the prices for crude oil and natural gas have been highly volatile, and we are currently experiencing a period of low prices primarily due to an oversupply of crude oil and natural gas. If these low prices continue, we will experience lower revenues and cash flows until these prices improve. We expect our oil production to decline in the future until we resume drilling on these properties. We expect our natural gas production to increase from our 2015 drilling and recompletion program on our Haynesville shale properties. Depending upon future prices and our production volumes, our cash flows from our operating activities may not be sufficient to fund our capital expenditures, and we may need additional borrowings which would increase our interest expense in 2015 and in future periods. If commodity prices remain low, we may also recognize further impairments of our producing oil and gas properties if the expected future cash flows from these properties becomes insufficient to recover their carrying value, and we may recognize additional impairments of our unevaluated oil and gas properties should we determine that we no longer intend to retain these properties for future oil and natural gas development.

Results of Operations

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

Our operating data for 2013 and 2014 is summarized below:

	Year Ended December 31,	
	2013	2014
Oil & Gas Sales (in thousands):		
Oil sales	$231,837	$389,770
Natural gas sales	188,453	165,461
Total oil and gas sales	$420,290	$555,231
Net Production Data:		
Natural gas (MMcf)	55,694	39,768
Oil (MBbls)	2,314	4,313
Natural gas equivalent (MMcfe)	69,577	65,645
Average Sales Price:		
Oil ($/Bbl)	$ 100.20	$ 90.37
Natural gas ($/Mcf)	$ 3.38	$ 4.16
Average equivalent price ($/Mcfe)	$ 6.04	$ 8.46
Expenses ($ per Mcfe):		
Production taxes	$ 0.21	$ 0.36
Gathering and transportation	$ 0.25	$ 0.20
Lease operating(1)	$ 0.76	$ 0.92
Depreciation, depletion and amortization(2)	$ 4.83	$ 5.74

(1) Includes ad valorem taxes.
(2) Represents depreciation, depletion and amortization of oil and gas properties only.

Oil and gas sales. Our oil and gas sales increased $134.9 million (32%) in 2014 to $555.2 million from $420.3 million in 2013. Oil sales in 2014 increased by $157.9 million (68%) from 2013 while our natural gas sales decreased by $23.0 million (12%) from 2013. The increase in oil sales was attributable to the 86% growth in oil production offset by a 10% decrease in our realized oil prices in 2014. Our drilling activity in the Eagleville and Giddings fields in South Texas principally generated the growth in the oil production. With limited drilling in our natural gas properties in 2014, our natural gas production fell by 29% from 2013 while our realized natural gas prices increased by 23%.

Production taxes. Production taxes increased $9.3 million or 64% to $23.8 million in 2014 from $14.5 million in 2013. The increase in 2014 was due to the 68% growth in our oil sales during the year. Much of our natural gas sales in 2013 and 2014 qualified for exemption from state production taxes.

Gathering and transportation. Gathering and transportation costs in 2014 decreased $4.3 million (25%) to $12.9 million as compared to $17.2 million in 2013 due to the lower natural gas volumes that we produced in North Louisiana in 2014.

Lease operating expenses. Our lease operating expenses, including ad valorem taxes, of $60.3 million in 2014 were $7.5 million or 14% higher than our operating expenses of $52.8 million in 2013.

Our lease operating expense per Mcfe produced increased by 21% to $0.92 per Mcfe in 2014 as compared to $0.76 per Mcfe in 2013. The increase in operating costs mainly reflects our growing oil production. Our oil wells are typically more costly to operate on a per Mcfe basis than our natural gas wells. The increase in our per unit costs is also partially attributable to the lower production on a Mcfe basis. Oil production comprised 39% of our total production in 2014 as compared to 20% in 2013.

Exploration expense. We incurred $19.4 million in exploration expense in 2014 as compared to $33.4 million in 2013. Exploration expense in 2014 consisted of $11.8 million in dry hole costs, $6.7 million in rig termination fees, $0.5 million of impairments of unevaluated leasehold costs and $0.4 million for the acquisition of seismic data. Our 2013 exploration cost consisted of $33.0 million of impairments of unevaluated leasehold costs and $0.4 million for the acquisition of seismic data.

Depreciation, depletion and amortization expense ("DD&A"). DD&A of $378.3 million increased by $41.2 million (12%) from DD&A of $337.1 million in 2013. Our DD&A rate per Mcfe produced averaged $5.74 in 2014 as compared to $4.83 for 2013. The increase in DD&A primarily resulted from the increased development costs per Mcfe associated with the oil wells drilled in 2014 and 2013.

General and administrative expenses. General and administrative expense of $32.4 million for 2014 was 7% lower than general and administrative expense of $34.8 million for 2013. The decrease is primarily related to stock-based compensation which decreased by $2.1 million to $10.7 million in 2014 as compared to $12.8 million in 2013.

Impairment of oil and gas properties. We recorded impairments to our oil and gas properties of $60.3 million and $0.7 million in 2014 and 2013, respectively. These impairments relate to older, conventional oil and gas properties with declining production and limited potential for future investments.

Derivative financial instruments. We utilized oil price swaps to manage our exposure to oil prices and protect returns on investment from our drilling activities in 2013 and 2014. We had a gain of $8.2 million and a loss of $8.4 million on derivative financial instruments in 2014 and 2013, respectively. Our total net cash received from derivative financial instruments was $9.1 million in 2014 and $2.3 million in 2013. The following table presents our crude oil equivalent prices before and after the effect of cash settlements of our derivative financial instruments:

Average Realized Oil Price:	2013	2014
Oil, per barrel	$100.20	$90.37
Cash settlements on derivative financial instruments, per barrel	0.99	2.13
Price per barrel, including cash settlements on derivative financial instruments	$101.19	$92.50

Interest expense. Interest expense decreased $14.6 million (20%) to $58.6 million in 2014 from interest expense of $73.2 million in 2013. The decrease was primarily related to lower interest expense due to the retirement in September 2013 of our 8⅜% senior notes due in 2017. We capitalized interest of $10.2 million and $4.7 million in 2014 and 2013, respectively, which reduced interest expense. We had interest expense allocated to discontinued operations of $8.4 million in 2013 of which $2.0 million was capitalized. Average borrowings under our bank credit facility increased to $319.2 million in 2014 as compared to $201.5 million for 2013 and the average interest rate on the outstanding borrowings under our bank credit facility of 2.0% in 2014 was lower than the interest rate of 2.6% in 2013. Interest expense related to our outstanding senior notes decreased by 21% due to the retirement of our 8⅜% senior notes offset partially by the issuance an additional $100.0 million of our 7¾% senior notes in 2014.

Income taxes. The benefit from income taxes from continuing operations decreased in 2014 to $24.7 million from $56.2 million in 2013 due to the lower net loss from continuing operations in 2014.

Our effective tax rate of 30.2% in 2014 and 34.5% in 2013 differed from the federal income tax rate of 35% primarily due to the effect of nondeductible compensation, state income taxes and an increase in the valuation allowance for state income tax net operating loss carry forwards in 2014.

Net income. We reported a net loss from continuing operations of $57.1 million or $1.24 per share for 2014 as compared to a loss of $106.7 million or $2.22 per share for 2013. The net loss in 2014 included impairments of proved and unproved properties of $60.8 million ($39.5 million after income taxes), rig termination fees of $6.7 million ($4.4 million after income taxes), dry hole costs of $11.8 million ($7.7 million after income taxes) and a gain on our oil derivatives of $8.2 million ($5.3 million after income taxes). The loss in 2013 included impairments of proved and unproved properties of $33.6 million ($21.9 million after income taxes), loss on early extinguishment of debt of $17.9 million ($11.6 million after income taxes), a loss on our oil derivatives of $8.4 million ($5.5 million after income taxes), and losses on sales of properties of $2.0 million ($1.3 million after income taxes), which were offset in part by gains on sales of marketable securities of $7.9 million ($5.1 million after income taxes).

Net income from discontinued operations for 2013 of $147.8 million, or $3.07 per share, included a gain on the sale of our West Texas oil and gas properties of $230.0 million ($148.6 million after income taxes). Excluding the gain, the net loss from discontinued operations for the year ended December 31, 2013 was $0.8 million.

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

Our operating data for 2012 and 2013 is summarized below:

	Year Ended December 31,	
	2012	2013
Oil & Gas Sales (in thousands):		
Oil sales	$181,163	$231,837
Natural gas sales	203,651	188,453
Total oil and gas sales	$384,814	$420,290
Net Production Data:		
Natural gas (MMcf)	81,762	55,694
Oil (MBbls)	1,792	2,314
Natural gas equivalent (MMcfe)	92,515	69,577
Average Sales Price:		
Oil ($/Bbl)	$ 101.09	$ 100.20
Natural gas ($/Mcf)	$ 2.49	$ 3.38
Average equivalent price ($/Mcfe)	$ 4.16	$ 6.04
Expenses ($ per Mcfe):		
Production taxes	$ 0.13	$ 0.21
Gathering and transportation	$ 0.28	$ 0.25
Lease operating(1)	$ 0.55	$ 0.76
Depreciation, depletion and amortization(2)	$ 3.76	$ 4.83

(1) Includes ad valorem taxes.
(2) Represents depreciation, depletion and amortization of oil and gas properties only.

Oil and gas sales. Our oil and gas sales increased $35.5 million (9%) in 2013 to $420.3 million from $384.8 million in 2012. Oil sales in 2013 increased by $50.7 million (28%) from 2012 while our natural gas sales decreased by $15.2 million (8%) from 2012. The increase in oil sales was attributable to the 29% growth in oil production offset by a 1% decrease in our prices in 2013. Our drilling activity in the Eagleville field in South Texas generated the oil production growth. With limited drilling in our natural gas properties in 2013, our natural gas production fell by 32% from 2012 while our realized natural gas prices increased by 36%.

Production taxes. Production taxes increased $2.8 million or 24% to $14.5 million in 2013 from $11.7 million in 2012. The increase in 2013 is due to the 28% growth in our oil sales during the year. Much of our natural gas sales in 2012 and 2013 qualified for exemption from state production taxes.

Gathering and transportation. Gathering and transportation costs in 2013 decreased $9.1 million (34%) to $17.2 million as compared to $26.3 million in 2012 due to the lower natural gas volumes that we produced in North Louisiana in 2013.

Lease operating expenses. Our lease operating expenses, including ad valorem taxes, of $52.8 million in 2013 were $1.6 million or 3% higher than our operating expenses of $51.2 million in 2012. Our lease operating expense per Mcfe produced increased by 38% to $0.76 per Mcfe in 2013 as compared to $0.55 per Mcfe in 2012. The increase in operating costs mainly reflects our growing oil production. Our oil wells are typically more costly to operate than our natural gas wells. Oil production comprised 20% of our total production in 2013 as compared to 12% in 2012. The increase in our per unit costs is largely attributable to the lower production on a Mcfe basis. Much of our operating costs are fixed in nature.

Exploration expense. We incurred $33.4 million in exploration expense in 2013 as compared to $61.4 million in 2012. Exploration expense in 2013 consisted of $33.0 million of impairments of unevaluated leasehold costs and $0.4 million for the acquisition of seismic data. Our 2012 exploration cost consisted of $61.3 million of impairments of unevaluated leasehold costs and $0.1 million for the acquisition of seismic data.

DD&A. DD&A of $337.1 million decreased by $6.8 million (2%) from DD&A of $343.9 million in 2012. Our DD&A rate per Mcfe produced averaged $4.83 in 2013 as compared to $3.76 for 2012. The decrease in DD&A primarily resulted from the decline in our natural gas production during 2013, which was partially offset by the increased development costs per Mcfe associated with the oil wells drilled in 2013 and the reduction in proved undeveloped natural gas reserves recognized in 2012 which increased our per unit DD&A rate on our natural gas properties.

General and administrative expenses. General and administrative expense of $34.8 million for 2013 was 3% higher than general and administrative expense of $33.8 million for 2012. Stock based compensation decreased by $0.9 million to $12.8 million in 2013 as compared to $13.7 million in 2012.

Impairment of oil and gas properties. We recorded impairments to our oil and gas properties of $0.7 million and $25.4 million in 2013 and 2012, respectively. These impairments relate to fields where an impairment was indicated based on estimated future net cash flows from the properties.

Derivative financial instruments. We utilized oil price swaps to manage our exposure to commodity prices and protect returns on investment from our drilling activities in 2013 and 2012. We had a loss of $8.4 million and a gain of $21.3 million on derivative financial instruments in 2013 and 2012, respectively. Our total net cash received from derivative financial instruments was $2.3 million in 2013 and $9.8 million in 2012. The following table presents our crude oil equivalent prices before and after the effect of cash settlements of our derivative financial instruments:

Average Realized Oil Price:	**2012**	**2013**
Oil, per barrel	$101.09	$100.20
Cash settlements on derivative financial instruments, per barrel	5.44	0.99
Price per barrel, including cash settlements on derivative financial instruments	$106.53	$101.19

Interest expense. Interest expense increased $15.3 million (26%) to $73.2 million in 2013 from interest expense of $57.9 million in 2012. The increase was primarily related to a reduction in the interest we capitalized in 2013. We capitalized interest of $4.7 million and $20.9 million in 2013 and 2012, respectively, which reduced interest expense. We had interest expense allocated to discontinued operations of $8.4 million and $16.3 million in 2013 and 2012, respectively, of which $2.0 million and $9.6 million, respectively, was capitalized. Average borrowings under our bank credit facility decreased to $201.5 million in 2013 as compared to $482.7 million for 2012 and the average interest rate on the outstanding borrowings under our credit facility of 2.6% in 2013 was lower than the interest rate of 3.0% in 2012. Interest expense related to our outstanding senior notes increased by 11% due to the issuance of 9½% senior notes in June 2012 offset in part the redemption of 8⅜% senior notes in November 2013.

Income taxes. The benefit from income taxes from continuing operations increased in 2013 to $56.2 million from $50.6 million in 2012 due to the higher net loss from continuing operations in 2013. Our effective tax rate of 34.5% in 2013 and 32.9% in 2012 differed from the federal income tax rate of 35% primarily due to the effect of nondeductible compensation and state income taxes.

Net income. We reported a loss from continuing operations of $106.7 million or $2.22 per share for 2013 as compared to a loss of $103.1 million or $2.22 per share for 2012. The loss in 2013 included impairments of proved and unproved properties of $33.6 million ($21.9 million after income taxes), loss on early extinguishment of debt of $17.9 million ($11.6 million after income taxes), losses on our oil derivatives of $8.4 million ($5.5 million after income taxes) and losses on sales of properties of $2.0 million ($1.3 million after income taxes) which were offset in part by gains on sales of marketable securities of $7.9 million ($5.1 million after income taxes). The loss in 2012 included impairments of proved and unproved properties of $86.7 million ($56.3 million after income taxes) which were offset in part by gains on sales of properties of $24.3 million ($15.8 million after income taxes), gains on sales of marketable securities of $26.6 million ($17.3 million after income taxes) and gains on our oil derivatives of $21.3 million ($13.8 million after tax).

Net income from discontinued operations for 2013 of $147.8 million, or $3.07 per share, included a gain on the sale of our West Texas oil and gas properties of $230.0 million ($148.6 million after income taxes). Excluding the gain, the net loss from discontinued operations for the year ended December 31, 2013 was $0.8 million as compared to net income of $3.0 million for the year ended December 31, 2012.

Liquidity and Capital Resources

Funding for our activities has historically been provided by our operating cash flow, debt or equity financings and asset dispositions. For 2014, our primary source of funds was operating cash flow and borrowings. Cash provided by operating activities from continuing operations in 2014 of $401.0 million increased $132.0 million (49%) from $269.0 million in 2013. Our other primary source of funds during 2014 included $103.3 million of proceeds from an additional issuance of our 7¾% senior notes and $165.0 million of borrowings under our bank credit facility. In 2013, our cash flow provided by operating activities of continuing operations totaled $269.0 million, while our other primary sources of funds included $836.6 million from sales of assets. In 2012, our cash flow provided by operating activities from continuing operations totaled $219.7 million. Our other primary source of funds in 2012 included $285.9 million of proceeds from a senior note offering and $179.6 million of proceeds from sales of assets.

Our cash flow from operating activities from continuing operations in 2014 of $401.0 million represented an increase of $132.0 million (49%) from our cash from operating activities of $269.0 million in 2013. Cash flow from continuing operations excluding changes in working capital accounts was $391.5 million in 2014 which was 57% higher than 2013 due to increased revenues related to the increased oil production and higher natural gas prices in 2014. Our cash flow from operating activities from continuing operations in 2013 increased by $49.3 million to $269.0 million as compared to $219.7 million in 2012 primarily due to the higher revenues related to higher natural gas prices in 2013 and higher oil production.

Our primary need for capital, in addition to funding our ongoing operations, relates to the acquisition, development and exploration of our oil and gas properties and the repayment of our debt. During 2014 our capital expenditures of $588.6 million represented an increase by $107.7 million as compared to 2013 capital expenditures of $480.9 million due primarily to our high level of drilling activity during 2014. In 2013, our capital expenditures of $480.9 million increased by $132.7 million as compared to 2012 capital expenditures of $348.2 million, mainly due to acquisitions of oil and gas properties in 2013.

Our capital expenditure activity related to our continuing operations is summarized in the following table:

	Year Ended December 31,		
	2012	2013	2014
		(In thousands)	
Exploration and development:			
Acquisitions of proved oil and gas properties	$ —	$ 6,450	$ 2,400
Acquisitions of unproved oil and gas properties	13,742	130,113	91,960
Developmental leasehold costs	2,157	461	3,386
Development drilling	321,924	338,030	427,612
Exploratory drilling[1]	5,317	—	51,725
Workovers and recompletions	3,728	5,559	10,274
	346,868[2]	480,613[3]	587,357[3]
Other	1,311	260	1,257
Total	$348,179[2]	$480,873[3]	$588,614[3]

(1) 2014 includes rig termination fees of $6.7 million.
(2) Excludes reimbursements from joint venture partner for preformation well costs of $23.8 million in 2012.
(3) Net of reimbursements received from joint venture partner of $51.5 million and $28.7 million in 2013 and 2014, respectively.

The timing of most of our capital expenditures is discretionary because we have no material long-term capital expenditure commitments except for contracted drilling and completion services. Consequently, we have a significant degree of flexibility to adjust the level of our capital expenditures as circumstances warrant. We currently expect to spend approximately $307.0 million in 2015 for development and exploration projects and $10.0 million for leasing, which will be funded primarily by cash flows from operating activities and borrowings under our bank credit facility. Our operating cash flow and, therefore, our capital expenditures are highly dependent on oil and natural gas prices that we realize in 2015. We operate most of our properties and have significant discretion over the amount and timing of our future capital expenditures.

We do not have a specific acquisition budget for 2015 because the timing and size of acquisitions are unpredictable. We intend to use borrowings under our bank credit facility, or other debt or equity financings to the extent available, to finance such acquisitions. The availability and attractiveness of these sources of financing will depend upon a number of factors, some of which will relate to our financial condition and performance and some of which will be beyond our control, such as prevailing interest rates, oil and natural gas prices and other market conditions. Lack of access to the debt or equity markets due to general economic conditions could impede our ability to complete acquisitions.

We have a $1.0 billion bank credit facility with Bank of Montreal, as the administrative agent. The bank credit facility is a five-year revolving credit commitment that matures on November 22, 2018. Indebtedness under the bank credit facility is secured by all of our assets and is guaranteed by all of our wholly owned subsidiaries. The bank credit facility is subject to borrowing base availability, which is redetermined semiannually based on the banks' estimates of the future net cash flows of our oil and gas properties. As of December 31, 2014, the borrowing base was $675.0 million, of which $300.0 million was available. The borrowing base may be affected by the performance of our properties and changes in oil and natural gas prices. Oil and natural gas prices used by the banks to redetermine the borrowing base in 2015 are expected to be lower than the prices used in 2014. The determination of the borrowing base is at the sole discretion of the administrative agent and the bank group.

Borrowings under the bank credit facility bear interest, based on the utilization of the borrowing base, at our option at either (1) LIBOR plus 1.5% to 2.5% or (2) the base rate (which is the higher of the administrative agent's prime rate, the federal funds rate plus 0.5% or 30 day LIBOR plus 1.0%) plus 0.5% to 1.5%. A commitment fee of 0.375% to 0.5%, based on the utilization of the borrowing base, is payable annually on the unused borrowing base. The bank credit facility contains covenants that, among other things, restrict the payment of cash dividends and repurchases of common stock in excess of $120.0 million per year, limit the amount of consolidated debt that we may incur and limit our ability to make certain loans and investments. The financial covenants under the bank credit facility consist of the maintenance of a leverage ratio which must be less than four to one and the maintenance of an interest coverage ratio which must not be less than 2.5 to one; provided, however, that the leverage ratio was recently amended such that during 2015 the maximum permitted leverage ratio is five to one. We were in compliance with these covenants as of December 31, 2014, and we expect to remain in compliance during 2015.

We have $400.0 million of 7¾% senior notes (the "2019 Notes") outstanding which are due on April 1, 2019 and bear interest which is payable semi-annually on each April 1 and October 1. In May 2014, we issued $100.0 million of the 2019 Notes in a public offering. Net proceeds from the issuance of the additional 2019 Notes of $103.3 million were used to pay down borrowings under our bank credit facility. We also have $300.0 million of 9½% senior notes (the "2020 Notes") which are due on June 15, 2020 and bear interest which is payable semi-annually on each June 15 and December 15. The 2019 and 2020 Notes are unsecured obligations which are guaranteed by all of our material subsidiaries. Such subsidiary guarantors are 100% owned and all of the guarantees are full and unconditional and joint and several obligations. As of December 31, 2014, we had no material assets or operations which are independent of our subsidiaries. There are no restrictions on our ability to obtain funds from our subsidiaries through dividends or loans.

At January 1, 2013 we had $300.0 million in principal amount of 8⅜% senior notes outstanding with a maturity date of October 15, 2017 (the "2017 Notes"). In June 2013, we repurchased $2.2 million in principal amount of the 2017 Notes at 103.3% of the par value and in September 2013, we called all of the remaining 2017 Notes at the call price of 104.2% of par value for redemption on October 15, 2013. The redemption amount of $310.2 million was funded with cash on hand of $210.2 million and borrowings under our bank credit facility. As a result of this redemption, we recognized a loss on early extinguishment of debt, before income taxes, of approximately $17.9 million comprised of the premium paid for the redemption, the costs incurred related to the redemption and the write-off of unamortized debt issuance costs, including original issuance discount.

We believe that our cash flow from operations and available borrowings under our bank credit facility will be sufficient to fund our operations and future growth as contemplated under our current business plan. However, if our available borrowing base is reduced substantially which could occur as a result of the significant decline in oil and natural gas prices, or if our plans or assumptions change or our assumptions prove to be inaccurate, we may be required to seek additional capital, including additional equity or debt financings to replace any liquidity that may be lost from a reduction to the borrowing base. We cannot provide any assurance that we will be able to obtain such capital, or if such capital is available, that we will be able to obtain it on acceptable terms.

The following table summarizes our aggregate liabilities and commitments by year of maturity:

	2015	2016	2017	2018	2019	Thereafter	Total
				(In thousands)			
Bank credit facility	$ —	$ —	$ —	$ 375,000	$ —	$ —	$ 375,000
7 ¾% senior notes	—	—	—	—	400,000	—	400,000
9 ½% senior notes	—	—	—	—	—	300,000	300,000
Interest on debt	67,600	67,600	67,600	66,745	36,250	13,063	318,858
Operating leases	1,994	1,994	2,021	2,060	1,560	3,120	12,749
Natural gas transportation and treating agreements	5,102	2,203	1,782	1,698	681	—	11,466
Contracted drilling services	15,279	—	—	—	—	—	15,279
	$ 89,975	$ 71,797	$ 71,403	$ 445,503	$ 438,491	$ 316,183	$1,433,352

Future interest costs are based upon the effective interest rates of our outstanding senior notes and the December 31, 2014 rate for our bank credit facility.

We have obligations to incur future payments for dismantlement, abandonment and restoration costs of oil and gas properties. These payments are currently estimated to be incurred primarily after 2019. We record a separate liability for the fair value of these asset retirement obligations, which totaled $14.9 million as of December 31, 2014.

Federal Taxation

At December 31, 2014 we had U.S. federal net operating loss carryforwards of approximately $212.8 million and Louisiana state net operating loss carryforwards of approximately $991.5 million. The utilization of $34.7 million of our U.S. federal net operating loss carryforwards is limited to approximately $1.1 million per year pursuant to a prior change of control of an acquired company. Accordingly, a valuation allowance of $23.0 million, with a tax effect of $8.0 million, has been established for the estimated U.S. federal net operating loss carryforwards that will not be utilized. Realization of the remaining U.S. federal net operating loss carryforwards requires Comstock to generate taxable income within the carryforward period. A valuation allowance of $528.1 million, with a tax effect of $27.5 million as of December 31, 2013, and a valuation allowance of $742.2 million, with a tax effect of $38.6 million as of December 31, 2014, has been established against our Louisiana state net operating loss carryforwards due to the uncertainty of generating taxable income in the state of Louisiana prior to the expiration of the carry-over period.

Our federal income tax returns for the years subsequent to December 31, 2010 remain subject to examination. Our income tax returns in major state income tax jurisdictions remain subject to examination for various periods subsequent to December 31, 2009. We currently believe that our significant filing positions are highly certain and that all of our other significant income tax filing positions and deductions would be sustained upon audit or the final resolution would not have a material effect on our consolidated financial statements. Therefore, we have not established any significant reserves for uncertain tax positions. Interest and penalties resulting from audits by tax authorities have been immaterial and are included in the provision for income taxes in the consolidated statements of operations.

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and use assumptions that can affect the reported amounts of assets, liabilities, revenues or expenses.

Successful efforts accounting. We are required to select among alternative acceptable accounting policies. There are two generally acceptable methods for accounting for oil and gas producing activities. The full cost method allows the capitalization of all costs associated with finding oil and natural gas reserves, including certain general and administrative expenses. The successful efforts method allows only for the capitalization of costs associated with developing proven oil and natural gas properties as well as exploration costs associated with successful exploration projects. Costs related to exploration that are not successful are expensed when it is determined that commercially productive oil and gas reserves were not found. We have elected to use the successful efforts method to account for our oil and gas activities and we do not capitalize any of our general and administrative expenses.

Oil and natural gas reserve quantities. The determination of depreciation, depletion and amortization expense is highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. The determination of whether impairments should be recognized on our oil and gas properties is also dependent on these estimates, as well as estimates of probable reserves. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate depends on the quality of available data, production history and engineering and geological interpretation and judgment. Because all reserve estimates are to some degree imprecise, 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 prices may all differ materially from those assumed in these estimates. The information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Any future downward revisions could adversely affect our financial condition, our borrowing ability, our future prospects and the value of our common stock.

Impairment of oil and gas properties. We evaluate our properties on a field area basis for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable. If impairment is indicated based on a comparison of the asset's carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Expected future cash flows are determined using estimated future prices based on market based forward prices applied to projected future production volumes. The projected production volumes are based on the property's proved and risk adjusted probable oil and natural gas reserves estimates at the end of the period. The estimated future cash flows that we use in our assessment of the need for an impairment are based on market prices for oil and natural gas for the next three years, with a 5% escalation of prices for subsequent years. Prices are not escalated to levels that exceed observed historical market prices. Costs are also assumed to escalate at a rate that is based on our historical experience, currently estimated at 2% per annum. The oil and natural gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows because the standardized measure requires the use of the average first day of the month historical price for the year. To the extent that oil and natural gas prices do not increase as anticipated in these assumptions or costs increase at a greater rate than assumed, certain of our evaluated properties which presently have a carrying value of $1.5 billion may require impairment in the future. This estimate is based upon a projection of future cash flows which used pricing assumptions of near term futures pricing with no escalation in price. The amount of any such future impairments would be based on the write down of these properties to their then current estimated fair value. In addition to these properties, other properties may become impaired due to downward revisions in reserve or price estimates or for other reasons.

Stock-based compensation. We follow the fair value based method in accounting for equity-based compensation. Under the fair value based method, compensation cost is measured at the grant date based on the fair value of the award and is recognized on a straight-line basis over the award vesting period.

Recent accounting pronouncements. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"), which supersedes nearly all existing revenue recognition guidance under existing generally accepted accounting principles. This new standard is based upon the principal that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2016. Early adoption is not permitted and entities have the option of using either a full retrospective or modified approach to adopt ASU 2014-09. We are currently evaluating the new guidance and have not determined the impact this standard may have on our financial statements or decided upon the method of adoption.

In August 2014, the FASB issued ASU No. 2014-15, *Presentation of Financial Statements — Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* ("ASU 2014-15"). ASU 2014-15 provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and sets rules for how this information should be disclosed in the financial statements. ASU 2014-15 is effective for annual periods ending after December 15, 2016 and interim periods thereafter. Early adoption is permitted. We do not expect our adoption of ASU 2014-15 to have any impact on our consolidated financial condition or results of operations.

Related Party Transactions

In recent years, we have not entered into any material transactions with our officers or directors apart from the compensation they are provided for their services. We also have not entered into any business transactions with our significant stockholders or any other related parties.

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

Oil and Natural Gas Prices

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. Based on our oil and natural gas production in 2014, a $1.00 change in the price per barrel of oil would have resulted in a change in our cash flow for such period by approximately $1.8 million and a $0.10 change in the price per Mcf of natural gas would have changed our cash flow by approximately $3.8 million.

Interest Rates

At December 31, 2014, we had $1,070.4 million of long-term debt. Of this amount, $400.0 million bears interest at a fixed rate of 7¾% and $300.0 million bears interest at a fixed rate of 9½%. The fair market value of our fixed rate debt as of December 31, 2014 was $453.0 million based on the market price of approximately 65% of the face amount. At December 31, 2014, we had $375.0 million of debt outstanding under our bank credit facility, which is subject to variable rates of interest that are tied to LIBOR or a corporate base rate, at our option. Any increase in these interest rates would have an adverse impact on our results of operations and cash flow. Based on borrowings outstanding at December 31, 2014, a 100 basis point change in interest rates would change our annual interest expense on our variable rate debt by approximately $3.8 million. We had no interest rate derivatives in 2014 or at December 31, 2014.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

Our consolidated financial statements are included on pages F-1 to F-31 of this report.

We have prepared these financial statements in conformity with generally accepted accounting principles. We are responsible for the fairness and reliability of the financial statements and other financial data included in this report. In the preparation of the financial statements, it is necessary for us to make informed estimates and judgments based on currently available information on the effects of certain events and transactions.

Our independent public accountants, Ernst & Young LLP, are engaged to audit our financial statements and to express an opinion thereon. Their audit is conducted in accordance with auditing standards generally accepted in the United States to enable them to report whether the financial statements present fairly, in all material respects, our financial position and results of operations in accordance with accounting principles generally accepted in the United States.

The audit committee of our board of directors is comprised of three directors who are not our employees. This committee meets periodically with our independent public accountants and management. Our independent public accountants have full and free access to the audit committee to meet, with and without management being present, to discuss the results of their audits and the quality of our financial reporting.

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

None.

ITEM 9A. *CONTROLS AND PROCEDURES*

Evaluation of Controls and Procedures. Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act) are designed to provide reasonable assurance that information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

We performed an evaluation of the effectiveness of our disclosure controls and procedures as of December 31, 2014. The evaluation was performed with the participation of senior management of each business segment and key corporate functions, and under the supervision of the Chief Executive Officer and Chief Financial Officer.

Based on our evaluation of our disclosure controls and procedures, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2014 to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and to provide reasonable assurance that information required to be disclosed by us is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting. There were no changes in our internal control over financial reporting during the quarter ended December 31, 2014 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting. We are responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, we conducted an assessment, including testing, using the criteria in Internal Control — Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. As of December 31, 2014, we assessed the effectiveness of the Company's internal control over financial reporting based on the COSO criteria, and based on that assessment we determined that the Company maintained effective internal control over financial reporting as of December 31, 2014.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2014. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2014, is included below.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Comstock Resources, Inc.

We have audited Comstock Resources, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Comstock Resources, Inc. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Comstock Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Comstock Resources, Inc. and subsidiaries as of December 31, 2013 and 2014, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity and cash flows for each of the three years in the period ended December 31, 2014 and our report dated February 24, 2015 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 24, 2015

ITEM 9B. *OTHER INFORMATION*

None.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

The information required by this item is incorporated herein by reference to “Business – Directors and Executive Officers” in this Form 10-K and to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2014.

Code of Ethics. We have adopted a Code of Business Conduct and Ethics that is applicable to all of our directors, officers and employees as required by New York Stock Exchange rules. We have also adopted a Code of Ethics for Senior Financial Officers that is applicable to our Chief Executive Officer and Senior Financial Officers. Both the Code of Business Conduct and Ethics and Code of Ethics for Senior Financial Officers may be found on our website at www.comstockresources.com. Both of these documents are also available, without charge, to any stockholder upon request to: Comstock Resources, Inc., Attn: Investor Relations, 5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034, (972) 668-8800. We intend to disclose any amendments or waivers to these codes that apply to our Chief Executive Officer and senior financial officers on our website in accordance with applicable SEC rules. Please see the definitive proxy statement for our 2015 annual meeting, which will be filed with the SEC within 120 days of December 31, 2014, for additional information regarding our corporate governance policies.

ITEM 11. *EXECUTIVE COMPENSATION*

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2014.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS*

The following table summarizes certain information regarding our equity compensation plans as of December 31, 2014:

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities authorized for future issuance under equity compensation plans (excluding outstanding options, warrants and rights)
Equity compensation plans approved by stockholders	989,278[1]	$32.90	1,239,151

(1) Includes performance share unit awards equivalent to 874,128 shares that would be issuable based upon achievement of the maximum awards under the terms of the performance share unit awards.

We do not have any equity compensation plans that were not approved by stockholders.

Further information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2014.

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

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2014.

ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2014.

PART IV

ITEM 15. *EXHIBITS AND FINANCIAL STATEMENT SCHEDULES*

(a) Financial Statements:

1. The following consolidated financial statements and notes of Comstock Resources, Inc. are included on Pages F-2 to F-31 of this report:

2. All financial statement schedules are omitted because they are not applicable, or are immaterial or the required information is presented in the consolidated financial statements or the related notes.

(b) Exhibits:

The exhibits to this report required to be filed pursuant to Item 15(c) are listed below.

Exhibit No.	Description
3.1(a)	Restated Articles of Incorporation (incorporated by reference to Exhibit 3.1 to our Annual Report on Form 10-K for the year ended December 31, 1995).
3.1(b)	Certificate of Amendment to the Restated Articles of Incorporation dated July 1, 1997 (incorporated by reference to Exhibit 3.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1997).
3.2	Certificate of Amendment to the Restated Articles of Incorporation dated May 19, 2009 (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-3 dated October 5, 2009).
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated August 21, 2014).

Exhibit No.	Description
4.1	Indenture dated February 25, 2004 between Comstock Resources, Inc, the guarantors and The Bank of New York Trust Company, N.A., Trustee for debt securities issued by Comstock Resources, Inc. (incorporated by reference to Exhibit 4.6 to our Annual Report on Form 10-K for the year ended December 31, 2003).
4.2	Third Supplemental Indenture dated March 14, 2011 between Comstock Resources, Inc, the guarantors and The Bank of New York Mellon Trust Company, N.A., for the 7¾% Senior Notes due 2019 (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 14, 2011).
4.3	Fourth Supplemental Indenture dated June 5, 2012 between Comstock Resources, Inc, the guarantors and The Bank of New York Mellon Trust Company, N.A., for the 9½% Senior Notes due 2020 (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 7, 2012).
10.1#	Amended and Restated Employment Agreement dated February 24, 2014 by and between Comstock Resources, Inc and M. Jay Allison (incorporated by reference to Exhibit 10.1 to our Annual Report on Form 10-K for the year ended December 31, 2013).
10.2#	Amended and Restated Employment Agreement dated February 24, 2014 by and between Comstock Resources, Inc and Roland O. Burns (incorporated by reference to Exhibit 10.2 to our Annual Report on Form 10-K for the year ended December 31, 2013).
10.3#*	Employment Agreement dated February 23, 2015 by and between Comstock Resources, Inc and Mack D. Good.
10.4#	Comstock Resources, Inc. 2009 Long-term Incentive Plan (incorporated by reference to Exhibit 99 to our Registration Statement on Form S-8 dated May 19, 2009).
10.5#	First Amendment to the Comstock Resources, Inc. 2009 Long-term Incentive Plan (incorporated by reference to Exhibit 10.4 to our Annual Report on Form 10-K for the year ended December 31, 2012).
10.6	Fourth Amended and Restated Credit Agreement, dated November 22, 2013, among Comstock Resources, Inc., as the borrower, the lenders from time to time thereto, Bank of Montreal, as administrative agent and issuing bank (incorporated by reference to Exhibit 10.6 to our annual report on Form 10-K for the year ended December 31, 2013).
10.7*	Amendment to Fourth Amended and Restated Credit Agreement dated February 20, 2015 among Comstock Resources, Inc., as the borrower, the lenders from time to time thereto, Bank of Montreal, as administrative agent and issuing bank.
10.8	Lease between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. dated May 6, 2004 (incorporated by reference to Exhibit 10.24 to our Annual Report on Form 10-K for the year ended December 31, 2004).
10.9	First Amendment to the Lease Agreement dated August 25, 2005, between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.20 to our Annual Report on Form 10-K for the year ended December 31, 2005).
10.10	Second Amendment to the Lease Agreement dated October 15, 2007 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.10 to our Annual Report on Form 10-K for the year ended December 31, 2008).
10.11	Third Amendment to the Lease Agreement dated September 30, 2008 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.11 to our Annual Report on Form 10-K for the year ended December 31, 2008).
10.12	Fourth Amendment to the Lease Agreement dated May 8, 2009 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009).

Exhibit No.	Description
10.13	Fifth Amendment to the Lease Agreement dated June 15, 2011 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2011).
10.14	Base Contract for Sale and Purchase of Natural Gas between Comstock Oil & Gas-Louisiana, LLC and BP Energy Company dated November 7, 2008, as amended by Third Amended and Restated Special Provisions dated January 5, 2010 (incorporated by reference to Exhibit 10.14 to our Annual Report on Form 10-K for the year ended December 31, 2009).
21*	Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Independent Petroleum Engineers.
31.1*	Chief Executive Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Chief Financial Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1+	Chief Executive Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2+	Chief Financial Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Independent Petroleum Engineers on Proved Reserves as of December 31, 2014.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

* Filed herewith.
\+ Furnished herewith.
\# Management contract or compensatory plan document.

SIGNATURES

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

COMSTOCK RESOURCES, INC.

By: /s/ M. JAY ALLISON

M. Jay Allison
Chief Executive Officer
(Principal Executive Officer)

Date: February 24, 2015

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

/s/ M. JAY ALLISON M. Jay Allison	Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)	February 24, 2015
/s/ ROLAND O. BURNS Roland O. Burns	President, Chief Financial Officer, Secretary and Director (Principal Financial and Accounting Officer)	February 24, 2015
/s/ ELIZABETH B. DAVIS Elizabeth B. Davis	Director	February 24, 2015
/s/ DAVID K. LOCKETT David K. Lockett	Director	February 24, 2015
/s/ CECIL E. MARTIN, JR. Cecil E. Martin, Jr.	Director	February 24, 2015
/s/ FREDERIC D. SEWELL Frederic D. Sewell	Director	February 24, 2015
/s/ DAVID W. SLEDGE David W. Sledge	Director	February 24, 2015
/s/ JIM L. TURNER Jim L. Turner	Director	February 24, 2015
/s/ NANCY E. UNDERWOOD Nancy E. Underwood	Director	February 24, 2015

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Comstock Resources, Inc.

We have audited the accompanying consolidated balance sheets of Comstock Resources, Inc. and subsidiaries as of December 31, 2013 and 2014, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Comstock Resources, Inc. and subsidiaries at December 31, 2013 and 2014, and the consolidated results of their operations and cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Comstock Resources, Inc.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 24, 2015 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 24, 2015

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
As of December 31, 2013 and 2014

	December 31, 2013	December 31, 2014
	(In thousands)	
ASSETS		
Cash and Cash Equivalents	$ 2,967	$ 2,071
Accounts Receivable:		
Oil and gas sales	35,728	32,849
Joint interest operations	15,534	16,192
Other Current Assets	2,905	10,105
Total current assets	57,134	61,217
Property and Equipment:		
Unevaluated oil and gas properties	134,350	201,459
Oil and gas properties, successful efforts method	3,781,313	4,282,088
Other	18,373	19,630
Accumulated depreciation, depletion and amortization	(1,867,301)	(2,305,008)
Net property and equipment	2,066,735	2,198,169
Other Assets	15,529	14,951
	$ 2,139,398	$ 2,274,337
LIABILITIES AND STOCKHOLDERS' EQUITY		
Accounts Payable	$ 101,872	$ 117,329
Income Taxes Payable	1,826	—
Accrued Expenses	91,297	44,842
Total current liabilities	194,995	162,171
Long-term Debt	798,700	1,070,445
Deferred Income Taxes Payable	177,026	154,547
Reserve for Future Abandonment Costs	14,534	14,900
Other Non-Current Liabilities	2,138	2,002
Total liabilities	1,187,393	1,404,065
Commitments and Contingencies		
Stockholders' Equity:		
Common stock—$0.50 par, 75,000,000 shares authorized, 47,680,516 and 46,858,415 shares issued and outstanding at December 31, 2013 and 2014, respectively	23,840	23,429
Additional paid-in capital	480,816	480,434
Retained earnings	447,349	366,409
Total stockholders' equity	952,005	870,272
	$ 2,139,398	$ 2,274,337

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2012, 2013 and 2014

	2012	2013	2014
	(In thousands, except per share amounts)		
Oil sales	$ 181,163	$ 231,837	$389,770
Natural gas sales	203,651	188,453	165,461
Total oil and gas sales	384,814	420,290	555,231
Gain on sale of oil and gas properties	24,271	—	—
Total revenues	409,085	420,290	555,231
Operating expenses:			
Production taxes	11,727	14,524	23,797
Gathering and transportation	26,265	17,245	12,897
Lease operating	51,248	52,844	60,283
Exploration	61,449	33,423	19,403
Depreciation, depletion and amortization	343,858	337,134	378,275
General and administrative, net	33,798	34,767	32,379
Impairment of oil and gas properties	25,368	652	60,268
Loss on sale of oil and gas properties	—	2,033	—
Total operating expenses	553,713	492,622	587,302
Operating loss	(144,628)	(72,332)	(32,071)
Other income (expenses):			
Gain on sale of marketable securities	26,621	7,877	—
Gain (loss) from derivative financial instruments	21,256	(8,388)	8,175
Loss on early extinguishment of debt	—	(17,854)	—
Other income	944	1,059	727
Interest expense	(57,906)	(73,242)	(58,631)
Total other income (expenses)	(9,085)	(90,548)	(49,729)
Loss from continuing operations before income taxes	(153,713)	(162,880)	(81,800)
Benefit from income taxes	50,634	56,157	24,689
Loss from continuing operations	(103,079)	(106,723)	(57,111)
Income from discontinued operations, net of income taxes	3,019	147,752	—
Net income (loss)	$(100,060)	$ 41,029	$ (57,111)
Net income (loss) per share:			
Basic — loss from continuing operations	$ (2.22)	$ (2.22)	$ (1.24)
— income from discontinued operations	0.06	3.07	—
— net income (loss)	$ (2.16)	$ 0.85	$ (1.24)
Diluted — loss from continuing operations	$ (2.22)	$ (2.22)	$ (1.24)
— income from discontinued operations	0.06	3.07	—
— net income (loss)	$ (2.16)	$ 0.85	$ (1.24)
Dividends per common share	$ —	$ 0.375	$ 0.500
Weighted average shares outstanding:			
Basic	46,422	46,553	46,547
Diluted	46,422	46,553	46,547

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2012, 2013 and 2014

	2012	2013	2014
		(In thousands)	
Net income (loss)	$(100,060)	$41,029	$(57,111)
Net change in fair value of derivative financial instruments, net of benefit from income taxes of $161 in 2012	(298)	—	—
Net change in fair value of marketable securities, net of benefit from income taxes of $8,487 and $2,380 in 2012 and 2013	(15,760)	(4,418)	—
Other comprehensive loss	(16,058)	(4,418)	—
Comprehensive income (loss)	$(116,118)	$36,611	$(57,111)

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2012, 2013 and 2014

	Common Shares	Common Stock- Par Value	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total
			(In thousands)			
Balance at December 31, 2011	48,125	$ 24,063	$ 468,709	$ 524,377	$ 20,476	$1,037,625
Stock-based compensation	284	141	13,587	—	—	13,728
Excess income taxes from stock-based compensation	—	—	(1,701)	—	—	(1,701)
Net loss	—	—	—	(100,060)	—	(100,060)
Other comprehensive loss	—	—	—	—	(16,058)	(16,058)
Balance at December 31, 2012	48,409	24,204	480,595	424,317	4,418	933,534
Stock-based compensation	14	7	12,778	—	—	12,785
Tax withholdings related to stock grants	(111)	(55)	(1,625)	—	—	(1,680)
Excess income taxes from stock-based compensation	—	—	(2,016)	—	—	(2,016)
Repurchases of common stock	(631)	(316)	(8,916)	—	—	(9,232)
Net income	—	—	—	41,029	—	41,029
Dividends paid	—	—	—	(17,997)	—	(17,997)
Other comprehensive loss	—	—	—	—	(4,418)	(4,418)
Balance at December 31, 2013	47,681	23,840	480,816	447,349	—	952,005
Stock-based compensation	308	154	10,543	—	—	10,697
Tax withholdings related to stock grants	(131)	(65)	(2,284)	—	—	(2,349)
Excess income taxes from stock-based compensation	—	—	(1,055)	—	—	(1,055)
Repurchases of common stock	(1,000)	(500)	(7,586)	—	—	(8,086)
Net loss	—	—	—	(57,111)	—	(57,111)
Dividends paid	—	—	—	(23,829)	—	(23,829)
Balance at December 31, 2014	46,858	$ 23,429	$ 480,434	$ 366,409	$ —	$ 870,272

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2013 and 2014

	2012	2013	2014
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$(100,060)	$ 41,029	$ (57,111)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Income from discontinued operations	(3,019)	(147,752)	—
Gain on sale of assets	(50,892)	(5,844)	—
Deferred income taxes	(50,472)	(56,291)	(24,677)
Dry hole costs, leasehold impairments and other exploration costs	61,300	32,984	19,003
Impairment of oil and gas properties	25,368	652	60,268
Depreciation, depletion and amortization	343,858	337,134	378,275
(Gain) loss on derivative financial instruments	(21,256)	8,388	(8,175)
Cash settlements of derivative financial instruments	9,766	2,293	9,145
Loss on early extinguishment of debt	—	17,854	—
Amortization of debt discount, premium and issuance costs	5,277	6,074	4,097
Stock-based compensation	13,728	12,785	10,697
Excess income taxes from stock-based compensation	1,701	2,016	1,055
Decrease (increase) in accounts receivable	16,166	(12,674)	2,221
Decrease (increase) in other current assets	(972)	3,459	(7,366)
Increase (decrease) in accounts payable and accrued expenses	(30,772)	26,887	13,552
Net cash provided by continuing operations	219,721	268,994	400,984
Net cash provided by (used for) discontinued operations	42,508	(7,715)	—
Net cash provided by operating activities	262,229	261,279	400,984
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(385,034)	(422,244)	(634,787)
Proceeds from sales of oil and gas properties	141,936	174	—
Proceeds from sales of marketable securities	37,705	13,392	—
Investing activities of continuing operations	(205,393)	(408,678)	(634,787)
Cash flow from investing activities of discontinued operations:			
Capital expenditures	(203,077)	(101,037)	—
Proceeds from sale of oil and gas properties	24,750	823,072	—
Investing activities of discontinued operations	(178,327)	722,035	—
Net cash provided by (used for) investing activities	(383,720)	313,357	(634,787)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings	515,912	305,000	370,750
Principal payments on debt	(390,000)	(835,000)	(100,000)
Costs related to early extinguishment of debt	—	(12,471)	—
Debt issuance costs	(6,709)	(2,744)	(2,524)
Tax withholding related to stock grants	—	(1,680)	(2,349)
Repurchases of common stock	—	(9,232)	(8,086)
Excess income taxes from stock-based compensation	(1,701)	(2,016)	(1,055)
Dividends paid	—	(17,997)	(23,829)
Net cash provided by (used for) financing activities	117,502	(576,140)	232,907
Net decrease in cash and cash equivalents	(3,989)	(1,504)	(896)
Cash and cash equivalents, beginning of the year	8,460	4,471	2,967
Cash and cash equivalents, end of the year	$ 4,471	$ 2,967	$ 2,071

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Accounting policies used by Comstock Resources, Inc. and subsidiaries reflect oil and natural gas industry practices and conform to accounting principles generally accepted in the United States of America.

Basis of Presentation and Principles of Consolidation

Comstock Resources, Inc. and its subsidiaries are engaged in oil and natural gas exploration, development and production, and the acquisition of producing oil and natural gas properties. The Company's operations are primarily focused in Texas, Louisiana and Mississippi. The consolidated financial statements include the accounts of Comstock Resources, Inc. and its wholly owned or controlled subsidiaries (collectively, "Comstock" or the "Company"). All significant intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its undivided interest in oil and gas properties using the proportionate consolidation method, whereby its share of assets, liabilities, revenues and expenses are included in its financial statements.

Reclassifications

Certain reclassifications have been made to prior periods' financial statements consisting primarily of reclassifications to change certain presentations of our derivative financial instruments.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from those estimates. Changes in the future estimated oil and natural gas reserves or the estimated future cash flows attributable to the reserves that are utilized for impairment analysis could have a significant impact on the future results of operations.

Discontinued West Texas Operations

In May 2013, the Company sold its oil and gas properties in the Delaware Basin located in Reeves County in West Texas which it acquired in December 2011 and certain other undeveloped leases in West Texas (the "West Texas Properties") to a third party. The Company received proceeds of $823.1 million and realized a gain of $230.0 million which is reflected as a component of income from discontinued operations in 2013. As a result of this divestiture, the consolidated financial statements and the related notes thereto present the results of the Company's West Texas Properties as discontinued operations. No general and administrative cost incurred by Comstock was allocated to discontinued operations during the periods presented. Unless indicated otherwise, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations.

Income from discontinued operations is comprised of the following:

	Year Ended December 31, 2012	Year Ended December 31, 2013
	(In thousands)	
Revenues:		
Oil and gas sales	$ 47,109	$ 25,125
Costs and expenses:		
Production taxes	2,294	1,120
Gathering and transportation	1,047	501
Lease operating	9,372	9,853
Depletion, depreciation and amortization	21,428	8,649
Interest expense(1)	6,669	6,346
Total costs and expenses	40,810	26,469
Gain on sale	—	230,008
Income from discontinued operations before income taxes	6,299	228,664
Income tax expense:		
Current	—	(2,218)
Deferred	(3,280)	(78,694)
Total income tax expense	(3,280)	(80,912)
Net income from discontinued operations	$ 3,019	$147,752

(1) Interest expense was allocated to discontinued operations based on the ratio of the net assets of discontinued operations to our consolidated net assets plus long-term debt. Interest expense is net of capitalized interest of $9,582 and $2,010 for the years ended December 31, 2012 and 2013, respectively.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject the Company to a concentration of credit risk consist principally of cash and cash equivalents, accounts receivable and derivative financial instruments. The Company places its cash with high credit quality financial institutions and its derivative financial instruments with financial institutions and other firms that management believes have high credit ratings. Substantially all of the Company's accounts receivable are due from either purchasers of oil and gas or participants in oil and gas wells for which the Company serves as the operator. Generally, operators of oil and gas wells have the right to offset future revenues against unpaid charges related to operated wells. Oil and gas sales are generally unsecured. The Company's policy is to assess the collectability of its receivables based upon their age, the credit quality of the purchaser or participant and the potential for revenue offset. The Company has not had any significant credit losses in the past and believes its accounts receivable are fully collectible. Accordingly, no allowance for doubtful accounts has been provided.

Marketable Securities

As of January 1, 2013, the Company owned 600,000 shares of Stone Energy Corporation ("Stone") common stock which was reflected in the consolidated balance sheets as marketable securities. During the year ended December 31, 2013 all of these shares were sold. The Company utilized the specific identification method to determine the cost of any securities sold. During 2012 and 2013, the Company sold 1,206,000 and 600,000 shares of Stone common stock for proceeds of $37.7 million and $13.4 million, respectively. Comstock realized gains before income taxes of $26.6 million and $7.9 million on these sales during 2012 and 2013, respectively.

Other Current Assets

Other current assets at December 31, 2013 and 2014 consist of the following:

	As of December 31,	
	2013	2014
	(In thousands)	
Derivative settlements receivable	$ 139	$ 7,890
Pipe and oil field equipment inventory	1,388	1,379
Derivative financial instruments	970	—
Drilling advances	—	311
Prepaid expenses	350	487
Other	58	38
	$ 2,905	$10,105

Fair Value Measurements

Certain accounts within the Company's consolidated balance sheets are required to be measured at fair value on a recurring basis. These include cash equivalents held in bank accounts and derivative financial instruments in the form of oil price swap agreements. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. A three-level hierarchy is followed for disclosure to show the extent and level of judgment used to estimate fair value measurements:

Level 1 – Inputs used to measure fair value are unadjusted quoted prices that are available in active markets for the identical assets or liabilities as of the reporting date.

Level 2 – Inputs used to measure fair value, other than quoted prices included in Level 1, are either directly or indirectly observable as of the reporting date through correlation with market data, including quoted prices for similar assets and liabilities in active markets and quoted prices in markets that are not active. Level 2 also includes assets and liabilities that are valued using models or other pricing methodologies that do not require significant judgment since the input assumptions used in the models, such as interest rates and volatility factors, are corroborated by readily observable data from actively quoted markets for substantially the full term of the financial instrument.

Level 3 – Inputs used to measure fair value are unobservable inputs that are supported by little or no market activity and reflect the use of significant management judgment. These values are generally determined using pricing models for which the assumptions utilize management's estimates of market participant assumptions.

The Company's cash equivalents valuation is based on a Level 1 measurement. The Company's oil price swap agreements were not traded on a public exchange, and their value was determined utilizing a discounted cash flow model based on inputs that were readily available in public markets and, accordingly, the valuation of these swap agreements was categorized as a Level 2 measurement.

As of December 31, 2014, the Company's financial assets accounted for at fair value were comprised of cash held in bank accounts of $2.1 million, a Level 1 measurement. The Company had no derivative financial instruments outstanding at December 31, 2014. At December 31, 2013, the Company had oil price swap agreements covering 1,985,000 barrels of oil to be produced in 2014 with a fair value of $970,000, a Level 2 measurement.

The following table presents the carrying amounts and estimated fair value of the Company's long-term debt as of December 31, 2013 and 2014:

	2013		2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Fixed rate debt	$588,700	$650,250	$695,445	$453,000
Floating rate debt	$210,000	$210,000	$375,000	$375,000

The fair market value of the Company's fixed rate debt was based on quoted prices as of December 31, 2013 and 2014, a Level 2 measurement. The fair value of the floating rate debt outstanding at December 31, 2013 and 2014 approximated its carrying value, a Level 2 measurement.

Property and Equipment

The Company follows the successful efforts method of accounting for its oil and gas properties. Costs incurred to acquire oil and gas leasehold are capitalized. Acquisition costs for proved oil and gas properties, costs of drilling and equipping productive wells, and costs of unsuccessful development wells are capitalized and amortized on an equivalent unit-of-production basis over the life of the remaining related oil and gas reserves. Equivalent units are determined by converting oil to natural gas at the ratio of one barrel of oil for six thousand cubic feet of natural gas. This conversion ratio is not based on the price of oil or natural gas, and there may be a significant difference in price between an equivalent volume of oil versus natural gas. Amortization is calculated at the field level. The estimated future costs of dismantlement, restoration, plugging and abandonment of oil and gas properties and related facilities disposal are capitalized when asset retirement obligations are incurred and amortized as part of depreciation, depletion and amortization expense. The costs of unproved properties which are determined to be productive are transferred to proved oil and gas properties and amortized on an equivalent unit-of-production basis. Exploratory expenses, including geological and geophysical expenses and delay rentals for unevaluated oil and gas properties, are charged to expense as incurred. Unproved oil and gas properties are periodically assessed for impairment on a property by property basis, and any impairment in value is charged to exploration expense. During 2012, 2013 and 2014, impairment charges of $61.3 million, $33.0 million and $0.5 million, respectively, were recognized in exploration expense related to certain leases that the Company no longer expects to drill on. Exploratory drilling costs are initially capitalized as unproved property but charged to expense if and when the well is determined not to have found commercial quantities of proved oil and gas reserves. Exploratory drilling costs are evaluated within a one-year period after the completion of drilling.

The Company periodically assesses the need for an impairment of the costs capitalized for its oil and gas properties on a property or cost center basis. If impairment is indicated based on undiscounted expected future cash flows attributable to the property, then a provision for impairment is recognized to the extent that net capitalized costs exceed the estimated fair value of the property. The fair value is based upon estimated discounted future cash flows which are derived from Level 3 inputs. Expected future cash flows are determined using estimated future prices based on market based forward prices applied to projected future production volumes. Costs are also projected to escalate at a rate that is based upon the Company's historical experience. The projected production volumes are based on the property's proved and risk adjusted probable oil and natural gas reserve estimates at the end of the period. The oil and natural gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows because the standardized measure requires the use of an average price based on the first day of each month of the preceding year and is limited to proved reserves. The Company recognized impairment charges related to its oil and gas properties of $25.4 million, $0.7 million and $60.3 million in 2012, 2013, and 2014, respectively. The properties subject to impairment were mainly older, conventional oil and natural gas properties with declining production and limited potential for future investments which had a fair value of $18.0 million, a Level 3 measurement.

Other property and equipment consists primarily of gas gathering systems, computer equipment, furniture and fixtures and an airplane which are depreciated over estimated useful lives ranging from three to 31 ½ years on a straight-line basis.

Other Assets

Other assets primarily consist of deferred costs associated with issuance of the Company's senior notes and bank credit facility. These costs are amortized over the life of the senior notes and the life of the bank credit facility on a straight-line basis which approximates the amortization that would be calculated using an effective interest rate method.

Accrued Expenses

Accrued expenses at December 31, 2013 and 2014 consist of the following:

	As of December 31,	
	2013	2014
	(In thousands)	
Accrued oil and gas property acquisition costs	$40,128	$ —
Accrued drilling costs	34,914	26,269
Accrued interest payable	7,051	9,011
Accrued rig termination fees	—	2,600
Other	9,204	6,962
	$91,297	$44,842

Reserve for Future Abandonment Costs

The Company's asset retirement obligations relate to future plugging and abandonment costs of its oil and gas properties and related facilities disposal. The Company records a liability in the period in which an asset retirement obligation is incurred, in an amount equal to the estimated fair value of the obligation that is capitalized. Thereafter, this liability is accreted up to the final retirement cost. Accretion of the discount is included as part of depreciation, depletion and amortization in the accompanying consolidated statements of operations.

The following table summarizes the changes in the Company's total estimated liability:

	2013	2014
	(In thousands)	
Reserve for Future Abandonment Costs at beginning of the year	$16,387	$14,534
New wells placed on production	1,083	1,480
Changes in estimates	(3,324)	(1,796)
Liabilities settled and assets disposed of	(558)	(153)
Accretion expense	946	835
Reserve for Future Abandonment Costs at end of the year	$14,534	$14,900

Stock-based Compensation

The Company has stock-based employee compensation plans under which stock awards, comprised of restricted stock, stock options and performance share units, are issued to employees and non-employee directors. The Company follows the fair value based method in accounting for equity-based compensation. Under the fair value based method, compensation cost is measured at the grant date based on the fair value of the award and is recognized on a straight-line basis over the award vesting period. Excess tax benefits on stock-based compensation are recognized as an adjustment to additional paid-in capital and as a part of cash flows from financing activities.

Segment Reporting

The Company presently operates in one business segment, the exploration and production of oil and natural gas.

Derivative Financial Instruments and Hedging Activities

The Company accounts for derivative financial instruments (including certain derivative instruments embedded in other contracts) as either an asset or liability measured at its fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. The Company estimates fair value based on a discounted cash flow model. The fair value of derivative contracts that expire in less than one year are recognized as current assets or liabilities. Those that expire in more than one year are recognized as long-term assets or liabilities. If the derivative is designated as a cash flow hedge, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. The Company had no derivative financial instruments outstanding as of December 31, 2014.

Major Purchasers

In 2014, the Company had two purchasers of its oil and natural gas production that accounted for 53% and 35% of total oil and gas sales. In 2013, the Company had two purchasers of its oil and natural gas production that accounted for 51% and 36% of total oil and gas sales. In 2012, the Company had two purchasers of its oil and natural gas production that accounted for 42% and 27% of total oil and gas sales. The loss of any of these customers would not have a material adverse effect on the Company as there is an available market for its oil and natural gas production from other purchasers.

Revenue Recognition and Gas Balancing

Comstock utilizes the sales method of accounting for oil and natural gas revenues whereby revenues are recognized at the time of delivery based on the amount of oil or natural gas sold to purchasers. Revenue is typically recorded in the month of production based on an estimate of the Company's share of volumes produced and prices realized. The amount of oil or natural gas sold may differ from the amount to which the Company is entitled based on its revenue interests in the properties. The Company did not have any significant imbalance positions at December 31, 2013 or 2014. Sales of oil and natural gas generally occur at the wellhead. When sales of oil and gas occur at locations other than the wellhead, the Company accounts for costs incurred to transport the production to the delivery point as operating expenses.

General and Administrative Expenses

General and administrative expenses are reported net of reimbursements of overhead costs that are received from working interest owners of the oil and gas properties operated by the Company of \$11.5 million, \$11.9 million and \$13.2 million in 2012, 2013 and 2014, respectively.

Income Taxes

The Company accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change in rate is enacted.

Earnings Per Share

Basic earnings per share is determined without the effect of any outstanding potentially dilutive stock options and diluted earnings per share is determined with the effect of outstanding stock options that are potentially dilutive. Unvested share-based payment awards containing nonforfeitable rights to dividends are considered to be participatory securities and included in the computation of basic and diluted earnings per share pursuant to the two-class method. Performance share units ("PSUs") represent the right to receive a number of shares of the Company's common stock that may range from zero to up to three times the number of PSUs granted on the award date based on the achievement of certain performance measures during a performance period. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, which would be issuable at the end of the respective period, assuming that date was the end of the contingency period. The treasury stock method is used to measure the dilutive effect of PSUs.

Basic and diluted earnings per share for 2012, 2013 and 2014 were determined as follows:

	2012			2013			2014		
	Income (Loss)	Shares	Per Share	Income (Loss)	Shares	Per Share	Loss	Shares	Per Share
	(In thousands except per share data)								
Net Loss From Continuing Operations	$(103,079)			$(106,723)			$(57,111)		
Loss (Income) Allocable to Unvested Stock Grants	—			3,424			(595)		
Basic Net Loss From Continuing Operations Attributable to Common Stock	$(103,079)	46,422	$(2.22)	$(103,299)	46,553	$(2.22)	$(57,706)	46,547	$(1.24)
Diluted Net Loss From Continuing Operations Attributable to Common Stock	$(103,079)	46,422	$(2.22)	$(103,299)	46,553	$(2.22)	$(57,706)	46,547	$(1.24)
Net Income From Discontinued Operations	$ 3,019			$ 147,752					
Income Allocable to Unvested Stock Grants	—			(4,742)					
Basic Net Income From Discontinued Operations Attributable to Common Stock	$ 3,019	46,422	$ 0.06	$ 143,010	46,553	$ 3.07			
Diluted Net Income From Discontinued Operations Attributable to Common Stock	$ 3,019	46,422	$ 0.06	$ 143,010	46,553	$ 3.07			

Basic and diluted per share amounts are the same for each of the years ended December 31, 2012, 2013, and 2014 due to the net loss from continuing operations reported during each of those years.

At December 31, 2012, 2013 and 2014, 1,960,835, 1,515,889 and 1,207,527 shares of unvested restricted stock, respectively, are included in common stock outstanding as such shares have a nonforfeitable right to participate in any dividends that might be declared and have the right to vote. Weighted average shares of unvested restricted stock included in common stock outstanding were as follows:

	2012	2013	2014
	(In thousands)		
Unvested restricted stock	1,737	1,544	1,190

All stock options and PSUs were anti-dilutive to earnings and excluded from weighted average shares used in the computation of earnings per share due to the net loss from continuing operations in each period.

Options to purchase common stock and PSUs that were outstanding and that were excluded as anti-dilutive from determination of diluted earnings per share were as follows:

	2012	2013	2014
	(In thousands except per share data)		
Weighted average anti-dilutive stock options	168	130	115
Weighted average exercise price	$37.81	$32.90	$32.90
Weighted average performance share units	—	75	323
Weighted average grant date fair value per unit	$ —	$20.92	$19.88

Supplementary Information With Respect to the Consolidated Statements of Cash Flows

For the purpose of the consolidated statements of cash flows, the Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Cash payments made for interest and income taxes for the years ended December 31, 2012, 2013 and 2014, respectively, were as follows:

	2012	2013	2014
		(In thousands)	
Cash Payments:			
Interest payments	$ 79,001	$ 83,560	$ 62,812
Income tax payments (refunds)	$ (58)	$ 769	$ 682

The Company capitalizes interest on its unevaluated oil and gas property costs during periods when it is conducting exploration activity on this acreage. The Company capitalized interest of $20.9 million, $4.7 million and $10.2 million in 2012, 2013 and 2014, respectively, which reduced interest expense and increased the carrying value of its unevaluated oil and gas properties.

Comprehensive Income (Loss)

Comprehensive income (loss) consists of the following:

	For the Year Ended December 31,		
	2012	2013	2014
		(In thousands)	
Net income (loss)	$(100,060)	$ 41,029	$ (57,111)
Other comprehensive income (loss):			
Realized gains on marketable securities reclassified to gain on sale of marketable securities, net of a benefit from income taxes of $9,318 and $2,757 in 2012 and 2013, respectively	(17,303)	(5,120)	—
Unrealized hedging gains, net of a benefit from income taxes of $161 in 2012	(298)	—	—
Unrealized gains on marketable securities, net of a provision for income taxes of $831 and $377 in 2012 and 2013, respectively	1,543	702	—
Total comprehensive income (loss)	$(116,118)	$ 36,611	$ (57,111)

The following table provides a summary of the amounts included in accumulated other comprehensive income, net of income taxes, for the years ended December 31, 2012 and 2013:

	Oil Price Swap Agreements	Marketable Securities	Total Accumulated Comprehensive Income
		(In thousands)	
Balance as of December 31, 2011	$ 298	$ 20,178	$ 20,476
Reclassification to earnings	(298)	(17,303)	(17,601)
Changes in value	—	1,543	1,543
Balance as of December 31, 2012	—	4,418	4,418
Reclassification to earnings	—	(5,120)	(5,120)
Changes in value	—	702	702
Balance as of December 31, 2013	$ —	$ —	$ —

Recent accounting pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"), which supersedes nearly all existing revenue recognition guidance under existing generally accepted accounting principles. This new standard is based upon the principal that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2016. Early adoption is not permitted and entities have the option of using either a full retrospective or modified approach to adopt ASU 2014-09. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements or decided upon the method of adoption.

In August 2014, the FASB issued ASU No. 2014-15, *Presentation of Financial Statements—Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* ("ASU 2014-15"). ASU 2014-15 provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and sets rules for how this information should be disclosed in the financial statements. ASU 2014-15 is effective for annual periods ending after December 15, 2016 and interim periods thereafter. Early adoption is permitted. The Company does not expect adoption of ASU 2014-15 to have any impact on its consolidated financial condition or results of operations.

(2) Acquisitions and Dispositions of Oil and Gas Properties

During 2013, the Company acquired oil and gas leases in Burleson County, Texas for $67.4 million and in Mississippi and Louisiana for $53.3 million. The Burleson County, Texas acquisition included one producing well and approximately 21,000 net acres which are prospective for oil in the Eagle Ford shale formation. During 2014, the Company acquired additional interests in certain leases in Burleson County, Texas for approximately $33.9 million. The acquisition included approximately 9,000 net undeveloped acres and an additional 30% working interest in one producing well. The Mississippi and Louisiana acquisition included approximately 51,000 net acres which are prospective for oil in the Tuscaloosa Marine shale formation.

During 2012, the Company completed the sale of certain oil and gas properties located in Tyler and Polk counties in South Texas and Lincoln Parish in North Louisiana. The Company received proceeds of \$119.8 million and recognized a total gain of \$26.0 million from these transactions.

On July 30, 2012, the Company entered into a participation agreement with Kohlberg Kravis Roberts & Co L.P. (together with its affiliates, "KKR") providing for the participation of KKR in Comstock's future development of certain of its Eagle Ford shale properties in South Texas. Under the terms of the participation agreement, KKR has the right to participate for one-third of Comstock's working interest in wells drilled on the Company's acreage comprising its Eagleville field in exchange for KKR paying \$25,000 per acre for the net acreage being acquired and one-third of the wells costs. Each well that KKR participates in is intended to earn KKR approximately one-third of the Company's working interest in approximately 80 acres. The agreement applies to wells spud by the Company on or subsequent to March 31, 2012. Comstock received \$23.8 million from KKR to fund its participation in drilling activity before the closing on July 30, 2012. The Company received \$8.7 million, \$51.5 million and \$28.7 million for acreage and facility costs for new wells drilled subsequent to the closing in 2012, 2013 and 2014, respectively. Formation costs of \$1.7 million incurred in connection with this joint venture are reflected as a reduction to the gains on sales of oil and gas properties in the consolidated statements of operations.

In connection with acquisitions of producing oil and gas properties, the Company estimates the value of proved properties based on estimated future net cash flows and discounts them using a market-based rate that the Company determined appropriate at the acquisition date for the various proved reserve categories. Due to the unobservable nature of the inputs, the fair values of the proved oil and gas properties are considered Level 3 fair value measurements.

(3) Oil and Gas Producing Activities

Set forth below is certain information regarding the aggregate capitalized costs of oil and gas properties and costs incurred by the Company for its oil and gas property acquisition, development and exploration activities:

Capitalized Costs

	As of December 31,	
	2013	2014
	(In thousands)	
Unproved properties	$ 134,350	$ 201,459
Proved properties:		
Leasehold costs	971,239	1,006,839
Wells and related equipment and facilities	2,810,074	3,275,249
Accumulated depreciation depletion and amortization	(1,861,894)	(2,298,450)
	$ 2,053,769	$ 2,185,097

Costs Incurred

	For the Years Ended December 31,		
	2012	2013	2014
		(In thousands)	
Property Acquisitions:			
Unproved property acquisitions	$ 13,742	$ 130,113	$ 91,960
Proved property acquisitions	—	6,471	2,400
Development costs	331,254	341,970	440,848
Exploration costs	5,522	439	52,080
	$ 350,518	$ 478,993	$ 587,288

(4) Long-term Debt

Long-term debt is comprised of the following:

	As of December 31,	
	2013	2014
	(In thousands)	
Bank credit facility	$ 210,000	$ 375,000
7¾% senior notes due 2019	300,000	400,000
Premium related to 7¾% senior notes due 2019	—	4,984
9½% senior notes due 2020	300,000	300,000
Discount related to 9½% senior notes due 2020	(11,300)	(9,539)
	$ 798,700	$1,070,445

The premium and discount on the senior notes are being amortized over the life of the senior notes using the effective interest rate method.

The following table summarizes Comstock's debt as of December 31, 2014 by year of maturity:

	2015	2016	2017	2018	2019	Thereafter	Total
				(In thousands)			
Bank credit facility	$ —	$ —	$ —	$375,000	$ —	$ —	$ 375,000
7¾% senior notes	—	—	—	—	404,984	—	404,984
9½% senior notes	—	—	—	—	—	290,461	290,461
	$ —	$ —	$ —	$375,000	$404,984	$290,461	$1,070,445

Comstock has a $1.0 billion bank credit facility with Bank of Montreal, as the administrative agent. The bank credit facility is a five year revolving credit commitment that matures on November 22, 2018. Indebtedness under the bank credit facility is secured by all of Comstock's assets and is guaranteed by all of its wholly owned subsidiaries. The credit facility is subject to borrowing base availability, which is redetermined semiannually based on the banks' estimates of the Company's future net cash flows of oil and natural gas properties. As of December 31, 2014, the borrowing base was $675.0 million, of which $300.0 million was available. The borrowing base may be affected by the performance of Comstock's properties and changes in oil and natural gas prices. Oil and natural gas prices used by the banks to redetermine the borrowing base in 2015 are expected to be lower than the prices used in 2014. The determination of the borrowing base is at the sole discretion of the administrative agent and the bank group.

Borrowings under the bank credit facility bear interest, based on the utilization of the borrowing base, at Comstock's option at either (1) LIBOR plus 1.5% to 2.5% or (2) the base rate (which is the higher of the administrative agent's prime rate, the federal funds rate plus 0.5% or 30 day LIBOR plus 1.0%) plus 0.5% to 1.5%. A commitment fee of 0.375% to 0.5%, based on the utilization of the borrowing base, is payable annually on the unused borrowing base. The bank credit facility contains covenants that, among other things, restrict the payment of cash dividends and repurchases of common stock in excess of $120.0 million per year, limit the amount of consolidated debt that Comstock may incur and limit the Company's ability to make certain loans and investments. The financial covenants under the bank credit facility consist of the maintenance of a leverage ratio which must be less than four to one and the maintenance of an interest coverage ratio which must not be less than 2.5 to one; provided, however, that the leverage ratio was recently amended such that during 2015 the maximum permitted leverage ratio is five to one. The Company was in compliance with these covenants as of December 31, 2014, and expects to remain in compliance during 2015.

Comstock has $400.0 million of 7¾% senior notes (the "2019 Notes") outstanding which are due on April 1, 2019 and bear interest which is payable semi-annually on each April 1 and October 1. In May 2014, the Company issued $100.0 million of the 2019 Notes in a public offering. Net proceeds from the issuance of the additional 2019 Notes of $103.3 million were used to pay down borrowings under the Company's bank credit facility. Comstock also has $300.0 million of 9½% senior notes (the "2020 Notes") which are due on June 15, 2020 and bear interest which is payable semi-annually on each June 15 and December 15. The 2019 and 2020 Notes are unsecured obligations of Comstock and are guaranteed by all of Comstock's material subsidiaries. Such subsidiary guarantors are 100% owned and all of the guarantees are full and unconditional and joint and several obligations. As of December 31, 2014, Comstock had no material assets or operations which are independent of its subsidiaries. There are no restrictions on the ability of Comstock to obtain funds from its subsidiaries through dividends or loans.

At January 1, 2013, Comstock had $300.0 million in principal amount of 8⅜% senior notes outstanding with a maturity date of October 15, 2017 (the "2017 Notes"). In June 2013, the Company repurchased $2.2 million in principal amount of the 2017 Notes at 103.3% of the par value and in September 2013, the Company called all of the remaining 2017 Notes at the call price of 104.2% of par value for redemption on October 15, 2013. The redemption amount of $310.2 million was funded with cash on hand of $210.2 million and borrowings under the Company's bank credit facility. As a result of this redemption, the Company realized a loss on early extinguishment of debt, before income taxes, of approximately $17.9 million comprised of the premium paid for the redemption, the costs incurred related to the redemption and the write-off of unamortized debt issuance costs, including original issuance discount.

(5) Commitments and Contingencies

Commitments

The Company rents office space and other facilities under noncancelable operating leases. Rent expense for the years ended December 31, 2012, 2013 and 2014 was $1.4 million, $1.4 million and $1.5 million, respectively. Minimum future payments under the leases are as follows:

	(In thousands)
2015	1,994
2016	1,994
2017	2,021
2018	2,060
2019	1,560
Thereafter	3,120
	$12,749

As of December 31, 2014, the Company had commitments for contracted drilling rigs of $15.3 million through November 2015.

The Company has entered into natural gas transportation and treating agreements through July 2019. Maximum commitments under these transportation agreements as of December 31, 2014 totaled $11.5 million.

Contingencies

From time to time, the Company is involved in certain litigation that arises in the normal course of its operations. The Company records a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. The Company does not believe the resolution of these matters will have a material effect on the Company's financial position or results of operations and no material amounts are accrued relative to these matters at December 31, 2013 or 2014.

(6) Stockholders' Equity

The authorized capital stock of Comstock consists of 75 million shares of common stock, $0.50 par value per share, and 5 million shares of preferred stock, $10.00 par value per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors. There were no shares of preferred stock outstanding at December 31, 2013 or 2014.

The Company has declared and paid quarterly dividends beginning in May, 2013 through December, 2014. Dividends in the aggregate amount of $23.8 million and $18.0 million were paid during 2014 and 2013, respectively. In February, 2015 the Company announced that it has temporarily suspended the quarterly dividend. During 2013, the Board of Directors also approved an open market share repurchase plan which permits the Company to repurchase up to $100.0 million of its common stock on the open market. The Company made various open market purchases of 1,000,000 shares and 631,096 shares with an aggregate cost of $8.1 million and $9.2 million in 2014 and 2013, respectively. As of December 31, 2014, $82.7 million remains available for future purchases.

(7) Stock-based Compensation

The Company grants restricted shares of common stock, stock options and performance share units to key employees and directors as part of their compensation under the 2009 Long-term Incentive Plan. Future awards of stock options, restricted stock grants or other equity awards under the 2009 Long-term Incentive Plan are available with up to 1,239,151 shares of common stock.

During 2012, 2013 and 2014, the Company had $13.7 million, $12.8 million and $10.7 million, respectively, in stock-based compensation expense which is in general and administrative expenses. The excess income tax provisions from tax deductions associated with stock-based compensation recognized in additional paid in capital were $1.7 million, $2.0 million and $1.1 million for the years ended December 31, 2012, 2013 and 2014, respectively.

Stock Options

The Company amortizes the fair value of stock options granted over the vesting period using the straight-line method.

The Company has not issued any stock options since 2008. The following table summarizes information related to stock options outstanding at December 31, 2014:

Exercise Price	Weighted Average Remaining Life (in years)	Number of Options Outstanding and Exercisable
$32.50	0.9	50,500
$33.22	1.9	64,650
		115,150

There were no changes in the number of stock options outstanding during 2014. There were no stock option exercises in 2012 or 2013. Forfeitures of options totaled 42,000 and 46,000 during the years ended December 31, 2012 and 2013, respectively. As of December 31, 2014, all compensation cost related to stock options had been recognized. Stock options outstanding at December 31, 2013 and 2014, which have a weighted average exercise price of $32.90 per share, had no intrinsic value based on the closing price for the Company's common stock at those dates.

Restricted Stock

The fair value of restricted stock grants is amortized over the vesting period, generally one to four years, using the straight-line method. Total compensation expense recognized for restricted stock grants was $13.5 million, $9.8 million and $7.3 million for the years ended December 31, 2012, 2013 and 2014, respectively. The fair value of each restricted share on the date of grant is equal to the fair market price of a share of the Company's stock.

A summary of restricted stock activity for the year ended December 31, 2014 is presented below:

	Number of Restricted Shares	Weighted Average Grant Price
Outstanding at January 1, 2014	1,515,889	$24.04
Granted	235,524	$20.24
Vested	(530,868)	$31.85
Forfeitures	(13,018)	$19.11
Outstanding at December 31, 2014	1,207,527	$19.91

The per share weighted average fair value of restricted stock grants in 2012, 2013 and 2014 was $15.49, $16.44 and $20.24, respectively. Total unrecognized compensation cost related to unvested restricted stock of $6.8 million as of December 31, 2014 is expected to be recognized over a period of 0.9 years. The fair value of restricted stock which vested in 2012, 2013 and 2014 was $6.7 million, $7.0 million and $10.0 million, respectively.

Performance Share Units

The Company issues PSUs as part of its long-term equity incentive compensation. PSU awards can result in the issuance of common stock to the holder if certain performance criteria is met during a performance period. The performance periods consist of one year, two years and three years, respectively. The performance criteria for the PSUs are based on the Company's annualized total stockholder return ("TSR") for the performance period as compared with the TSR of certain peer companies for the performance period. The costs associated with PSUs are recognized as general and administrative expense over the performance periods of the awards.

The fair value of PSUs was measured at the grant date using a stochastic process method utilizing the Geometric Brownian Motion Model ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSUs, the Company cannot predict with certainty the path its stock price or the stock prices of its peers will take over the future performance periods. By using a stochastic simulation, the Company can create multiple prospective total return pathways, statistically analyze these simulations, and ultimately make inferences to the most likely path the total return will take. As such, because future stock returns are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSUs. Significant assumptions used in this simulation include the Company's expected volatility and a risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the vesting periods, as well as the volatilities for each of the Company's peers. Assumptions regarding volatility included the historical volatility of each Company's stock and the implied volatilities of publicly traded stock options. For the PSUs granted in 2012, the valuation inputs included a risk-free interest rate of 0.4% and a range of volatilities of 29% to 70%. For the PSUs granted in 2014, the valuation inputs included a risk free interest rate of 0.6% and a range of volatilities of 38% to 70%.

In 2012 the Company granted 254,133 PSUs with a grant date fair value of $5.4 million, or $21.14 per unit. In 2014 the Company granted 188,958 PSUs with a grant date fair value of $3.7 million, or $19.81 per unit. No PSUs were awarded in 2013. The fair value of PSUs is amortized over the vesting period of one to three years, using the straight-line method. Total compensation expense recognized for PSUs was $0.2 million, $3.0 million and $3.4 million for the years ended December 31, 2012, 2013 and 2014, respectively.

A summary of PSU activity for the year ended December 31, 2014 is presented below:

	Number of PSUs	Weighted Average Grant Price
Outstanding at January 1, 2014	254,918	$20.92
Awards granted and adjustments for dividend paid	203,783	$19.81
Earned and issued	(85,629)	$19.37
Outstanding at December 31, 2014	373,072	$19.88

The number of awards assumes a one multiplier. The final number of shares of common stock issued may vary depending upon the performance multiplier, and can result in the issuance of zero to 874,128 shares of common stock based on the achieved performance ranges from zero to three. As of December 31, 2014, there was $2.5 million of total unrecognized expense related to PSUs, which is being amortized through December 31, 2016.

(8) Retirement Plan

The Company has a 401(k) profit sharing plan which covers all of its employees. At its discretion, Comstock may match the employees' contributions to the plan. Matching contributions to the plan were $365,000, $702,000 and $834,000 for the years ended December 31, 2012, 2013 and 2014, respectively.

(9) Income Taxes

The following is an analysis of the consolidated income tax benefit from continuing operations:

	2012	2013	2014
		(In thousands)	
Current	$ (162)	$ 134	$ (12)
Deferred	(50,472)	(56,291)	(24,677)
	$(50,634)	$(56,157)	$(24,689)

Deferred income taxes are provided to reflect the future tax consequences or benefits of differences between the tax basis of assets and liabilities and their reported amounts in the financial statements using enacted tax rates. The difference between the Company's customary rate of 35% and the effective tax rate on income from continuing operations is due to the following:

	2012	2013	2014
		(In thousands)	
Tax benefit at statutory rate	$ (53,799)	$ (57,008)	$ (28,630)
Tax effect of:			
Nondeductible compensation	2,545	1,545	756
State taxes, net of federal tax benefit and valuation allowance	410	(799)	2,979
Other	210	105	206
Total	$ (50,634)	$ (56,157)	$ (24,689)

	2012	2013	2014
Statutory rate	35.0%	35.0%	35.0%
Tax effect of:			
Nondeductible compensation	(1.7)	(0.9)	(0.9)
State taxes, net of federal tax benefit and valuation allowance	(0.3)	0.5	(3.6)
Other	(0.1)	(0.1)	(0.3)
Effective tax rate	32.9%	34.5%	30.2%

The tax effects of significant temporary differences representing the net deferred tax asset and liability at December 31, 2013 and 2014 were as follows:

	2013	2014
	(In thousands)	
Current deferred tax liabilities:		
Derivative financial instruments	$ (339)	$ —
Net current deferred tax liability	(339)	—
Noncurrent deferred tax assets (liabilities):		
Property and equipment	(238,361)	(259,222)
Other assets	8,221	7,854
Net operating loss carryforwards	70,207	126,026
Alternative minimum tax carryforward	21,178	20,435
Valuation allowance on net operating loss carryforwards	(35,507)	(46,639)
Other	(2,764)	(3,001)
Net noncurrent deferred tax liability	(177,026)	(154,547)
Net deferred tax liability	$(177,365)	$(154,547)

At December 31, 2014, Comstock had the following carryforwards available to reduce future income taxes:

Types of Carryforward	Years of Expiration Carryforward	Amount
		(In thousands)
Net operating loss — U.S. federal	2017 — 2033	$212,769
Net operating loss — Louisiana	2015 — 2028	$991,483
Alternative minimum tax credits	Unlimited	$ 20,435

The utilization of $34.7 million of the U.S. federal net operating loss carryforwards is limited to approximately $1.1 million per year pursuant to a prior change of control of an acquired company. Accordingly, a valuation allowance of $23.0 million, with a tax effect of $8.0 million, has been established for the estimated U.S. federal net operating loss carryforwards that will not be utilized. Realization of the remaining U.S. federal net operating loss carryforwards requires Comstock to generate taxable income within the carryforward period. A valuation allowance of $528.1 million, with a tax effect of $27.5 million as of December 31, 2013, and a valuation allowance of $742.2 million, with a tax effect of $38.6 million as of December 31, 2014, has been established against the Louisiana state net operating loss carryforwards due to the uncertainty of generating taxable income in the state of Louisiana prior to the expiration of the carry-over period.

The Company's federal income tax returns for the years subsequent to December 31, 2010 remain subject to examination. The Company's income tax returns in major state income tax jurisdictions remain subject to examination for various periods subsequent to December 31, 2009. State tax returns in two state jurisdictions are currently under review. The Company currently believes that resolution of these matters will not have a material impact on its financial statements. The Company currently believes that its significant filing positions are highly certain and that all of its other significant income tax filing positions and deductions would be sustained upon audit or the final resolution would not have a material effect on the consolidated financial statements. Therefore, the Company has not established any significant reserves for uncertain tax positions. Interest and penalties resulting from audits by tax authorities have been immaterial and are included in the provision for income taxes in the consolidated statements of operations.

(10) Derivative Financial Instruments and Hedging Activities

Comstock periodically uses swaps, floors and collars to hedge oil and natural gas prices and interest rates. Swaps are settled monthly based on differences between the prices specified in the instruments and the settlement prices of futures contracts. Generally, when the applicable settlement price is less than the price specified in the contract, Comstock receives a settlement from the counterparty based on the difference multiplied by the volume or amounts hedged. Similarly, when the applicable settlement price exceeds the price specified in the contract, Comstock pays the counterparty based on the difference. Comstock generally receives a settlement from the counterparty for floors when the applicable settlement price is less than the price specified in the contract, which is based on the difference multiplied by the volumes hedged. For collars, generally Comstock receives a settlement from the counterparty when the settlement price is below the floor and pays a settlement to the counterparty when the settlement price exceeds the cap. No settlement occurs when the settlement price falls between the floor and cap.

All of the Company's derivative financial instruments are used for risk management purposes and by policy none are held for trading or speculative purposes. Comstock minimizes credit risk to counterparties of its derivative financial instruments through formal credit policies, monitoring procedures, and diversification. All of Comstock's derivative financial instruments are with parties that are lenders under its bank credit facility. The Company is not required to provide any credit support to its counterparties other than cross collateralization with the assets securing its bank credit facility. None of the Company's derivative financial instruments involve payment or receipt of premiums.

During 2012, 2013 and 2014, the Company hedged 1,710,000 barrels, 2,160,000 barrels and 2,438,000 barrels, respectively, of its oil production at an average NYMEX West Texas Intermediate oil price of $99.46 per barrel, $98.67 per barrel and $96.56 per barrel, respectively. As of December 31, 2014, the Company had no outstanding commodity derivatives.

None of the derivative contracts were designated as cash flow hedges. The Company recognizes cash settlements and changes in the fair value of its derivative financial instruments as a single component of other income (expenses).

The gain (loss) on derivative financial instruments was a gain of $21.3 million, a loss of $8.4 million and a gain of $8.2 million for the years ended December 31, 2012, 2013 and 2014, respectively. Cash settlements received on derivative financial instruments were $9.8 million, $2.3 million and $9.1 million for the years ended December 31, 2012, 2013 and 2014, respectively. The estimated fair value of the Company's derivative financial instruments, which equaled their carrying value, was an asset of $1.0 million as of December 31, 2013 which was reflected as a current asset based on estimated settlement dates.

(11) Supplementary Quarterly Financial Data (Unaudited)

	2013				
	First	Second	Third	Fourth	Total
	(In thousands, except per share data)				
Total oil and gas sales	$ 95,020	$ 107,820	$ 111,590	$ 105,860	$ 420,290
Operating loss	$ (20,856)	$ (18,004)	$ (9,086)	$ (24,386)	$ (72,332)
Loss from continuing operations	$ (24,517)	$ (21,531)	$ (24,034)	$ (36,641)	$(106,723)
Income (Loss) from discontinued operations	$ (2,627)	$ 151,236	$ —	$ (857)	$ 147,752
Net income (loss)	$ (27,144)	$ 129,705	$ (24,034)	$ (37,498)	$ 41,029
Basic net income (loss) per share:					
Continuing operations	$ (0.52)	$ (0.45)	$ (0.52)	$ (0.80)	$ (2.22)
Discontinued operations	$ (0.06)	$ 3.13	$ —	$ (0.02)	$ 3.07
Total	$ (0.58)	$ 2.68	$ (0.52)	$ (0.82)	$ 0.85
Diluted net income (loss) per share:					
Continuing operations	$ (0.52)	$ (0.45)	$ (0.52)	$ (0.80)	$ (2.22)
Discontinued operations	$ (0.06)	$ 3.13	$ —	$ (0.02)	$ 3.07
Total	$ (0.58)	$ 2.68	$ (0.52)	$ (0.82)	$ 0.85

	2014				
	First	Second	Third	Fourth	Total
	(In thousands, except per share data)				
Total oil and gas sales	$ 141,909	$ 155,723	$ 144,983	$ 112,616	$ 555,231
Operating income (loss)	$ 20,228	$ 27,729	$ 263	$ (80,291)	$ (32,071)
Net income (loss)	$ 1,165	$ 1,898	$ (1,903)	$ (58,271)	$ (57,111)
Income (loss) per share:					
Basic	$ 0.02	$ 0.04	$ (0.04)	$ (1.26)	$ (1.24)
Diluted	$ 0.02	$ 0.04	$ (0.04)	$ (1.26)	$ (1.24)

Basic and diluted per share amounts are the same for each of the quarters and for the years ended where there was a net loss from continuing operations reported.

Results of continuing operations include the following non-routine items of income (expense), which are presented before the effect of income taxes:

	2013				
	First	Second	Third	Fourth	Total
			(In thousands)		
Gain (loss) on sale of oil and gas properties	$ —	$ 81	$ (2,165)	$ 51	$ (2,033)
Gain on sales of marketable securities	$ 7,877	$ —	$ —	$ —	$ 7,877
Loss on early extinguishment of debt	$ —	$ —	$ —	$ (17,854)	$ (17,854)
Impairments of unproved oil and gas properties	$ (2,443)	$ (9,465)	$ (2,995)	$ (18,081)	$ (32,984)
Impairments of proved oil and gas properties	$ —	$ (652)	$ —	$ —	$ (652)

	2014				
	First	Second	Third	Fourth	Total
			(In thousands)		
Impairments of unproved oil and gas properties	$ —	$ —	$ —	$ (487)	$ (487)
Impairments of proved oil and gas properties	$ —	$ (256)	$ (15)	$ (59,997)	$ (60,268)

(12) Oil and Gas Reserves Information (Unaudited)

Set forth below is a summary of the changes in Comstock's net quantities of oil and natural gas reserves for its continuing operations for each of the three years in the period ended December 31, 2014:

	2012		2013		2014	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved Reserves:						
Beginning of year	13,234	1,080,644	18,899	437,445	21,976	452,653
Revisions of previous estimates	327	(529,272)	28	23,321	(2,182)	3,998
Extensions and discoveries	11,953	21,525	5,363	47,581	5,373	78,383
Sales of minerals in place	(4,823)	(53,690)	—	—	—	—
Production	(1,792)	(81,762)	(2,314)	(55,694)	(4,313)	(39,768)
End of year	18,899	437,445	21,976	452,653	20,854	495,266
Proved Developed Reserves:						
Beginning of year	6,499	546,627	8,389	362,426	13,914	344,278
End of year	8,389	362,426	13,914	344,278	16,247	324,598

During 2012, the Company's estimated quantities of proved undeveloped natural gas reserves decreased by 460 Bcf due to downward revisions related to the lower natural gas price that was used to determine estimated reserve quantities at December 31, 2012. Proved reserve additions for natural gas in 2014 primarily reflect proved undeveloped reserves associated with our upcoming natural gas drilling program. Substantially all of the Company's proved undeveloped natural gas reserves related to undrilled natural gas wells at December 31, 2012 were not economic at the lower natural gas price at December 31, 2012.

The proved oil and gas reserves utilized in the preparation of the financial statements were estimated by Lee Keeling and Associates, independent petroleum consultants, in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve reports be prepared under existing economic and operating conditions with no provision for price and cost escalation except by contractual agreement. All of the Company's reserves are located onshore in the continental United States of America.

The following table sets forth the standardized measure of discounted future net cash flows relating to proved reserves at December 31, 2013 and 2014:

	2013	2014
	(In thousands)	
Cash Flows Relating to Proved Reserves:		
Future Cash Flows	$ 3,817,982	$ 3,891,953
Future Costs:		
Production	(1,307,923)	(1,260,580)
Development and Abandonment	(649,758)	(571,200)
Future Income Taxes	(451,708)	(192,600)
Future Net Cash Flows	1,408,593	1,867,573
10% Discount Factor	(601,376)	(776,913)
Standardized Measure of Discounted Future Net Cash Flows	$ 807,217	$ 1,090,660

The standardized measure of discounted future net cash flows at the end of 2013 and 2014 was determined based on the simple average of the first of month market prices for oil and natural gas for each year. Prices were $104.38 per barrel of oil and $3.37 per Mcf of natural gas for 2013 and $92.55 per barrel of oil and $3.96 per Mcf of natural gas for 2014. Prices used in determining quantities of oil and natural gas reserves and future cash inflows from oil and natural gas reserves represent prices received at the Company's sales point. These prices have been adjusted from posted or index prices for both location and quality differences. Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits, but do not reflect the impact of future operations.

The following table sets forth the changes in the standardized measure of discounted future net cash flows relating to proved reserves for the years ended December 31, 2012, 2013 and 2014:

	2012	2013	2014
		(In thousands)	
Standardized Measure, Beginning of Year	$ 887,798	$ 641,325	$ 807,217
Net change in sales price, net of production costs	(217,925)	43,117	5,911
Development costs incurred during the year which were previously estimated	179,549	187,643	344,590
Revisions of quantity estimates	(886,531)	48,411	(40,993)
Accretion of discount	117,381	81,434	105,400
Changes in future development and abandonment costs	628,088	(157,207)	(10,909)
Changes in timing and other	27,077	80,348	(19,028)
Extensions and discoveries	337,223	291,582	163,559
Sales of minerals in place	(236,925)	—	—
Sales, net of production costs	(307,407)	(335,677)	(458,254)
Net changes in income taxes	112,997	(73,759)	193,167
Standardized Measure, End of Year	$ 641,325	$ 807,217	$1,090,660

Directors

M. Jay Allison [1,3]
Roland O. Burns [3]
Elizabeth B. Davis [5]
David K. Lockett [4,6]
Cecil E. Martin, Jr. [2,3,4,5]
Frederic D. Sewell [5]
David W. Sledge [6]
Jim L. Turner [4]
Nancy E. Underwood [6]

[1] Chairman of the Board of Directors
[2] Lead Independent Director
[3] Executive Committee
[4] Compensation Committee
[5] Audit Committee
[6] Corporate Governance Committee

Management

M. Jay Allison
Chief Executive Officer and
Chairman of the Board of Directors

Roland O. Burns
President, Chief Financial Officer,
Secretary and Director

Mack D. Good
Chief Operating Officer

D. Dale Gillette
Vice President of Legal and General Counsel

Michael D. McBurney
Vice President of Marketing

Daniel K. Presley
Vice President of Accounting, Treasurer
and Controller

Russell W. Romoser
Vice President of Reservoir Engineering

LaRae L. Sanders
Vice President of Land

Richard D. Singer
Vice President of Financial Reporting

Blaine M. Stribling
Vice President of Corporate Development

Website

www.comstockresources.com

Independent Public Accountants

Ernst & Young LLP

Primary Subsidiaries

Comstock Oil & Gas, LP
Comstock Oil & Gas – Louisiana, LLC

Independent Petroleum Consultants

Lee Keeling and Associates

Exchange Listing

The Company's common stock is listed for trading on the New York Stock Exchange ("NYSE") under the symbol "CRK".

Transfer Agent and Registrar

For stock certificate transfers, changes of address or lost stock certificates, please contact:
American Stock Transfer & Trust Company, 59 Maiden Lane, New York, New York 10038
(800) 937-5449

Annual Meeting

The annual meeting of stockholders will be held on Thursday, May 7, 2015 at 10:00 a.m. at Comstock's Headquarters, 5300 Town and Country Blvd., Suite 300, Frisco, Texas. All stockholders are encouraged to attend.

Investor Relations

Requests for additional information should be directed to:
Gary H. Guyton, 5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034, (800) 877-1322
gguyton@comstockresources.com

Corporate Governance and Executive Certifications

Our Corporate Governance Guidelines are available by selecting Investor Info on our web site at www.comstockresources.com. We have included as exhibits to our 2014 Annual Report on Form 10-K filed with the Securities and Exchange Commission, certificates of our chief executive officer and chief financial officer regarding the quality of our public disclosure. We have also submitted to the NYSE a certificate of our chief executive officer certifying that he is not aware of any violation by the company of the NYSE corporate governance listing standards.

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