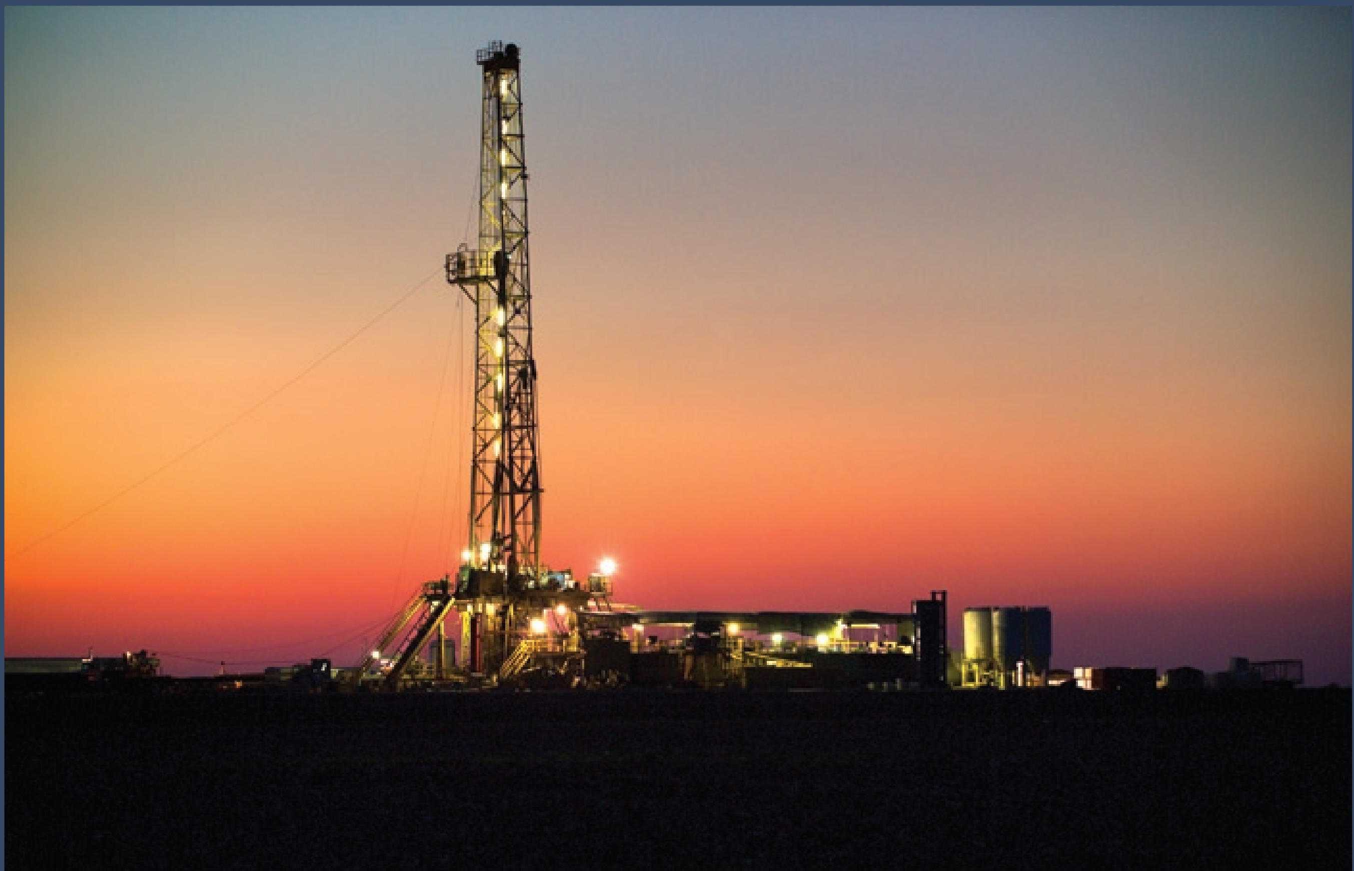
COMSTOCK RESOURCES

2012 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.

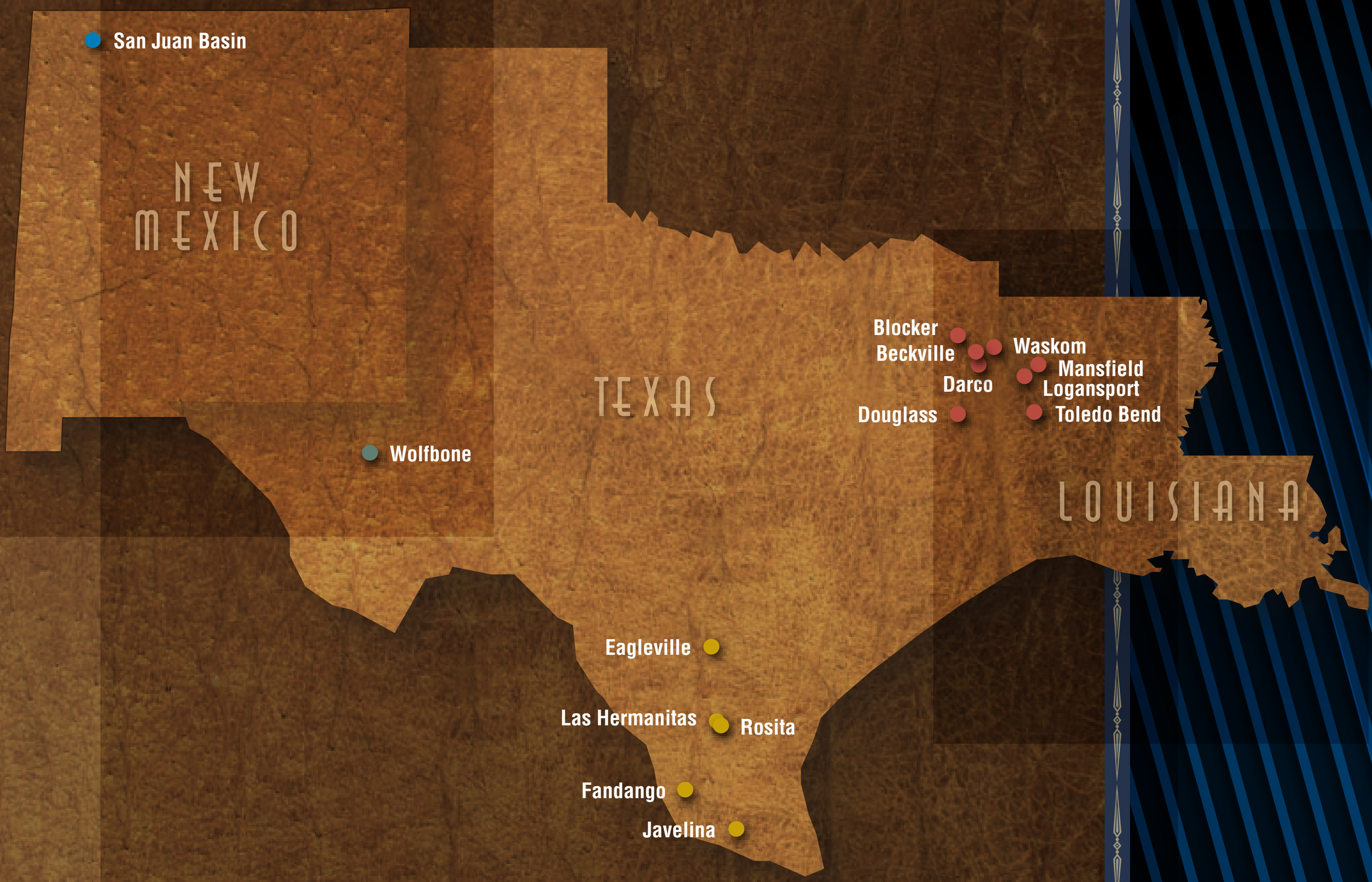
FINANCIAL HIGHLIGHTS

(in thousands except per share data)	2008	2009	2010	2011	2012
Oil and gas sales	$563,749	$292,583	$349,141	$434,367	$431,923
Net income (loss)	$251,962	($36,471)	($19,586)	($33,472)	($100,060)
Per Share - Net income (loss)	$5.46	($0.81)	($0.43)	($0.73)	($2.16)
Cash flow from operations	$438,236	$224,410	$219,746	$297,559	$261,325
Total assets	$1,577,890	$1,858,961	$1,964,214	$2,639,884	$2,567,143
Total debt	$210,000	$470,836	$513,372	$1,196,908	$1,324,383
Stockholders' equity	$1,062,085	$1,066,111	$1,068,531	$1,037,625	$933,534

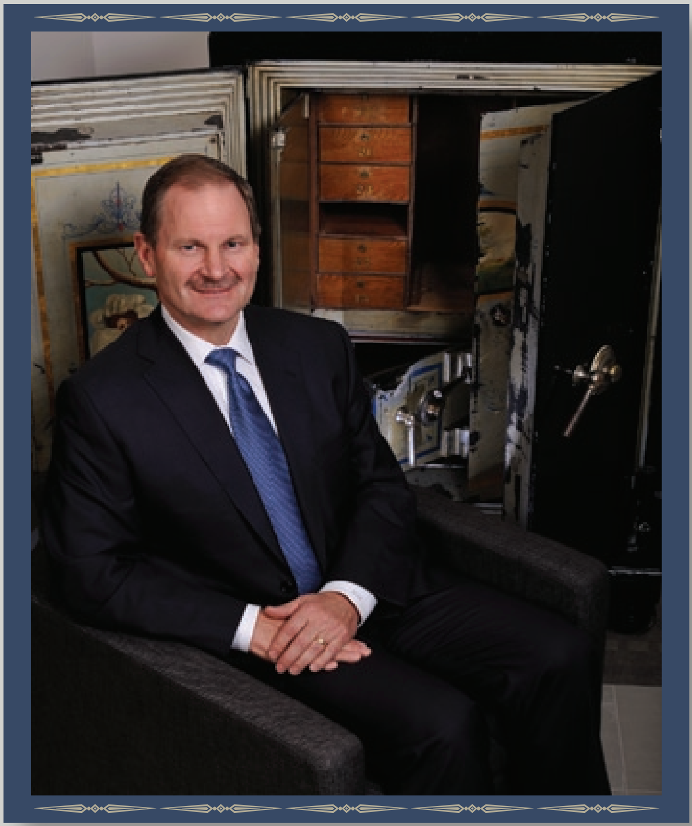
OPERATIONAL HIGHLIGHTS

	2008	2009	2010	2011	2012
Capital expenditures (000)	$426,401	$344,841	$545,650	$1,047,743	$550,580
Net producing wells	896.4	903.4	854.0	925.6	914.5
Natural gas production (MMcf per day)	147	167	189	248	225
Oil production (Barrels per day)	2,758	2,122	1,958	2,297	6,309
Equivalent units (MMcfe per day)	164	179	201	262	263
Proved gas reserves (Bcf)	524	682	1,026	1,119	477
Proved oil reserves (MBbls)	9,668	7,214	4,219	32,099	39,219

MAJOR PROPERTIES



	2012 Reserves			*2012 Daily Production*		
	Oil (MMBbls)	*Natural Gas (Bcf)*	*Total (Bcfe)*	*Oil (MBbls)*	*Natural Gas (MMcf)*	*Total (MMcfe)*
East Texas / North Louisiana	0.4	339.4	341.9	0.2	194.2	195.6
South Texas	18.4	86.2	196.5	4.6	23.6	51.1
West Texas	20.3	39.2	161.1	1.4	2.0	10.5
Other Regions	0.1	11.8	12.4	0.1	5.6	6.1
Total	39.2	476.6	711.9	6.3	225.4	263.3



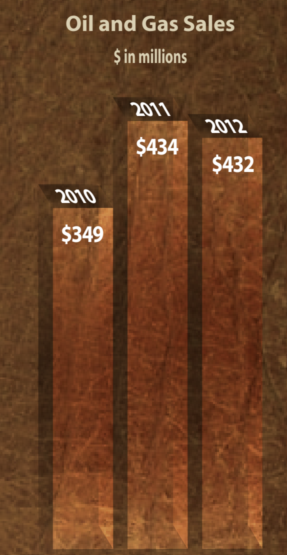
TO OUR STOCKHOLDERS:

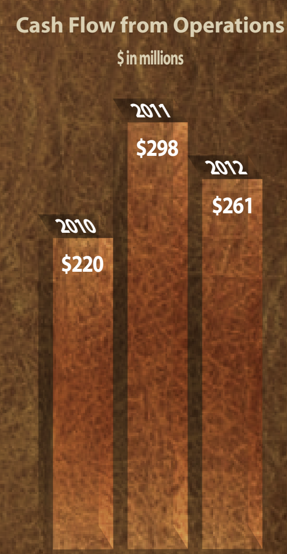
In the face of deteriorating natural gas prices, we completed several transactions in 2012 to improve our financial profile.

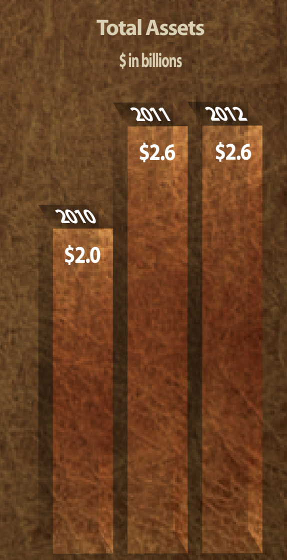
2012 as well as 2013 are transition years for Comstock as we are changing from a company with 98% of its reserves being natural gas to one with more balance between oil and natural gas. We started 2012 with a promising Eagle Ford shale oil program and added a new core area in the Permian Basin. In 2012, we saw natural gas prices decrease 36% from 2011 and our natural gas production decline by 9%. But we also saw our oil production grow by 175% from 2011 with our Eagle Ford shale properties becoming our main growth engine. Oil production made up 14% of our total production in 2012 as compared to only 5% in 2011. Given the weak natural gas prices, oil accounted for 53% of our total sales in 2012 as compared to only 18% in 2011.

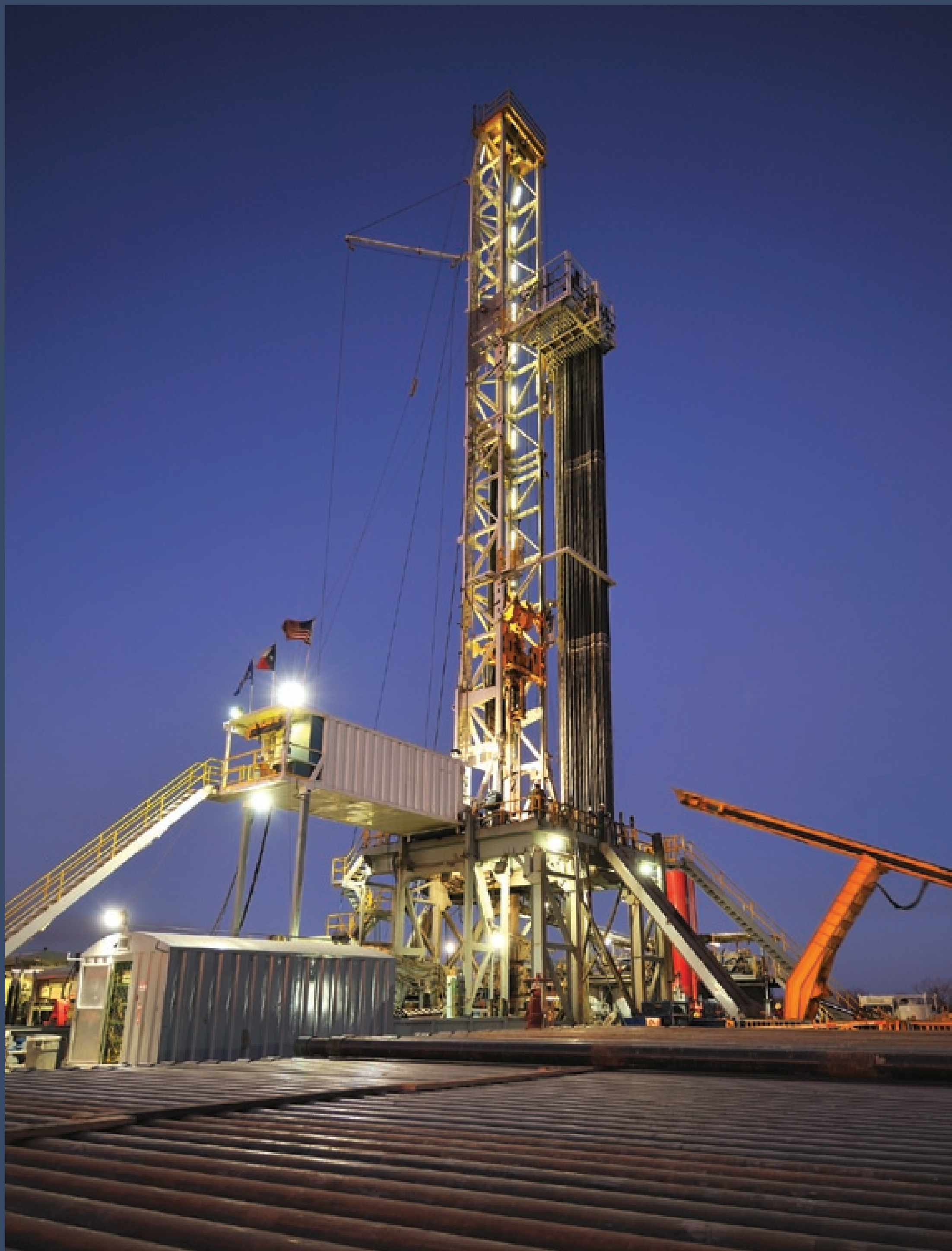
Our Wolfbone field in West Texas has tremendous potential to be a second growth engine both from proven vertical well development and from the emerging Wolfcamp shale horizontal well development. Our properties in the Haynesville and Bossier shales in East Texas and North Louisiana provide us with over 6 Tcfe of upside when natural gas prices support drilling again.

In the face of deteriorating natural gas prices, we completed several transactions in 2012 to improve our financial profile. We were able to reduce the leverage we took on at the end of 2011 with the Permian Basin acquisition with several asset divestitures which generated $204 million in net proceeds. We also completed a bond offering which freed up over $200 million of our bank credit facility. And lastly we entered into a joint venture on our Eagle Ford shale properties which allowed us to accelerate our drilling activity in South Texas starting in late 2012.





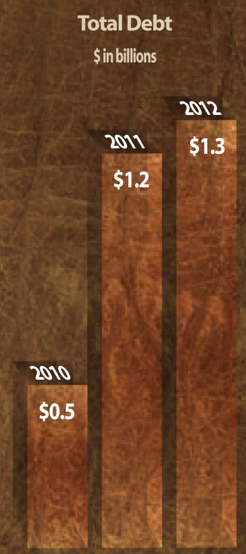


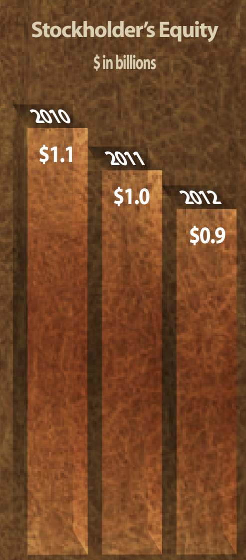


2012 FINANCIAL RESULTS

Our oil production increased 175% in 2012 driven by our oil focused drilling program while natural gas production declined by 9%. Natural gas prices in 2012 declined 36%. The higher oil production was mostly offset by the weaker natural gas prices and lower natural gas production as our oil and gas sales, including realized gains from our oil hedging program, increased by 2% to $442 million as compared to $434 million in 2011.

In 2012, oil made up 53% of our sales as compared to only 18% in 2011. We generated operating cash flow of $261 million in 2012 which was 12% less than 2011's operating cash flow of $298 million. Our operating costs increased 30% in 2012 to $102 million as compared to $79 million in 2011. The increase is attributable to the higher lifting costs associated with the increased oil production. Depreciation, depletion and amortization in 2012 of $365 million increased 25% as compared to the $291 million we had in 2011. Our depreciation, depletion and amortization per Mcfe produced increased to $3.83 in 2012 from $3.00 in 2011 due to the higher finding costs of our oil projects combined with the downward revisions to our proved undeveloped natural gas reserves related to the low 2012 natural gas prices. Our general and administrative expenses in 2012 decreased to $34 million as compared to $35 million in 2011. Our exploration costs increased in 2012 to $61 million as compared to $10 million in 2011. The increase in 2012 was due to impairments of certain of our natural gas undrilled leases which we no longer expect to develop. Our interest expense increased to $65 million in 2012 as compared to $43 million in 2011 due to the increase in the amount of debt we had outstanding. With the low outlook for natural gas prices for 2013, we recorded an impairment of $25 million to write down the carrying value of certain of our natural gas fields. We also had realized gains of $51 million on sales of our marketable securities and oil and gas properties. For the year we reported a net loss of $100 million or $2.16 per share.

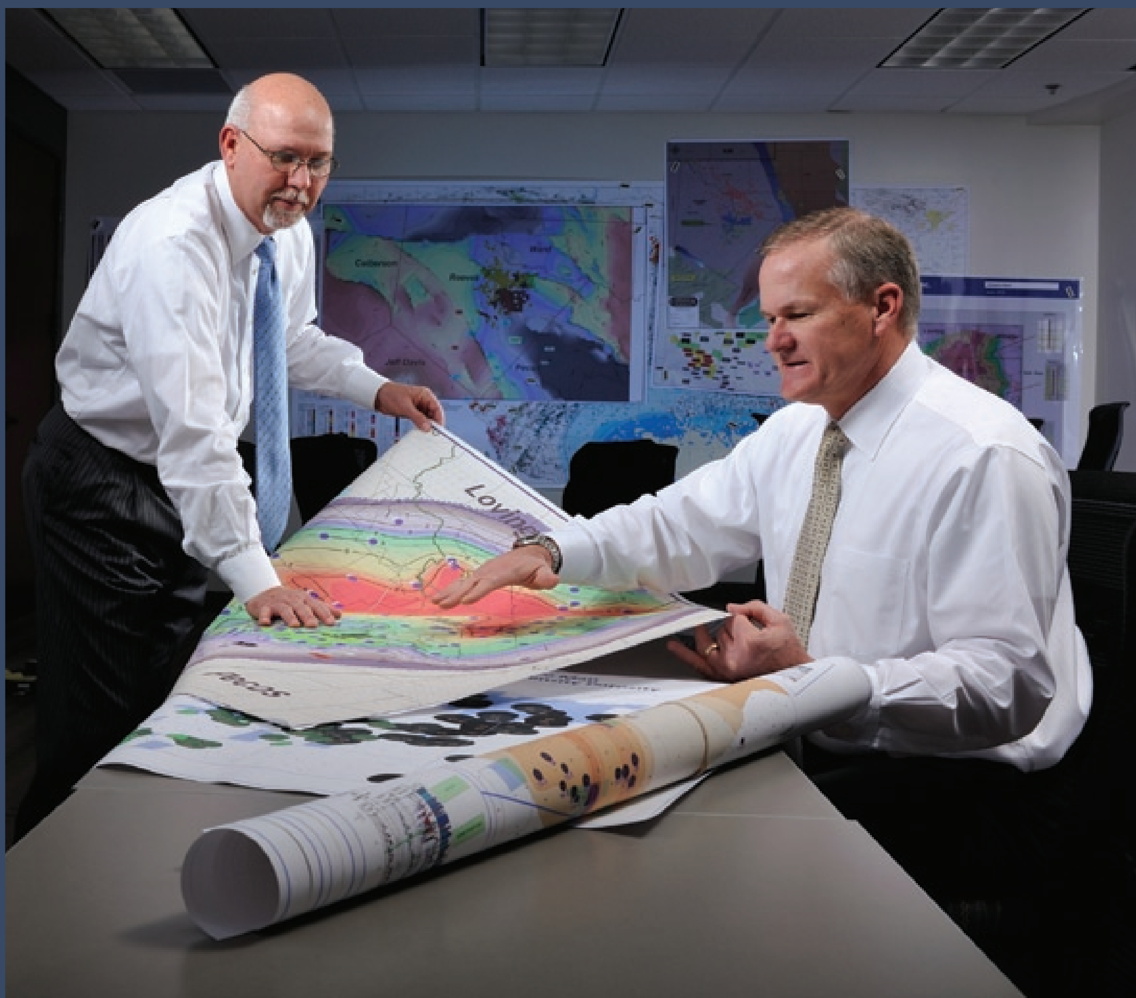




DRILLING PROGRAM

Our Eagle Ford shale horizontal well drilling program in South Texas and our Wolfbone vertical well drilling program in West Texas were the primary drivers of growth in our oil production and proved oil reserves in 2012. Our successful drilling program in the Eagle Ford shale in South Texas added 11.9 million barrels of oil and 7.5 Bcf of natural gas to our proved reserves in 2012. The West Texas drilling program contributed 5.4 million barrels of oil and 9.5 Bcf to our proved reserves in 2012. Our limited activity in the Haynesville shale and other regions added 14 Bcf of proved natural gas reserves in 2012. We spent $490 million for our drilling activities in 2012 (net of reimbursements from our Eagle Ford shale joint venture) and an additional $35 million to acquire leases for future exploration and development activities. In 2013, we plan on focusing primarily on our oil projects in the Eagle Ford shale in South Texas and in the Wolfbone and Wolfcamp shale in West Texas.

Our successful drilling program in the Eagle Ford shale in South Texas added 11.9 million barrels of oil and 7.5 Bcf of natural gas to our proved reserves in 2012.



SOUTH TEXAS REGION

In our South Texas region we have 32.8 million barrels of oil equivalent in reserves which is 28% of our total reserves. 56% of our reserves in this region are oil. We have 35,000 acres (28,000 net) in South Texas that are in the oil window of the Eagle Ford shale play. This region accounted for 73% of our oil production in 2012 at 4,600 barrels of oil per day and 11% of our natural gas production at 24 MMcf per day. Natural gas production in this region fell by 23% in 2012 but oil production increased 140% as a result of our Eagle Ford shale drilling program. We spent $203 million in 2012 to drill 30 (20.5 net) horizontal Eagle Ford shale wells. These wells had an average per well initial production rate of 675 barrels of oil equivalent per day. We plan to spend $219 million in 2013 to drill 42 (27.3 net) Eagle Ford shale horizontal wells. Our costs to drill and complete these wells are down considerably which is allowing us to drill 33% more net wells in 2013 with only an 8% higher spending level.

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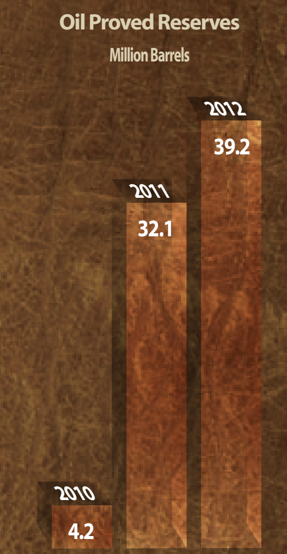
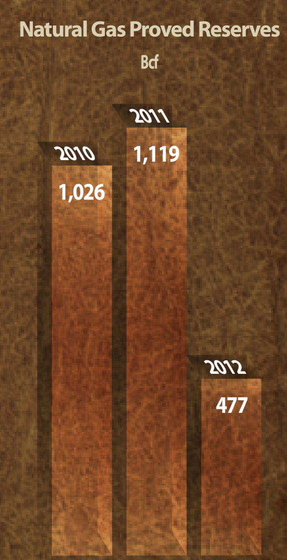


WEST TEXAS REGION

In our West Texas region we have 26.8 million barrels of oil equivalent in reserves which is 23% of our total reserves. 76% of our reserves in this region are oil. We have 89,000 acres (54,000 net) in the Permian Basin in West Texas. We believe that these properties are prospective for oil development primarily in the Avalon, Bone Spring and Wolfcamp shales. This region accounted for 22% of our oil production at 1,400 barrels of oil per day and less than 1% of our natural gas production at 2 MMcf per day. We spent $184 million in 2012 to drill 48 (30.5 net) wells. These wells had an average per well initial production rate of 322 barrels of oil equivalent per day. We plan to spend $169 million in 2013 to drill 33 (27.2 net) wells including eight horizontal wells targeting the Wolfcamp shale.



EAST TEXAS/NORTH LOUISIANA REGION

At the end of 2012, we had 342 Bcfe of our proved reserves (48%) 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 and moved all of our operating drilling rigs to our oil regions during the first quarter of 2012. As a result our production from this region, which averaged 196 MMcfe per day in 2012, declined by 8% from 2011. Most of our proved undeveloped reserves in this region had to be written off by the end of 2012 due to the low average natural gas price in 2012. In 2012, we spent $101 million in this region to drill seven wells (3.2 net) and to complete 16 wells (10.4 net) that were drilled in 2011. We currently have 94,000 gross acres and 80,000 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. We expect to have minimal activity in this region in 2013 unless natural gas prices improve.

OTHER REGIONS

We have 12 Bcfe in the San Juan basin, Mid-Continent and in other areas. Our properties in the other regions accounted for 2% of our 2012 daily production at 6 MMcfe per day. We plan to continue to divest of many of these assets on an opportunistic basis.

OUTLOOK FOR 2013

Despite the continued low natural gas prices we are experiencing, we are excited about the prospects for Comstock in 2013. We anticipate the strong growth in our oil production to offset the low natural gas prices to allow us to have higher revenues and cash flow and to be a much more profitable company in 2013. We expect oil to comprise more than 25% of our 2013 production as 94% of the wells that we expect to drill will be oil wells and 92% of our budget is expected to be spent on oil projects. Our Eagle Ford shale program will be our largest growth engine this year. We also see tremendous upside in future horizontal development in the emerging Wolfcamp shale based on recent activity in Reeves County, Texas.

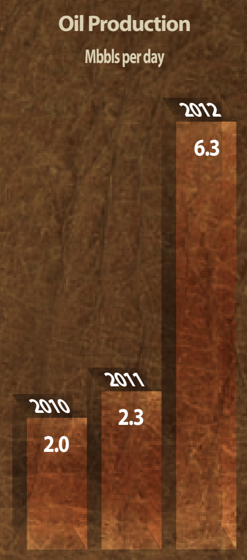
We will strive to continue to have one of the lowest overall cost structures in the industry even as we transition to oil. We believe that we have adequate liquidity for our 2013 drilling plans. We expect operating cash flow to fund most of our planned drilling program and that the availability under our bank credit facility will increase with our oil reserve growth. We will continue utilizing an oil price hedging strategy to protect our oil focused drilling program.

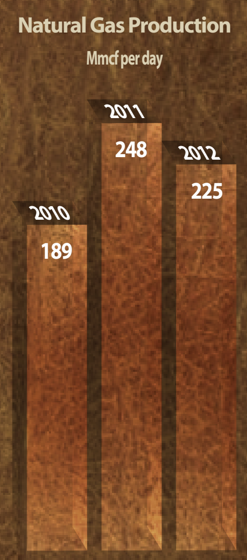
A major goal for Comstock in 2013 is to improve our balance sheet. We also want to bring in more capital for our oil focused drilling program. We expect to accomplish this at the asset level by entering into a joint venture or selling a portion of our large acreage position in the Permian Basin.

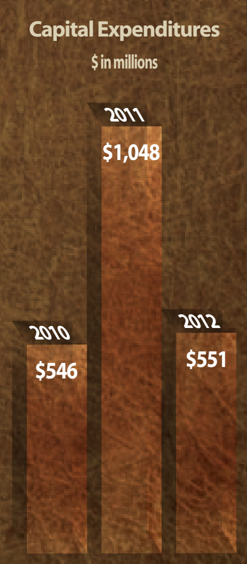
The directors and management of Comstock want to thank the stockholders for their continued support.

M. Jay Allison
Chairman and President

We anticipate the strong growth in our oil production to offset the low natural gas prices to allow us to have higher revenues and cash flow and to be a much more profitable company in 2013.







UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2012

OR

☐ **TRANSITION REPORT PURSUANT TO SECTIONS 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 ☑

As of February 28, 2013, there were 48,303,517 shares of common stock outstanding.

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, 2012 (the last business day of the registrant's most recently completed second fiscal quarter), was $734.6 million.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement for the 2012 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, 2012

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;
- the availability of exploration and development opportunities;
- amount, nature and timing of capital expenditures;
- the number of anticipated wells to be drilled after the date hereof;
- 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. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery will be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"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 may also include 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 only by contractual arrangements, but not on escalations based upon future conditions.

"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 shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances are estimates for proved undeveloped reserves attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

"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 a Nevada corporation 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.

Our oil and gas operations are concentrated in East Texas/North Louisiana, South Texas and West Texas. Our oil and natural gas properties are estimated to have proved reserves of 711.9 Bcfe with an estimated PV 10 Value of $1.0 billion as of December 31, 2012 and a standardized measure of discounted future net cash flows of $0.8 billion. Our consolidated proved oil and natural gas reserve base is 67% natural gas and 33% oil. Our proved reserves are 62% developed on a Bcfe basis as of December 31, 2012.

Our proved reserves at December 31, 2012 and our 2012 average daily production are summarized below:

	Reserves at December 31, 2012				2012 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	0.4	339.4	341.9	48.0%	0.2	194.2	195.6	74.3%
South Texas	18.4	86.2	196.5	27.6%	4.6	23.6	51.1	19.4%
West Texas	20.3	39.2	161.1	22.6%	1.4	2.0	10.5	4.0%
Other Regions	0.1	11.8	12.4	1.8%	0.1	5.6	6.1	2.3%
Total	39.2	476.6	711.9	100.0%	6.3	225.4	263.3	100.0%

Strengths

High Quality Properties. Our operations are focused in three primary operating areas: East Texas/ North Louisiana, South Texas and West Texas. Our properties have an average reserve life of approximately 7.4 years and have extensive development and exploration potential. In response to the continuing low natural gas price environment, we have focused our drilling activity primarily on oil projects. Our two primary properties that provide opportunities to increase our oil production and reserves are our South Texas Eagle Ford shale properties and our Wolfbone field in West Texas. We have 34,727 acres (27,689 net to us) in the Eagle Ford shale and we have 88,666 acres (54,355 net to us) in West Texas prospective in the Bone Spring and Wolfcamp shales. Our properties in the East Texas/North Louisiana region, including 93,620 acres (80,046 net to us) in the Haynesville or Bossier shales, are primarily prospective for natural gas.

Successful Exploration and Development Program. In 2012 we spent $524.9 million, net of reimbursed costs from our joint venture partner, on exploration and development activities. We drilled 85 wells (54.2 net to us) in 2012 at a cost of $415.1 million and we spent $70.9 million to complete 20 wells (13.6 net to us) that were drilled in 2011. We also spent $35.1 million in 2012 to acquire additional leasehold, $0.1 million to acquire seismic data and $3.7 million for recompletions, workovers, abandonment and production facilities. 80% of our 2012 capital expenditures were directed towards oil projects. Our drilling activities in 2012 added 22.5 MMBOE to our proved reserves and increased our oil production by 175% from 2011.

Efficient Operator. We operated 90% of our proved oil and natural gas reserve base as of December 31, 2012. 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. We apply strict economic and reserve risk criteria in evaluating acquisitions. Over the last twenty years, we have added 1.1 Tcfe of proved oil and natural gas reserves from 38 acquisitions 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. We conduct exploration activities to grow our reserve base and to replace our production each year. During 2012 we refocused our efforts on prospects with potential for oil development, and we have limited our drilling on our natural gas properties due to the decline in natural gas prices.

From 2010 through 2012 we spent approximately $155.2 million to acquire 34,727 acres (27,689 net to us) in South Texas, which we believe to be prospective for oil in the Eagle Ford shale formation. In 2012, we spent approximately $201.7 million to drill 30 wells (20.5 net to us) on our Eagle Ford shale properties. In 2012 we entered into a joint venture arrangement to allow us to accelerate the development of our acreage. 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. In 2012, our Eagle Ford shale drilling program added 13.2 MMBOE to our proved reserves. In 2013 we have budgeted to spend $219.0 million, net of reimbursements from our joint venture partner, to drill 42 wells (27.3 net to us) on our Eagle Ford shale properties and to complete six wells (3.8 net to us) that were drilled in 2012.

We have spent approximately $340.0 million to acquire 68,764 acres (41,071 net to us) in Reeves County in West Texas, which we believe to be prospective for oil in the Bone Spring and Wolfcamp shales in the Delaware Basin. During 2012 we spent $183.4 million and drilled 48 wells (30.5 net to us) in West Texas. Our drilling program added 6.9 MMBOE to our reserves in 2012. In 2013 we have budgeted $168.9 million to drill 33 wells (27.2 net to us), including eight horizontal Wolfcamp shale wells (7.3 net to us).

We have a significant acreage position of 93,620 acres (80,046 net to us) in East Texas and North Louisiana with Haynesville or Bossier shale natural gas potential but in 2012 we have deferred most of our drilling operations due to the low natural gas price environment. In 2012, we drilled seven Haynesville and Bossier shale horizontal wells (3.2 net to us) which added 14 Bcfe to our proved reserves in 2012. With the low natural gas price outlook in 2013, we continue to defer our natural gas focused drilling. We have budgeted to spend $32.1 million in 2013 to drill ten Haynesville and Bossier shale horizontal wells (3.6 net to us).

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, improved logging tools, and formation stimulation techniques.

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. We have budgeted to spend approximately $420.0 million in 2013 on our development and exploration projects and $25.0 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. Over the last twenty years, we have added 1.1 Tcfe of proved oil and natural gas reserves from 38 acquisitions 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, 2012:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)(1)	%	PV 10 Value(2) (000's)	%
East Texas / North Louisiana:						
Logansport	15	212,172	212,263	29.8%	$ 123,779	12.1%
Toledo Bend	—	44,965	44,965	6.3%	27,810	2.7%
Beckville	125	31,130	31,880	4.5%	28,357	2.8%
Waskom	98	14,207	14,798	2.1%	14,365	1.4%
Blocker	46	10,901	11,175	1.6%	9,351	0.9%
Mansfield	—	8,614	8,614	1.2%	4,990	0.5%
Darco	12	3,845	3,919	0.6%	2,136	0.2%
Douglass	—	2,995	2,995	0.4%	976	0.1%
Other	117	10,560	11,256	1.5%	9,240	0.8%
	413	339,389	341,865	48.0%	221,004	21.5%
South Texas:						
Eagleville	18,281	14,051	123,739	17.4%	532,714	51.9%
Fandango	—	37,274	37,274	5.2%	19,782	1.9%
Rosita	—	16,295	16,296	2.3%	6,601	0.6%
Javelina	39	7,809	8,046	1.1%	9,759	1.0%
Las Hermanitas	—	4,482	4,483	0.6%	2,300	0.2%
Other	61	6,335	6,696	1.0%	6,768	0.7%
	18,381	86,246	196,534	27.6%	577,924	56.3%
West Texas:						
Wolfbone	20,320	39,155	161,073	22.6%	212,186	20.7%
	20,320	39,155	161,073	22.6%	212,186	20.7%
Other:						
San Juan Basin	12	3,311	3,381	0.5%	4,107	0.4%
Other	93	8,499	9,064	1.3%	11,309	1.1%
	105	11,810	12,445	1.8%	15,416	1.5%
Total	39,219	476,600	711,917	100.0%	1,026,530	100.0%
Discounted Future Income Taxes					(242,313)	
Standardized Measure of Discounted Future Cash Flows					$ 784,217	

(1) Oil is converted to natural gas equivalents by using a conversion factor of one barrel of oil for six Mcf of natural gas.

(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 48% or 341.9 Bcfe of our proved reserves are located in East Texas and North Louisiana where we own interests in 958 producing wells (585.8 net to us) in 28 field areas. We operate 664 of these wells. The largest of our fields in this region are the Logansport, Toledo Bend, Beckville, Waskom, Blocker, Mansfield, Darco and Douglass fields. Production from this region averaged 194 MMcf of natural gas per day and 220 barrels of oil per day during 2012 or 196 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 2012, we spent $101.1 million drilling seven wells (3.2 net to us) and completing 16 wells (10.4 net to us) that were drilled in 2011. We also spent $8.2 million on leasehold costs and $1.7 million on workovers and recompletions in this region. All seven of the wells we drilled in 2012 were horizontal wells that targeted the Haynesville or Bossier shales. We plan to spend approximately $32.1 million in 2013 in this region to drill ten (3.6 net to us) horizontal wells targeting the Haynesville or Bossier shales. These wells are required to retain our interest in certain undeveloped leases.

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 212.3 Bcfe in the Logansport field represent approximately 30% of our proved reserves. We own interests in 254 wells (163.2 net to us) and operate 180 of these wells in this field. During December 2012 net daily production attributable to our interest from this field averaged 94 MMcf of natural gas and 20 barrels of oil. In 2012 we completed ten Haynesville or Bossier shale horizontal wells (8.2 net to us) in Logansport that were drilled in 2011. In 2013 we plan to drill three horizontal Haynesville or Bossier shale wells (0.6 net to us) in our Logansport field.

Toledo Bend

The Toledo Bend field in Desoto and Sabine Parishes, Louisiana was discovered in 2008 with our first horizontal Haynesville shale well. Production from the Haynesville shale in the Toledo Bend field ranges from 11,400 to 11,800 feet and from 10,880 to 11,300 feet in the Bossier shale. Our proved reserves of 45 Bcfe in the Toledo Bend field represent approximately 6% of our reserves. We own interests in 72 producing wells (37.3 net to us) and operate 39 of these wells in this field. During 2012 we drilled four Haynesville or Bossier shale horizontal wells (1.3 net to us) at Toledo Bend and we completed six wells (2.1 net to us) that were drilled in 2011. During December 2012, net daily production attributable to our interest from this field averaged 35 MMcf of natural gas. In 2013, we plan to drill five horizontal Haynesville or Bossier shale wells (2.6 net to us) in this field.

Beckville

The Beckville field, located in Panola and Rusk Counties, Texas, has estimated proved reserves of 31.9 Bcfe which represents approximately 5% of our proved reserves. We operate 192 wells in this field and own interests in 81 additional wells for a total of 273 wells (160.4 net to us). During December 2012, production attributable to our interest from this field averaged 8 MMcf of natural gas per day and 40 barrels of oil per day. 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.

Waskom

The Waskom field, located in Harrison and Panola Counties in Texas, represents approximately 2% (14.8 Bcfe) of our proved reserves as of December 31, 2012. We own interests in 63 wells in this field (40.5 net to us) and operate 48 wells in this field. During December 2012, net daily production attributable to our interest averaged 5 MMcf of natural gas and 20 barrels of oil from 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 11.2 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. During December 2012, net daily production attributable to our interest from this field averaged 4 MMcf of natural gas and 22 barrels of oil. 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 four of these wells. Our proved reserves in this field of 8.6 Bcfe represent approximately 1% of our total reserves. During December 2012, net daily production attributable to our interest for this field averaged 4 MMcf of natural gas. In 2013, we plan to drill two (0.4 net to us) horizontal Haynesville shale wells in this field.

Darco

The Darco field is located in Harrison County, Texas and produces from the Cotton Valley formation at depths from approximately 9,800 to 10,200 feet. Our proved reserves of 3.9 Bcfe in the Darco field represent approximately 1% of our reserves. We own interests in 23 wells (18 net to us) and operate all of these wells. During December 2012, net daily production attributable to our interest from this field averaged 1 MMcf of natural gas.

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 3.0 Bcfe in the Douglass field represent less than 1% of our reserves. We own interests in 40 wells (25.8 net to us) and operate 33 of these wells. During December 2012, net daily production attributable to our interest from this field averaged 1 MMcf of natural gas.

South Texas Region

Approximately 28%, or 32.8 MMBOE (196.5 Bcfe,) of our proved reserves are located in South Texas, where we own interests in 191 producing wells (116.6 net to us). We own interests in 16 field areas in the region, the largest of which are the Eagleville, Fandango, Rosita, Javelina and Las Hermanitas fields. Net daily production rates from this region averaged 4,587 barrels of oil and 24 MMcf of natural gas during 2012 or 8,521 BOE per day. We spent $202.9 million in 2012, net of cost recoveries from our joint venture partner, to drill 30 (20.5 net to us) Eagle Ford shale wells and for other development activity. We also spent $7.7 million in this region in 2012 to acquire acreage. In 2013 we plan to spend approximately $219.0 million to drill 42 horizontal wells (27.3 net to us) and to complete six Eagle Ford shale wells (3.8 net to us) that were drilled in 2012.

Eagleville

We have 34,727 acres (27,689 net to us) in McMullen, La Salle, Atascosa, Wilson and Karnes Counties which are prospective for Eagle Ford shale development in South Texas. The Eagle Ford Shale is found between 7,500 feet and 11,500 feet across our acreage position. During December 2012 we had 49 wells (40.5 net to us) that were producing a total of 4,023 barrels of oil per day and 2.4 MMcf per day of natural gas net to our interest or 4,418 BOE per day. Our proved reserves in this field are estimated to be 20.6 MMBOE (123.7 Bcfe) (89% oil) and represent 17% of our total proved reserves. All of our planned South Texas drilling activity in 2013 will be in the Eagleville field.

Fandango

We own interests in 20 wells (20.0 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 37.3 Bcfe in this field represent approximately 5% of our total proved reserves. Production from this field averaged 9 MMcf of natural gas per day during December 2012.

Rosita

We own interests in 30 wells (16.2 net to us) in the Rosita field, located in Duval County, Texas. We operate four of these wells which produce from the Wilcox formation at depths from approximately 9,300 to 17,000 feet. Our proved reserves of 16.3 Bcfe in this field represent approximately 2% of our total proved reserves. Production from this field averaged 3 MMcf of natural gas per day during December 2012.

Javelina

We own interests in and operate 18 wells (18.0 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 8.0 Bcfe, which represents 1% of our total proved reserves. During December 2012, production attributable to our interest from this field averaged 3 MMcf of natural gas per day and 21 barrels of oil per day.

Las Hermanitas

We own interests in and operate 11 natural gas wells (9.0 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 4.5 Bcfe in this field represent approximately 1% of our total proved reserves. During December 2012, net daily production attributable to our interest from this field averaged 2 MMcf of natural gas.

West Texas Region

Wolfbone

We own interests in 68,764 acres (41,071 net to us) in Reeves County in the Delaware Basin in West Texas that are prospective for the Bone Spring formation from depths of 10,000 to 10,300 feet and the Wolfcamp shale formation from depths of 10,300 to 11,500 feet, most of which was acquired by us in 2011. Our proved reserves of 26.8 MMBOE (161.1 Bcfe) in the Wolfbone field are 76% oil and represent 23% of our total proved reserves. Net daily production rates from this region averaged 1,410 barrels of oil and 2 MMcf of natural gas during 2012 or 1,744 BOE per day. During 2012 we spent $183.9 million to drill 48 (30.5 net to us) oil wells and for other development activity. We also spent $19.2 million in this region in 2012 to acquire acreage. In 2013 we have budgeted to spend $168.9 million to drill 33 wells (27.2 net to us) in this region and to complete three wells (1.0 net to us) drilled in 2012.

Other Regions

Approximately 2%, or 12.4 Bcfe, of our proved reserves are in other regions, primarily in New Mexico and the Mid-Continent region. We own interests in 421 producing wells (161.0 net to us) in 20 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 2012 totaled 6 MMcf of natural gas and 87 barrels of oil or 6 MMcfe per day.

San Juan

Our San Juan Basin properties are located in the west-central portion of the basin in 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 3.4 Bcfe in the San Juan field represent less than 1% of our reserves. We own interests in 93 wells (14.1 net to us) in this field. During December 2012, net daily production attributable to our interest from this field averaged 1 MMcf of natural gas and 2 barrels of oil.

Major Property Acquisitions

As a result of our acquisitions, we have added 1.1 Tcfe of proved oil and natural gas reserves since 1991. Our ten 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).

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.

Javelina Acquisition. In June 2007 we acquired additional working interests in oil and gas properties in the Javelina field in South Texas from Abaco Operating LLC for $31.2 million. The properties acquired had estimated proved reserves of approximately 9.1 Bcfe.

Denali Acquisition. In September 2006 we acquired proved and unproved oil and gas properties in the Las Hermanitas field in South Texas from Denali Oil & Gas Partners LP and other working interest owners for $67.2 million. The properties acquired had estimated proved reserves of approximately 16.5 Bcfe.

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.

Ovation Energy Acquisition. In October 2004, we acquired producing oil and gas properties in the East Texas, Arkoma, Anadarko and San Juan basins from Ovation Energy, L.P. for $62.0 million. The properties acquired had estimated proved reserves of approximately 41.0 billion cubic feet of gas equivalent and included 165 active wells, of which 69 were operated by us.

DevX Energy Acquisition. In December 2001, we completed the acquisition of DevX Energy, Inc. by acquiring 100% of the common stock of DevX for $92.6 million. The total purchase price including debt and other liabilities assumed in the acquisition was $160.8 million. The acquisition included 600 producing wells located onshore primarily in East and South Texas, Kentucky, Oklahoma and Kansas with 1.2 MMBbls of oil reserves and 156.5 Bcf of natural gas reserves at the time of the acquisition.

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.

Sonat Acquisition. In July 1995, we purchased interests in certain producing oil and gas properties located in East Texas and North Louisiana from Sonat Inc. for $48.1 million. We acquired interests in 319 producing wells (188.0 net to us). The acquisition included interests in the Logansport, Beckville, Waskom, Hico-Knowles, and Blocker fields. The net proved reserves acquired in this acquisition were estimated at 0.8 MMBbls of oil and 104.7 Bcf of natural gas. We divested of the Hico-Knowles field 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, 2012:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)	PV 10 Value (000's)
Proved Developed:				
Producing	11,503	367,140	436,157	$ 759,743
Non-producing	805	1,635	6,466	37,877
Total Proved Developed	12,308	368,775	442,623	797,620
Proved Undeveloped	26,911	107,825	269,294	228,910
Total Proved	39,219	476,600	711,917	1,026,530
Discounted Future Income Taxes				(242,313)
Standardized Measure of Discounted Future Net Cash Flows(1)				$ 784,217

(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:

	2010		2011		2012	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved Developed	2,961	506,809	8,405	550,474	12,308	368,775
Proved Undeveloped	1,258	518,824	23,694	568,158	26,911	107,825
Total Proved Reserves	4,219	1,025,633	32,099	1,118,632	39,219	476,600

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, excluding the effect of hedging, 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,		
	2010	2011	2012
Oil Price — $/Bbl	$68.35	$95.73	$96.95
Natural Gas Price — $/Mcf	$ 4.35	$ 3.91	$ 2.52
Lifting costs — $/Mcfe	$ 1.10	$ 0.82	$ 1.06

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 point of sale. 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)
2010	$76.31	$4.16
2011	$92.93	$4.18
2012	$94.61	$2.84

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, 2012 reserve report, reserves on undrilled acreage were limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled. Using empirical evidence, we utilize control points and sample sizes to show continuity in the reservoir.

The following table presents the changes in our estimated proved undeveloped oil and natural gas reserves for the years ended December 31, 2010, 2011 and 2012:

	Proved Undeveloped Reserves					
	2010		2011		2012	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Beginning Balance	2,320	315,287	1,258	518,824	23,694	568,158
Sales and Disposals	(1,996)	(2,378)	—	—	(5,698)	(21,459)
Acquisitions	—	—	16,959	45,792	—	—
Extension & Discoveries	1,012	241,160	5,151	66,978	10,526	11,778
Conversions from undeveloped to developed	—	(8,825)	—	(39,761)	(1,597)	(1,466)
Price, Performance and Other Revisions	(78)	(26,420)	326	(23,675)	(14)	(449,186)
Total Change	(1,062)	203,537	22,436	49,334	3,217	(460,333)
Ending Balance	1,258	518,824	23,694	568,158	26,911	107,825

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					
	2010		2011		2012	
Year ended December 31,	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
2011	527	107,729	—	—	—	—
2012	426	163,984	8,250	51,034	—	—
2013	305	138,831	4,909	264,497	4,402	16,220
2014	—	93,547	9,329	215,756	4,545	34,695
2015	—	14,733	925	36,311	4,769	25,472
2016	—	—	201	402	7,708	22,411
2017	—	—	80	158	5,487	9,027
Total	1,258	518,824	23,694	568,158	26,911	107,825

Our oil proved undeveloped reserves increased by 3.2 MMBbls during 2012. This increase was primarily due to our drilling program which added 8.1 MMBbls in the Eagle Ford shale and 2.4 MMBbls in West Texas. We also sold 5.7 million barrels of proved undeveloped oil reserves, and converted 1.6 million barrels to developed in 2012.

Our natural gas proved undeveloped reserves decreased by 460 Bcf at December 31, 2012 as compared with December 31, 2011. This decrease was primarily related to the decline in natural gas prices, which caused approximately 465 Bcf of our natural gas proved undeveloped reserves to become uneconomic under the natural gas price used to determine proved reserves in 2012. We also sold 22 Bcf of natural gas proved undeveloped reserves, added 11 Bcf of natural gas proved undeveloped reserves from our drilling program, and had other revisions of 16 Bcf. Included in the 465 Bcf of reserves reductions associated with downward price revisions were 330 Bcf of proved undeveloped natural gas reserves that, as of December 31, 2011 had positive undiscounted future cash flows but had a rate of return that was less than 10%. These reserves became uneconomic due to the lower natural gas prices used to determine our 2012 year end reserve estimates.

As of December 31, 2012, our proved undeveloped reserves included 26.9 MMBbls of oil and 107.8 Bcf of natural gas, for a total of 269.3 Bcfe of undeveloped reserves. Approximately 16.4 MMBbls of oil and 33 Bcf of natural gas of our proved undeveloped reserves at December 31, 2012 were associated with the future development of our West Texas properties that we acquired in December 2011 and an additional 10.5 MMBbls of oil and 7 Bcf of natural gas were associated with our Eagle Ford shale properties in South Texas. The proved undeveloped reserves associated with our Haynesville or Bossier shale properties represented approximately 55 Bcf of our natural gas proved undeveloped reserves at December 31, 2012. The remaining proved undeveloped reserves are primarily associated with developing reserves in our Cotton Valley and Hosston sand reservoirs in East Texas/North Louisiana and the Wilcox and Vicksburg reservoirs in South Texas. In 2012, we focused on drilling oil properties due to the weak natural gas prices. Seven of the Eagle Ford shale wells and four of the Wolfbone shale oil wells we drilled in 2012 resulted in conversions of proved undeveloped reserves to proved developed producing reserves at December 31, 2012. Undeveloped natural gas reserves originally expected to be converted to developed reserves in 2012 were removed from our proved reserves due to the low natural gas prices during 2012.

Our oil proved undeveloped reserves increased by 22.4 MMBbls during 2011. This increase was primarily due to our acquisition of proved undeveloped reserves in West Texas of 17.0 MMBbls, proved undeveloped reserves additions of 4.7 MMBbls from our Eagle Ford shale properties and 0.7 MMBbls of oil additions and revisions on our other properties. Our natural gas proved undeveloped reserves increased by 49 Bcf during 2011. This increase was primarily related to our successful Haynesville and Bossier shale drilling program which added 44 Bcf of natural gas reserves, our acquisition in West Texas which added 34 Bcf and we had other additions of approximately 36 Bcf. Our proved undeveloped natural gas reserves additions were partially offset by conversions to proved developed reserves of approximately 40 Bcf during 2011 and other downward revisions to previous estimates of approximately 23 Bcf.

As of December 31, 2011, our proved undeveloped reserves included 23.7 MMBbls of oil and 568 Bcf of natural gas, for a total of 710 Bcfe of undeveloped reserves. Approximately 17.0 MMBbls of oil and 34 Bcf of natural gas of our proved undeveloped reserves at December 31, 2011 were associated with the future development of our West Texas properties that we acquired in December 2011 and an additional 6.0 MMBbls of oil 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 or Bossier shale properties represented approximately 425 Bcf of our total natural gas proved undeveloped reserves at December 31, 2011. The remaining proved undeveloped reserves are primarily associated with developing reserves in our Cotton Valley and Hosston sand reservoirs in East Texas/North Louisiana and our Wilcox and Vicksburg reservoirs in South Texas. During the year ended December 31, 2011, the price of oil increased significantly, and the value of oil relative to natural gas on a heating equivalent basis widened to historic levels. This, coupled with a growing over-supply of natural gas in the United States, caused us to change our strategic focus towards oil and away from natural gas. As a result, our drilling program during 2011, which was initially focused on our Haynesville and Bossier shale reserves, was refocused during the year towards our oil prone properties in the Eagle Ford shale in South Texas. Eleven of the Haynesville shale wells we drilled in 2011 resulted in conversions of proved undeveloped reserves to proved developed producing reserves at the end of 2011. To better position the company for future growth of oil production, in late 2011 we acquired a substantial acreage position in West Texas which is prospective for oil. A portion of this acquisition was determined to contain proved undeveloped reserves.

Our estimates of oil and natural gas reserves at December 31, 2012 include 80.6 Bcfe related to undrilled wells that have positive undiscounted future cash flows but which, based upon oil and natural gas prices that we use to prepare the proved reserve estimates, have a rate of return that is less than the 10% discount rate used in the Standardized Measure of Discounted Future Cash Flows attributable to the proved reserve estimates. We intend to drill the proved undeveloped wells in the time frame reflected in the estimates of proved oil and natural gas reserves as of December 31, 2012 based upon the oil and natural gas prices that we used to prepare the reserve estimates. We anticipate drilling such proved undeveloped locations based on our current development plans for our properties. Certain of these wells may be drilled to retain leasehold interests or to properly manage reservoir performance. To the extent that actual oil or natural gas prices are substantially weaker, we may have to modify our development plans or we may not fully recover our investment in drilling these wells from future cash flows.

The following table presents the estimated timing of our estimated future development capital costs to be incurred for the years ended December 31, 2010, 2011 and 2012:

Year ended December 31,	Future Development Costs Total Proved Undeveloped Reserves		
	2010	2011	2012
		(in millions)	
2011	$ 237.3	$ —	$ —
2012	381.0	395.4	—
2013	299.6	734.4	122.5
2014	199.0	742.4	111.5
2015	28.4	117.9	325.8
2016	—	9.4	275.3
2017	—	4.2	233.1
Total	$1,145.3	$2,003.7	$1,068.2

The following table presents the changes in our estimated future development costs for the years ended December 31, 2011 and 2012:

	Future Development Costs — Proved Undeveloped Reserves				
	Haynesville Shale	Eagle Ford Shale	West Texas Properties	All Other Properties	Total
			(in millions)		
Total as of December 31, 2010	$ 698.9	$ 49.0	$ —	$ 397.4	$1,145.3
Development Costs Incurred	(56.3)	—	—	—	(56.3)
Additions and Revisions	243.5	169.0	653.5	(151.3)	914.7
Total Changes	187.2	169.0	653.5	(151.3)	858.4
Total as of December 31, 2011	886.1	218.0	653.5	246.1	2,003.7
Development Costs Incurred	(24.7)	(43.4)	(19.2)	—	(87.3)
Sales and Disposals	—	—	—	(48.1)	(48.1)
Additions and Revisions	(777.5)	174.2	(19.5)	(177.3)	(800.1)
Total Changes	(802.2)	130.8	(38.7)	(225.4)	(935.5)
Total as of December 31, 2012	$ 83.9	$348.8	$614.8	$ 20.7	$1,068.2

Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2012 of $1.1 billion decreased by $0.9 billion from our estimated future capital costs of $2.0 billion as of December 31, 2011. During 2012 we incurred approximately $87.3 million to develop proved undeveloped reserves, primarily in our Eagle Ford shale and West Texas properties. Our oil focused future capital expenditures increased by $155.0 million and our natural gas focused capital expenditures decreased by $955.0 million. Approximately $749.0 million of the reduction in our estimated future development costs in 2012 was associated with wells that, as of December 31, 2011, had positive undiscounted cash flows but had a rate of return of less than 10%.

Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2011 of $2.0 billion increased by $858.0 million from our estimated future capital costs of $1.1 billion as of December 31, 2010. During 2011, we incurred approximately $56.3 million to develop proved undeveloped reserves in our Haynesville shale properties. Due to the success of our oil focused drilling programs, we increased our proved undeveloped reserve estimates in the Eagle Ford shale and we acquired properties in West Texas with significant potential for oil during 2011. During 2011 our oil focused future capital expenditures increased by $169.0 million in the Eagle Ford shale and $654.0 million in West Texas. Our future capital expenditures in the Haynesville and Bossier shales increased by $244.0 million during 2011 reflecting our 2011 drilling success on these properties, while we further reduced our forecast of capital expenditures on our remaining conventional natural gas undeveloped reserves by $151.0 million during 2011.

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, 2010, 2011 or 2012 to any federal authority or agency, other than the SEC.

Drilling Activity Summary

During the three-year period ended December 31, 2012, we drilled development and exploratory wells as set forth in the table below:

	2010		2011		2012	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	—	—	17	16.2	78	51.0
Gas	65	41.1	61	26.6	7	3.2
Dry	—	—	—	—	—	—
	65	41.1	78	42.8	85	54.2
Exploratory:						
Oil	3	3.0	3	3.0	—	—
Gas	10	5.2	6	1.9	—	—
Dry	—	—	—	—	—	—
	13	8.2	9	4.9	—	—
Total	78	49.3	87	47.7	85	54.2

In 2013 to the date of this report, we have drilled ten wells (7.2 net to us) and we have eight wells (5.0 net to us) that are 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, 2012:

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Arkansas	—	—	15	8.0
Kansas	—	—	9	5.0
Kentucky	—	—	86	76.1
Louisiana	17	5.4	450	251.6
New Mexico	1	—	92	14.1
Oklahoma	10	1.2	127	17.9
Texas	141	96.1	669	437.2
Wyoming	—	—	26	1.9
Total	169	102.7	1,474	811.8

We operate 962 of the 1,643 producing wells presented in the above table. As of December 31, 2012, we owned interests in 14 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, 2012, 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	—	—
Kentucky	7,206	5,773	—	—
Louisiana	95,516	60,597	24,576	18,910
New Mexico	10,240	1,896	—	—
Oklahoma	38,080	5,707	—	—
Texas	123,553	74,361	96,090	60,968
Wyoming	13,440	927	—	—
Total	295,715	154,009	120,666	79,878

Our undeveloped acreage expires as follows:

Expires in 2013	29%
Expires in 2014	38%
Expires in 2015	10%
Thereafter	23%
	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. The Company anticipates retaining ownership of a substantial amount of the acreage with primary terms expiring in 2013 through drilling activity or by extending the leases.

Markets and Customers

The market for oil and natural gas produced by us 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 89% of our 2012 natural gas sales were priced utilizing first of the month index prices and approximately 11% were priced utilizing daily spot prices. BP Energy Company and its subsidiaries and Shell Oil Company and its subsidiaries accounted for 42% and 27%, respectively, of our total 2012 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 80,000 MMBtus per day for our North Louisiana natural gas production on the long-haul pipelines. These agreements expire from 2013 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, 2012. 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, 2012 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. Storage tanks emitting certain levels of VOCs may also require a 95% reduction of VOC emissions by October 1, 2015. 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 2012, EPA issued draft guidance on when UIC permitting requirements apply to fracking fluids containing diesel. We are not able to predict at this time the effect on our operations should EPA require UIC permits be obtained prior to utilizing diesel as a fracking agent. 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.

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 new 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, 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 $118,934. This lease expires on December 31, 2021. We also own production offices and pipe yard facilities near Marshall, Midland, Pecos and Zapata, Texas; Logansport, Louisiana and Guston, Kentucky.

Employees

As of December 31, 2012, we had 116 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	President, Chief Executive Officer and Chairman of the Board of Directors	57
Roland O. Burns	Senior Vice President, Chief Financial Officer, Secretary, Treasurer and Director	52
Mark A. Williams	Chief Operating Officer and Vice President of Operations	51
Gerry L. Blackshear	Vice President of Exploration	54
D. Dale Gillette	Vice President of Land and General Counsel	67
Stephen E. Neukom	Vice President of Marketing	63
Daniel K. Presley	Vice President of Accounting and Controller	52
Russell W. Romoser	Vice President of Reservoir Engineering	61
Richard D. Singer	Vice President of Financial Reporting	58
Blaine M. Stribling	Vice President of Corporate Development	42
David K. Lockett	Director	58
Cecil E. Martin	Director	71
Frederic D. Sewell	Director	78
David W. Sledge	Director	56
Nancy E. Underwood	Director	61

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 President and Chief Executive Officer since 1988. Mr. Allison was elected Chairman of the board of directors in 1997. From 1987 to 1988, Mr. Allison 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 Senior Vice President since 1994, Chief Financial Officer and Treasurer since 1990, our Secretary since 1991 and a director since 1999. 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 serves on the Board of Directors of the University of Mississippi Foundation.

Mark A. Williams was appointed our Chief Operating Officer in May 2012. From 2011 to 2012, he served as Vice President of Operations. From 2007 to 2011, he served as our Engineering and Operations Manager. From 1996 until 2007, Mr. Williams served as our Drilling Manager and as our South Texas District Engineer. Prior to joining Comstock Mr. Williams was a production engineer at Mitchell Energy Corporation and Citation Oil & Gas. Mr. Williams received a B.S. degree in Petroleum Engineering from Texas A&M University in 1984.

Gerry L. Blackshear was named our Vice President of Exploration in May 2012. From 2007 to 2011 Mr. Blackshear served as our Geoscience Manager. Prior to joining us, Mr. Blackshear was a lead geologist at Encana Oil & Gas from 2004 to 2007. Prior to 2004 he worked as a senior geologist for several large independent oil and gas exploration and development companies. Mr. Blackshear received a B.S. degree in Geology from East Texas State University in 1981 and is a Certified Petroleum Geologist.

D. Dale Gillette has been our Vice President of Land and General Counsel since 2006. Prior to joining us, Mr. Gillette practiced law extensively in the energy sector for 33 years, most recently as a partner with Gardere Wynne Sewell LLP, and before that with Locke Liddell & Sapp 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.

Stephen E. Neukom has been our Vice President of Marketing since 1997 and has served as our manager of oil and natural gas marketing since 1996. From 1994 to 1996, Mr. Neukom served as vice president of Comstock Natural Gas, Inc., our former wholly owned gas marketing subsidiary. Prior to joining us, Mr. Neukom was senior vice president of Victoria Gas Corporation from 1987 to 1994. Mr. Neukom received a B.B.A. degree from the University of Texas in 1972.

Daniel K. Presley has been our Vice President of Accounting since 1997 and has been with us since 1989, serving as controller since 1991. 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 was named our Vice President of Reservoir Engineering in May 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.

Richard D. Singer has been our Vice President of Financial Reporting since 2005. Mr. Singer has over 36 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 was named our Vice President of Corporate Development in May 2012. From 2007 to 2011, 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

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. Mr. Lockett, who has over 35 years of experience in the technology industry, is presently considering opportunities to provide consulting services for 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. Mr. Lockett received a B.B.A. degree from Texas A&M University in 1976.

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 serves on the board of directors of Crosstex Energy, Inc. and Crosstex Energy, L.P. and on the Board of Directors and Audit Committee of Garrison Capital, a privately held business development company. Mr. Martin holds a B.B.A. degree from Old Dominion University and is a Certified Public Accountant.

Frederic D. Sewell was first elected as a director in May 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 and 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. Mr. Sewell holds a B.S. Degree in Petroleum Engineering from the University of Texas.

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. He received a B.B.A. degree from Baylor University in 1979.

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. Ms. Underwood holds B.S. and J.D. degrees from Emory University and practiced law at an Atlanta, Georgia based law firm before joining River Hill Development Corporation in 1981. Ms. Underwood currently serves on the Executive Board and Campaign Steering Committee of the Southern Methodist University Dedman School of Law and on the Board of Directors of Texas Health Presbyterian Foundation.

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. Prices for oil remained relatively strong in 2012, but our realized natural gas prices continued to decline in 2012, reaching a thirteen year low of $2.03 per Mcf in the second quarter of 2012. The continued growth in production of natural gas in the United States has increased supply and resulted in high natural gas storage inventories. As a result, natural gas prices continue to face downward pressures.

The prices we receive for our oil and natural gas production and the level of such production will be 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.

If the decline in the price of natural gas that first started in 2008 continues through 2013, the lower 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.

We have entered into certain oil price hedging arrangements on certain of our anticipated sales in 2013. In the future we may enter into additional hedging arrangements in order to reduce our exposure to price risks. Such arrangements would limit our ability to benefit from increases in oil and natural gas prices.

The recent recession could have a material adverse impact on our financial position, results of operations and cash flows.

The oil and gas industry is cyclical and tends to reflect general economic conditions. The United States and other countries have been in a recession which could continue through 2013 and beyond, and the capital markets have experienced significant volatility. The recession has had an adverse impact on demand and pricing for oil and natural gas. A continuation of the recession could have a further negative impact on oil and natural gas prices. Our operating cash flows and profitability will be significantly affected by declining oil and natural gas prices. Further declines in oil and natural gas prices may also impact the value of our oil and gas reserves, which could result in future impairment charges to reduce the carrying value of our oil and gas properties and our marketable securities. Our future access to capital could be limited due to tightening credit markets and volatile capital markets. If our access to capital is limited, development of our assets may be delayed or limited, and we may not be able to execute our growth strategy.

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.

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, Wolfcamp shale, Bone Spring, 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 being drilled by us in 2013 utilize hydraulic fracturing in their completion. We estimate we will incur approximately $178.0 million for hydraulic fracturing services in connection with our 2013 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 will be net of a $25,000 deductible 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 repeal of many tax incentives and deductions that are currently used by independent oil and gas producers. Examples of changes being considered that would impact us are: elimination of the ability to fully deduct intangible drilling costs in the year incurred, repeal of the manufacturing tax deduction for oil and gas companies, increasing the geological and geophysical cost amortization period, and implementation of a fee on non-producing leases located on federal lands. If these proposals are enacted, our current income tax liability will increase, potentially significantly, which would have a negative impact on our cash flow from operating activities. A reduction in operating cash flow could require us to reduce our drilling activities. Since none of these proposals have yet to be included in new legislation, we do not know the ultimate impact they may have on our business.

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

We had $1.3 billion in debt as of December 31, 2012, and our ratio of total debt to total capitalization was approximately 59%.

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 working capital, 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.

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 recent years as the result of higher demand for these services. Costs and delivery times of rigs, equipment and supplies have been substantially greater than they were several years ago. In addition, demand for, and wage rates of, qualified drilling rig crews have escalated due to the higher activity levels. 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.

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 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. 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 the East Texas/North Louisiana, South Texas and West Texas regions, we may pursue acquisitions or properties located in other geographic areas.

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.

Our competitors may use superior technology that we may be unable to afford or which would require costly investment by us in order to compete.

If our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, our competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advances and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. All of these factors may inhibit our ability to acquire additional prospects and compete successfully in the future.

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.

If oil prices decline and natural gas prices remain low or continue to decline, we may be required to 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. Such a reduction in carrying value could impact our borrowing ability and may result in accelerating the repayment date of any outstanding debt.

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, 2012, 38% of our total proved reserves were undeveloped and 8% 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.

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 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 President and Chief Executive Officer, and a limited number of other senior management personnel. Loss of the services of Mr. Allison 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.

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 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 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. 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.

In June 2010 the Bureau of Land Management issued a proposed oil and gas leasing reform. The proposal would require, 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 proposed 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.

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.

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
2011 —	First Quarter	$31.38	$23.68
	Second Quarter	$33.00	$26.14
	Third Quarter	$33.63	$15.40
	Fourth Quarter	$20.21	$13.69
2012 —	First Quarter	$17.79	$11.05
	Second Quarter	$18.54	$12.56
	Third Quarter	$20.46	$14.95
	Fourth Quarter	$21.16	$14.40

As of February 28, 2013, we had 48,303,517 shares of common stock outstanding, which were held by 221 holders of record and approximately 7,900 beneficial owners who maintain their shares in "street name" accounts.

We have never paid cash dividends on our common stock. We presently intend to retain any earnings for the operation and expansion of our business and we do not anticipate paying cash dividends in the foreseeable future. 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. In addition, we are limited under our bank credit facility and by the terms of the indentures for our senior notes from paying or declaring cash dividends.

During the fourth quarter of 2012, we did not repurchase any of our equity securities.

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, 2012 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." In 2008, we divested our interests in offshore operations which were conducted through our subsidiary Bois d'Arc Energy, Inc. ("Bois d'Arc"). Accordingly, we have adjusted the presentation of selected financial data to reflect the offshore operations on a discontinued basis.

Statement of Operations Data:

	Year Ended December 31,				
	2008	2009	2010	2011	2012
	(In thousands, except per share data)				
Revenues:					
Oil and gas sales	$ 563,749	$292,583	$349,141	$434,367	$ 431,923
Gain on sale of oil and gas properties	26,560	213	—	—	24,271
Total revenues	590,309	292,796	349,141	434,367	456,194
Operating expenses:					
Production taxes	20,648	8,643	9,894	3,670	14,021
Gathering and transportation	3,910	8,696	17,256	28,491	27,312
Lease operating[1]	62,172	53,560	53,525	46,552	60,620
Exploration	5,032	907	2,605	10,148	61,449
Depreciation, depletion and amortization	182,179	213,238	213,809	290,776	365,286
General and administrative, net	32,266	39,172	37,200	35,172	33,798
Impairment of oil and gas properties	922	115	224	60,817	25,368
Loss on sale of oil and gas properties	—	—	26,632	57	—
Total operating expenses	307,129	324,331	361,145	475,683	587,854
Income (loss) from operations	283,180	(31,535)	(12,004)	(41,316)	(131,660)
Other income (expenses):					
Gain on sale of marketable securities	—	—	16,529	35,118	26,621
Marketable securities impairment	(162,672)	—	—	—	—
Realized gain from derivatives	—	—	—	—	9,766
Unrealized gain from derivatives	—	—	—	—	11,490
Interest and other income	1,656	378	499	790	944
Interest expense	(25,336)	(16,086)	(29,456)	(42,688)	(64,575)
Total other income (expenses)	(186,352)	(15,708)	(12,428)	(6,780)	(15,754)
Income (loss) from continuing operations before income taxes	96,828	(47,243)	(24,432)	(48,096)	(147,414)
Benefit from (provision for) income taxes	(38,611)	10,772	4,846	14,624	47,354
Income (loss) from continuing operations	58,217	(36,471)	(19,586)	(33,472)	(100,060)
Income (loss) from discontinued operations	193,745[2]	—	—	—	—
Net income (loss)	$ 251,962	$ (36,471)	$ (19,586)	$ (33,472)	$(100,060)
Basic net income (loss) per share:					
Continuing operations	$ 1.27	$ (0.81)	$ (0.43)	$ (0.73)	$ (2.16)
Discontinued operations	4.23	—	—	—	—
	$ 5.50	$ (0.81)	$ (0.43)	$ (0.73)	$ (2.16)
Diluted net income (loss) per share:					
Continuing operations	$ 1.26	$ (0.81)	$ (0.43)	$ (0.73)	$ (2.16)
Discontinued operations	4.20	—	—	—	—
	$ 5.46	$ (0.81)	$ (0.43)	$ (0.73)	$ (2.16)
Weighted average shares outstanding:					
Basic	44,524	45,004	45,561	45,997	46,422
Diluted	44,813	45,004[3]	45,561[3]	45,997[3]	46,422[3]

(1) Includes ad valorem taxes.
(2) Includes gain of $158.1 million, net of income taxes of $85.3 million, from the sale of our offshore operations.
(3) Basic and diluted weighted average shares are the same due to the net loss.

Balance Sheet Data:

	As of December 31,				
	2008	2009	2010	2011	2012
			(In thousands)		
Cash and cash equivalents	$ 6,281	$ 90,472	$ 1,732	$ 8,460	$ 4,471
Property and equipment, net	1,444,715	1,576,287	1,816,248	2,509,845	2,470,053
Total assets	1,577,890	1,858,961	1,964,214	2,639,884	2,567,143
Total debt	210,000	470,836	513,372	1,196,908	1,324,383
Stockholders' equity	1,062,085	1,066,111	1,068,531	1,037,625	933,534

Cash Flow Data:

	Year Ended December 31,				
	2008	2009	2010	2011	2012
			(In thousands)		
Cash flows provided by operating activities from continuing operations	$ 450,533	$ 176,257	$ 311,662	$ 284,904	$ 262,229
Cash flows used for investing activities from continuing operations	(289,194)	(348,777)	(440,473)	(952,086)	(383,720)
Cash flows provided by (used for) financing activities from continuing operations	(452,883)	256,711	40,071	673,910	117,502
Cash flows provided by discontinued operations	292,260	—	—	—	—

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 1,643 producing oil and natural gas wells (914.5 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.

Our future growth will be driven primarily by acquisition, development and exploration activities. In 2012 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 $420.0 million in 2013 for development and exploration activities, which will primarily be focused on oil projects. We plan to drill 85 wells (58.1 net to us) in 2013, of which 75 wells (54.5 net to us) will target oil in our South Texas and West Texas regions and ten will target natural gas in our East Texas / North Louisiana region. 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 $18.0 million as of December 31, 2012.

Results of Operations

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

Our operating data for 2011 and 2012 is summarized below:

	Year Ended December 31, 2011	Year Ended December 31, 2012
Net Production Data:		
Natural gas (MMcf)	90,593	82,490
Oil (MBbls)	838	2,309
Natural gas equivalent (MMcfe)	95,622	96,345
Average Sales Price:		
Oil ($/Bbl)	$95.73	$96.95
Oil including hedging ($/Bbl)(1)	$95.73	$101.18
Natural gas ($/Mcf)	$3.91	$2.52
Average equivalent price ($/Mcfe)	$4.54	$4.48
Average equivalent price including hedging ($/Mcfe)(1)	$4.54	$4.58
Expenses ($ per Mcfe):		
Production taxes	$0.04	$0.15
Gathering and transportation	$0.30	$0.28
Lease operating(2)	$0.48	$0.63
Depreciation, depletion and amortization(3)	$3.00	$3.83

(1) Includes realized gains from derivatives of $9.8 million in 2012.
(2) Includes ad valorem taxes.
(3) Represents depreciation, depletion and amortization of oil and gas properties only.

Oil and gas sales. Our oil and gas sales decreased $2.5 million (1%) in 2012 to $431.9 million from sales of $434.4 million in 2011. Our oil production in 2012 increased by 175% while our natural gas production decreased by 9% from our 2011 production levels. On an equivalent unit basis, our production in 2012 increased by 1% over 2011. Our successful drilling program grew our oil production which offset the decline in natural gas production. Prices realized for oil sales increased by 1% in 2012 as compared to 2011 while the average price we realized for natural gas sales decreased by 36% in 2012 as compared to 2011. Our oil hedging program generated $9.8 million in realized gains in 2012. Including the results of our hedging program, our average oil price in 2012 of $101.18 increased 6% above last year's average price.

Production taxes. Production taxes increased $10.3 million or 282% to $14.0 million in 2012 from $3.7 million in 2011. The increase in 2012 is due to the significant growth in our oil sales during the year. Much of our natural gas sales in 2011 and 2012 qualify for exemption from state production taxes.

Gathering and transportation. Gathering and transportation costs in 2012 decreased $1.2 million (4%) to $27.3 million as compared to $28.5 million in 2011 due to the lower natural gas volumes that we produced in North Louisiana in 2012.

Lease operating expenses. Our lease operating expenses, including ad valorem taxes, of $60.6 million in 2012 were $14.0 million or 30% higher than our operating expenses of $46.6 million in 2011. Our lease operating expense per Mcfe produced increased by 29% to $1.06 per Mcfe in 2012 as compared to $0.82 per Mcfe in 2011. The increase mainly reflects our growing oil production. Our oil wells are typically more costly to operate than our natural gas wells. Oil production comprised 14% of our total production in 2012 as compared to 5% in 2011.

Exploration expense. We incurred $61.4 million in exploration expense in 2012 as compared to $10.1 million in 2011. Exploration expense in 2012 consisted of $61.3 million of impairments of unevaluated leasehold costs and $0.1 million for the acquisition of seismic data. Our 2011 exploration cost consisted of $9.8 million of impairments of unevaluated leasehold costs and $0.3 million for the acquisition of seismic data.

Depreciation, depletion and amortization expense ("DD&A"). DD&A of $365.3 million was an increase of $74.5 million (26%) over DD&A of $290.8 million in 2011. Our DD&A rate per Mcfe produced averaged $3.83 in 2012 as compared to $3.00 for 2011. The increase in DD&A primarily resulted from increased development costs per Mcfe associated with the oil wells drilled in 2012, and the substantial decline in our proved natural gas reserves due to the low natural gas prices in 2012.

Impairment of oil and gas properties. We recorded impairments to our oil and gas properties of $25.4 million and $60.8 million in 2012 and 2011, respectively. These impairments relate to fields where an impairment was indicated based on estimated future cash flows from the properties.

General and administrative expenses. General and administrative expense of $33.8 million for 2012 was 4% lower than general and administrative expense of $35.2 million for 2011. The decrease primarily reflects lower stock based compensation in 2012. Stock based compensation decreased by $1.3 million to $13.7 million in 2012 as compared to $15.0 million in 2011.

Interest expense. Interest expense increased $21.9 million (51%) to $64.6 million in 2012 from interest expense of $42.7 million in 2011. The increase was primarily related to the increase in outstanding debt during 2012 including the issuance of $300.0 million in senior notes in June 2012. Average borrowings under our bank credit facility increased to $482.7 million in 2012 as compared to $121.4 million for 2011. The average interest rate on the outstanding borrowings under our credit facility of 3.0% in 2012 was higher than the interest rate of 2.2% in 2011. We capitalized interest of $20.9 million and $13.2 million in 2012 and 2011, respectively, which amounts reduced interest expense.

Income taxes. The benefit from income taxes increased in 2012 to $47.4 million from $14.6 million in 2011 due to the higher net loss in 2012. Our effective tax rate of 32% in 2012 and 30% in 2011 differed from the federal income tax rate of 35% primarily due to the effect of nondeductible compensation and state income taxes.

Net loss. We reported a loss of $100.1 million for 2012 as compared to a loss of $33.5 million for 2011. The loss per share for 2012 was $2.16 on weighted average shares outstanding of 46.4 million as compared to a loss per share of $0.73 for 2011 on weighted average shares outstanding of 46.0 million. The loss in 2012 was primarily related to the increase in DD&A expense and 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) and sales of marketable securities of $26.6 million ($17.3 million after income taxes) and also unrealized gains on our oil derivatives of $11.5 million ($7.5 million after tax). The loss in 2011 was primarily related to the impairments to proved and unproved properties in 2011 of $70.6 million ($45.9 million after income taxes) offset in part by gains on sales of marketable securities of $35.1 million ($22.8 million after income taxes).

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

Our operating data for 2010 and 2011 is summarized below:

	Year Ended December 31,	
	2010	**2011**
Net Production Data:		
Natural gas (MMcf)	68,973	90,593
Oil (MBbls)	715	838
Natural gas equivalent (MMcfe)	73,262	95,622
Average Sales Price:		
Oil ($/Bbl)	$68.35	$95.73
Natural gas ($/Mcf)	$4.35	$3.91
Average equivalent price ($/Mcfe)	$4.77	$4.54
Expenses ($ per Mcfe):		
Production taxes	$0.14	$0.04
Gathering and transportation	$0.24	$0.30
Lease operating(1)	$0.72	$0.48
Depreciation, depletion and amortization(2)	$2.91	$3.00

(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 $85.3 million (24%) in 2011 to $434.4 million from sales of $349.1 million in 2010. This increase resulted from higher natural gas production and higher prices realized for oil sales in 2011. Our production in 2011 increased by 31% over 2010's production as production from new wells drilled in South Texas targeting the Eagle Ford shale and in North Louisiana targeting the Haynesville/Bossier shales exceeded declines from our existing producing properties. Prices realized for oil sales increased by 40% in 2011 as compared to 2010 while the average price we realized for natural gas sales decreased by 10% in 2011 as compared to 2010. During 2011 we drilled 87 wells (47.7 net to us), 62 of which were Haynesville or Bossier shale horizontal wells and 20 of which were Eagle Ford shale horizontal wells. At December 31, 2011 we had 23 wells (15.5 net to us) that were drilled in 2011 awaiting completion.

Production taxes. Production taxes decreased $6.2 million (63%) to $3.7 million in 2011 from $9.9 million in 2010. Our Haynesville and Bossier shale wells, which comprise a large percentage of our production, qualify for exemption from certain state production taxes. The exempt wells together with the lower natural gas prices account for the decrease.

Gathering and transportation. Gathering and transportation costs in 2011 increased $11.2 million (65%) to $28.5 million as compared to $17.3 million in 2010 due to the transportation costs related to the higher production from our Haynesville/Bossier shale properties in North Louisiana.

Lease operating expenses. Our lease operating expenses, including ad valorem taxes, of $46.6 million in 2011 were $6.9 million or 13% lower than our operating expenses of $53.5 million in 2010. Our lease operating expense per Mcfe produced decreased by 33% to $0.48 per Mcfe in 2011 as compared to $0.72 per Mcfe in 2010. The decreases in lease operating expenses are primarily due to the sale of our higher operating cost properties in Mississippi in 2010.

Exploration expense. We incurred $10.1 million in exploration expense in 2011 as compared to $2.6 million in 2010. Exploration expense in 2011 consisted of $9.8 million of impairments of unevaluated leasehold costs and $0.3 million for the acquisition of seismic data. Our 2010 exploration cost primarily related to costs incurred for the acquisition of seismic data.

DD&A. DD&A of $290.8 million increased $77.0 million (36%) as compared to DD&A of $213.8 million in 2010. Our DD&A rate per Mcfe produced averaged $3.00 in 2011 as compared to $2.91 for 2010. The increase in DD&A primarily resulted from our 31% growth in production in 2011.

Impairment of oil and gas properties. We recorded impairments to our oil and gas properties of $60.8 million and $0.2 million in 2011 and 2010, respectively. These impairments relate to fields where an impairment was indicated based on estimated future cash flows from the properties. The 2011 impairment is a result of lower anticipated natural gas prices.

General and administrative expenses. General and administrative expense of $35.2 million for 2011 was 5% lower than general and administrative expense of $37.2 million for 2010. The decrease primarily reflects our lower personnel costs in 2011. Stock based compensation decreased by $2.4 million to $15.0 million in 2011 as compared to $17.4 million in 2010.

Interest expense. Interest expense increased $13.2 million (45%) to $42.7 million in 2011 from interest expense of $29.5 million in 2010. The increase was primarily related to the increase in outstanding debt during 2011 including the issuance of $300.0 million in senior notes in March 2011. Average borrowings under our bank credit facility increased to $121.4 million in 2011 as compared to $70.0 million for 2010. The average interest rate on the outstanding borrowings under our credit facility of 2.2% in 2011 was unchanged from 2010. We capitalized interest of $13.2 million and $13.0 million in 2011 and 2010, respectively, which reduced interest expense. Interest expense in 2011 includes $1.1 million for the early retirement of our 6⅞% senior notes which were due in March 2012.

Income taxes. The benefit from income taxes increased in 2011 to $14.6 million from $4.8 million in 2010 due to the higher net loss in 2011. Our effective tax rate of 30% in 2011 and 20% in 2010 differed from the federal income tax rate of 35% primarily due to the effect of nondeductible compensation and state income taxes.

Net loss. We reported a loss of $33.5 million for 2011 as compared to a loss of $19.6 million for 2010. The loss per share for 2011 was $0.73 on weighted average shares outstanding of 46.0 million as compared to a loss per share of $0.43 for 2010 on weighted average shares outstanding of 45.6 million. The loss in 2011 was primarily related to the impairments to proved and unproved properties in 2011 of $70.6 million ($45.9 million after income taxes) offset in part by gains on sales of marketable securities of $35.1 million ($22.8 million after income taxes). The loss in 2010 was primarily related to the loss on our divestiture of oil and gas properties in Mississippi of $25.8 million ($16.8 million after income taxes).

Liquidity and Capital Resources

Funding for our activities has historically been provided by our operating cash flow, debt or equity financings and asset dispositions. Our net cash provided by operating activities in 2012 totaled $262.2 million. Our other primary sources of funds in 2012 included $285.9 million of net proceeds from a senior notes offering and $204.4 million from sales of assets. In 2011, our net cash flow provided by operating activities totaled $284.9 million, while our other primary sources of funds included $293.4 million of net proceeds from a senior notes offering, $555.0 million of borrowings under our bank credit facility and $53.4 million of proceeds from sales of marketable securities. In 2010, our net cash flow provided by operating activities from continuing operations totaled $311.7 million. Our other primary source of funds in 2010 was $96.9 million of net proceeds from sales of oil and gas properties and marketable securities and $45.0 million of borrowings under our bank credit facility.

Our cash flow from operating activities in 2012 of $262.2 million represented a decrease of $22.7 million from our cash from operating activities of $284.9 million in 2011. Cash flow from operations excluding changes in working capital accounts of $261.3 million in 2012 decreased by $36.3 million or 12% as compared to $297.6 million in 2011 due to the lower revenues we received because of the decline in natural gas prices during 2012 which was partially offset by higher oil production. Our cash flow from operating activities in 2011 decreased by $26.8 million to $284.9 million as compared to $311.7 million in 2010 primarily due to changes in working capital at the end of 2011.

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 2012 our capital expenditures of $550.6 million decreased by $497.1 million as compared to 2011 capital expenditures of $1.0 billion due primarily to the acquisitions of proved and unproved properties we made in 2011. Capital expenditures in 2012 include $70.9 million spent to complete wells drilled in 2011. In 2011, our capital expenditures of $1.0 billion increased by $502.0 million as compared to 2010 capital expenditures of $545.7 million, mainly due to the acquisition of oil and gas properties in 2011.

Our annual capital expenditure activity is summarized in the following table:

	Year Ended December 31,		
	2010	2011	2012
		(In thousands)	
Exploration and development:			
Acquisitions of proved oil and gas properties	$ —	$ 218,661	$ 3,235
Acquisitions of unproved oil and gas properties	134,728	255,699	29,677
Developmental leasehold costs	3,208	798	2,157
Development drilling	305,410	483,816	504,482
Exploratory drilling	85,140	82,028	5,317
Workovers and recompletions	5,648	6,516	3,728
	534,134	1,047,518	548,596(1)
Other	11,516	225	1,984
Total	$ 545,650	$ 1,047,743	$550,580(1)

(1) Excludes reimbursements from joint venture partner for preformation well costs of $23.8 million.

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 $445.0 million for development and exploration projects and lease acquisitions in 2013, which will be funded primarily by cash flows from operating activities, proceeds from asset sales and borrowings under our credit facility. Our operating cash flow and, therefore, our capital expenditures are highly dependent on oil and natural gas prices and, in particular, natural gas prices.

We do not have a specific acquisition budget for 2013 because the timing and size of acquisitions are unpredictable. Smaller acquisitions will generally be funded from operating cash flow. With respect to significant acquisitions, 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 $850.0 million 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 30, 2015.

Indebtedness under the bank credit facility is secured by all of our and our wholly owned subsidiaries' 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 natural gas properties. As of December 31, 2012, the borrowing base was $570.0 million, $130.0 million of which was available. The borrowing base may be affected by the performance of our properties and changes in oil and natural gas prices. 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 1.75% to 2.75% 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 0.75% to 1.75%. A commitment fee of 0.5% is payable on the unused borrowing base. The bank credit facility contains covenants that, among other things, restrict the payment of cash dividends in excess of $50.0 million, limit the amount of consolidated debt that we may incur and limit our ability to make certain loans and investments. The only financial covenants are the maintenance of a ratio of current assets, including the availability under the bank credit facility, to current liabilities and maintenance of a leverage ratio. We were in compliance with these covenants as of December 31, 2012.

We have $300.0 million of 8⅜% senior notes outstanding which are due October 15, 2017, $300.0 million of 7¾% senior notes outstanding which are due April 1, 2019 and $300.0 million of 9½% senior notes outstanding which are due June 15, 2020. All senior notes have semi-annual interest payment obligations, are unsecured obligations and are guaranteed by all of our material subsidiaries.

On January 1, 2011, we had $172.0 million in principal amount of 6⅞% senior notes outstanding due in 2012 (the "2012 Notes"). We redeemed all of the 2012 Notes in 2011 for $172.4 million. The early extinguishment of the 2012 Notes resulted in a loss of $1.1 million. This loss is comprised of the premium paid for the redemption of the 2012 Notes, the costs incurred related to the tender offer, and the write-off of unamortized debt issuance costs related to the 2012 Notes.

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 plans or assumptions change or if our assumptions prove to be inaccurate, we may be required to seek additional capital. 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:

	2013	2014	2015	2016	2017	Thereafter	Total
				(In thousands)			
Bank credit facility	$ —	$ —	$ 440,000	$ —	$ —	$ —	$ 440,000
8⅜% senior notes	—	—	—	—	300,000	—	300,000
7¾% senior notes	—	—	—	—	—	300,000	300,000
9½% senior notes	—	—	—	—	—	300,000	300,000
Interest on debt	88,843	88,843	87,846	76,875	71,641	99,126	513,174
Operating leases	1,983	2,012	2,038	1,994	2,021	6,740	16,788
Natural gas transportation agreements	9,416	6,840	4,074	1,696	1,277	1,968	25,271
Contracted drilling services	31,149	20,112	14,030	—	—	—	65,291
	$ 131,391	$ 117,807	$ 547,988	$ 80,565	$ 374,939	$ 707,834	$ 1,960,524

Future interest costs are based upon the effective interest rates of our outstanding senior notes and the December 31, 2012 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 2017. We record a separate liability for the fair value of these asset retirement obligations, which totaled $18.0 million as of December 31, 2012.

Federal Taxation

At December 31, 2012 we had U.S. federal net operating loss carryforwards of approximately $192.3 million and Louisiana state net operating loss carryforwards of approximately $536.4 million. Utilization of $36.9 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 and a valuation allowance of $23.0 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 $288.0 million 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 carryforward period.

Our federal income tax returns for the years subsequent to December 31, 2007 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, 2007. We currently believe that our significant filing positions are highly certain and that all of our 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 reserve 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 $463.0 million may require impairment in the future. The amount of such 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.

Asset retirement obligations. We have obligations to remove tangible equipment and facilities and to restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of any surface equipment used in production operations. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

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.

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 2012, 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 $0.6 million and a $0.10 change in the price per Mcf of natural gas would have changed our cash flow by approximately $8.0 million.

We have entered into oil price swap agreements covering 2.2 million barrels of our expected 2013 oil production which fix the NYMEX West Texas Intermediate (“WTI”) price at $98.67 per barrel. As of December 31, 2012, our outstanding oil swap agreements had a fair value of $11.7 million. The change in the fair value of our oil swaps that would result from a 10% change in commodities prices at December 31, 2012 would be $12.9 million. Such a change in fair value could be a gain or a loss depending on whether prices increase or decrease.

Interest Rates

At December 31, 2012, we had $1.3 billion of long-term debt. Of this amount, $300.0 million bears interest at 8⅜%, $300.0 million bears interest at a fixed rate of 7¾%, and $300.0 million bears interest at 9½%. The fair market value of our fixed rate debt as of December 31, 2012 was $942.0 million based on the market price of approximately 107% of the face amount. At December 31, 2012, we had $440.0 million outstanding under our bank credit facility, which is subject to variable rates of interest. Borrowings under the bank credit facility bear interest at a fluctuating rate that is tied to LIBOR or the 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, 2012, a 100 basis point change in interest rates would change our annual interest expense on our variable rate debt by approximately $4.4 million. We had no interest rate derivatives outstanding during 2012 or at December 31, 2012.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

Our consolidated financial statements are included on pages F-1 to F-34 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, 2012. 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. As described below, management has identified a material weakness in our internal control over financial reporting, which is an integral component of our disclosure controls and procedures. As a result of this material weakness, we concluded that our disclosure controls and procedures were not effective as of December 31, 2012.

As part of the preparation of our financial statements for the year ended December 31, 2012, we undertook a review of our accounting for oil price derivative financial instruments. We use derivative financial instruments as a means of reducing our exposure to fluctuating commodity prices for oil and natural gas. During the quarters ended March 31, 2012, June 30, 2012 and September 30, 2012, we applied cash flow hedge accounting for our derivative financial instruments as provided for in Accounting Standards Codification Topic 815, *Derivatives and Hedging* ("ASC 815"). Accordingly, we included changes from period to period in the fair value of derivative financial instruments classified as cash flow hedges as increases or decreases to Accumulated Other Comprehensive Income ("AOCI"). In order to qualify for cash flow hedge accounting treatment, specific standards and contemporaneous documentation requirements must be met. We believed that we had met those requirements and that our hedge accounting treatment was permitted under ASC 815. However, in connection with preparing our 2012 Annual Report, and based upon discussions with Ernst & Young, LLP, our independent public accounting firm, we determined that our hedge documentation was not completed in a timely manner, and as a result our commodity derivative financial instruments did not qualify for hedge accounting treatment under ASC 815.

In February 2013 the Audit Committee of our Board of Directors concluded that our previously issued consolidated financial statements contained a material error with respect to accounting for derivative financial instruments, and should be restated. Accordingly, we are restating the consolidated financial statements for each of the three months ended March 31, 2012, June 30, 2012 and September 30, 2012 to reflect the change in the fair value of our derivative financial instruments, as a separate component of other income (expenses) in our statements of operations rather than as a component of AOCI. We are also reclassifying the realized gains and losses from our derivative financial instruments as a component of other income (expenses) rather than as a component of oil and gas sales.

We have concluded, based on the circumstances involving the restatement of the financial statements for the three months ended March 31, 2012, June 30, 2012 and September 30, 2012, that a material weakness in internal control over financial reporting existed at December 31, 2012 with respect to the design of our controls over the timeliness of documentation required to designate our derivative financial instruments as cash flow hedges in accordance with ASC 815.

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 (COSO). 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.

A "material weakness" is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness relating to the accounting for derivative financial instruments resulted in misstatements of the aforementioned accounts and disclosures that resulted in material misstatements in our interim financial statements. Because of this material weakness, management has concluded that we did not maintain effective internal control over financial reporting as of December 31, 2012. Our internal control over financial reporting as of December 31, 2012, has been audited by Ernst & Young, LLP, an independent registered public accounting firm, as stated in their report included herein.

Plans for Remediation of the Material Weakness. In response to the material weakness, we did not account for derivative financial instruments as cash flow hedges under ASC 815 in the fourth quarter of 2012 and are recognizing realized gains and losses and changes in the fair value of our derivative financial instruments in current earnings as separate components of other income (losses). We are developing a remediation plan to address the material weakness described above. The remediation plan will include designing and implementing a control framework over entering into derivative financial instruments to ensure that our accounting for derivative financial instruments which was affected by the material control weakness is appropriate. The remediation plan will involve key leaders from across the organization, including the Chief Executive Officer, the Chief Financial Officer and our internal auditors. We will report quarterly and as needed to the Audit Committee of our Board of Directors on the progress made toward completion of the remediation plan.

We continue to monitor the effectiveness of our internal control over financial reporting with respect to our accounting for derivatives which was affected by the material weakness described above. We will perform additional procedures prescribed by management, including the use of manual mitigating control procedures, and we will employ any additional tools and resources deemed necessary to ensure that our financial statements continue to be fairly stated in all material respects.

Changes in Internal Control over Financial Reporting. Except as noted above with respect to our discontinuation of cash flow hedge accounting in the fourth quarter of 2012, there were no changes in our internal control over financial reporting during the quarter ended December 31, 2012 that materially affected or are reasonably likely to materially affect our internal control over financial reporting. However, as described above under "Plans for Remediation of Material Weaknesses," we have initiated a process to improve the control environment and to remedy the control weakness described herein.

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, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management's assessment. Management has identified a material weakness in controls related to the Company's accounting for derivative financial instruments at December 31, 2012. 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, 2011 and 2012, and the related consolidated statements of operations, comprehensive loss, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2012. This material weakness was considered in determining the nature, timing and extent of audit tests applied in our audit of the 2012 financial statements and this report does not affect our report dated February 28, 2013, which expressed an unqualified opinion on those financial statements.

In our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, Comstock Resources, Inc. and subsidiaries have not maintained effective internal control over financial reporting as of December 31, 2012, based on the COSO criteria.

Dallas, Texas
February 28, 2013

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, 2012.

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 2013 annual meeting, which will be filed with the SEC within 120 days of December 31, 2012, 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, 2012.

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, 2012:

	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	845,695(1)	$38.36(2)	1,607,372

(1) Includes performance share unit awards equivalent to 688,545 shares that would be issuable based upon achievement of the maximum awards under the terms of the performance share unit awards.
(2) Price reflects the grant date fair value of 157,150 stock options that are outstanding; excludes performance share units for which the price cannot be determined until the performance targets are met.

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, 2012.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTORS 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, 2012.

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, 2012.

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-34 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).

Exhibit No.	Description
3.3	Bylaws (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated November 8, 2011).
4.1	Indenture dated February 25, 2004 between Comstock, 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	Indenture dated October 9, 2009 between Comstock, the guarantors and The Bank of New York Mellon Trust Company, N.A., Trustee for debt securities (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated October 9, 2009).
4.3	First Supplemental Indenture, dated October 9, 2009 between Comstock, the guarantors and The Bank of New York Mellon Trust Company, N.A., Trustee for the 8⅜% Senior Notes due 2017 (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated October 9, 2009).
4.4	Second Supplemental Indenture dated April 30, 2010 between Comstock, the guarantors and The Bank of New York Mellon Trust Company, N.A., Trustee for the 8⅜ Senior Notes due 2017 (incorporated by reference to our Annual Report on Form 10-K for the year ended December 31, 2010).
4.5	Third Supplemental Indenture dated March 14, 2011 between Comstock, 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).
4.6	Fourth Supplemental Indenture dated June 5, 2012 between Comstock, 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#	Employment Agreement dated December 22, 2008 by and between Comstock and M. Jay Allison (incorporated by reference to Exhibit 99.1 to our Current Report on Form 8-K dated December 22, 2008).
10.2#	Employment Agreement dated December 22, 2008 by and between Comstock and Roland O. Burns (incorporated by reference to Exhibit 99.2 to our Current Report on Form 8-K dated December 22, 2008).
10.3#	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).
10.4*#	First Amendment to the Comstock Resources, Inc. 2009 Long-term Incentive Plan.
10.5#	Form of Restricted Stock Agreement under 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, 2009).
10.6*#	Form of Performance Share Unit Agreement under the Comstock Resources, Inc. 2009 Long-term Incentive Plan.
10.7	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).
10.8	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).

Exhibit No.	Description
10.9	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).
10.10	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).
10.11	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).
10.12	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).
10.13	Third Amended and Restated Credit Agreement, dated November 30, 2010, among Comstock Resources, Inc., as the borrower, the lenders from time to time thereto, Bank of Montreal, as administrative agent and issuing bank, Bank of America, N.A., as syndication agent and Comerica, JP Morgan Chase Bank, N.A., and Union Bank, N.A., as co-documentation agents (incorporated by reference to Exhibit 10.10 to our Annual Report on Form 10-K for the year ended December 31, 2010).
10.14	Assignment and First Amendment to Third Amended and Restated Credit Agreement dated October 31, 2011 (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2011).
10.15	Second Amendment and Waiver to Third Amended and Restated Credit Agreement, dated December 29, 2011, among Comstock Resources, Inc., as the borrower, the lenders from time to time thereto, and Bank of Montreal, as administrative agent (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated December 29, 2011).
10.16	Third Amendment to Third Amended and Restated Credit Agreement, dated October 29, 2012, among Comstock Resources, Inc., as the borrower, the lenders from time to time thereto, and Bank of Montreal, as administrative agent (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).
10.17*	Fourth Amendment to Third Amended and Restated Credit Agreement dated February 8, 2013, among Comstock Resources, Inc., as the borrower, the lenders from time to time thereto, and Bank of Montreal, as administrative agent.
10.18	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).
10.19	Purchase and Sale Agreement dated December 5, 2011 among Eagle Oil & Gas Co., certain other sellers and Comstock Oil & Gas, LP (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated December 5, 2011).
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.

Exhibit No.	Description
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, 2012.
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
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 28, 2013

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	President, Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)	February 28, 2013
/s/ ROLAND O. BURNS Roland O. Burns	Senior Vice President, Chief Financial Officer, Secretary, Treasurer and Director (Principal Financial and Accounting Officer)	February 28, 2013
/s/ DAVID K. LOCKETT David K. Lockett	Director	February 28, 2013
/s/ CECIL E. MARTIN, JR. Cecil E. Martin, Jr.	Director	February 28, 2013
/s/ FREDERIC D. SEWELL Frederic D. Sewell	Director	February 28, 2013
/s/ DAVID W. SLEDGE David W. Sledge	Director	February 28, 2013
/s/ NANCY E. UNDERWOOD Nancy E. Underwood	Director	February 28, 2013

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, 2011 and 2012, and the related consolidated statements of operations, comprehensive loss, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2012. 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, 2011 and 2012, and the consolidated results of their operations and cash flows for each of the three years in the period ended December 31, 2012, 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), the effectiveness of Comstock Resources, Inc.'s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2013 expressed an adverse opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 28, 2013

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
As of December 31, 2011 and 2012

	December 31, 2011	December 31, 2012
	(In thousands)	
ASSETS		
Cash and Cash Equivalents	$ 8,460	$ 4,471
Accounts Receivable:		
Oil and gas sales	47,082	36,150
Joint interest operations	6,651	5,608
Marketable Securities	47,642	12,312
Derivative Financial Instruments	459	11,651
Other Current Assets	2,796	6,954
Total current assets	113,090	77,146
Property and Equipment:		
Unevaluated oil and gas properties	369,096	263,652
Oil and gas properties, successful efforts method	3,476,146	3,779,716
Other	18,062	19,301
Accumulated depreciation, depletion and amortization	(1,353,459)	(1,592,616)
Net property and equipment	2,509,845	2,470,053
Other Assets	16,949	19,944
	$ 2,639,884	$ 2,567,143
LIABILITIES AND STOCKHOLDERS' EQUITY		
Accounts Payable	$ 94,041	$ 86,346
Deferred Income Taxes Payable	7,664	5,340
Accrued Expenses	85,502	47,372
Total current liabilities	187,207	139,058
Long-term Debt	1,196,908	1,324,383
Deferred Income Taxes Payable	201,705	149,901
Reserve for Future Abandonment Costs	13,997	17,994
Other Non-Current Liabilities	2,442	2,273
Total liabilities	1,602,259	1,633,609
Commitments and Contingencies		
Stockholders' Equity:		
Common stock—$0.50 par, 75,000,000 shares authorized, 48,125,296 and 48,408,734 shares issued and outstanding at December 31, 2011 and 2012, respectively	24,063	24,204
Additional paid-in capital	468,709	480,595
Accumulated other comprehensive income	20,476	4,418
Retained earnings	524,377	424,317
Total stockholders' equity	1,037,625	933,534
	$ 2,639,884	$ 2,567,143

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, 2010, 2011 and 2012

	2010	2011	2012
	(In thousands, except per share amounts)		
Oil and gas sales	$ 349,141	$ 434,367	$ 431,923
Gain on sale of oil and gas properties	—	—	24,271
Total revenues	349,141	434,367	456,194
Operating expenses:			
Production taxes	9,894	3,670	14,021
Gathering and transportation	17,256	28,491	27,312
Lease operating	53,525	46,552	60,620
Exploration	2,605	10,148	61,449
Depreciation, depletion and amortization	213,809	290,776	365,286
General and administrative, net	37,200	35,172	33,798
Impairment of oil and gas properties	224	60,817	25,368
Loss on sale of oil and gas properties	26,632	57	—
Total operating expenses	361,145	475,683	587,854
Operating loss	(12,004)	(41,316)	(131,660)
Other income (expenses):			
Gain on sale of marketable securities	16,529	35,118	26,621
Realized gain from derivatives	—	—	9,766
Unrealized gain from derivatives	—	—	11,490
Other income	499	790	944
Interest expense	(29,456)	(42,688)	(64,575)
Total other income (expenses)	(12,428)	(6,780)	(15,754)
Loss before income taxes	(24,432)	(48,096)	(147,414)
Benefit from income taxes	4,846	14,624	47,354
Net loss	$ (19,586)	$ (33,472)	$(100,060)
Net loss per share:			
Basic	$ (0.43)	$ (0.73)	$ (2.16)
Diluted	$ (0.43)	$ (0.73)	$ (2.16)
Weighted average shares outstanding:			
Basic	45,561	45,997	46,422
Diluted	45,561	45,997	46,422

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
For the Years Ended December 31, 2010, 2011 and 2012

	2010	2011	2012
		(In thousands)	
Net loss	$ (19,586)	$ (33,472)	$(100,060)
Unrealized hedging gains, net of provision for (benefit from) income taxes of $—, $161 and $(161)	—	298	(298)
Net change in unrealized gains and losses on marketable securities, net of benefit from (provision for) income taxes of ($923), $6,543 and $8,487	1,711	(12,152)	(15,760)
Other comprehensive income (loss)	1,711	(11,854)	(16,058)
Comprehensive loss	$ (17,875)	$ (45,326)	$(116,118)

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, 2010, 2011 and 2012

	Common Shares	Common Stock-Par Value	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total
			(In thousands)			
Balance at December 31, 2009	47,104	$ 23,552	$ 434,505	$ 577,435	$ 30,619	$ 1,066,111
Exercise of stock options	184	92	1,335	—	—	1,427
Stock-based compensation	418	209	17,168	—	—	17,377
Excess income taxes from stock-based compensation	—	—	1,491	—	—	1,491
Net loss	—	—	—	(19,586)	—	(19,586)
Other comprehensive income	—	—	—	—	1,711	1,711
Balance at December 31, 2010	47,706	23,853	454,499	557,849	32,330	1,068,531
Stock-based compensation	419	210	14,822	—	—	15,032
Excess income taxes from stock-based compensation	—	—	(612)	—	—	(612)
Net loss	—	—	—	(33,472)	—	(33,472)
Other comprehensive loss	—	—	—	—	(11,854)	(11,854)
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

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, 2010, 2011 and 2012

	2010	2011	2012
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (19,586)	$ (33,472)	$ (100,060)
Adjustments to reconcile net loss to net cash provided by operating activities:			
(Gain) loss on sale of assets	10,103	(35,061)	(50,892)
Deferred income taxes	(4,617)	(14,652)	(47,192)
Dry hole costs and leasehold impairments	—	9,819	61,300
Impairment of oil and gas properties	224	60,817	25,368
Depreciation, depletion and amortization	213,809	290,776	365,286
Unrealized gains from derivatives	—	—	(11,490)
Debt issuance cost and discount amortization	2,436	4,300	5,277
Stock-based compensation	17,377	15,032	13,728
Excess income taxes from stock-based compensation	(1,491)	612	1,701
Decrease (increase) in accounts receivable	(4,432)	(9,046)	11,975
Decrease (increase) in other current assets	48,070	3,311	(4,309)
Increase (decrease) in accounts payable and accrued expenses	49,769	(7,532)	(8,463)
Net cash provided by operating activities	311,662	284,904	262,229
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(537,400)	(1,005,503)	(588,111)
Proceeds from sales of oil and gas properties	66,428	—	166,686
Proceeds from sales of marketable securities	30,499	53,417	37,705
Net cash used for investing activities	(440,473)	(952,086)	(383,720)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings	110,000	970,000	515,912
Principal payments on debt	(68,000)	(287,000)	(390,000)
Debt issuance costs	(4,847)	(8,478)	(6,709)
Proceeds from issuance of common stock	1,427	—	—
Excess income taxes from stock-based compensation	1,491	(612)	(1,701)
Net cash provided by financing activities	40,071	673,910	117,502
Net increase (decrease) in cash and cash equivalents	(88,740)	6,728	(3,989)
Cash and cash equivalents, beginning of the year	90,472	1,732	8,460
Cash and cash equivalents, end of the year	$ 1,732	$ 8,460	$ 4,471

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. 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. is 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 and Louisiana. The consolidated financial statements include the accounts of Comstock Resources, Inc. and its wholly owned or controlled subsidiaries (collectively, "Comstock" or the "Company"). During 2011 and 2012 the consolidated financial statements also include the accounts of a variable interest entity where the Company was the primary beneficiary of the arrangements. 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 to conform to the current presentation.

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.

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 December 31, 2011 and 2012, the Company owned 1,806,000 and 600,000 shares, respectively, of Stone Energy Corporation common stock which was reflected in the consolidated balance sheets as marketable securities. As of December 31, 2011 and 2012, the cost basis of the marketable securities was $16.6 million and $5.5 million, respectively. As of December 31, 2011 and 2012, the estimated fair value of the marketable securities was $47.6 million and $12.3 million, respectively, after recognizing unrealized gain after income taxes of $20.2 million and $4.4 million, respectively. The Company does not exert influence over the operating and financial policies of Stone, and has classified its investment in these shares as an available-for-sale security in the consolidated balance sheets. Available-for-sale securities are accounted for at fair value, with any unrealized gains and unrealized losses not determined to be other than temporary reported in the consolidated balance sheet within accumulated other comprehensive income as a separate component of stockholders' equity. The Company utilizes the specific identification method to determine the cost of any securities sold. During 2010, 2011 and 2012 the Company sold 1,520,000, 1,991,000 and 1,206,000 shares of Stone common stock for proceeds of $30.5 million, $53.4 million and $37.7 million, respectively. Comstock realized gains before income taxes of $16.5 million, $35.1 million and $26.6 million on these sales during 2010, 2011 and 2012, respectively. The Company reviews its available-for-sale securities to determine whether a decline in fair value below the respective cost basis is other than temporary. Unrealized losses are charged against net earnings when a decline in fair value is determined to be other than temporary.

Other Current Assets

Other current assets at December 31, 2011 and 2012 consist of the following:

	As of December 31,	
	2011	2012
	(In thousands)	
Pipe and oil field equipment inventory	$2,314	$1,922
Production tax refunds receivable	—	1,830
Derivative settlements receivable	—	1,693
Drilling advances	—	1,160
Prepaid expenses	397	300
Other	85	49
	$2,796	$6,954

Fair Value Measurements

The Company holds or has held certain items that are required to be measured at fair value. These include cash equivalents held in bank accounts, marketable securities 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 and marketable securities valuation are based on Level 1 measurements. The Company's oil and natural gas 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 are readily available in public markets and, accordingly, the valuation of these swap agreements was categorized as a Level 2 measurement.

The following table summarizes financial assets accounted for at fair value as of December 31, 2012:

	Carrying Value Measured at Fair Value at December 31, 2012	Level 1	Level 2
	(In thousands)		
Assets measured at fair value on a recurring basis:			
Cash held in bank accounts	$ 4,471	$ 4,471	$ —
Marketable securities	12,312	12,312	—
Derivative financial instruments	11,651	—	11,651
Total assets	$28,434	$16,783	$11,651

As of December 31, 2012 the Company had oil price swap agreements for 2,160,000 barrels of oil to be produced in 2013 with a fair value of $11.7 million. The Company has recognized an asset for this amount, and has recognized corresponding unrealized gain which is included in other income (expenses) during 2012. At December 31, 2011 the Company had oil price swap agreements for 1,440,000 barrels of oil to be produced in 2012 with a fair value of $0.5 million. The Company recognized a current asset for this amount, and recognized an unrealized gain of $0.3 million, net of income taxes of $0.2 million, which was included in other comprehensive income.

The following table summarizes the changes in the fair values of derivative financial instruments, which are Level 2 liabilities, for the years ended December 31, 2010, 2011 and 2012:

	2010	2011	2012
		(In thousands)	
Balance beginning of period	$ —	$ —	$ 459
Purchases and settlements (net)	—	—	(9,766)
Total realized or unrealized gains:			
Realized gains included in earnings	—	—	9,766
Unrealized gains included in earnings	—	—	11,651
Unrealized gains included in other comprehensive income	—	459	(459)
Balance end of period	$ —	$ 459	$ 11,651

The following table presents the carrying amounts and estimated fair value of the Company's other financial instruments as of December 31, 2011 and 2012:

	2011		2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In thousands)		
Long-term debt, including current portion	$1,196,908	$1,167,000	$1,324,383	$1,382,000

The fair market value of the Company's fixed rate debt was based on the market prices as of December 31, 2011 and 2012, a Level 1 measurement. The fair value of the floating rate debt outstanding at December 31, 2011 and 2012 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. 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. Cost centers for amortization purposes are determined on a field area basis. Costs incurred to acquire oil and gas leasehold are capitalized. 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 2011 and 2012, impairment charges of $9.8 million and $61.3 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 $0.2 million, $60.8 million and $25.4 million in 2010, 2011, and 2012, respectively.

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 31½ 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, 2011 and 2012 consist of the following:

	As of December 31,	
	2011	2012
	(In thousands)	
Accrued drilling costs	$29,291	$14,050
Accrued interest payable	11,113	12,351
Advance from joint venture partner	—	7,286
Accrued oil and gas property acquisition costs	31,988	2,413
Other	13,110	11,272
	$85,502	$47,372

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 discounted 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 financial statements.

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

	2010	2011	2012
		(In thousands)	
Reserve for Future Abandonment Costs at beginning of the year	$ 6,561	$ 6,674	$13,997
New wells placed on production	338	417	1,837
Changes in estimates	596	5,839	2,736
Acquisition liabilities assumed	—	741	—
Liabilities settled and assets disposed of	(1,212)	(56)	(1,304)
Accretion expense	391	382	728
Reserve for Future Abandonment Costs at end of the year	$ 6,674	$13,997	$17,994

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 Instruments and Hedging Activities

The Company accounts for derivative 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 and quotes obtained from the counterparties to the derivative contract. 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. Derivative financial instruments that are not accounted for as hedges are adjusted to fair value through income. 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.

Major Purchasers

In 2012 the Company had two purchasers of its oil and natural gas production that accounted for 42% and 27%, respectively, of total oil and gas sales. In 2011 the Company had two purchasers of its oil and natural gas production that accounted for 49% and 14%, respectively, of total oil and gas sales. In 2010 the Company had one purchaser of its oil and natural gas production that accounted for 39% 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. Revisions to such estimates are recorded as actual results are known. 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, 2011 or 2012. 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 $10.6 million, $10.5 million and $11.5 million in 2010, 2011 and 2012, 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 2010, 2011 and 2012 were determined as follows:

	2010			2011			2012		
	Loss	Shares	Per Share	Loss	Shares	Per Share	Loss	Shares	Per Share
	(In thousands except per share data)								
Net Loss	$(19,586)			$(33,472)			$(100,060)		
Income Allocable to Unvested Stock Grants	—			—			—		
Basic Net Loss Attributable to Common Stock	$(19,586)	45,561	$(0.43)	$(33,472)	45,997	$(0.73)	$(100,060)	46,422	$(2.16)
Effect of Dilutive Securities:									
Stock Options	—	—		—	—		—	—	
Performance Stock Units	—	—		—	—		—	—	
Diluted Net Loss Attributable to Common Stock	$(19,586)	45,561	$(0.43)	$(33,472)	45,997	$(0.73)	$(100,060)	46,422	$(2.16)

At December 31, 2010, 2011 and 2012, 2,069,275, 2,114,520 and 1,960,835 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:

	2010	2011	2012
	(In thousands)		
Unvested restricted stock	1,715	1,683	1,737

All stock options, unvested stock 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 in each period.

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

	2010	2011	2012
	(In thousands except per share data)		
Weighted average anti-dilutive stock options	240	215	168
Weighted average exercise price	$35.98	$36.42	$37.81

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, 2010, 2011 and 2012, respectively, were as follows:

	2010	2011	2012
		(In thousands)	
Cash Payments:			
Interest payments	$ 40,467	$ 49,109	$ 79,001
Income tax refunds	$ (48,575)	$ (1,403)	$ (58)

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 $13.0 million, $13.2 million and $20.9 million in 2010, 2011 and 2012, respectively, which reduced interest expense and increased the carrying value of its unevaluated oil and gas properties.

Comprehensive Loss

Comprehensive loss consists of the following:

	For the Year Ended December 31,		
	2010	2011	2012
		(In thousands)	
Net Loss	$ (19,586)	$ (33,472)	$(100,060)
Other comprehensive income (loss):			
Realized gains on marketable securities reclassified to earnings, net of provision for income taxes of ($5,785) in 2010, ($12,291) in 2011 and ($9,318) in 2012	(10,744)	(22,827)	(17,303)
Unrealized hedging gains, net of provision for (benefit from) income taxes of $161 in 2011 and ($161) in 2012	—	298	(298)
Unrealized gains on marketable securities, net of provision for income taxes of $6,707 in 2010, $5,748 in 2011 and $831 in 2012	12,455	10,675	1,543
Total comprehensive loss	$ (17,875)	$ (45,326)	$(116,118)

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, 2010, 2011 and 2012:

	Oil Price Swap Agreements	Marketable Securities	Total Accumulated Comprehensive Income
		(In thousands)	
Balance as of December 31, 2009	$ —	$ 30,619	$ 30,619
Reclassification to earnings	—	(10,744)	(10,744)
Changes in value	—	12,455	12,455
Balance as of December 31, 2010	—	32,330	32,330
Reclassification to earnings	—	(22,827)	(22,827)
Changes in value	298	10,675	10,973
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

Subsequent Events

Subsequent events were evaluated through the issuance date of these consolidated financial statements.

(2) Acquisitions and Dispositions of Oil and Gas Properties

On December 29, 2011, the Company completed an acquisition, from an unrelated party, of oil and gas properties in the Delaware Basin located in Reeves County in West Texas (the "Delaware Basin Acquisition"). Total cash consideration paid of $337.9 million was funded with borrowings under the Company's bank credit facility. The Company acquired proved oil and gas reserves of 25.2 million barrels of oil equivalent and leases covering 43,591 net acres. The effective date of the acquisition was November 1, 2011. Concurrent with the Delaware Basin Acquisition, Comstock entered into a transaction structured as a reverse like-kind exchange in accordance with Section 1031 of the Internal Revenue Code. In connection with this reverse like-kind exchange, Comstock assigned the right to acquire ownership in the oil and gas properties that were acquired to a variable interest entity formed by an exchange accommodation titleholder. Comstock operated these properties pursuant to lease and management agreements with that entity, and had a call option which allowed the Company to terminate the exchange transaction at any time up and until the expiration date of the exchange. The exchange transaction was completed in May 2012 and the variable interest entity was then merged into a wholly owned subsidiary of the Company. Because the Company was the primary beneficiary of these arrangements, the properties acquired are included in its consolidated balance sheet as of December 31, 2011, and all revenues earned and expenses incurred related to the properties were included in the Company's consolidated results of operations during the term of the agreements.

The purchase price allocation, including final post-closing adjustments finalized during 2012, was as follows:

	(In thousands)
Consideration paid:	
Cash	$337,896
Total consideration paid	$337,896

Amounts recognized for the fair value of assets acquired and liabilities assumed were as follows:

	(In thousands)
Proved properties	$205,758
Unproved properties	143,751
Asset retirement obligation	(741)
Liabilities assumed	(10,872)
Net fair value of properties acquired and liabilities assumed	$337,896

On December 30, 2011, the Company acquired oil and gas properties in North Louisiana from a third party for $27.1 million. This acquisition included proved oil and gas reserves of 13 billion cubic feet of natural gas equivalent and leases covering 3,500 net acres.

Comstock considered the property acquisitions as business combinations and estimated the fair value of the properties as of the acquisition date. To estimate the fair value of the properties, the Company used a net asset value approach. The Company utilized a discounted cash flow model that took into account the following inputs to arrive at estimates of future net cash flows:

- Estimated ultimate recovery of oil and natural gas;
- Estimated future commodity prices based on NYMEX oil and natural gas futures prices adjusted for estimated location and quality differentials as well as related transportation costs;
- Estimated future production rates; and
- Estimated timing and amounts of future operating and development costs.

To estimate the fair value of proved properties, the Company discounted the future net cash flows 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 and unproved oil and gas properties are considered Level 3 fair value measurements.

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 aggregate net proceeds of $119.8 million and recognized a total gain of $26.0 million from these transactions. Also during 2012, the Company completed the sale of certain non-operated oil and gas properties acquired as part of the Delaware Basin Acquisition and received net proceeds of $24.8 million. The Company accounted for the disposal of these properties as a retirement since they represented a small portion of the assets within one of its major oil and gas properties.

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 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 28,160 net acres 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. The Company retains all of its interest in wells that were spud prior to March 31, 2012. Subject to certain conditions, KKR is obligated to acquire acreage for the first 100 wells drilled on the Company's Eagle Ford Shale acreage after July 30, 2012 and can continue to participate in additional wells drilled on the acreage under the same terms. Comstock received $23.8 million from KKR to fund its participation in drilling activity before the closing on July 30, 2012. During 2012 the Company also received $8.7 million for acreage and facility costs for new wells drilled subsequent to the closing. The Company accounted for the receipt of these funds as a retirement since they represented a small portion of the costs within one of its major oil and gas properties. Formation costs of $1.7 million incurred in connection with this joint venture are reflected as a reduction to the realized gain on sale of oil and gas properties in the consolidated financial statements.

(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,	
	2011	2012
	(In thousands)	
Unproved properties	$ 369,096	$ 263,652
Proved properties:		
Leasehold costs	1,162,094	1,125,460
Wells and related equipment and facilities	2,314,052	2,654,256
Accumulated depreciation depletion and amortization	(1,349,871)	(1,588,046)
	$ 2,495,371	$ 2,455,322

Costs Incurred

	For the Years Ended December 31,		
	2010	2011	2012
		(In thousands)	
Property Acquisitions:			
Unproved property acquisitions	$ 134,728	$ 255,699	$ 29,677
Proved property acquisitions	—	219,402	3,235
Development costs	315,041	496,506	514,629
Exploration costs	87,823	83,182	5,522
	$ 537,592	$ 1,054,789	$ 553,063

(4) Long-term Debt

Long-term debt is comprised of the following:

	As of December 31,	
	2011	2012
	(In thousands)	
Bank credit facility	$ 600,000	$ 440,000
8⅜% senior notes due 2017	300,000	300,000
Discount related to 8⅜% senior notes due 2017	(3,092)	(2,556)
7¾% senior notes due 2019	300,000	300,000
9½% senior notes due 2020	—	300,000
Discount related to 9½% senior notes due 2020	—	(13,061)
	$ 1,196,908	$ 1,324,383

The discount on the 8⅜% and 9½% 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, 2012 by year of maturity:

	2013	2014	2015	2016	2017	Thereafter	Total
				(In thousands)			
Bank credit facility	$ —	$ —	$ 440,000	$ —	$ —	$ —	$ 440,000
8⅜% senior notes	—	—	—	—	297,444	—	297,444
7¾% senior notes	—	—	—	—	—	300,000	300,000
9½% senior notes	—	—	—	—	—	286,939	286,939
	$ —	$ —	$ 440,000	$ —	$ 297,444	$ 586,939	$1,324,383

Comstock has a $850.0 million bank credit facility with Bank of Montreal, as the administrative agent. The credit facility is a five year revolving credit commitment that matures on November 30, 2015. Indebtedness under the credit facility is secured by substantially 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. The borrowing base may be affected by the performance of Comstock's properties and changes in oil and natural gas prices. The determination of the borrowing base is at the sole discretion of the administrative agent and the bank group. As of December 31, 2012, the borrowing base was $570.0 million, $130.0 million of which was available. Borrowings under the credit facility bear interest, based on the utilization of the borrowing base, at Comstock's option at either (1) LIBOR plus 1.75% to 2.75% 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 0.75% to 1.75%. A commitment fee of 0.5% is payable annually on the unused borrowing base. The credit facility contains covenants that, among other things, restrict the payment of cash dividends in excess of $50.0 million, limit the amount of consolidated debt that Comstock may incur and limit the Company's ability to make certain loans and investments. The only financial covenants are the maintenance of a ratio of current assets, including availability under the bank credit facility, to current liabilities and maintenance of a leverage ratio. The Company was in compliance with these covenants as of December 31, 2012.

On June 5, 2012 the Company issued $300.0 million of senior notes (the "2020 Notes") pursuant to an underwritten public offering. The 2020 Notes are due on June 15, 2020 and bears interest at 9½%, which is payable semi-annually on each June 15 and December 15. Proceeds from the issuance of the 2020 Notes were used to pay down outstanding borrowings under the Company's bank credit facility. On March 14, 2011, Comstock issued $300.0 million of senior notes (the "2019 Notes") pursuant to an underwritten public offering. The 2019 Notes are due on April 1, 2019 and bear interest at 7¾%, which is payable semiannually on each April 1 and October 1. Comstock also has $300.0 million of 8⅜% senior notes outstanding which mature on October 15, 2017 (the "2017 Notes"). Interest on the 2017 Notes is payable semiannually on each April 15 and October 15. The 2017, 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, 2012, 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.

On January 1, 2011, Comstock had $172.0 million in principal amount of 6⅞% senior notes outstanding due in 2012 (the "2012 Notes"). Comstock redeemed all of the 2012 Notes in March 2011 for $172.4 million. The early extinguishment of the 2012 Notes resulted in a loss of $1.1 million which is included in interest expense in the consolidated financial statements. This loss is comprised of the premium paid for the redemption of the 2012 Notes, the costs incurred related to the tender offer, and the write-off of unamortized debt issuance costs related to the 2012 Notes.

(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, 2010, 2011 and 2012 was $1.3 million, $1.1 million and $1.4 million, respectively. Minimum future payments under the leases are as follows:

	(In thousands)
2013	$ 1,983
2014	2,012
2015	2,038
2016	1,994
2017	2,021
Thereafter	6,740
	$16,788

As of December 31, 2012, the Company had commitments for contracted drilling rigs of $65.3 million through November 2015.

The Company has entered into natural gas transportation agreements through July 2019. Maximum commitments under these transportation agreements as of December 31, 2012 totaled $25.3 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, 2011 or 2012.

(6) Stockholders' Equity

The authorized capital stock of Comstock consists of 75 million shares of common stock, $.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, 2011 or 2012.

(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 1,607,372 shares of common stock.

During 2010, 2011 and 2012, the Company had $17.4 million, $15.0 million and $13.7 million, respectively, in stock-based compensation expense which is in general and administrative expenses. The excess income tax benefit realized from tax deductions associated with stock-based compensation recognized in additional paid in capital totaled $1.5 million in 2010 and excess tax provisions from tax deductions associated with stock-based compensation of $0.6 million and $1.7 million were recognized in additional paid in capital for the years ended December 31, 2011 and 2012, respectively.

Stock Options

The Company amortizes the fair value of stock options granted over the vesting period using the straight-line method. Compensation expense recognized for outstanding stock options was $0.4 million for the year ended December 31, 2010.

The Company has not issued any stock options since 2008. The following table summarizes information related to stock options outstanding at December 31, 2012:

Exercise Price	Weighted Average Remaining Life (in years)	Number of Options Outstanding	Number of Options Exercisable
$32.50	2.9	51,500	51,500
$33.22	4.0	65,650	65,650
$54.36	0.4	40,000	40,000
		157,150	157,150

The following table summarizes information related to stock option activity under the Company's incentive plans for the year ended December 31, 2012:

	Number of Options	Weighted Average Exercise Price
Outstanding at January 1, 2012	203,150	$36.64
Expired and forfeited	(46,000)	$30.74
Outstanding at December 31, 2012	157,150	$38.36
Vested and Exercisable at December 31, 2012	157,150	$38.36

	2010	2011	2012
		(In thousands)	
Cash received for options exercised	$ 1,427	$ —	$ —
Actual tax benefit realized	$ 4,221	$ —	$ —

As of December 31, 2012, all compensation cost related to stock options had been recognized. Stock options outstanding at December 31, 2011 and 2012 had no intrinsic value based on the closing price for the Company's common stock on December 31, 2011 and December 31, 2012. There were no stock option exercises in 2011 or 2012.

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 $17.0 million, $15.0 million and $13.5 million for the years ended December 31, 2010, 2011 and 2012, respectively. The fair value of each restricted share on the date of grant is equal to its fair market price. A summary of restricted stock activity for the year ended December 31, 2012 is presented below:

	Number of Restricted Shares	Weighted Average Grant Price
Outstanding at January 1, 2012	2,114,520	$31.25
Granted	303,530	$15.49
Vested	(437,123)	$35.07
Forfeitures	(20,092)	$26.10
Outstanding at December 31, 2012	1,960,835	$28.01

The per share weighted average fair value of restricted stock grants in 2010, 2011 and 2012 was $25.61, $18.31 and $15.49, respectively. Total unrecognized compensation cost related to unvested restricted stock of $19.1 million as of December 31, 2012 is expected to be recognized over a period of 2.3 years. The fair value of restricted stock which vested in 2010, 2011 and 2012 was $15.1 million, $9.3 million and $6.7 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. 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%.

The Company granted 254,133 PSUs in 2012, all of which were outstanding at December 31, 2012, with a grant date fair value of $5.4 million, or $21.14 per unit. 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 688,545 shares of common stock based on the achieved performance ranges from zero to three.

Total compensation expense for PSUs was $0.2 million for the year ended December 31, 2012. As of December 31, 2012, there was $5.2 million of total unrecognized expense related to PSUs, which is being amortized through December 2015.

(8) Retirement Plan

The Company has a 401(k) profit sharing plan which covers all of its employees. At its discretion, Comstock may match a certain percentage of the employees' contributions to the plan. Matching contributions to the plan were $341,000, $323,000 and $365,000 for the years ended December 31, 2010, 2011 and 2012, respectively.

(9) Income Taxes

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

	2010	2011	2012
		(In thousands)	
Current	$ (229)	$ 28	$ (162)
Deferred	(4,617)	(14,652)	(47,192)
	$ (4,846)	$ (14,624)	$ (47,354)

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 before income taxes is due to the following:

	2010	2011	2012
		(In thousands)	
Tax benefit at statutory rate	$ (8,551)	$ (16,834)	$ (51,595)
Tax effect of:			
Nondeductible compensation	4,253	2,753	2,545
State taxes, net of federal tax benefit	(343)	(741)	1,486
Net operating loss carryback adjustments	(369)	—	—
Other	164	198	210
Total	$ (4,846)	$ (14,624)	$ (47,354)

	2010	2011	2012
Statutory rate	35.0%	35.0%	35.0%
Tax effect of:			
Nondeductible compensation	(17.4)	(5.7)	(1.7)
State taxes, net of federal tax benefit	1.4	1.5	(1.0)
Net operating loss carryback adjustments	1.5	—	—
Other	(0.7)	(0.4)	(0.2)
Effective tax rate	19.8%	30.4%	32.1%

The tax effects of significant temporary differences representing the net deferred tax asset and liability at December 31, 2011 and 2012 were as follows:

	2011	2012
	(In thousands)	
Current deferred tax liabilities:		
Marketable securities	$ (7,503)	$ (1,262)
Derivative financial instruments	(161)	(4,078)
Net current deferred tax liability	(7,664)	(5,340)
Noncurrent deferred tax liabilities:		
Property and equipment	(253,580)	(247,062)
Other assets	8,772	8,319
Net operating loss carryforwards	47,320	95,180
Alternative minimum tax carryforward	19,093	19,080
Valuation allowance on net operating loss carryforwards	(19,630)	(23,009)
Other	(3,680)	(2,409)
Net noncurrent deferred tax liability	(201,705)	(149,901)
Net deferred tax liability	$(209,369)	$(155,241)

At December 31, 2012, 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 — 2032	$192,255
Net operating loss — Louisiana	2012 — 2027	$536,365
Alternative minimum tax credits	Unlimited	$ 19,080

Utilization of $36.9 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, and 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 $288.0 million, with a tax effect of $15.0 million, 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 carryforward period.

The Company's federal income tax returns for the years subsequent to December 31, 2007 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, 2007. 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.

During 2012, the Company hedged 1,710,000 barrels of its oil production at an average NYMEX West Texas Intermediate ("WTI") oil price of $99.46 per barrel. As of December 31, 2012, the Company had the following outstanding commodity derivatives:

Commodity and Derivative Type	Weighted-Average Contract Price	Volume (Barrels)	Contract Period
Oil Price Swap Agreements	$98.67 per Bbl.	2,160,000	Jan. 2013 – Dec. 2013

The Company recognizes the realized gains and losses, and the unrealized gains and losses due to the change in the fair value of its derivative financial instruments, as separate components of other income (expenses). The Company had realized gains of $9.8 million on its oil swaps that settled during

2012. The estimated fair value of the Company's derivative financial instruments, which equals their carrying value, was an asset of $11.7 million as of December 31, 2012, which is reflected as a current asset based on estimated settlement dates.

(11) Supplementary Quarterly Financial Data (Unaudited)

	2011				
	First	Second	Third	Fourth	Total
	(In thousands, except per share data)				
Total oil and gas sales	$ 88,038	$112,451	$119,422	$ 114,456	$ 434,367
Income (loss) from operations	$ (8,263)	$ 8,378	$ 12,086	$ (53,517)	$ (41,316)
Net income (loss)	$ 2,404	$ 3,949	$ 1,309	$ (41,134)	$ (33,472)
Net income (loss) per share:					
Basic	$ 0.05	$ 0.08	$ 0.03	$ (0.89)	$ (0.73)
Diluted	$ 0.05	$ 0.08	$ 0.03	$ (0.89)	$ (0.73)

	2012				
	First	Second	Third	Fourth	Total
	(In thousands, except per share data)				
	(As Restated)	(As Restated)	(As Restated)		
Total oil and gas sales	$111,689	$100,736	$112,895	$ 106,603	$ 431,923
Income (loss) from operations	$ 2,841	$ (8,046)	$ (24,419)	$(102,036)	$(131,660)
Net income (loss)	$ 1,375	$ 7,165	$ (30,449)	$ (78,151)	$(100,060)
Net income (loss) per share:					
Basic	$ 0.03	$ 0.15	$ (0.66)	$ (1.68)	$ (2.16)
Diluted	$ 0.03	$ 0.15	$ (0.66)	$ (1.68)	$ (2.16)

Basic and diluted per share amounts are the same for each of the quarters ended December 31, 2011, September 30, 2012, December 31, 2012 and for the years ended December 31, 2011 and December 31, 2012 due to the net loss reported during each of these periods.

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

	2011				
	First	Second	Third	Fourth	Total
	(In thousands, except per share data)				
Gain on sales of marketable securities	$21,249	$8,480	$2,484	$ 2,905	$ 35,118
Impairments of unproved oil and gas properties	$ (9,454)	$ —	$ (364)	$ —	$ (9,818)
Impairments of proved oil and gas properties	$ —	$ —	$ —	$(60,817)	$(60,817)

	2012				
	First	Second	Third	Fourth	Total
	(In thousands, except per share data)				
Gain on sale of oil and gas properties	$ 6,727	$20,338	$(2,794)	$ —	$ 24,271
Gain on sales of marketable securities	$26,621	$ —	$ —	$ —	$ 26,621
Impairments of unproved oil and gas properties	$ (1,315)	$ —	$(1,370)	$(58,615)	$(61,300)
Impairments of proved oil and gas properties	$ (49)	$ (5,301)	$ —	$(20,018)	$(25,368)

The Company is restating its financial statements for each of the fiscal quarters ended March 31, 2012, June 30, 2012, and September 30, 2012 with respect to the accounting and disclosures for certain derivative financial transactions under Accounting Standards Codification Topic 815, *Derivatives and Hedging* (“ASC 815”). The Company determined that the formal documentation it had prepared to support its initial hedge designations for effectiveness in connection with the Company’s oil hedging program was not compliant with the technical documentation requirements to qualify for cash flow hedge accounting treatment in accordance with ASC 815, and as a result, the Company was not permitted to utilize hedge accounting treatment in the preparation of its financial statements. The restatements eliminate hedge accounting treatment which had been applied in 2012 and reflect other immaterial adjustments to oil and gas sales.

Under ASC 815, the fair value of hedge contracts is recognized in the Company’s consolidated balance sheet as an asset or liability, as the case may be, and the amounts received or paid under the hedge contracts are reflected in earnings during the period in which the underlying production occurs. If the hedge contracts qualify for cash flow hedge accounting treatment, the fair value of the hedge contract is recorded in “accumulated other comprehensive income”, and changes in the fair value do not affect net income in the period. If the hedge contract does not qualify for hedge accounting treatment, the change in the fair value of the hedge contract is reflected in earnings during the period as unrealized gain or loss from derivatives. Under the cash flow hedge accounting treatment used by the Company, the fair value of the hedge contracts were recognized in the consolidated balance sheet with the resulting unrealized gain or loss recorded initially in “accumulated other comprehensive income” and later reclassified through earnings when the hedged production impacted earnings. As a result of the determination that the designation documentation failed to meet the requirements necessary to utilize cash flow hedge accounting treatment, the unrealized gain or loss should have been recorded in the consolidated statements of operations as a component of earnings. The Company has also been recognizing realized gains and losses from its derivative financial instruments in oil and gas sales, and is reclassifying these amounts as a separate component of non-operating income and expense.

The following tables present the restated condensed consolidated statements of operations and statements of other comprehensive income (loss) for the three months ended March 31, 2012, June 30, 2012 and September 30, 2012 and the nine months ended September 30, 2012, the restated condensed consolidated balance sheets as of March 31, 2012, June 30, 2012 and September 30, 2012, the consolidated statement of stockholders' equity for the nine months ended September 30, 2012 and the condensed consolidated statements of cash flows for the three months ended March 31, 2012, the six months ended June 30, 2012 and the nine months ended September 30, 2012:

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended March 31, 2012			Three Months Ended June 30, 2012			Three Months Ended September 30, 2012			Nine Months Ended September 30, 2012		
	As Reported	Adjustments	As Restated	As Reported	Adjustments	As Restated	As Reported	Adjustments	As Restated	As Reported	Adjustments	As Restated
	(In thousands, except per share amounts)											
Oil and gas sales	$110,335	$ 1,354	$111,689	$104,690	$ (3,954)	$100,736	$117,129	$ (4,234)	$112,895	$332,154	$ (6,834)	$325,320
Gain on sale of oil and gas properties	6,727	—	6,727	20,338	—	20,338	(2,794)	—	(2,794)	24,271	—	24,271
Total Revenues	117,062	1,354	118,416	125,028	(3,954)	121,074	114,335	(4,234)	110,101	356,425	(6,834)	349,591
Total operating expenses	115,575	—	115,575	129,120	—	129,120	134,520	—	134,520	379,215	—	379,215
Operating income (loss)	1,487	1,354	2,841	(4,092)	(3,954)	(8,046)	(20,185)	(4,234)	(24,419)	(22,790)	(6,834)	(29,624)
Other income (expenses):												
Gain on sale of marketable securities	26,621	—	26,621	—	—	—	—	—	—	26,621	—	26,621
Realized gain (loss) from derivatives	—	(1,354)	(1,354)	—	2,719	2,719	—	3,293	3,293	—	4,658	4,658
Unrealized gain (loss) from derivatives	—	(10,187)	(10,187)	—	34,797	34,797	—	(11,112)	(11,112)	—	13,498	13,498
Other income	(23)	262	239	545	(262)	283	153	—	153	675	—	675
Interest expense	(13,237)	—	(13,237)	(14,529)	—	(14,529)	(17,535)	—	(17,535)	(45,301)	—	(45,301)
Total other income (expenses)	13,361	(11,279)	2,082	(13,984)	37,254	23,270	(17,382)	(7,819)	(25,201)	(18,005)	18,156	151
Income (loss) before income taxes	14,848	(9,925)	4,923	(18,076)	33,300	15,224	(37,567)	(12,053)	(49,620)	(40,795)	11,322	(29,473)
Benefit from (provision for) income taxes	(7,989)	4,441	(3,548)	7,772	(15,831)	(8,059)	11,579	7,592	19,171	11,362	(3,798)	7,564
Net income (loss)	$ 6,859	$ (5,484)	$ 1,375	$ (10,304)	$ 17,469	$ 7,165	$ (25,988)	$ (4,461)	$ (30,449)	$ (29,433)	$ 7,524	$ (21,909)
Net income (loss) per share:												
Basic	$ 0.14	$ (0.11)	$ 0.03	$ (0.22)	$ 0.37	$ 0.15	$ (0.56)	$ (0.10)	$ (0.66)	$ (0.63)	$ 0.16	$ (0.47)
Diluted	$ 0.14	$ (0.11)	$ 0.03	$ (0.22)	$ 0.37	$ 0.15	$ (0.56)	$ (0.10)	$ (0.66)	$ (0.63)	$ 0.16	$ (0.47)
Weighted average shares outstanding:												
Basic	46,372	—	46,372	46,426	—	46,426	46,443	—	46,443	46,414	—	46,414
Diluted	46,372	—	46,372	46,426	—	46,426	46,443	—	46,443	46,414	—	46,414

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)

	Three Months Ended March 31, 2012			Three Months Ended June 30, 2012		
	As Reported	Adjustments	As Restated	As Reported	Adjustments	As Restated
	(In thousands, except per share amounts)					
Net loss	$ 6,859	$(5,484)	$ 1,375	$(10,304)	$ 17,469	$ 7,165
Reclassified to earnings, net of provision for (benefit from) income taxes of $—, $161, $161, and $—, $—, $—	—	(298)	(298)	—	—	—
Unrealized hedging gains, net of provision for (benefit from) income taxes of $3,578, ($3,578), $— and ($12,087), $12,087, $—	(6,645)	6,645	—	22,448	(22,448)	—
Net change in unrealized gains and losses on marketable securities, net of benefit from (provision for) income taxes of $6,793, $—, $6,793, and $682, $—, $682	(12,612)	—	(12,612)	(1,268)	—	(1,268)
Other comprehensive income (loss)	(19,257)	6,347	(12,910)	21,180	(22,448)	(1,268)
Comprehensive income (loss)	$(12,398)	$ 863	$(11,535)	$ 10,876	$ (4,979)	$ 5,897

	Three Months Ended September 30, 2012			Nine Months Ended September 30, 2012		
	As Reported	Adjustments	As Restated	As Reported	Adjustments	As Restated
	(In thousands, except per share amounts)					
Net loss	$(25,988)	$ (4,461)	$(30,449)	$(29,433)	$ 7,524	$(21,909)
Reclassified to earnings, net of provision for (benefit from) income taxes of $—,$—, $— and $—, $161, $161	—	—	—	—	(298)	(298)
Unrealized hedging gains, net of provision for (benefit from) income taxes of $3,889, ($3,889), $— and ($4,620), $4,620, $—	(7,223)	7,223	—	8,580	(8,580)	—
Net change in unrealized gains and losses on marketable securities, net of benefit from (provision for) income taxes of $46, $—, $46 and $7,520, $—,$7,520	(86)	—	(86)	(13,966)	—	(13,966)
Other comprehensive income (loss)	(7,309)	7,223	(86)	(5,386)	(8,878)	(14,264)
Comprehensive income (loss)	$(33,297)	$ 2,762	$(30,535)	$(34,819)	$ (1,354)	$(36,173)

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	Three Months Ended March 31, 2012			Six Months Ended June 30, 2012			Nine Months Ended September 30, 2012		
	As Reported	Adjustments	As Restated	As Reported	Adjustments	As Restated	As Reported	Adjustments	As Restated
					(In thousands)				
ASSETS									
Cash and Cash Equivalents	$ 3,750	$ —	$ 3,750	$ 3,505	$ —	$ 3,505	$ 2,569	$ —	$ 2,569
Restricted Cash	9,549	—	9,549	—	—	—	—	—	—
Accounts Receivable	51,918	—	51,918	42,122	(1,235)	40,887	51,907	(2,176)	49,731
Marketable Securities	17,154	—	17,154	15,204	—	15,204	15,072	—	15,072
Assets Held for Sale	91,520	—	91,520	—	—	—	—	—	—
Derivative Financial Instruments	—	—	—	18,536	—	18,536	10,823	—	10,823
Other Current Assets	2,908	—	2,908	6,695	—	6,695	7,658	—	7,658
Total Current Assets	176,799	—	176,799	86,062	(1,235)	84,827	88,029	(2,176)	85,853
Net Property and Equipment	2,517,672	—	2,517,672	2,547,219	—	2,547,219	2,546,024	—	2,546,024
Derivative Financial Instruments	—	—	—	6,235	—	6,235	2,836	—	2,836
Other Assets	16,201	—	16,201	21,796	—	21,796	20,950	—	20,950
	$2,710,672	$ —	$2,710,672	$2,661,312	$ (1,235)	$2,660,077	$2,657,839	$(2,176)	$2,655,663
LIABILITIES AND STOCKHOLDERS' EQUITY									
Current Liabilities	$ 250,060	$ —	$ 250,060	$ 176,726	—	$ 176,726	200,086	$ —	$ 200,086
Long-term Debt	1,207,042	—	1,207,042	1,223,235	—	1,223,235	1,238,809	—	1,238,809
Deferred Income Taxes Payable	208,078	(863)	207,215	203,530	2,881	206,411	190,784	(822)	189,962
Reserve for Future Abandonment Costs	13,536	—	13,536	14,191	—	14,191	14,545	—	14,545
Derivative Financial Instruments	2,205	—	2,205	—	—	—	—	—	—
Other Non-Current Liabilities	2,394	—	2,394	2,337	—	2,337	2,301	—	2,301
Total Liabilities	1,683,315	(863)	1,682,452	1,620,019	2,881	1,622,900	1,646,525	(822)	1,645,703
Commitments and Contingencies									
Stockholders' Equity:									
Common stock	24,058	—	24,058	24,081	—	24,081	24,081	—	24,081
Additional Paid-in Capital	470,844	—	470,844	473,881	—	473,881	477,199	—	477,199
Retained Earnings	531,236	(5,484)	525,752	520,932	11,985	532,917	494,944	7,524	502,468
Accumulated Other Comprehensive Income	1,219	6,347	7,566	22,399	(16,101)	6,298	15,090	(8,878)	6,212
Total Stockholders' Equity	1,027,357	863	1,028,220	1,041,293	(4,116)	1,037,177	1,011,314	(1,354)	1,009,960
	$2,710,672	$ —	$2,710,672	$2,661,312	$ (1,235)	$2,660,077	$2,657,839	$(2,176)	$2,655,663

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(Unaudited)

	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	37	18	10,171	—	—	10,189
Excess income taxes from stock-based compensation	—	—	(1,681)	—	—	(1,681)
Net loss – as restated	—	—	—	(21,909)	—	(21,909)
Other comprehensive loss – as restated	—	—	—	—	(14,264)	(14,264)
Balance at September 30, 2012 – as restated	48,162	$24,081	$477,199	$502,468	$ 6,212	$1,009,960

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31, 2012			Six Months Ended June 30, 2012			Nine Months Ended September 30, 2012		
	As Reported	Adjustments	As Restated	As Reported	Adjustments	As Restated	As Reported	Adjustments	As Restated
					(In thousands)				
CASH FLOWS FROM OPERATING ACTIVITIES:									
Net income (loss)	$ 6,859	$(5,484)	$ 1,375	$ (3,445)	$ 11,985	$ 8,540	$ (29,433)	$ 7,524	$ (21,909)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:									
Gain on sale of assets	(33,348)	—	(33,348)	(53,686)	—	(53,686)	(50,892)	—	(50,892)
Deferred income taxes	8,072	(4,441)	3,631	416	11,390	11,806	(11,151)	3,798	(7,353)
Dry hole costs and leasehold impairments	1,315	—	1,315	1,315	—	1,315	2,685	—	2,685
Impairment of oil and gas properties	49	—	49	5,350	—	5,350	5,350	—	5,350
Depreciation, depletion and amortization	79,097	—	79,097	169,180	—	169,180	268,410	—	268,410
Unrealized gains from derivatives	262	9,925	10,187	—	(24,610)	(24,610)	—	(13,498)	(13,498)
Debt issuance cost and discount amortization	944	—	944	2,103	—	2,103	3,689	—	3,689
Stock-based compensation	3,535	—	3,535	6,860	—	6,860	10,189	—	10,189
Excess income taxes from stock-based compensation	1,405	—	1,405	1,670	—	1,670	1,681	—	1,681
Decrease in accounts receivable	1,815	—	1,815	11,611	1,235	12,846	1,826	2,176	4,002
Increase in other current assets	(199)	—	(199)	(4,097)	—	(4,097)	(5,059)	—	(5,059)
Increase in accounts payable and accrued expenses	63,374	—	63,374	4,621	—	4,621	28,403	—	28,403
Net cash provided by operating activities	133,180	—	133,180	141,898	—	141,898	225,698	—	225,698
CASH FLOWS FROM INVESTING ACTIVITIES:									
Net cash used for investing activities	(146,423)	—	(146,423)	(164,560)	—	(164,560)	(264,119)	—	(264,119)
CASH FLOWS FROM FINANCING ACTIVITIES:									
Net cash provided by financing activities	8,533	—	8,533	17,707	—	17,707	32,530	—	32,530
Net decrease in cash and cash equivalents	(4,710)	—	(4,710)	(4,955)	—	(4,955)	(5,891)	—	(5,891)
Cash and cash equivalents, beginning of the year	8,460	—	8,460	8,460	—	8,460	8,460	—	8,460
Cash and cash equivalents, end of the year	$ 3,750	$ —	$ 3,750	$ 3,505	$ —	$ 3,505	$ 2,569	$ —	$ 2,569

(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 each of the three years ended December 31, 2012:

	2010		2011		2012	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved Reserves:						
Beginning of year	7,214	682,389	4,219	1,025,633	32,099	1,118,632
Revisions of previous estimates	351	(6,137)	8	(36,150)	(397)	(531,335)
Extensions and discoveries	1,484	421,657	9,845	169,188	17,312	31,050
Purchases of minerals in place	—	—	18,865	50,554	—	—
Disposals of minerals in place	(4,115)	(3,303)	—	—	(7,486)	(59,257)
Production	(715)	(68,973)	(838)	(90,593)	(2,309)	(82,490)
End of year	4,219	1,025,633	32,099	1,118,632	39,219	476,600
Proved Developed Reserves:						
Beginning of year	4,894	367,102	2,961	506,809	8,405	550,474
End of year	2,961	506,809	8,405	550,474	12,308	368,775

During 2012, the Company's estimated quantities of proved undeveloped natural gas reserves decreased by 460 Bcf from total proved undeveloped reserves as of December 31, 2011 due to downward revisions related to the lower natural gas price that was used to determine estimated reserve quantities at December 31, 2012. Substantially all of the Company's proved undeveloped natural gas reserves related to undrilled natural gas wells at December 31, 2011 were not economic at the lower natural gas price at December 31, 2012. The decrease in proved undeveloped natural gas reserves in 2012 resulted in an increase to the Company's per unit amortization rate for its proved oil and gas properties and, accordingly, increased depletion, depreciation and amortization expense during 2012 as compared to previous periods.

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, 2011 and 2012:

	2011	2012
	(In thousands)	
Cash Flows Relating to Proved Reserves:		
Future Cash Flows	$ 7,656,654	$ 5,064,519
Future Costs:		
Production	(2,259,147)	(1,585,309)
Development and Abandonment	(2,174,656)	(1,165,991)
Future Income Taxes	(843,266)	(552,843)
Future Net Cash Flows	2,379,585	1,760,376
10% Discount Factor	(1,266,090)	(976,159)
Standardized Measure of Discounted Future Net Cash Flows	$ 1,113,495	$ 784,217

The standardized measure of discounted future net cash flows at the end of 2011 and 2012 was determined based on the simple average of the first of month market prices for oil and natural gas for each year. Prices were $92.93 per barrel of oil and $4.18 per Mcf of natural gas for 2011 and $94.61 per barrel of oil and $2.84 per Mcf of natural gas for 2012. 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, 2010, 2011 and 2012:

	2010	2011	2012
		(In thousands)	
Standardized Measure, Beginning of Year	$ 426,590	$ 606,136	$1,113,495
Net change in sales price, net of production costs	141,570	1,061	(428,469)
Development costs incurred during the year which were previously estimated	69,216	205,418	211,020
Revisions of quantity estimates	(5,433)	(50,398)	(892,645)
Accretion of discount	48,911	79,763	148,697
Changes in future development and abandonment costs	(15,201)	10,151	653,824
Changes in timing and other	66,657	(58,049)	(16,176)
Extensions and discoveries	321,909	540,937	467,080
Purchases of minerals in place	—	316,118	—
Sales of minerals in place	(50,651)	—	(261,971)
Sales, net of production costs	(268,466)	(355,654)	(341,803)
Net changes in income taxes	(128,966)	(181,988)	131,165
Standardized Measure, End of Year	$ 606,136	$1,113,495	$ 784,217

Directors

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

[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
President, Chief Executive Officer and Chairman of the Board of Directors

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

Mark A. Williams
Chief Operating Officer and Vice President of Operations

Gerry L. Blackshear
Vice President of Exploration

D. Dale Gillette
Vice President of Land and General Counsel

Stephen E. Neukom
Vice President of Marketing

Daniel K. Presley
Vice President of Accounting and Controller

Russell W. Romoser
Vice President of Reservoir Engineering

Richard D. Singer
Vice President of Financial Reporting

Blaine M. Stribling
Vice President of Corporate Development

Website

www.comstockresources.com

Primary Subsidiaries

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

Independent Public Accountants

Ernst & Young LLP

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".

Commercial Banks

Bank of Montreal
Bank of America
JPMorgan Chase Bank
Comerica Bank
Union Bank
Bank of Nova Scotia
Bank of Texas
Branch Banking and Trust Company
Compass Bank
Fifth Third Bank
Iberia Bank
Natixis
OneWest Bank
Regions Bank
SunTrust Bank
U.S. Bank
Whitney Bank

Annual Meeting

The annual meeting of stockholders will be held on Tuesday, May 7, 2013 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:
Roland O. Burns
5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034
(800) 877-1322
rburns@comstockresources.com

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

Stock Market Prices

2011	High	Low
First Quarter	$31.38	$23.68
Second Quarter	$33.00	$26.14
Third Quarter	$33.63	$15.40
Fourth Quarter	$20.21	$13.69

2012	High	Low
First Quarter	$17.79	$11.05
Second Quarter	$18.54	$12.56
Third Quarter	$20.46	$14.95
Fourth Quarter	$21.16	$14.40

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 2012 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.

COMSTOCK RESOURCES

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