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, 2009

OR

o **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**
Preferred Stock Purchase Rights	**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 o

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 o 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 o

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 o 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 o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of February 26, 2010, there were 47,105,606 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, 2009 (the last business day of the registrant's most recently completed second fiscal quarter), was $1.5 billion.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement for the 2010 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, 2009

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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.

"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.

"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.

"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 the East Texas/North Louisiana and South Texas regions. Our oil and natural gas properties are estimated to have proved reserves of 725.7 Bcfe with an estimated PV 10 Value of $489.1 million as of December 31, 2009 and a standardized measure of discounted future net cash flows of $426.6 million. Our consolidated proved oil and natural gas reserve base is 94% natural gas and 55% proved developed on a Bcfe basis as of December 31, 2009.

Our proved reserves at December 31, 2009 and our 2009 average daily production are summarized below:

	Reserves at December 31, 2009				2009 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	1.3	502.6	510.2	70.3%	0.6	107.0	110.4	61.5%
South Texas	1.3	153.3	161.3	22.2%	0.4	51.8	54.5	30.4%
Other Regions	4.6	26.5	54.2	7.5%	1.1	7.8	14.5	8.1%
Total	7.2	682.4	725.7	100.0%	2.1	166.6	179.4	100.0%

Strengths

High Quality Properties. Our operations are focused in two primary operating areas, the East Texas/North Louisiana and South Texas regions. Our properties have an average reserve life of approximately 11.1 years and have extensive development and exploration potential. We have an extensive acreage position in our East Texas/North Louisiana region in the Haynesville shale resource play where we have identified 85,589 gross (72,638 net to us) acres prospective for Haynesville shale development.

Successful Exploration and Development Program. In 2009 we spent $345.4 million on exploration and development of our oil and natural gas properties. We drilled 54 wells in 2009, 38.6 net to us, at a cost of $307.0 million. We spent $26.0 million to acquire additional leases in the Haynesville shale, $1.9 million on other leasehold costs and $0.9 million to acquire seismic data. We also spent $9.6 million for recompletions, workovers, abandonment and production facilities. Our drilling activities in 2009 added 350 Bcfe to our proved reserves and drove our 9% production growth in 2009.

Efficient Operator. We operate 90% of our proved oil and natural gas reserve base as of December 31, 2009. 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. Since 1991, we have added 984.1 Bcfe of proved oil and natural gas reserves from 36 acquisitions at an average cost of $1.14 per Mcfe. Our application of strict economic and reserve risk criteria have enabled us to successfully evaluate and integrate acquisitions. We did not make any acquisitions of producing oil and gas properties in 2008 or 2009.

Business Strategy

Pursue Exploration Opportunities. We conduct exploration activities to grow our reserve base and to replace our production each year. In late 2007 we identified the potential in our largest operating region, East Texas/North Louisiana, to explore for natural gas in the Haynesville shale formation, which was below the Cotton Valley, Hosston and Travis Peak sand formations that we have been developing. We drilled eight pilot wells to evaluate the prospectivity of the Haynesville shale in 2007 and 2008. We undertook an active leasing program in 2008 and 2009 to acquire additional acreage where we believed the Haynesville shale formation would be prospective and spent $116.9 million in 2008 and $26.9 million in 2009 to increase our leasehold with Haynesville shale potential to 85,589 gross acres (72,638 net to us). We started the commercial development of the Haynesville shale in late 2008 and drilled two (1.1 net to us) successful horizontal wells. In 2009, our drilling program was primarily focused on exploring and developing our Haynesville shale acreage and we spent approximately $243.6 million drilling 43 (30.7 net to us) Haynesville shale horizontal wells. Our Haynesville shale drilling program added 325 Bcfe to our proved reserves in 2009. We plan to continue to develop our Haynesville shale acreage in 2010 and have budgeted to spend $348.0 million to drill 56 (41.1 net to us) Haynesville shale horizontal wells.

In prior years we have had an active drilling program in our South Texas region utilizing 3-D seismic to identify prospects in the Wilcox and Vicksburg formations. We have reduced our activity in the region in response to lower natural gas prices to focus on the higher return Haynesville shale program. We spent $29.2 million in 2009 to drill five (3.4 net to us) successful wells in South Texas.

Exploit Existing Reserves. We seek to maximize the value of our oil and natural 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. During 2009, outside of our Haynesville shale and South Texas drilling programs, we spent $13.3 million to drill six wells (4.5 net to us). We also spent $9.6 million for recompletion and workover activity in 2009.

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 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 $385.0 million on our development and exploration projects in 2010. We intend to primarily use operating cash flow to fund our development and exploration expenditures in 2010 and, to a lesser extent, cash on hand and borrowings under our bank credit facility. We may also make additional property acquisitions in 2010 that would require additional sources of funding. Such sources may include borrowings under our bank credit facility or sales of our equity or debt securities.

Acquire High Quality Properties at Attractive Costs. In prior years we have had a successful track record of increasing our oil and natural gas reserves through opportunistic acquisitions. Since 1991, we have added 984.1 Bcfe of proved oil and natural gas reserves from 36 acquisitions at a total cost of $1.1 billion, or $1.14 per Mcfe. The acquisitions were acquired at an average of 67% of their PV 10 Value in the year the acquisitions were completed. We did not complete any acquisitions of producing oil and gas properties in 2008 or 2009 due to our focus on developing our Haynesville shale properties. 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 twenty largest field areas as of December 31, 2009:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)	%	PV 10 Value(1) (000's)	%
East Texas / North Louisiana						
Logansport	30	203,294	203,472	28.0%	$ 90,460	18.5%
Toledo Bend	—	104,069	104,069	14.3%	3,816	0.8%
Beckville	144	54,132	54,996	7.6%	36,276	7.4%
Waskom	440	34,407	37,045	5.1%	18,315	3.7%
Blocker	106	24,952	25,590	3.5%	18,304	3.7%
Mansfield	—	21,269	21,269	2.9%	4,830	1.0%
Hico-Knowles/Terryville	293	14,016	15,774	2.2%	21,031	4.3%
Darco	46	11,833	12,110	1.7%	4,092	0.8%
Douglass	3	7,816	7,835	1.1%	5,650	1.2%
Cadeville	41	6,878	7,125	1.0%	4,587	0.9%
Longwood	54	4,176	4,501	0.6%	3,283	0.7%
Other	109	15,765	16,426	2.3%	10,789	2.3%
	1,266	502,607	510,212	70.3%	221,433	45.3%
South Texas						
Fandango	—	54,163	54,163	7.5%	50,676	10.4%
Double A Wells	974	26,586	32,431	4.5%	45,459	9.3%
Rosita	1	31,429	31,437	4.3%	29,721	6.1%
Las Hermanitas	3	14,382	14,397	2.0%	13,323	2.7%
Javelina	54	12,936	13,258	1.8%	16,114	3.3%
Ball Ranch	13	3,889	3,970	0.5%	6,712	1.4%
Other	298	9,893	11,673	1.6%	17,947	3.6%
	1,343	153,278	161,329	22.2%	179,952	36.8%
Other						
Laurel	4,358	56	26,205	3.6%	60,406	12.4%
San Juan Basin	14	4,609	4,693	0.6%	5,426	1.1%
Maxie	39	3,460	3,696	0.5%	3,962	0.8%
Other	194	18,379	19,540	2.8%	17,935	3.6%
	4,605	26,504	54,134	7.5%	87,729	17.9%
Total	7,214	682,389	725,675	100.0%	489,114	100.0%
Discounted Future Income Taxes					(62,524)	
Standardized Measure of Discounted Future Cash Flows					$ 426,590	

(1) 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 70.3% or 510.2 Bcfe of our proved reserves are located in East Texas and North Louisiana where we own interests in 923 producing wells (561.5 net to us) in 28 field areas. We operate 633 of these wells. The largest of our fields in this region are the Logansport, Toledo Bend, Beckville, Waskom, Blocker, Mansfield, Hico-Knowles/Terryville, Darco, Douglass, Cadeville and Longwood fields. Production from this region averaged 107.0 MMcf of natural gas per day and 576 barrels of oil per day during 2009 or 110.4 MMcfe per day. Most of the reserves in this area produce from the upper Jurassic aged Haynesville shale or Cotton Valley formations and the Cretaceous aged Travis Peak/Hosston formation. In 2009, we spent $277.5 million drilling 49 wells (35.3 net to us) and $31.4 million on leasehold costs, workovers and recompletions in this region. Forty-six (32.9 net to us) of the 49 wells we drilled were horizontal wells. Forty-three (30.7 net) of these horizontal wells drilled targeted the Haynesville shale. We plan to spend approximately $368.0 million in 2010 for drilling activities in this region which will focus primarily on the development of our Haynesville shale properties.

Logansport

The Logansport field located in DeSoto and Sabine Parishes, Louisiana primarily produces from the Haynesville shale formation 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 203.5 Bcfe in the Logansport field represent approximately 28% of our proved reserves. We own interests in 190 wells (119.9 net to us) and operate 133 of these wells in this field. During December 2009, net daily production attributable to our interest from this field averaged 61.1 MMcf of natural gas and 50 barrels of oil. In 2009, we drilled 19 (13.8 net to us) Haynesville shale horizontal wells and three (2.4 net to us) Cotton Valley vertical wells at Logansport. In 2010, we plan to drill 27 (18.6 net to us) horizontal Haynesville shale wells 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. In 2009, we drilled 16 (10.1 net to us) Haynesville shale horizontal wells at Toledo Bend. One of these wells successfully tested the Upper Haynesville shale. Production from the Lower Haynesville shale in the Toledo Bend ranges from 11,400 to 11,800 feet and from 10,880 to 11,300 in the Upper Haynesville shale. Our proved reserves of 104.1 Bcfe in the Toledo Bend field represent approximately 14.3% of our reserves. We own interests in 15 producing wells (9.3 net to us) and operate ten of these wells. At December 31, 2009 we had three wells (2.3 net to us) that were in the process of being drilled and two wells (1.8 net to us) in the process of being completed. During December 2009, net daily production attributable to our interest from this field averaged 23.7 MMcf of natural gas. In 2010, we plan to drill 25 (19.2 net to us) horizontal Haynesville shale wells in this field.

Beckville

The Beckville field, located in Panola and Rusk Counties, Texas, has estimated proved reserves of 55.0 Bcfe which represents approximately 7.6% of our proved reserves. We operate 193 wells in this field and own interests in 78 additional wells for a total of 271 wells (162.4 net to us). During December 2009, production attributable to our interest from this field averaged 12.4 MMcf of natural gas per day and 60 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 5.1% (37.0 Bcfe) of our proved reserves as of December 31, 2009. We own interests in 75 wells in this field (48.7 net to us) and operate 57 wells in this field. During December 2009, net daily production attributable to our interest averaged 5.3 MMcf of natural gas and 45 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. In 2009, we drilled two successful horizontal Cotton Valley wells and one Haynesville shale well in the Waskom field. In 2010, we plan to drill one (.8 net to us) horizontal Haynesville shale well in the Waskom field.

Blocker

Our proved reserves of 25.6 Bcfe in the Blocker field located in Harrison County, Texas represent approximately 3.5% of our proved reserves. We own interests in 77 wells (71.3 net to us) and operate 72 of these wells. During December 2009, net daily production attributable to our interest from this field averaged 9.8 MMcf of natural gas and 35 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. During 2009 we drilled three successful Haynesville shale horizontal wells and one Cotton Valley horizontal well at Blocker. In 2010, we plan to drill one Haynesville shale horizontal and one Cotton Valley vertical well at Blocker.

Mansfield

The Mansfield field is located in DeSoto Parish Louisiana and produces from the Haynesville shale between 12,250 and 12,350 feet. During 2009 we drilled three (1.9 net to us) Haynesville shale horizontal wells. Our proved reserves in this field of 21.3 Bcfe represent approximately 2.9% of our reserves. During 2010 we plan to drill two (1.5 net to us) horizontal Haynesville shale wells at Mansfield. During December 2009, net daily production attributable to our interest for this field averaged 8.0 MMcf of natural gas.

Hico-Knowles/Terryville

We have 15.8 Bcfe of proved reserves in the Hico-Knowles/Terryville field area located in Lincoln County, Louisiana which represent approximately 2.2% of our reserves. We own interests in 71 wells (25.9 net to us) and operate 23 of these wells. This field produces primarily from the Hosston/Cotton Valley formations between 7,200 and 11,000 feet. During December 2009, net daily production attributable to our interest from this field averaged 7.2 MMcf of natural gas and 190 barrels of oil.

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 12.1 Bcfe in the Darco field represent approximately 1.7% of our reserves. We own interests in 24 wells (18.8 net to us) and operate all of these wells. During December 2009, net daily production attributable to our interest from this field averaged 1.4 MMcf of natural gas and 6 barrels of oil.

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 7.8 Bcfe in the Douglass field represent approximately 1.1% of our reserves. We own interests in 42 wells (26.9 net to us) and operate 34 of these wells. During December 2009, net daily production attributable to our interest from this field averaged 1.7 MMcf of natural gas.

Cadeville

Our proved reserves of 7.1 Bcfe in the Cadeville field located in Ouachita Parrish, Louisiana represent approximately 1.0% of our reserves. We own interests in seven wells (4.0 net to us) and operate five of these wells. During December 2009, net daily production attributable to our interest from this field averaged 0.4 MMcf of natural gas and 1 barrel of oil. This production is primarily from the Cotton Valley formation between 9,800 and 10,700 feet.

Longwood

The Longwood field located in Harrison County, Texas primarily produces from stacked sandstone reservoirs of the Travis Peak and Cotton Valley formations at depths ranging from 6,000 to 10,000 feet and the Haynesville shale formation at depths ranging from 10,450 to 10,750. We own interests in 25 wells in this field, 20.6 net to us, and operate 22 wells in this field. Our proved reserves of 4.5 Bcfe in the Longwood field represent approximately 0.6% of our total reserves. We drilled one (1.0 net to us) successful Haynesville shale horizontal well in this field during 2009. During December 2009, net daily production attributable to our interest from this field averaged 1.3 MMcf of natural gas and 2 barrels of oil.

South Texas Region

Approximately 22.2%, or 161.3 Bcfe, of our proved reserves are located in South Texas, where we own interests in 236 producing wells (125.6 net to us). We own interests in 16 field areas in the region, the largest of which are the Fandango, Double A Wells, Rosita, Las Hermanitas, Javelina and Ball Ranch fields. Net daily production rates from this region averaged 51.8 MMcf of natural gas and 448 barrels of oil during 2009 or 54.5 MMcfe per day. We spent $34.7 million in this region in 2009 to drill five successful wells (3.4 net to us) and for other development activity. We plan to spend approximately $12.0 million in 2010 for development and exploration activity in this region.

Fandango

We own interests in 21 natural gas wells (21.0 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 54.2 Bcfe in this field represent approximately 7.5% of our total reserves. Production from this field averaged 17.2 MMcf of natural gas per day during December 2009. We have drilled one successful exploration well in 2008 and two successful development wells in 2009 since we acquired this field as part of the Shell Wilcox acquisition in December 2007.

Double A Wells

Our properties in the Double A Wells field have proved reserves of 32.4 Bcfe, which represent 4.5% of our reserves. We own interests in and operate 59 producing wells (28.6 net to us) in this field in Polk County, Texas. Net daily production from the Double A Wells area averaged 5.2 MMcf of natural gas and 170 barrels of oil during December 2009. These wells produce from the Woodbine formation at an average depth of 14,300 feet.

Rosita

We own interests in 32 natural gas wells (17.3 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 31.4 Bcfe in this field represent approximately 4.3% of our total reserves. Production from this field averaged 4.5 MMcf of natural gas per day during December 2009. We acquired our interest in the field in the Shell Wilcox acquisition in December 2007.

Las Hermanitas

We own interests in and operate 15 natural gas wells (12.2 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 14.4 Bcfe in this field represent approximately 2.0% of our proved reserves. During December 2009, net daily production attributable to our interest from this field averaged 5.1 MMcf of natural gas. We acquired interests in this field in 2006 and have subsequently drilled eleven successful wells in this field since the acquisition.

Javelina

We own interests in 17 natural gas wells and one oil well, 18 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 13.3 Bcfe, which represents 1.8% of our total proved reserves. During December 2009, production attributable to our interest from this field averaged 5.8 MMcf of natural gas per day and 50 barrels of oil per day.

Ball Ranch

The Ball Ranch field is located in Kenedy County in South Texas and produces from the Vicksburg formation at depths of approximately 11,700 and 14,600 feet. We have interests in 34 producing wells (7.8 net to us) in this field. The proved reserves in this field of 4.0 Bcfe represent 1% of our total proved reserves. During 2009 we drilled three (1.4 net to us) successful wells in this field. During December 2009, net daily production attributable to our interests in this field averaged 5.1 MMcf of natural gas and 40 barrels of oil per day.

Other Regions

Approximately 7.5%, or 54.1 Bcfe, of our proved reserves are in other regions, primarily in Mississippi, New Mexico, Kentucky and the Mid-Continent regions. Within these regions we own interests in 482 producing wells (216.3 net to us) in 19 fields. Fields with the largest proved reserves include the Laurel field in Laurel, Mississippi, our San Juan Basin properties in New Mexico and our Maxie field in Mississippi. Net daily production from our other regions totaled 7.8 MMcf of natural gas and 1,099 barrels of oil or 14.5 MMcfe per day during 2009.

Laurel

The Laurel field is located in Jones County, Mississippi near a structurally complex salt dome. We own interests in and operate 52 producing wells (49.1 net to us) in the Laurel field. This field’s estimated proved reserves of 26.2 Bcfe represent 3.6% of our reserves. The field produces from more than 42 horizons that range in depth from 6,600 feet in the Stanley sand to 13,100 feet in the Middle Hosston formation. Recovery of low viscosity crude oil from this field is being enhanced through waterflood operations. During December 2009, net daily production attributable to our interests in this field averaged 975 barrels of oil 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 4.7 Bcfe in the San Juan field represent approximately 0.6% of our reserves. We own interests in 97 wells (14.6 net to us) in this field. During December 2009, net daily production attributable to our interest from this field averaged 1.1 MMcf of natural gas and 5 barrels of oil.

Maxie

The Maxie field is located along the southern boundary of the Mississippi Salt Basin and northern edge of Wiggins Arch in Forrest and Pearl River Counties in Mississippi. Maxie is primarily a gas field producing from Upper Cretaceous Sands and Lower Eocene Wilcox Sands. Our proved reserves of 3.7 Bcfe in the Maxie field represent approximately 1% of our reserves. We own interests in and operate three wells (2.1 net to us) in this field. During December 2009, net daily production attributable to our interest from this field averaged 0.9 MMcf of natural gas and 25 barrels of oil.

Major Property Acquisitions

As a result of our acquisitions, we have added 984.1 Bcfe of proved oil and natural gas reserves since 1991. Our largest acquisitions include the following:

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 ("Shell") 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. The acquisition was funded with borrowings under our bank credit facility.

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. The transaction was funded with borrowings under our bank credit facility.

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. The transaction was funded with borrowings under our bank credit facility.

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. The acquisition was funded with proceeds from a public stock offering completed in April 2005 and borrowings under our bank credit facility.

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. The acquisition was funded by borrowings under our bank credit facility.

DevX Energy Acquisition. In December 2001, we completed the acquisition of DevX Energy, Inc. ("DevX") 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. As a result of the acquisition of DevX, we acquired interests in 600 producing oil and natural gas wells located onshore primarily in East and South Texas, Kentucky, Oklahoma and Kansas. DevX's properties had 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.

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, Blocker and Hico-Knowles fields. The net proved reserves acquired in this acquisition were estimated at 0.8 MMBbls of oil and 104.7 Bcf of natural gas.

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, 2009:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)	PV 10 Value (000's)
Proved Developed:				
Producing	3,220	301,149	320,471	$ 425,366
Non-producing	1,674	65,953	75,998	86,937
Total Proved Developed	4,894	367,102	396,469	512,303
Proved Undeveloped	2,320	315,287	329,206	(23,189)
Total Proved	7,214	682,389	725,675	489,114
Discounted Future Income Taxes				(62,524)
Standardized Measure of Discounted Future Net Cash Flows(1)				$ 426,590

(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:

	2007		2008		2009	
	Oil (Mbbls)	Natural Gas (MMcf)	Oil (Mbbls)	Natural Gas (MMcf)	Oil (Mbbls)	Natural Gas (MMcf)
Proved Developed	7,449	370,339	5,446	354,934	4,894	367,102
Proved Undeveloped	3,061	217,379	4,222	168,709	2,320	315,287
Total Proved Reserves	10,510	587,718	9,668	523,643	7,214	682,389

Proved oil and natural gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are 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.

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude 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 crude oil and natural gas that are ultimately recovered.

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

	Year Ended December 31,		
	2007	2008	2009
Oil Price — $/Bbl	$60.96	$87.15	$50.94
Natural Gas Price — $/Mcf	$6.89	$8.83	$4.13
Lifting costs — $/Mcfe	$1.02	$0.95	$0.82

The oil and natural gas prices used for reserves estimation were as follows:

Year	Oil Price (per Bbl)	Natural Gas Price (per Mcf)
2007	$ 81.36	$ 6.70
2008	$ 34.49	$ 5.33
2009	$ 49.60	$ 3.54

We adopted the new rules relating to the estimation and disclosure of oil and natural gas reserves as of December 31, 2009 that were established by the Securities and Exchange Commission (“SEC”). The PV 10 Value and standardized measure of discounted future net cash flows for 2009 were determined based on the simple average of the first of month market prices for oil and natural gas during 2009 which, after basis adjustments, were $49.60 per barrel for oil and $3.54 per Mcf for natural gas. Under the prior rules the prices would have been based on the market prices at December 31, 2009, which would have been, after basis adjustments, $64.43 per barrel for oil and $5.29 per Mcf for natural gas. The following table shows the sensitivity of our total 2009 proved reserves to prices between the average prices used and the year end market prices that would have been used had we applied the same pricing methodology that was in effect for 2007 and 2008 in 2009:

	Oil (Mbbls)	Natural Gas (MMcf)	Total (MMcfe)	PV 10 Value (000's)
2009 Average Prices	7,214	682,389	725,675	$ 489,114
2009 Year End Prices	7,633	754,170	799,967	$1,151,871

The new rules also revised the guidelines for reporting proved undeveloped reserves. 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 addition, undeveloped reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

As of December 31, 2009, our proved reserves included 2.3 MMBbls of crude oil and 315 Bcf of natural gas, for a total of 329 Bcfe of undeveloped reserves. Approximately 68% of our proved undeveloped reserves at the end of 2009 were associated with the future development of our Haynesville shale properties. 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. Estimated future costs relating to the development of the undeveloped reserves are projected to be approximately $669.8 million, of which $85.1 million, $245.8 million and $169.5 million are expected to be incurred in 2010, 2011 and 2012, respectively. Costs incurred relating to the development of our undeveloped reserves were approximately $122.2 million, $104.4 million and $20.1 million in 2007, 2008 and 2009, respectively.

Our drilling activities in 2008 resulted in the conversion of 53 wells from proved undeveloped reserves to proved developed producing reserves at the end of 2008. These wells are primarily in our East Texas/North Louisiana and South Texas regions where our 2008 drilling program was primarily focused on exploitation of reserves in the Cotton Valley, Hosston, Vicksburg and Wilcox formations. Following the initial success of our Haynesville shale evaluation wells, our 2009 drilling program was refocused primarily to further evaluate and develop acreage that is prospective in the Haynesville shale formation. As a result, only six of the wells we drilled in 2009 resulted in conversions of proved undeveloped reserves to proved developed producing reserves at the end of 2009. In the course of evaluating our proved undeveloped reserves in accordance with the SEC's new reserve estimation rules, we determined that approximately 49 Bcfe of our proved undeveloped reserves as of December 31, 2008 would not be developed within the required five year period and therefore these reserves were excluded from our proved undeveloped reserves at December 31, 2009.

All undeveloped drilling locations which comprise our undeveloped reserves at the end of 2009 are scheduled to be drilled within five years of the first year that such reserves were included in our reported reserves except for 20 Bcfe. We have substantial acreage in our East Texas/North Louisiana region which is productive in the Cotton Valley and Hosston sand reservoirs. Prior to 2008, we actively pursued exploitation of the reserves in these formations, and substantially all of this acreage is held by production. Our focus in 2009 on our Haynesville shale program required us to partially reschedule development of much of our Cotton Valley and Hosston sand reserves to future periods. These reserves, which are on acreage that is currently being developed in the deeper Haynesville shale formation, will be developed after the Haynesville shale formation is developed.

We had proved reserve additions of 325 Bcfe in 2009 relating to discoveries resulting from our Haynesville shale drilling program. These reserve additions related to 109 Bcfe assigned to 43 (30.7 net to us) producing Haynesville shale wells that we drilled and 216 Bcfe assigned to 75 (56.8 net to us) proved undeveloped locations offsetting these wells. Direct offsets to the forty-three producing Haynesville shale wells accounted for 185 Bcfe of the 216 Bcfe total proved undeveloped reserves added. The remaining 31 Bcfe are attributable to additional offset locations that are not a direct offset to a producing Haynesville shale well. The inclusion of these eight additional proved locations as proved undeveloped reserves is based on a combination of data that demonstrates consistency across the reservoir including log data, pressure data, seismic data and production performance.

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.

Our policies regarding internal controls over the recording of reserves estimates requires that such estimates are in compliance with the SEC definitions and guidance and prepared in accordance with generally accepted petroleum engineering principles. 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 management group, comprised of qualified petroleum engineers, works with Lee Keeling to ensure that all data provided by us is properly reflected in the final reserves estimates and consults with Lee Keeling throughout the reserves estimation process on technical questions regarding the reserve estimates.

We did not provide estimates of total proved oil and natural gas reserves during the years ended December 31, 2007, 2008 or 2009 to any federal authority or agency, other than the SEC.

Drilling Activity Summary

During the three-year period ended December 31, 2009, we drilled development and exploratory wells as set forth in the table below:

	2007		2008		2009	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	5	4.8	—	—	—	—
Gas	152	115.7	127	71.5	37	27.2
Dry	3	2.6	3	1.0	—	—
	160	123.1	130	72.5	37	27.2
Exploratory:						
Oil	—	—	—	—	—	—
Gas	1	0.6	5	2.7	17	11.4
Dry	4	2.5	1	0.5	—	—
	5	3.1	6	3.2	17	11.4
Total	165	126.2	136	75.7	54	38.6

In 2010 to the date of this report, we have drilled five wells (4.1 net to us) and we have seven wells (4.4 net to us) that were in the process of drilling.

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, 2009:

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Arkansas	—	—	15	8.0
Kansas	—	—	8	4.4
Kentucky	—	—	87	77.1
Louisiana	16	6.2	392	206.5
Mississippi	58	50.5	5	2.1
New Mexico	1	—	96	14.6
Oklahoma	9	1.2	122	16.9
Texas	34	16.8	772	497.2
Wyoming	—	—	26	1.9
Total	118	74.7	1,523	828.7

We operate 950 of the 1,641 producing wells presented in the above table. As of December 31, 2009, we owned interests in 19 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, 2009, 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	654	654
Louisiana	81,909	45,751	29,899	26,505
Mississippi	3,076	1,878	8,929	8,368
New Mexico	10,240	1,896	—	—
Oklahoma	38,080	5,707	—	—
Texas	121,707	67,395	18,623	12,269
Wyoming	13,440	927	—	—
Total	283,338	134,075	58,105	47,796

Our undeveloped acreage expires as follows:

Expires in 2010	15%
Expires in 2011	66%
Expires in 2012	4%
Thereafter	15%
	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 or by payment of delay rentals.

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 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 68% of our 2009 natural gas sales were priced utilizing index prices and approximately 32% were priced utilizing daily spot prices. BP Energy Company and Shell Oil Company and its subsidiaries accounted for 22% and 11%, respectively, of our total 2009 sales. The loss 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.

With the significant increase in our natural gas production in Northwest Louisiana attributable to our Haynesville shale drilling program, we have entered into longer term marketing arrangements to insure that we have adequate transportation to get our natural gas production 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 dedicated our production in our Logansport and Toledo Bend fields under such agreements for terms which expire from 2016 to 2018. We have a commitment to transport a minimum of 12 Bcf over four years under one of these agreements.

We have also entered into certain agreements with a major natural gas marketing company to provide us with firm transportation and markets for our Northwest Louisiana natural gas production on the long-haul pipelines. Under these agreements, we have priority access at certain delivery points for 85,000 MMBtus per day expanding to 145,000 MMBtus per day by mid 2010. These agreements expire from 2012 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 Northwest 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.

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. In recent years, the FERC has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. 636, issued in April 1992, the interstate natural gas transportation and marketing system has been substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas supplies. In many instances, the results of Order No. 636 and related initiatives have been to substantially reduce or eliminate the traditional role of interstate pipelines as wholesalers of natural gas in favor of providing storage and transportation services.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC's pricing policy by waiving price ceilings for short-term released capacity for an experimental period, and effected changes in the FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. While most major aspects of Order No. 637 have been upheld on judicial review, certain issues such as capacity segmentation and right of first refusal are pending further consideration by the FERC. We cannot predict what action the FERC will take on these matters in the future or whether the FERC's actions will survive further judicial review.

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 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 recently 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 Minerals Management Service ("MMS"), through its Minerals Revenue Management Program, which is responsible for the management of revenues from both onshore and offshore leases. Additionally, some of our federal leases are subject to the Indian Mineral Development Act of 1982, and are therefore subject to supplemental regulations and orders of the Department of Interior's Bureau of Indian Affairs. While we cannot predict how various federal agencies may change their interpretations of existing regulations and orders or how regulations and orders issued in the future will impact our operations located on these federal leases, we do not believe we will be affected differently than other similarly situated oil and natural gas producers.

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 regulation of pipelines that transport crude oil, condensate and natural gas liquids is generally more light-handed than the FERC's regulation of natural gas pipelines under the NGA. 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 market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to FERC Order No. 561, issued in October 1993, the FERC implemented regulations generally grandfathering all previously unchallenged interstate pipeline rates and made these rates subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in the Producer Price Index for Finished Goods, minus one percent. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge a market-based rate if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline. As provided for in Order No. 561, in July 2000, the FERC issued a Notice of Inquiry seeking comment on whether to retain or to change the existing oil rate-indexing method. In December 2000, the FERC issued an order concluding that the rate index reasonably estimated the actual cost changes in the pipeline industry and should be continued for another five-year period, subject to review in July 2005. In February 2003, on remand of its December 2000 order from the D.C. Circuit, the FERC increased its index slightly. A challenge to FERC's remand order was denied by the D.C. Circuit in April 2004.

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 cost, 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. 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.

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 National Environmental Policy Act, the Coastal Zone Management Act, 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.

Changes in environmental laws and regulations which result in more stringent and costly reporting, waste handling, storage, transportation, disposal or cleanup activities could materially affect companies operating in the energy industry. Climate change regulation, primarily focused on regulating emissions of certain gases such as methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas, is under consideration by the U.S. Congress and various state governments. Adoption of new laws and regulations that regulate or restrict emissions of gases such as methane or carbon dioxide, or which levy taxes or other costs on such emissions, could result in changes to the consumption and demand for natural gas, which could adversely affect our business, financial position, results of operations and prospects. We may also be assessed administrative, civil and/or criminal penalties if we fail to comply with any such new laws and regulations.

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 53,364 square feet at a monthly rate of $100,057. This lease expires on July 31, 2014. We also own production offices and pipe yard facilities near Marshall, Livingston, and Zapata, Texas; Logansport, Louisiana; Guston, Kentucky and Laurel, Mississippi.

Employees

As of December 31, 2009, we had 130 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	54
Roland O. Burns	Senior Vice President, Chief Financial Officer, Secretary, Treasurer and Director	49
D. Dale Gillette	Vice President of Land and General Counsel	64
Mack D. Good	Chief Operating Officer	60
Stephen E. Neukom	Vice President of Marketing	60
Daniel K. Presley	Vice President of Accounting and Controller	49
Richard D. Singer	Vice President of Financial Reporting	55
David K. Lockett	Director	55
Cecil E. Martin	Director	68
David W. Sledge	Director	53
Nancy E. Underwood	Director	58

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 August 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 Marine, Inc., and on the Advisory Board of the Salvation Army in Dallas, Texas.

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 August 2008. Mr. Burns received B.A. and M.A. degrees from the University of Mississippi in 1982 and is a Certified Public Accountant.

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 32 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.

Mack D. Good was appointed our Chief Operating Officer in 2004. From 1999 to 2004, he served as Vice President of Operations. From August 1997 until February 1999, Mr. Good served as our district engineer for the East Texas/North Louisiana region. From 1983 until July 1997, Mr. Good was with Enserch Exploration, Inc. serving in various operations management and engineering positions. Mr. Good received a B.S. of Biology/Chemistry from Oklahoma State University in 1975 and a B.S. of Petroleum Engineering from the University of Tulsa in 1983. He is a Registered Professional Engineer in the State of Texas.

Stephen E. Neukom has been our Vice President of Marketing since 1997 and has served as our manager of crude oil and natural gas marketing since December 1996. From October 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 December 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. from Texas A & M University in 1983.

Richard D. Singer has been our Vice President of Financial Reporting since 2005. Mr. Singer has over 30 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 March 2004 to May 2005 and as assistant controller for Santa Fe International Corporation from July 1988 to December 2002. Mr. Singer received a B.S. degree from the Pennsylvania State University in 1976 and is a Certified Public Accountant.

Outside Directors

David K. Lockett has served as a director since 2001. Mr. Lockett is a Vice President with Dell Inc. and has held executive management positions in several divisions within Dell since 1991. Mr. Lockett has been employed by Dell Inc. for the past 18 years and has been in the technology industry for the past 33 years. 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 1988. 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. Mr. Martin holds a B.B.A. degree from Old Dominion University and is a Certified Public Accountant.

David W. Sledge has served as a director since 1996. 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 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 the Presbyterian Hospital of Dallas 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. 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 crude 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 crude oil or natural gas that first started in 2008 continues again during 2010, 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.

In the future we may enter into 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 current 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 are in a recession which could last through 2010 and beyond, and the capital markets are experiencing significant volatility. The recession has had an adverse impact on demand and pricing for crude 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 hydraulic fracturing legislation could increase our costs and restrict our access to our oil and gas reserves.

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. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. The use of hydraulic fracturing is necessary to produce commercial quantities of crude oil and natural gas from many reservoirs including the Haynesville shale, Cotton Valley and other tight natural gas reservoirs.

Although it is not possible at this time to predict the final outcome of any legislation regarding hydraulic fracturing, any new federal restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could significantly increase our operating, capital and compliance costs as well as delay or inhibit our ability to develop our oil and natural gas reserves.

The proposed US federal budget for fiscal year 2011 includes certain provisions that, if passed as originally submitted, will have an adverse effect on us.

On February 1, 2010, the federal government released its proposed budget for fiscal year 2011. The proposed budget contains provisions which would impose new taxes and which would repeal many tax incentives and deductions that are currently used by independent oil and gas producers. The provisions 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 $470.8 million in debt as of December 31, 2009, and our ratio of total debt to total capitalization was approximately 31%.

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 $6^7/_8$% senior notes due 2012 and $8^3/_8$% senior notes due 2017. 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 and South 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 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, 2009, 45% of our total proved reserves are undeveloped and 10% are 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 a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- 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, has been introduced in the Senate, but has not passed. Both bills contain the basic feature of establishing a "cap and trade" system for restricting greenhouse gas emissions in the United States. Under such 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. The ultimate outcome of these legislative initiatives remain uncertain. In addition to the pending climate legislation, the EPA has issued the Final Mandatory Reporting of Greenhouse Gases Rule, which requires many suppliers of fossil fuels or industrial chemicals, manufacturers of vehicles and engines, and other facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year to begin collecting greenhouse gas emissions data under a new reporting system beginning on January 1, 2010 with the first annual report due March 31, 2011. Although we currently are not required to report under these new regulations, we may be required to do so in the future. 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 proposed regulation that would require permits for and reductions in greenhouse gas emissions for certain facilities, and may issue final rules this year. Since all of our crude oil and natural gas production is in the United States, any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating costs, and could have an adverse effect on demand for the crude oil and natural gas we produce.

In January 2010 the Bureau of Land Management announced that it will be issuing a new draft oil and gas leasing policy that will 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 and development plans prior to leasing areas where intensive new oil and gas development is anticipated, and a comprehensive parcel review process. As the policy has not yet been released, we are not able to determine the impact these potential leasing policy changes may have on our business.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly 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.

We have in place a stockholders' rights plan. The provisions of the stockholders' rights plan and the above 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. *SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS*

No matters were submitted to a vote of our security holders during the fourth quarter of 2009.

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
2008 —	First Quarter	$ 40.92	$ 28.52
	Second Quarter	$ 85.26	$ 38.84
	Third Quarter	$ 90.61	$ 43.96
	Fourth Quarter	$ 52.62	$ 24.34
2009 —	First Quarter	$ 52.70	$ 26.62
	Second Quarter	$ 43.93	$ 28.13
	Third Quarter	$ 42.65	$ 27.88
	Fourth Quarter	$ 49.14	$ 35.47

As of February 26, 2010, we had 47,105,606 shares of common stock outstanding, which were held by 263 holders of record and approximately 15,286 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 2009, we did not repurchase any of our equity securities.

The following table summarizes certain information regarding our equity compensation plans as of December 31, 2009:

	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	424,620	$23.73	3,447,675

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

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, 2009 are derived from our consolidated financial statements. The financial results are not necessarily indicative of our future operations or future financial results. The data presented below should be read in conjunction with our consolidated financial statements and the notes thereto and "Management's Discussion and Analysis of Financial Condition and Results of Operations." During 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, (In thousands, except per share data)				
	2005	2006	2007	2008	2009
Revenues:					
Oil and gas sales	$ 264,806	$ 257,218	$ 331,613	$ 563,749	$ 290,863
Gain on sale of assets	—	—	—	26,560	213
Total revenues	264,806	257,218	331,613	590,309	291,076
Operating expenses:					
Oil and gas operating[1]	44,267	53,903	64,791	86,730	69,179
Exploration	16,899	1,424	7,039	5,032	907
Depreciation, depletion and amortization	53,123	75,278	125,349	182,179	213,238
Impairment of oil and gas properties	3,400	8,812	482	922	115
General and administrative, net	14,686	20,395	27,813	32,266	39,172
Total operating expenses	132,375	159,812	225,474	307,129	322,611
Income (loss) from operations	132,431	97,406	106,139	283,180	(31,535)
Other income (expenses):					
Interest income	388	682	877	1,537	245
Other income	209	184	144	119	133
Interest expense	(20,266)	(20,733)	(32,293)	(25,336)	(16,086)
Marketable securities impairment	—	—	—	(162,672)	—
Gain (loss) from derivatives	(13,556)	10,716	—	—	—
Total other income (expense)	(33,225)	(9,151)	(31,272)	(186,352)	(15,708)
Income (loss) from continuing operations before income taxes	99,206	88,255	74,867	96,828	(47,243)
Benefit from (provision for) income taxes	(36,525)	(34,190)	(29,223)	(38,611)	10,772
Income (loss) from continuing operations	62,681	54,065	45,644	58,217	(36,471)
Income (loss) from discontinued operations	(2,202)	16,600	23,257	193,745[2]	—
Net income (loss)	$ 60,479	$ 70,665	$ 68,901	$ 251,962	$ (36,471)
Basic net income (loss) per share:					
Continuing operations	$ 1.57	$ 1.25	$ 1.03	$ 1.27	$ (0.81)
Discontinued operations	(0.06)	0.38	0.52	4.23	—
	$ 1.51	$ 1.63	$ 1.55	$ 5.50	$ (0.81)
Diluted net income (loss) per share:					
Continuing operations	$ 1.51	$ 1.22	$ 1.01	$ 1.26	$ (0.81)
Discontinued operations	(0.06)	0.38	0.52	4.20	—
	$ 1.45	$ 1.60	$ 1.53	$ 5.46	$ (0.81)
Weighted average shares outstanding:					
Basic	39,216	42,220	43,415	44,524	45,004
Diluted	40,852	43,252	44,080	44,813	45,004

(1) Includes lease operating costs and production and 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.

Balance Sheet Data:

	As of December 31,				
	2005	2006	2007 (In thousands)	2008	2009
Cash and cash equivalents	$ 89	$ 1,228	$ 5,565	$ 6,281	$ 90,472
Property and equipment, net	706,928	917,854	1,310,559	1,444,715	1,576,287
Net assets of discontinued operations	252,258	913,478	981,682	—	—
Total assets	1,016,663	1,878,125	2,354,387	1,577,890	1,858,961
Total debt	243,000	355,000	680,000	210,000	470,836
Stockholders' equity	582,859	902,912	1,039,085	1,062,085	1,066,111

Cash Flow Data:

	Year Ended December 31,				
	2005	2006	2007 (In thousands)	2008	2009
Cash flows provided by operating activities from continuing operations	$ 173,193	$ 186,169	$ 201,539	$ 450,533	$ 176,257
Cash flows used for investing activities from continuing operations	(327,234)	(281,505)	(531,493)	(289,194)	(348,777)
Cash flows provided by (used for) financing activities from continuing operations	2,127	132,882	334,357	(452,883)	256,711
Cash flows provided by (used for) discontinued operations	150,747	(36,407)	(66)	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 1,641 (903.4 net to us) producing oil and natural gas wells and we operate 950 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 offshore operations were historically conducted through our subsidiary, Bois d'Arc. Bois d'Arc was acquired by Stone Energy Corporation ("Stone") in exchange for a combination of cash and shares of Stone common stock on August 28, 2008. Our offshore operations are presented as discontinued operations in our financial statements for all periods presented. Unless indicated otherwise, the amounts in the accompanying tables and discussion relate to our continuing onshore operations. In 2008, we recorded an impairment of $162.7 million ($105.8 million after income taxes) to reduce our carrying value for our investment in Stone common stock to fair market value.

Our future growth will be driven primarily by acquisition, development and exploration activities. In 2009 our growth in production and proved reserves was primarily driven by our successful drilling activities in the Haynesville shale formation. Under our current drilling budget, we plan to spend approximately $385.0 million in 2010 for development and exploration activities which will primarily be focused on developing our Haynesville shale properties. We plan to drill approximately 59 wells (42.6 net to us) in 2010. Fifty-six of these wells will be horizontal Haynesville shale wells. However, we could increase or decrease the number of wells that we drill depending on oil and natural gas prices. We do not 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 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 $6.6 million as of December 31, 2009.

Results of Operations

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Our operating data for 2008 and 2009 is summarized below:

	Year Ended December 31,	
	2008	2009
Net Production Data:		
Natural gas (MMcf)	53,867	60,820
Oil (MBbls)	1,009	775
Natural gas equivalent (MMcfe)	59,923	65,468
Average Sales Price:		
Oil ($/Bbl)	$87.15	$50.94
Natural gas ($/Mcf)	$8.92	$3.70
Natural gas including hedging ($/Mcf)	$8.83	$4.13
Average equivalent price ($/Mcfe)	$9.49	$4.04
Average equivalent price including hedging ($/Mcfe)	$9.41	$4.44
Expenses ($ per Mcfe):		
Oil and gas operating(1)	$1.45	$1.06
Depreciation, depletion and amortization(2)	$3.03	$3.25

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

Oil and gas sales. Our oil and gas sales decreased $272.8 million (48%) in 2009 to $290.9 million from sales of $563.7 million in 2008. This decrease primarily reflects lower prices realized by us for natural gas and crude oil in 2009. The average price for natural gas realized by us decreased by 53% in 2009 as compared to 2008. Prices for crude oil decreased by 42% in 2009 as compared to 2008. Our production in 2009 increased by 9% over 2008's production as our successful drilling in the Haynesville shale more than replaced the declines from our existing producing properties.

Oil and gas operating expenses. Our oil and gas operating expenses, including production taxes, decreased $17.5 million (20%) to $69.2 million in 2009 from operating expenses of $86.7 million in 2008. Oil and gas operating expenses per equivalent Mcf produced decreased to $1.06 as compared to $1.45 in 2008. The decrease in operating costs mainly reflects lower production taxes resulting from the lower oil and natural gas prices.

Exploration expense. We had $0.9 million in exploration expense in 2009 as compared to $5.0 million in 2008. Exploration expense in 2009 primarily related to costs incurred for the acquisition of seismic data. Exploration expense in 2008 includes the cost of one exploratory dry hole, leasehold impairments and cost incurred for seismic data acquisition.

Depreciation, depletion and amortization expense ("DD&A"). DD&A increased $31.0 million (17%) to $213.2 million in 2009 from DD&A of $182.2 million in 2008. Our DD&A rate per Mcfe produced averaged $3.25 in 2009 as compared to $3.03 for 2008. DD&A increased due to our higher production level and an increase in the amortization rate.

Impairment of oil and gas properties. We recorded impairments to our oil and gas properties of $0.1 million in 2009 as compared to impairment expense of $0.9 million in 2008. The impairments in 2009 and 2008 relate to fields where an impairment was indicated based on estimated future cash flows attributable to the fields' estimated proved oil and natural gas reserves.

General and administrative expenses. General and administrative expenses of $39.2 million for 2009 were 21% higher than general and administrative expenses of $32.3 million for 2008. The increase primarily reflects our higher personnel costs in 2009 due to increased staffing necessary to support our exploration and development activities and an increase of $3.5 million in our stock-based compensation in 2009 as compared to 2008.

Interest expense. Interest expense decreased $9.2 million (37%) to $16.1 million in 2009 from interest expense of $25.3 million in 2008. The decrease was primarily the result of our lower outstanding borrowings and our lower average interest rates in 2009 as well as an increase in capitalized interest related to our unevaluated properties during 2009. Average borrowings under our bank credit facility decreased to $116.8 million in 2009 as compared to $301.5 million for 2008. The average interest rate on the outstanding borrowings under our credit facility decreased to 2.1% in 2009 as compared to 4.5% in 2008. Interest expense in 2009 also includes $6.1 million related to the issuance of $300.0 million of 8$^{3}/_{8}$% senior notes in October 2009. We capitalized interest of $6.6 million and $2.3 million in 2009 and 2008, respectively, which reduced interest expense.

Income taxes. Income tax expense from continuing operations decreased in 2009 to a benefit of $10.8 million from a provision of $38.6 million in 2008. Our effective tax rate of 22.8% in 2009 and our effective tax rate of 39.9% in 2008 differed from federal income tax rate of 35% primarily due to the effect of nondeductible compensation and state income taxes.

Income (loss). We reported a loss of $36.5 million for 2009 as compared to income from continuing operations of $58.2 million for 2008. The loss per diluted share for 2009 was $0.81 on weighted average shares outstanding of 45.0 million as compared to income per share $1.26 for 2008 on weighted average diluted shares outstanding of 44.8 million. The loss in 2009 was primarily attributable to the declines in oil and natural gas prices that we realized.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Our operating data for 2007 and 2008 is summarized below:

	Year Ended December 31, 2007	2008
Net Production Data:		
Natural gas (MMcf)	39,231	53,867
Oil (MBbls)	1,008	1,009
Natural gas equivalent (MMcfe)	45,282	59,923
Average Sales Price:		
Oil ($/Bbl)	$60.96	$87.15
Natural gas ($/Mcf)	$6.89	$8.92
Natural gas including hedging ($/Mcf)	$6.89	$8.83
Average equivalent price ($/Mcfe)	$7.32	$9.49
Average equivalent price including hedging ($/Mcfe)	$7.32	$9.41
Expenses ($ per Mcfe):		
Oil and gas operating(1)	$1.43	$1.45
Depreciation, depletion and amortization(2)	$2.76	$3.03

(1) Includes lease operating costs and production and 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 $232.1 million (70%) in 2008 to $563.7 million from $331.6 million in 2007. The increase in our sales is primarily due to a 32% increase in our production combined with stronger oil and natural gas prices in 2008. Our realized oil price in 2008 increased by 43% and our realized natural gas price increased by 28% as compared to 2007. Production in 2008 increased by

15% over 2007 as the result of an acquisition of producing properties in South Texas which closed in December 2007. Our successful drilling activity replaced declines from our existing producing properties and accounted for the remaining 17% production increase in 2008.

Oil and gas operating expenses. Our oil and gas operating expenses, including production taxes, increased $21.9 million (34%) to $86.7 million in 2008 from $64.8 million in 2007. Oil and gas operating expenses per equivalent Mcf produced increased $0.02 to $1.45 in 2008 as compared to $1.43 in 2007. The increase in operating costs is due to the start-up of new wells and higher production and ad valorem taxes due to increased oil and gas prices.

Exploration expense. In 2008, we incurred $5.0 million in exploration expense as compared to $7.0 million in 2007. Exploration expense in 2008 primarily relates to one dry hole drilled, the impairment of unevaluated leases and the acquisition of seismic data. Exploration expense in 2007 included costs for four dry holes, leasehold impairments and costs incurred for seismic data acquisition.

DD&A. DD&A increased $56.9 million (45%) to $182.2 million in 2008 from $125.3 million in 2007. This increase resulted from our 32% increase in production in 2008 as compared to 2007 and an increase in our average DD&A rate from $2.76 to $3.03 per Mcfe produced. The increase in the average DD&A rate results from the higher finding costs associated with our property acquisitions and exploration and development activities in 2007 and 2008.

Impairment of oil and gas properties. We recorded impairments to our oil and gas properties of $0.9 million in 2008 and $0.5 million in 2007. The impairments in 2008 and 2007 relate to fields where an impairment was indicated based on estimated future cash flows attributable to the fields' estimated proved oil and natural gas reserves.

General and administrative expenses. General and administrative expenses increased $4.5 million (16%) in 2008 to $32.3 million from $27.8 million in 2007. The increase primarily reflects higher personnel costs resulting from increased hiring to support our operating activities and an increase of $1.5 million in stock based compensation in 2008 as compared to 2007.

Interest expense. Interest expense decreased $7.0 million (22%) to $25.3 million in 2008 from $32.3 million in 2007. The decrease was primarily due to lower interest rates in 2008 and the capitalization of interest related to our unevaluated properties on which we are conducting exploration activity. The average interest rate on the outstanding borrowings under our credit facility decreased to 4.5% in 2008 as compared to 6.6% in 2007. We capitalized interest of $2.3 million in 2008 which reduced interest expense. No interest was capitalized in 2007. Average borrowings under our bank credit facility increased to $301.5 million in 2008 as compared to $279.7 million for 2007.

Impairment of marketable securities. We received shares of common stock of Stone from the sale of Bois d'Arc which were initially valued at $211.4 million. Subsequent to August 2008, the market value of the Stone shares declined significantly. We recognized an impairment charge of $162.7 million in the fourth quarter of 2008 based upon our assessment that this decline is other than temporary.

Income taxes. Income tax expense related to continuing operations increased by $9.4 million to $38.6 million in 2008 from $29.2 million for 2007. Higher income tax expenses in 2008 are primarily due to our higher income. Our effective tax rate of 39.9% for continuing operations in 2008 was comparable to our effective tax rate in 2007 of 39.0%.

Income from continuing operations. We reported income from continuing operations of $58.2 million in 2008, as compared to $45.6 million for 2007. The income per diluted share from continuing operations for

2008 was $1.26 on weighted average diluted shares outstanding of 44.8 million as compared to $1.01 for 2007 on weighted average diluted shares outstanding of 44.1 million. The higher income from continuing operations in 2008 results from higher oil and gas sales reflecting increased production and significantly higher oil and natural gas prices received. Higher revenues were only partially offset by higher operating costs, DD&A expense and general and administrative expense. Impairments of $163.6 million in 2008 reduced our income from continuing operations by $106.4 million.

Income from discontinued operations. Income from discontinued operations was $193.7 million in 2008 as compared to $23.3 million in 2007. The increase in income from discontinued operations in 2008 reflects the higher oil and gas prices in 2008 offset in part by higher operating and exploration expenses of the offshore operations. Also included in income from discontinued operations in 2008 is a net gain, after income taxes, of $158.1 million as a result of the sale of our interest in Bois d'Arc.

Liquidity and Capital Resources

Funding for our activities has historically been provided by our operating cash flow, debt or equity financings or asset dispositions. Our net cash provided by operating activities from continuing operations in 2009 totaled $176.3 million. Our other primary source of funds in 2009 was $289.2 million of net proceeds from the issuance of senior notes and $135.0 million of borrowings under our bank credit facility. A portion of the cash proceeds from our senior notes offering in 2009 was used to repay the balance outstanding on our bank credit facility. In 2008, our net cash flow provided by operating activities from continuing operations totaled $450.5 million. Our other primary source of funds in 2008 was the after tax proceeds of $421.8 million from the disposition of assets, including sale of our offshore operations. In 2007, our net cash flow provided by operating activities from continuing operations totaled $201.5 million. Our other primary source of funds in 2007 was a net increase of $325.0 million under our bank credit facility.

Our cash flow from operating activities from continuing operations in 2009 decreased by $274.2 million to $176.3 million as compared to 2008 primarily due to lower revenues which were primarily attributable to the lower natural gas and crude oil prices we realized during 2009. Our cash flow from operating activities from continuing operations in 2008 increased by $249.0 million to $450.5 million as compared to $201.5 million in 2007 primarily due to higher revenues which were attributable to our increased production and higher oil and natural gas prices.

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. In 2009, our capital expenditures of $344.8 million decreased by $81.6 million as compared to 2008 capital expenditures of $426.4 million. During 2009 we initially funded our capital expenditures with operating cash flow and borrowings of $135.0 million under our bank credit facility. In October 2009 we issued $300.0 million of $8^3/_8$% senior notes due in 2017 and used the net proceeds from this offering of $289.2 to pay down the balance outstanding under our bank credit facility and to fund current and future capital expenditures. In 2008, we reduced the amount outstanding under our bank credit facility by $470.0 million, primarily by using the proceeds from our asset sales. Our capital expenditures in 2008 of $426.4 million decreased by $100.6 million from 2007 capital expenditures of $527.0 million. Capital expenditures in 2007 included $191.3 million for acquisitions of producing oil and gas properties. In 2008, we spent $113.0 million to acquire unevaluated acreage primarily relating to the exploration of the Haynesville shale formation. We did not acquire any producing oil and natural gas properties in 2008 or 2009.

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

	Year Ended December 31, 2007	2008 (In thousands)	2009
Exploration and development:			
Acquisitions of proved oil and gas properties	$ 191,290	$ —	$ —
Acquisitions of unproved oil and gas properties	6,202	113,023	26,040
Developmental leasehold costs	2,780	6,242	1,898
Development drilling	302,355	230,604	205,901
Exploratory drilling	14,289	61,113	101,049
Workovers and recompletions	8,799	14,248	9,579
	525,715	425,230	344,467
Other	1,257	1,171	374
Total	$ 526,972	$ 426,401	$ 344,841

The timing of most of our capital expenditures is discretionary because we have no material long-term capital expenditure commitments except for contracted drilling 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 $385.0 million for development and exploration projects in 2010, which will be funded primarily by cash flows from operating activities and cash on hand. 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 2010 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 December 15, 2011. Indebtedness under the bank credit facility is secured by all of our and our subsidiaries' assets and is guaranteed by all of our 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, 2009 the borrowing base was $500.0 million, all 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 2% 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 1.5%) plus 0.5% to 1.25%. 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 $40.0 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 of at least one-to-one and maintenance of a minimum tangible net worth. We were in compliance with these covenants as of December 31, 2009.

We have $175.0 million of 6 7/8% senior notes outstanding which are due March 1, 2012. Interest is payable semiannually on each March 1 and September 1. We also have $300.0 million of 8 7/8% senior notes outstanding which are due October 15, 2017. Interest is payable semiannually on each October 15 and April 15. The senior notes are unsecured obligations and are guaranteed by all of our subsidiaries.

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:

	2010	2011	2012	2013	2014	Thereafter	Total
				(In thousands)			
6 7/8% senior notes	$ —	$ —	$ 175,000	$ —	$ —	$ —	$ 175,000
8 3/8% senior notes	—	—	—	—	—	300,000	300,000
Interest on debt	37,156	37,156	27,136	25,125	25,125	70,141	221,839
Operating leases	1,701	1,701	1,701	1,701	1,200	2,000	10,004
Natural gas transportation agreements	7,153	7,434	7,434	6,157	2,729	5,959	36,866
Contracted drilling services	50,771	32,151	14,292	—	—	—	97,214
	$ 96,781	$ 78,442	$ 225,563	$ 32,983	$ 29,054	$ 378,100	$ 840,923

Future interest costs are based upon the effective interest rates of our outstanding senior notes.

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 2014. We record a separate liability for the fair value of these asset retirement obligations which totaled $6.6 million as of December 31, 2009.

Federal Taxation

Our federal income tax returns for the years ended December 31, 2006 and 2007 were recently under examination by the Internal Revenue Service, and these examinations have been closed with no additional tax liability. 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, 2004. 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. Therefore, we have no 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.

At December 31, 2009, we had federal income tax net operating loss carryforwards of approximately $40.2 million. We have established a $23.0 million valuation allowance against a portion of the net operating loss carryforwards that we acquired in an acquisition due to a “change in control” limitation which will prevent us from fully realizing these carryforwards. The carryforwards expire from 2017 through 2021. The realization of these carryforwards depends on our ability to generate future taxable income in order to utilize these carryforwards.

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 as well as impairments that are recognized on our oil and gas properties are highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. 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 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.

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.

New accounting standards. In December 2007, the Financial Accounting Standards Board (the "FASB") issued new accounting guidance, which we adopted January 1, 2009, requiring reporting entities to present noncontrolling minority interests as a component of stockholder's equity instead of a liability and providing guidance on the accounting for transactions between an entity and noncontrolling interests.

In September 2008, the FASB issued new guidance which requires that unvested share-based payment awards containing nonforfeitable rights to dividends be considered participating securities and included in the computation of basic and diluted earnings per share pursuant to the two-class method. Earnings per share data for all periods presented have been adjusted retrospectively for the effects of this new guidance.

In December 2008, the SEC released the Final Rule, "Modernization of Oil and Gas Reporting" (the "Final Rule") which revises oil and gas reserve estimations and reporting disclosures. This release permits the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The revised rules also limit the inclusion of proved undeveloped reserves to those that can be developed within a five year period unless specific circumstances justify a longer time. The Final Rule also allows companies to disclose their probable and possible oil and gas reserves. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its oil and gas reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (iii) report oil and gas reserves using an average price based upon the average first of the month prior twelve month period rather than a year end price. In October 2009 the SEC staff issued Staff Accounting Bulletin 113 to modify Topic 12, *Oil and Gas Producing Activities*, in order to conform financial reporting practices for public companies with the Final Rule. In January 2010 the FASB issued new accounting guidance to align the reserve calculation and disclosure requirements within generally accepted accounting principles with the Final Rule. All of these rule changes became effective on December 31, 2009. We have adopted these changes and conformed our reserve estimation and disclosure practices in accordance with the guidance contained in all of these releases.

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 crude 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 2009, 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 $0.8 million and a $1.00 change in the price per Mcf of natural gas would have changed our cash flow by approximately $53.0 million.

We hedged approximately 10% of our price risks associated with our natural gas sales during 2009. Because our swap agreements were designated as hedge derivatives, changes in their fair value generally were reported as a component of accumulated other comprehensive loss until the related sales of production occurred. At that time, the realized hedge derivative gain or loss was transferred to oil and gas sales in our consolidated income statement. None of our derivative contracts had margin requirements or collateral provisions that could have required funding prior to the scheduled cash settlement date. We had no crude oil or natural gas derivative financial instruments outstanding as of December 31, 2009 and none of our oil or gas production is hedged in 2010 or thereafter.

Interest Rates

At December 31, 2009, we had $470.8 million of long-term debt. Of this amount, $175.0 million bears interest at a fixed rate of $6^{7}/_{8}\%$ and $295.8 million bears interest at $8^{3}/_{8}\%$ (with an effective interest rate of $8^{5}/_{8}\%$). The fair market value of our fixed rate debt as of December 31, 2009 was $479.9 million based on the market price of 102% of the face amount. At December 31, 2009, we had no amounts 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. We had no interest rate derivatives outstanding during 2009 or at December 31, 2009.

ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

Our consolidated financial statements are included on pages F-1 to F-28 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 disclosure controls and procedures. Our Chief Executive Officer and Chief Financial Officer have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), our disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by this Annual Report on Form 10-K. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures are adequate and effective in ensuring that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management’s Report on Internal Control Over Financial Reporting

The management of Comstock Resources, Inc. (the “Company”) is responsible for establishing and maintaining adequate internal control over financial reporting. The Company’s internal control over financial reporting is a process designed under the supervision of the Company’s Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company’s financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2009, management assessed the effectiveness of the Company’s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in “Internal Control — Integrated Framework,” issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2009, based on those criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company’s internal control over financial reporting as of December 31, 2009. The report, which expresses unqualified opinions on the effectiveness of the Company’s internal control over financial reporting as of December 31, 2009 is included below.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Comstock Resources, Inc.

We have audited Comstock Resources, Inc.'s internal control over financial reporting as of December 31, 2009, 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.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Comstock Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Comstock Resources, Inc. and subsidiaries as of December 31, 2008 and 2009, and the related consolidated statements of operations, stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2009 and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 26, 2010

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, 2009.

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 2010 annual meeting, which will be filed with the SEC within 120 days of December 31, 2009, 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, 2009.

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

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, 2009.

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, 2009.

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, 2009.

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-28 of this report:

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

(b) *Exhibits:*

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

Exhibit No.	Description
3.1(a)	Restated Articles of Incorporation (incorporated by reference to Exhibit 3.1 to our Annual Report on Form 10-K for the year ended December 31, 1995).
3.1(b)	Certificate of Amendment to the Restated Articles of Incorporation dated July 1, 1997 (incorporated by reference to Exhibit 3.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1997).
3.2	Certificate of Amendment to the Restated Articles of Incorporation dated May 19, 2009 (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-3 dated October 5, 2009).
3.3	Bylaws (incorporated by reference to Exhibit 3.2 to our Registration Statement on Form S-3, dated October 25, 1996).
4.1	Rights Agreement dated as of December 14, 2000, by and between Comstock and American Stock Transfer and Trust Company, as Rights Agent (incorporated herein by reference to Exhibit 1 to our Registration Statement on Form 8-A dated January 11, 2001).
4.2	Certificate of Designation, Preferences and Rights of Series B Junior Participating Preferred Stock (incorporated by reference to Exhibit 2 to our Registration Statement on Form 8-A dated January 11, 2001).
4.3	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).

Exhibit No.	Description
4.4	First Supplemental Indenture, dated February 25, 2004 between Comstock, the guarantors and The Bank of New York Trust Company, N.A., Trustee for the $6^{7}/_{8}$% Senior Notes due 2012 (incorporated by reference to Exhibit 4.7 to our Annual Report on Form 10-K for the year ended December 31, 2003).
4.5	Second Supplemental Indenture, dated March 11, 2004 between Comstock, the guarantors and The Bank of New York Trust Company, N.A. for the $6^{7}/_{8}$% Senior Notes due 2012 (incorporated by reference to Exhibit 4.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.6	Third Supplemental Indenture dated July 16, 2004 between Comstock, the guarantors and The Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.7	Fourth Supplemental Indenture dated May 20, 2005 between Comstock, the guarantors and The Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2005).
4.8	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).
4.9	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 $8^{3}/_{8}$% Senior Notes due 2017 (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated October 9, 2009).
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#*	Form of Restricted Stock Agreement under the Comstock Resources, Inc. 2009 Long-term Incentive Plan.
10.5	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).
10.6	First Amendment to the Lease Agreement dated August 25, 2005, between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.20 to our Annual Report on Form 10-K for the year ended December 31, 2005).
10.7	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).
10.8	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).

Exhibit No.	Description
10.9	Fourth Amendment to the Lease Agreement dated September 30, 2008 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009).
10.10	Second Amended and Restated Credit Agreement, dated December 15, 2006, among Comstock, 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 Bank, Fortis Capital Corp., and Union Bank of California, N.A. as co-documentation agents (incorporated by reference to Exhibit 10.1 to our Annual Report on Form 10-K for the year ended December 31, 2006).
10.11	First Amendment to Second Amended and Restated Credit Agreement dated April 30, 2008, among Comstock as the borrower, the lenders, from time to time thereto, and Bank of Montreal, as administrative agent (incorporated by reference to Exhibit 10.2 to our Quarterly report on Form 10-Q for the quarter ended March 31, 2008).
10.12	Second Amendment to Second Amended and Restated Credit Agreement dated May 1, 2009, among Comstock 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 March 31, 2009).
10.13	Third Amendment to Second Amended and Restated Credit Agreement dated October 5, 2009, among Comstock as the borrower, the lenders, from time to time thereto, and Bank of Montreal, as administrative agent (incorporated by reference to Exhibit 99.1 to our Current Report on Form 8-K dated October 6, 2009).
10.14*	Base Contract for Sale and Purchase of Natural Gas between Comstock Oil & Gas-Louisiana, LLC and BP Energy Company dated November 7, 2008, as amended by Third Amended and Restated Special Provisions dated January 5, 2010.
21*	Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Independent Petroleum Engineers.
31.1*	Chief Executive Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Chief Financial Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1+	Chief Executive Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2+	Chief Financial Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Independent Petroleum Engineers on Proved Reserves as of December 31, 2009.

* 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 26, 2010

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 26, 2010
/s/ ROLAND O. BURNS Roland O. Burns	Senior Vice President, Chief Financial Officer, Secretary, Treasurer and Director (Principal Financial and Accounting Officer)	February 26, 2010
/s/ DAVID K. LOCKETT David K. Lockett	Director	February 26, 2010
/s/ CECIL E. MARTIN, JR. Cecil E. Martin, Jr.	Director	February 26, 2010
/s/ DAVID W. SLEDGE David W. Sledge	Director	February 26, 2010
/s/ NANCY E. UNDERWOOD Nancy E. Underwood	Director	February 26, 2010

COMSTOCK RESOURCES, INC.

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, 2008 and 2009, and the related consolidated statements of operations, stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2009. 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, 2008 and 2009, and the consolidated results of their operations and cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1 to the consolidated financial statements, during the year ended December 31, 2009 the Company adopted new accounting standards relating to the manner in which basic and diluted earnings per share are calculated and the presentation of noncontrolling interests in consolidated subsidiaries, and changed its oil and gas reserves and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2009, 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 26, 2010 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 26, 2010

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
As of December 31, 2008 and 2009

	December 31, 2008	December 31, 2009
	(In thousands)	
ASSETS		
Cash and Cash Equivalents	$ 6,281	$ 90,472
Accounts Receivable:		
Oil and gas sales	34,401	31,435
Joint interest operations	7,876	8,845
Marketable Securities	48,868	95,973
Derivative Financial Instruments	13,974	—
Current Income Taxes Receivable	1,824	42,402
Deferred Income Taxes Receivable	4,995	—
Other Current Assets	11,809	4,259
Total current assets	130,028	273,386
Property and Equipment:		
Unevaluated oil and gas properties	116,489	130,364
Oil and gas properties, successful efforts method	1,960,544	2,289,571
Other	6,162	6,477
Accumulated depreciation, depletion and amortization	(638,480)	(850,125)
Net property and equipment	1,444,715	1,576,287
Other Assets	3,147	9,288
	$ 1,577,890	$ 1,858,961
LIABILITIES AND STOCKHOLDERS' EQUITY		
Accounts Payable	$ 99,460	$ 67,488
Deferred Income Taxes Payable	—	6,588
Accrued Expenses	14,995	20,695
Total current liabilities	114,455	94,771
Long-term Debt	210,000	470,836
Deferred Income Taxes Payable	185,870	220,682
Reserve for Future Abandonment Costs	5,480	6,561
Total liabilities	515,805	792,850
Commitments and Contingencies		
Stockholders' Equity:		
Common stock — $0.50 par, 75,000,000 shares authorized, 46,442,595 and 47,103,770 shares issued and outstanding at December 31, 2008 and 2009, respectively	23,221	23,552
Additional paid-in capital	415,875	434,505
Accumulated other comprehensive income	9,083	30,619
Retained earnings	613,906	577,435
Total stockholders' equity	1,062,085	1,066,111
	$ 1,577,890	$ 1,858,961

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, 2007, 2008 and 2009

	2007	2008	2009
		(In thousands, except per share amounts)	
Revenues:			
Oil and gas sales	$ 331,613	$ 563,749	$ 290,863
Gain on sale of assets	—	26,560	213
Total revenues	331,613	590,309	291,076
Operating expenses:			
Oil and gas operating	64,791	86,730	69,179
Exploration	7,039	5,032	907
Depreciation, depletion and amortization	125,349	182,179	213,238
Impairment of oil and gas properties	482	922	115
General and administrative, net	27,813	32,266	39,172
Total operating expenses	225,474	307,129	322,611
Operating income (loss) from continuing operations	106,139	283,180	(31,535)
Other income (expenses):			
Interest income	877	1,537	245
Other income	144	119	133
Interest expense	(32,293)	(25,336)	(16,086)
Marketable securities impairment	—	(162,672)	—
Total other income (expenses)	(31,272)	(186,352)	(15,708)
Income (loss) from continuing operations before income taxes	74,867	96,828	(47,243)
Benefit from (provision for) income taxes	(29,223)	(38,611)	10,772
Income (loss) from continuing operations	45,644	58,217	(36,471)
Income from discontinued operations	23,257	193,745	—
Net income (loss)	$ 68,901	$ 251,962	$ (36,471)
Basic net income (loss) per share:			
Continuing operations	$ 1.03	$ 1.27	$ (0.81)
Discontinued operations	0.52	4.23	—
	$ 1.55	$ 5.50	$ (0.81)
Diluted net income (loss) per share:			
Continuing operations	$ 1.01	$ 1.26	$ (0.81)
Discontinued operations	0.52	4.20	—
	$ 1.53	$ 5.46	$ (0.81)
Weighted average shares outstanding:			
Basic	43,415	44,524	45,004
Diluted	44,080	44,813	45,004

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2007, 2008 and 2009

	Common Shares	Common Stock-Par Value	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Non-Controlling Interest in Discontinued Operations	Total
				(In thousands)			
Balance at December 31, 2006	44,395	$ 22,197	$ 367,323	$ 293,043	$ —	$ 220,349	$ 902,912
Exercise of stock options and warrants	596	298	2,571	—	—	—	2,869
Stock-based compensation	437	219	10,570	—	—	—	10,789
Tax benefit of stock-based compensation	—	—	6,522	—	—	—	6,522
Net income	—	—	—	68,901	—	—	68,901
Minority interest in earnings of Bois d'Arc	—	—	—	—	—	39,905	39,905
Stock issuances by Bois d'Arc	—	—	—	—	—	756	756
Stock repurchases by Bois d'Arc	—	—	—	—	—	(1,942)	(1,942)
Stock-based compensation of Bois d'Arc	—	—	—	—	—	8,373	8,373
Balance at December 31, 2007	45,428	22,714	386,986	361,944	—	267,441	1,039,085
Exercise of stock options and warrants	591	295	8,033	—	—	—	8,328
Stock-based compensation	423	212	12,051	—	—	—	12,263
Tax benefit of stock-based compensation	—	—	8,805	—	—	—	8,805
Net income	—	—	—	251,962	—	—	251,962
Unrealized hedging gain, net of income taxes	—	—	—	—	9,083	—	9,083
Total comprehensive income	—	—	—	—	—	—	261,045
Minority interest in earnings of Bois d'Arc	—	—	—	—	—	46,883	46,883
Stock issuances by Bois d'Arc	—	—	—	—	—	4,612	4,612
Stock repurchases by Bois d'Arc	—	—	—	—	—	(3,009)	(3,009)
Stock-based compensation of Bois d'Arc	—	—	—	—	—	19,294	19,294
Sale of shares of Bois d'Arc	—	—	—	—	—	(335,221)	(335,221)
Balance at December 31, 2008	46,442	23,221	415,875	613,906	9,083	—	1,062,085
Exercise of stock options and warrants	113	57	2,024	—	—	—	2,081
Stock-based compensation	549	274	15,509	—	—	—	15,783
Tax benefit of stock-based compensation	—	—	1,097	—	—	—	1,097
Net loss	—	—	—	(36,471)	—	—	(36,471)
Unrealized hedging loss, net of income taxes	—	—	—	—	(9,083)	—	(9,083)
Unrealized gain on marketable securities, net of income taxes	—	—	—	—	30,619	—	30,619
Total comprehensive loss	—	—	—	—	—	—	(14,935)
Balance at December 31, 2009	47,104	$ 23,552	$ 434,505	$ 577,435	$ 30,619	$ —	$ 1,066,111

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, 2007, 2008 and 2009

	2007	2008 (In thousands)	2009
CASH FLOWS FROM CONTINUING OPERATIONS —			
Cash Flows From Operating Activities:			
Net income (loss)	$ 68,901	$ 251,962	$ (36,471)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Income from discontinued operations	(23,257)	(193,745)	—
Gain on sale of assets	—	(26,560)	(213)
Impairment of marketable securities	—	162,672	—
Impairment of oil and gas properties	482	922	115
Deferred income taxes	25,543	43,620	30,796
Dry hole costs and leasehold impairments	6,846	4,113	—
Depreciation, depletion and amortization	125,349	182,179	213,238
Debt issuance costs and discount amortization	810	810	1,162
Stock-based compensation	10,789	12,263	15,783
Excess tax benefit from stock-based compensation	(6,522)	(8,805)	(1,097)
Decrease (increase) in accounts receivable	(11,605)	6,418	1,997
Increase in other current assets	(230)	(9,646)	(27,927)
Increase (decrease) in accounts payable and accrued expenses	4,433	24,330	(21,126)
Net cash provided by operating activities from continuing operations	201,539	450,533	176,257
Cash Flows From Investing Activities:			
Capital expenditures and acquisitions	(531,493)	(418,730)	(349,987)
Proceeds from asset sales	—	129,536	1,210
Net cash used for investing activities from continuing operations	(531,493)	(289,194)	(348,777)
Cash Flows From Financing Activities:			
Borrowings	325,000	85,000	430,713
Principal payments on debt	—	(555,000)	(170,000)
Debt issuance costs	(34)	(16)	(7,180)
Proceeds from common stock issuances	2,869	8,328	2,081
Excess tax benefit from stock-based compensation	6,522	8,805	1,097
Net cash provided by (used for) financing activities from continuing operations	334,357	(452,883)	256,711
Net cash provided by (used for) continuing operations	4,403	(291,544)	84,191
CASH FLOWS FROM DISCONTINUED OPERATIONS —			
Net Cash Provided by Operating Activities	235,412	240,332	—
Cash Flows From Investing Activities:			
Proceeds from sale of Bois d'Arc Energy, net of income taxes	—	292,260	—
Capital expenditures	(213,878)	(159,368)	—
Net cash provided by (used for) investing activities	(213,878)	132,892	—
Net Cash Used for Financing Activities	(21,600)	(80,964)	—
Net cash provided by (used for) discontinued operations	(66)	292,260	—
Net increase in cash and cash equivalents	4,337	716	84,191
Cash and cash equivalents, beginning of year	1,228	5,565	6,281
Cash and cash equivalents, end of year	$ 5,565	$ 6,281	$ 90,472

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"). All significant intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its undivided interest in properties using the proportionate consolidation method, whereby its share of assets, liabilities, revenues and expenses are included in its financial statements.

Discontinued Offshore Operations

On August 28, 2008, the Company's subsidiary, Bois d'Arc Energy, Inc. ("Bois d'Arc") completed a merger with Stone Energy Corporation ("Stone") pursuant to which each outstanding share of the common stock of Bois d'Arc was exchanged for cash in the amount of $13.65 per share and 0.165 shares of Stone common stock. Prior to the merger, Comstock conducted all of its offshore operations through Bois d'Arc. As a result of the merger, Comstock received net proceeds of $439.0 million in cash and 5,317,069 shares of Stone common stock in exchange for its interest in Bois d'Arc. As a result of the merger of Bois d'Arc and Stone, the consolidated financial statements and the related notes thereto present the Company's offshore operations as a discontinued operation. No general and administrative or interest costs incurred by Comstock have been allocated to the discontinued operations during the periods presented. Unless indicated otherwise, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations.

The merger of Bois d'Arc with Stone resulted in Comstock recognizing a gain on the disposal of the discontinued operations in the three months ended September 30, 2008 of $158.1 million, after income taxes of $85.3 million and the Company's share of transaction-related costs incurred by Bois d'Arc of $11.7 million. Transaction-related costs incurred by Bois d'Arc included accounting, legal and investment banking fees, change-in-control and other compensation costs that became obligations as a result of the merger.

Income from discontinued operations is comprised of the following:

	For the Year Ended December 31, 2007	2008
	(In thousands)	
Oil and gas sales	$ 355,460	$ 360,719
Total operating expenses	(228,364)	(198,894)
Operating income from discontinued operations	127,096	161,825
Other income (expense)	(7,980)	(2,630)
Provision for income taxes	(55,954)	(76,626)
Minority interest in earnings	(39,905)	(46,883)
Income from discontinued operations, excluding gain on sale	23,257	35,686
Gain on sale of discontinued operations, net of income taxes of $85,327	—	158,059
Income from discontinued operations	$ 23,257	$ 193,745

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 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

Marketable securities are recorded at fair value, and temporary unrealized holding gains and losses are recorded, net of income tax, as a separate component of accumulated other comprehensive income. Unrealized losses are charged against net earnings when a decline in fair value is determined to be other than temporary. Comstock considers several factors to determine whether a loss is other than temporary. These factors include but are not limited to: (i) the length of time a security is in an unrealized loss position, (ii) the extent to which fair value is less than cost, (iii) the financial condition and near term prospects of the issuer and (iv) the ability to hold the security for a period of time sufficient to allow for any anticipated recovery in fair value. Realized gains and losses are accounted for using the specific identification method.

The Company received shares of Stone common stock as part of the proceeds from the sale of its interest in Bois d'Arc. 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 accompanying consolidated balance sheet. Prior to the lapse of certain trading restrictions in August 2009, the fair value of the Stone common stock included a discount to the public market price to reflect certain trading restrictions.

When the Stone shares were acquired in August 2008, the value was determined to be $211.4 million by an independent valuation specialist. As of December 31, 2008 the estimated fair value of the Stone shares had fallen to $48.9 million. Comstock determined that this decline in the fair value of the Stone common stock in 2008 was not temporary, which resulted in the recognition of an impairment charge of $162.7 million before income taxes in 2008. As of December 31, 2009, the estimated fair value of the Stone shares, based on the market price for the shares, was $96.0 million after recognizing an unrealized gain before income taxes of $47.1 million.

Other Current Assets

Other current assets at December 31, 2008 and 2009 consist of the following:

	As of December 31,	
	2008	2009
	(In thousands)	
Drilling advances	$5,273	$ 195
Prepaid expenses	358	523
Pipe inventory	6,172	2,060
Production tax refunds receivable	—	1,480
Other	6	1
	$11,809	$ 4,259

Property and Equipment

The Company follows the successful efforts method of accounting for its oil and natural gas properties. Acquisition costs for proved oil and natural 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. Cost centers for amortization purposes are determined on a field area basis. Costs incurred to acquire oil and gas leasehold are capitalized. Unproved oil and gas properties are periodically assessed and any impairment in value is charged to exploration expense. 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. Exploratory drilling costs are initially capitalized as unproved property but charged to expense if and when the well is determined not to have found proved oil and gas reserves. Exploratory drilling costs are evaluated within a one-year period after the completion of drilling.

The Company 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. 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 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 actual prices on the last day of the period, for periods prior to December 31, 2009, and an average price based on the first day of each month of the year commencing with December 31, 2009. The Company recognized impairment charges related to its oil and gas properties of $0.5 million, $0.9 million and $0.1 million in 2007, 2008, and 2009, respectively.

Other property and equipment consists primarily of gas gathering systems, computer equipment, furniture and fixtures and interests in private aircraft which are depreciated over estimated useful lives ranging from five to 31 1/2 years on a straight-line basis.

Reserve for Future Abandonment Costs

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 Company's asset retirement obligations relate to future plugging and abandonment costs of its oil and gas properties and related facilities disposal.

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

	2007	2008 (In thousands)	2009
Reserve for Future Abandonment Costs at beginning of the year	$ 9,052	$ 7,512	$ 5,480
New wells placed on production and changes in estimates	(2,179)	(1,537)	853
Acquisition liabilities assumed	774	—	—
Liabilities settled and assets disposed of	(684)	(939)	(86)
Accretion expense	549	444	314
Reserve for Future Abandonment Costs at end of the year	$ 7,512	$ 5,480	$ 6,561

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.

Stock-based Compensation

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 increase to additional paid-in capital and as a part of cash flows from financing activities. Comstock's excess income tax benefit realized from tax deductions associated with stock-based compensation totaled $6.5 million, $8.8 million and $1.1 million for the years ended December 31, 2007, 2008 and 2009, respectively.

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 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 2009 the Company had two purchasers of its oil and natural gas production that accounted for 22% and 11%, respectively, of total oil and gas sales. In 2008, the Company had three purchasers of its oil and natural gas production that accounted for 14%, 12% and 11%, respectively, of total oil and gas sales. In 2007, the Company had three purchasers of its oil and natural gas production that accounted for 15%, 11% and 11%, respectively, 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 crude 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. 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, 2008 or 2009.

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 $9.3 million, $10.1 million and $10.2 million in 2007, 2008 and 2009, 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. On January 1, 2009, the Company adopted new accounting guidance issued by the Financial Accounting Standards Board (the "FASB") which requires that unvested share-based payment awards containing nonforfeitable rights to dividends be considered participating securities and included in the computation of basic and diluted earnings per share pursuant to the two-class method. Earnings per share data for all periods presented have been adjusted retrospectively for the effects of this new guidance. The effect of adoption in each year was as follows:

	Year Ended December 31, 2007	2008
	Increase (decrease) from previously reported amounts	
Basic net income per share:		
Continuing operations	$ (0.02)	$ (0.04)
Discontinued operations	(0.02)	(0.12)
	$ (0.04)	$ (0.16)
Diluted net income per share:		
Continuing operations	$ (0.02)	$ (0.02)
Discontinued operations	0.01	(0.05)
	$ (0.01)	$ (0.07)

Basic and diluted earnings per share for 2007, 2008 and 2009 were determined as follows:

	2007			2008			2009		
	Income	Shares	Per Share	Income	Shares	Per Share	Income	Shares	Per Share
				(In thousands except per share data)					
Income (Loss) From Continuing Operations	$ 45,644			$ 58,217			$ (36,471)		
Income Allocable to Unvested Stock Grants	(1,088)			(1,648)			—		
Basic Income (Loss) From Continuing Operations Attributable to Common Stock	$ 44,556	43,415	$ 1.03	$ 56,569	44,524	$ 1.27	$ (36,471)	45,004	$ (0.81)
Effect of Dilutive Securities:									
Stock Options	—	665		—	289		—	—	
Diluted Income (Loss) From Continuing Operations Attributable to Common Stock	$ 44,556	44,080	$ 1.01	$ 56,569	44,813	$ 1.26	$ (36,471)	45,004	$ (0.81)
Income from Discontinued Operations	$ 23,257			$ 193,745					
Income Allocable to Unvested Stock Grants	(554)			(5,486)					
Basic Income from Discontinued Operations Attributable to Common Stock	$ 22,703	43,415	$ 0.52	$ 188,259	44,524	$ 4.23			
Effect of Dilutive Securities:									
Stock Options	—	665		—	289				
Diluted Income from Discontinued Operations Attributable to Common Stock	$ 22,703	44,080	$ 0.52	$ 188,259	44,813	$ 4.20			

Weighted average shares of unvested restricted stock included in common stock outstanding were as follows:

	2007	2008	2009
		(In thousands)	
Unvested restricted stock	1,060	1,297	1,583

Stock options and warrants to purchase common stock at exercise prices in excess of the average actual stock price for the period that were anti-dilutive and that were excluded from the determination of diluted earnings per share are as follows:

	2007	2008	2009
		(In thousands except per share data)	
Weighted average anti-dilutive stock options	235	40	447
Weighted average exercise price	$ 32.60	$ 54.36	$ 24.93

Such options were excluded as anti-dilutive to earnings per share due to the net loss in 2009. In 2008, the excluded options that were anti-dilutive were at exercise prices in excess of the average actual stock price for the period.

At December 31, 2008 and 2009, 1,691,750 and 2,036,450 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.

Fair Value Measurements

The Company holds certain items that are required to be measured at fair value. These include cash equivalents held in money market funds, marketable securities comprised of shares of Stone common stock, and derivative financial instruments in the form of natural gas 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.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Prior to August 2009, the fair value of the Stone common stock recorded by the Company included a discount from the quoted public market price to reflect the impact of trading restrictions. The Company determined the impact of the trading restrictions on the fair value of the Stone common stock utilizing a standard option pricing model based on inputs that were either readily available in public markets or which could be derived from information available in publicly quoted markets. Accordingly, the Company categorized the Stone common stock valuation as a Level 2 measurement for periods prior to August 2009. For periods subsequent to August 2009, the date at which the trading restrictions lapsed, the Company measures the value of the Stone common stock based on unadjusted public market prices, and the valuation of these shares is now categorized as a Level 1 measurement. The Company's natural gas price swap agreements were not traded on a public exchange. The value of natural gas price swap agreements, prior to their expiration in December 2009, was determined utilizing a discounted cash flow model based on inputs that are not readily available in public markets and, accordingly, the valuation of these swap agreements was categorized as a Level 3 measurement.

The following table summarizes financial assets accounted for at fair value as of December 31, 2009:

	Carrying Value Measured at Fair Value at December 31, 2009	Level 1	Level 2	Level 3
		(In thousands)		
Items measured at fair value on a recurring basis:				
Cash equivalents — money market funds	$90,472	$ 90,472	$ —	$ —
Marketable securities — Stone common stock	95,973	95,973	—	—
Total assets	$186,445	$ 186,445	$ —	$ —

The following table summarizes the changes in the fair values of the natural gas swap derivative financial instruments, which are Level 3 liabilities, for the twelve months ended December 31, 2008 and 2009:

	2008	2009
	(In thousands)	
Balance beginning of period	$ —	$ 13,974
Purchases and settlements (net)	4,810	(26,322)
Total realized or unrealized gains (losses):		
Realized gains (losses) included in earnings	(4,810)	26,322
Unrealized gains (losses) included in other comprehensive income	13,974	(13,974)
Balance end of period	$ 13,974	$ —

The following table presents the carrying amounts and estimated fair value of the Company's other financial instruments as of December 31, 2008 and 2009:

	2008		2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Long-term debt, including current portion	$210,000	$169,750	$470,836	$479,938

The fair market value of the Company's fixed rate debt was based on the market prices as of December 31, 2008 and 2009. The fair market value of the floating rate debt outstanding at December 31, 2008 approximated its carrying value.

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. At December 31, 2008 and 2009, the Company's cash investments consisted of prime shares in institutional preferred money market funds.

Cash payments made for interest and income taxes for the years ended December 31, 2007, 2008 and 2009, respectively, were as follows:

	2007	2008	2009
	(In thousands)		
Cash Payments:			
Interest payments	$31,864	$ 27,022	$15,827
Income tax payments (refunds)	$ 3,492	$140,198	$ (4,924)

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 $2.3 million and $6.6 million in 2008 and 2009, respectively, which reduced interest expense and increased the carrying value of its unevaluated oil and gas properties.

New Accounting Standards

In December 2007, the FASB issued new accounting guidance, which the Company adopted January 1, 2009, requiring reporting entities to present noncontrolling minority interests as a component of stockholder's equity instead of a liability and providing guidance on the accounting for transactions between an entity and noncontrolling interests. As a result of the implementation of this guidance, $220.3 million relating to noncontrolling interests in Bois d'Arc as of December 31, 2006 has been reclassified from liabilities to noncontrolling interests within stockholder's equity.

In September 2008, the FASB issued new guidance which requires that unvested share-based payment awards containing nonforfeitable rights to dividends be considered participating securities and included in the computation of basic and diluted earnings per share pursuant to the two-class method. Earnings per share data for all periods presented have been adjusted retrospectively for the effects of this new guidance.

In December 2008, the Securities and Exchange Commission released the Final Rule, "Modernization of Oil and Gas Reporting" (the "Final Rule") which revises oil and gas reserve estimations and reporting disclosures. This release permits the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The revised rules also limit the inclusion of proved undeveloped reserves to those that can be developed within a five year period unless specific circumstances justify a longer time. The Final Rule allows companies to disclose their probable and possible oil and gas reserves. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its oil and gas reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (iii) report oil and gas reserves using an average price based upon the average first of the month prior twelve month period rather than a year-end price. In October 2009, the SEC staff issued Staff Accounting Bulletin 113 to modify Topic 12, *Oil and Gas Producing Activities*, in order to conform financial reporting practices for public companies with the Final Rule. In January 2010, the FASB issued new accounting guidance to align the reserve estimation and disclosure requirements within generally accepted accounting principles with the Final Rule. All of these rule changes became effective on December 31, 2009. The Company has adopted these changes and conformed its reserve estimation and disclosure practices in accordance with the guidance contained in all of these releases.

Comprehensive Income

Comprehensive income consists of the following:

	For the Year Ended December 31,		
	2007	2008	2009
		(In thousands)	
Income (loss) from continuing operations	$ 45,644	$ 58,217	$ (36,471)
Other comprehensive income (loss):			
Unrealized hedging gains (losses), net of income tax expense (benefit) of $-, $4,891 and $(4,891), respectively	—	9,083	(9,083)
Unrealized gain on marketable securities, net of income tax expense of $-, $- and $16,487, respectively	—	—	30,619
Total from continuing operations	45,644	67,300	(14,935)
Income from discontinued operations, net of income taxes and minority interest	23,257	193,745	—
Total comprehensive income (loss)	$ 68,901	$ 261,045	$ (14,935)

The following table provides a summary of the amounts included in accumulated other comprehensive income (loss), net of income taxes, which are solely attributable to the Company's natural gas price swap financial instruments and marketable securities, for the years ended December 31, 2008 and 2009:

	Natural Gas Price Swap Agreements	Marketable Securities	Accumulated Other Comprehensive Income (Loss)
		(In thousands)	
Balance as of December 31, 2008	$ 9,083	$ —	$ 9,083
2009 changes in value	(35,405)	30,619	(4,786)
Reclassification to earnings	26,322	—	26,322
Balance as of December 31, 2009	$ —	$ 30,619	$ 30,619

Subsequent Events

Subsequent events were evaluated through February 26, 2010, the date the consolidated financial statements were issued.

(2) Acquisitions and Dispositions of Oil and Gas Properties

In June 2007, the Company acquired oil and gas properties in South Texas for $31.2 million in cash. The Company acquired proved oil and gas reserves of 9.1 billion cubic feet ("Bcf") of natural gas. The transaction was funded with borrowings under Comstock's bank credit facility. The pro forma impact of this acquisition was not material to the Company's historical results of operations.

In December 2007, the Company acquired certain oil and gas properties in South Texas for $160.1 million in cash. The Company acquired proved oil and gas reserves of 70.1 Bcf. The transaction was funded with borrowings under the Company's bank credit facility and the pro forma effect of the transaction was not material to the Company's historical results of operations.

In June and September 2008, the Company sold its interests in certain producing properties in East and South Texas and received aggregate net proceeds of $129.6 million. Comstock recognized a gain of $26.6 million on these sales for financial reporting purposes.

(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, 2008	As of December 31, 2009
	(In thousands)	
Unproved properties	$ 116,489	$ 130,364
Proved properties:		
Leasehold costs	845,097	864,380
Wells and related equipment and facilities	1,115,447	1,425,191
Accumulated depreciation depletion and amortization	(636,530)	(847,568)
	$ 1,440,503	$ 1,572,367

Costs Incurred

	2007	2008	2009
		(In thousands)	
Property acquisitions —			
Unproved properties	$ 3,875	$ 113,023	$ 26,040
Proved properties	192,064	—	—
Development costs	313,938	249,527	218,191
Exploration costs	14,482	62,031	101,956
	$ 524,359	$ 424,581	$ 346,187

(4) Long-term Debt

Long-term debt is comprised of the following:

	As of December 31, 2008	As of December 31, 2009
	(In thousands)	
Bank credit facility	$ 35,000	$ —
6$^{7}/_{8}$% senior notes due 2012	175,000	175,000
8$^{3}/_{8}$% senior notes due 2017	—	300,000
Discount related to 8$^{3}/_{8}$% senior notes due 2017	—	(4,164)
	$ 210,000	$ 470,836

The discount is being amortized over the life of the senior notes using the effective interest rate method.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes Comstock's debt as of December 31, 2009 by year of maturity:

	2010	2011	2012	2013 (In thousands)	2014	Thereafter	Total
$6^{7}/_{8}$% senior notes	$ —	$ —	$ 175,000	$ —	$ —	$ —	$ 175,000
$8^{3}/_{8}$% senior notes	—	—	—	—	—	295,836	295,836
	$ —	$ —	$ 175,000	$ —	$ —	$ 295,836	$ 470,836

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 December 15, 2011. Indebtedness under the credit facility is secured by substantially all of Comstock's assets and is guaranteed by all of its 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, 2009, the borrowing base was $500.0 million, all 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 2% 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 1.5%) plus 0.5% to 1.25%. 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 $40.0 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 of at least one-to-one and maintenance of a minimum tangible net worth. The Company was in compliance with these covenants as of December 31, 2009.

Comstock has $175.0 million of $6^{7}/_{8}$% senior notes outstanding which mature on March 1, 2012. Interest is payable semiannually on each March 1 and September 1. The Company also has $300.0 million of $8^{3}/_{8}$% senior notes outstanding which mature on October 15, 2017. Interest is payable semiannually on each April 15 and October 15. The senior notes are unsecured obligations of Comstock and are guaranteed by all of Comstock's subsidiaries. The subsidiary guarantors are 100% owned and all of the guarantees are full and conditional and joint and several. As of December 31, 2009, Comstock had no 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.

(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, 2007, 2008 and 2009 was $0.8 million, $1.0 million and $1.2 million, respectively. Minimum future payments under the leases are as follows:

	(In thousands)
2010	$ 1,701
2011	1,701
2012	1,701
2013	1,701
2014	1,200
Thereafter	2,000
	$ 10,004

As of December 31, 2009, the Company had commitments for contracted drilling rigs of $97.2 million through September 2012. The Company also has entered into natural gas transportation agreements through July 2019. Maximum commitments under these transportation agreements as of December 31, 2009 totaled $36.9 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.

(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, 2008 or 2009.

Comstock's Board of Directors has designated 500,000 shares of the preferred stock as Series B Junior Participating Preferred Stock (the "Series B Junior Preferred Stock") in connection with the adoption of a shareholder rights plan. At December 31, 2008 and 2009, there were no shares of Series B Junior Preferred Stock issued or outstanding. The Series B Junior Preferred Stock is entitled to receive cumulative quarterly dividends per share equal to the greater of $1.00 or 100 times the aggregate per share amount of all dividends (other than stock dividends) declared on common stock since the immediately preceding quarterly dividend payment date or, with respect to the first payment date, since the first issuance of Series B Junior Preferred Stock. Holders of the Series B Junior Preferred Stock are entitled to 100 votes per share (subject to adjustment to prevent dilution) on all matters submitted to a vote of the stockholders. The Series B Junior Preferred Stock is neither redeemable nor convertible. The Series B Junior Preferred Stock ranks senior to the common stock but junior to all other classes of preferred stock.

The Company had 80,600 stock purchase warrants outstanding at December 31, 2008, all of which were exercised during 2009. Warrants were exercised to purchase 7,600, 98,900 and 80,600 shares in 2007, 2008 and 2009, respectively. Such exercises yielded net proceeds to the Company of $0.1 million, $1.8 million and $1.6 million in 2007, 2008 and 2009, respectively.

(7) Stock-based Compensation

The Company grants restricted shares of common stock and stock options to key employees and directors as part of their compensation. On May 19, 2009, the stockholders approved the 2009 Long-term Incentive Plan for management including officers, directors and managerial employees which replaced the 1999 Long-term Incentive Plan. As of December 31, 2009, the 2009 Long-term Incentive Plan provides for future awards of stock options, restricted stock grants or other equity awards of up to 3,447,675 shares of common stock.

During 2007, 2008 and 2009, the Company recorded $10.8 million, $12.3 million and $15.8 million, respectively, in stock-based compensation expense in general and administrative expenses. The excess income tax benefit realized from tax deductions associated with stock-based compensation totaled $6.5 million, $8.8 million and $1.1 million for the years ended December 31, 2007, 2008 and 2009, respectively.

Stock Options

The Company amortizes the fair value of stock options granted over the vesting period using the straight-line method. The fair value of each award is estimated as of the date of grant using the Black-Scholes options pricing model. Total compensation expense recognized for all outstanding stock options for the years ended December 31, 2007, 2008 and 2009 was $1.6 million, $1.5 million and $0.8 million, respectively.

The Company did not issue any stock options during 2009. The following table summarizes the assumptions used to value stock options granted in the years ended December 31, 2007 and 2008:

	2007	2008
Weighted average grant date fair value	$10.32	$19.76
Weighted average assumptions used:		
Expected volatility	36.0%	38.9%
Expected lives	3.9 yrs.	4.3 yrs.
Risk-free interest rates	4.9%	3.3%
Expected dividend yield	—	—

The expected volatility for grants is calculated using an analysis of the common stock's historical volatility. Risk-free interest rates are determined using the implied yield currently available for zero-coupon U.S. government issues with a remaining term equal to the expected life of the options.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes information related to stock options outstanding at December 31, 2009:

Exercise Price	Weighted Average Remaining Life (in years)	Number of Options Outstanding	Number of Options Exercisable
$6.42	0.5	168,750	168,750
$20.03	1.0	8,720	8,720
$20.92	0.4	5,000	5,000
$29.49	2.3	30,000	30,000
$32.44	1.4	30,000	30,000
$32.50	5.9	57,500	57,500
$33.22	7.0	84,650	61,150
$54.36	3.4	40,000	40,000
		424,620	401,120

The following tables summarize information related to stock option activity under the Company's incentive plans for the years ended December 31, 2007, 2008 and 2009:

	2007		2008		2009	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding at January 1	1,468,970	$11.59	914,970	$16.68	456,870	$23.56
Granted	40,000	$29.49	40,000	$54.36	—	—
Exercised	(588,500)	$4.70	(492,350)	$13.17	(32,250)	$21.37
Forfeited	(5,500)	$33.02	(5,750)	$33.06	—	—
Outstanding at December 31	914,970	$16.68	456,870	$23.56	424,620	$23.73
Vested and Exercisable at December 31	797,470	$14.28	389,245	$21.92	401,120	$23.17

	2007	2008 (In thousands)	2009
Cash received for options exercised	$ 2,765	$ 6,483	$ 480
Actual tax benefit realized	$ 17,307	$ 26,169	$ 2,405

As of December 31, 2009, total unrecognized compensation cost related to unvested stock options of $0.4 million was expected to be recognized over a period of one year. The aggregate intrinsic value of stock options outstanding at December 31, 2009 was $7.7 million based on the closing price for the Company's common stock on December 31, 2009. The aggregate intrinsic value of vested stock options was $7.5 million on December 31, 2009. Options granted in 2007 and 2008 were granted with exercise prices equal to the closing prices of the Company's common stock on the respective grant dates. The total intrinsic value of options exercised was $17.1 million, $24.4 million and $0.6 million for the years ended December 31, 2007, 2008 and 2009, respectively.

Restricted Stock

The fair value of restricted stock grants is amortized over the vesting period using the straight-line method. Total compensation expense recognized for restricted stock grants was $9.2 million, $10.8 million and $15.0 million for the years ended December 31, 2007, 2008 and 2009, 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 years ended December 31, 2007, 2008 and 2009 is presented below:

	Number of Restricted Shares	Weighted Average Grant Price
Outstanding at January 1, 2007	1,206,750	$27.08
Granted	436,500	$34.10
Vested	(183,750)	$19.50
Outstanding at December 31, 2007	1,459,500	$30.14
Granted	426,750	$44.31
Vested	(191,000)	$20.36
Forfeitures	(3,500)	$34.30
Outstanding at December 31, 2008	1,691,750	$34.81
Granted	552,325	$36.80
Vested	(203,625)	$22.48
Forfeitures	(4,000)	$41.81
Outstanding at December 31, 2009	2,036,450	$36.57

Total unrecognized compensation cost related to unvested restricted stock of $43.4 million as of December 31, 2009 is expected to be recognized over a period of three years. The fair value of restricted stock which vested in 2007, 2008 and 2009 was $5.7 million, $6.9 million and $9.4 million, respectively.

(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 $255,000, $302,000 and $358,000 for the years ended December 31, 2007, 2008 and 2009, respectively.

(9) Income Taxes

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

	2007	2008	2009
		(In thousands)	
Current	$ 3,680	$ (5,009)	$ (41,568)
Deferred	25,543	43,620	30,796
	$ 29,223	$ 38,611	$ (10,772)

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	2007	2008	2009
		(In thousands)	
Tax expense (benefit) at statutory rate	$ 26,203	$ 33,890	$ (16,535)
Tax effect of:			
Nondeductible compensation	1,885	3,536	4,339
State taxes, net of federal tax benefit	862	1,639	441
Deferred state taxes provided due to tax law changes	597	—	—
Other	(324)	(454)	983
Total	$ 29,223	$ 38,611	$ (10,772)

	2007	2008	2009
Statutory rate	35.0%	35.0%	35.0%
Tax effect of:			
Nondeductible compensation	2.5	3.7	(9.2)
State taxes, net of federal tax benefit	1.1	1.7	(0.9)
Deferred state taxes provided due to tax law changes	0.8	—	—
Other	(0.4)	(0.5)	(2.1)
Effective tax rate	39.0%	39.9%	22.8%

The tax effects of significant temporary differences representing the net deferred tax asset and liability at December 31, 2008 and 2009 were as follows:

	2008	2009
	(In thousands)	
Current deferred tax assets (liabilities):		
Marketable securities	$ 9,886	$ (6,588)
Derivatives	(4,891)	—
Net current deferred tax asset (liability)	4,995	(6,588)
Noncurrent deferred tax assets (liabilities):		
Property and equipment	(193,398)	(287,052)
Other assets	4,116	6,417
Net operating loss carryforwards	14,079	14,079
Alternative minimum tax carryforward	—	58,032
Valuation allowance on net operating loss carryforwards	(8,043)	(8,043)
Other	(2,624)	(4,115)
Net noncurrent deferred tax liability	(185,870)	(220,682)
Net deferred tax liability	$ (180,875)	$ (227,270)

At December 31, 2009, Comstock had the following carryforwards available to reduce future income taxes:

Types of Carryforward	Years of Expiration Carryforward	Amounts (In thousands)
Net operating loss — U.S. federal	2017 — 2021	$40,226
Alternative minimum tax credits	Unlimited	$58,032

The utilization of the net operating loss carryforward is limited to approximately $1.1 million per year pursuant to a prior change of control of an acquired company. Accordingly, a valuation allowance of $23.0 million, with a tax effect of $8.0 million, has been established for the estimated net operating loss carryforwards that will not be utilized. Realization of the net operating carryforwards requires Comstock to generate taxable income within the carryforward period.

The Company's federal income tax returns for the years ended December 31, 2006 and 2007 were recently under examination by the Internal Revenue Service and have been closed with no additional tax liability. 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, 2004. The Company currently believes that all significant filing positions are highly certain and that all of its significant income tax filing positions and deductions would be sustained upon audit. Therefore, the Company has no 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) Derivatives 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.

In January 2008, Comstock entered into natural gas swaps to fix the price at $8.00 per Mmbtu (at the Houston Ship Channel) for 520,000 Mmbtu's per month of production from certain properties in South Texas for the period February 2008 through December 2009. The Company designated these swaps at their inception as cash flow hedges. Realized gains and losses were included in oil and natural gas sales in the month of production. Changes in the fair value of derivative instruments designated as cash flow hedges to the extent they were effective in offsetting cash flows attributable to the hedged risk were recorded in other comprehensive income until the hedged item was recognized in earnings. Changes in fair value resulting from ineffectiveness was recognized currently in oil and natural gas sales as unrealized gains (losses). The Company realized losses of $4.8 million and gains of $26.3 million on the natural gas price swaps settled during 2008 and 2009, respectively, which are included in oil and gas sales in the accompanying consolidated statements of operations. As of December 31, 2009, the Company had no derivative financial instruments outstanding.

(11) Supplementary Quarterly Financial Data (Unaudited)

	2008 First	2008 Second	2008 Third	2008 Fourth	2008 Total
	(In thousands, except per share data)				
Total oil and gas sales	$ 127,721	$ 172,022	$ 163,852	$ 100,154	$ 563,749
Income from operations	$ 56,372	$ 118,760	$ 91,673	$ 16,375	$ 283,180
Income (loss) from continuing operations	$ 29,402	$ 70,428	$ 54,764	$ (96,377)	$ 58,217
Income from discontinued operations	$ 11,693	$ 12,199	$ 169,853	$ —	$ 193,745
Net income (loss)	$ 41,095	$ 82,627	$ 224,617	$ (96,377)	$ 251,962
Basic net income (loss) per share:					
Continuing operations	$ 0.65	$ 1.55	$ 1.19	$ (2.09)	$ 1.27
Discontinued operations	0.26	0.27	3.69	—	4.23
Total	$ 0.91	$ 1.82	$ 4.88	$ (2.09)	$ 5.50
Diluted net income (loss) per share:					
Continuing operations	$ 0.64	$ 1.53	$ 1.18	$ (2.09)	$ 1.26
Discontinued operations	0.26	0.27	3.67	—	4.20
Total	$ 0.90	$ 1.80	$ 4.85	$ (2.09)	$ 5.46

	2009 First	2009 Second	2009 Third	2009 Fourth	2009 Total
	(In thousands, except per share data)				
Total oil and gas sales	$ 68,351	$ 64,875	$ 67,436	$ 90,201	$ 290,863
Loss from operations	$ (5,712)	$ (12,588)	$ (11,547)	$ (1,688)	$ (31,535)
Net loss	$ (5,657)	$ (11,475)	$ (12,572)	$ (6,767)	$ (36,471)
Net loss per share					
Basic	$ (0.12)	$ (0.26)	$ (0.28)	$ (0.15)	$ (0.81)
Diluted	$ (0.12)	$ (0.26)	$ (0.28)	$ (0.15)	$ (0.81)

The Company recognized a gain on the disposal of its discontinued offshore operations in the three months ended September 30, 2008 of approximately $158.1 million, after income taxes of $85.3 million. The Company recognized an unrealized loss before income taxes of $162.7 million in the three months ended December 31, 2008 to write down its marketable securities. Basic and diluted per share amounts for the three months ended December 31, 2008 and for all periods presented in 2009 are the same due to the net loss during these periods.

(12) Oil and Gas Reserves Information (Unaudited)

Set forth below is a summary of the changes in Comstock's net quantities of crude oil and natural gas reserves for each of the three years ended December 31, 2009:

	2007		2008		2009	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved Reserves:						
Beginning of year	11,984	435,508	10,510	587,718	9,668	523,643
Revisions of previous estimates	(1,449)	14,145	551	(56,153)	(1,590)	(130,224)
Extensions and discoveries	891	98,665	528	99,232	19	349,920
Purchases of minerals in place	92	78,631	—	—	—	—
Sales of minerals in place	—	—	(912)	(53,287)	(108)	(130)
Production	(1,008)	(39,231)	(1,009)	(53,867)	(775)	(60,820)
End of year	10,510	587,718	9,668	523,643	7,214	682,389
Proved Developed Reserves:						
Beginning of year	7,912	241,243	7,449	370,339	5,446	354,934
End of year	7,449	370,339	5,446	354,934	4,894	367,102

The proved oil and gas reserves utilized in the preparation of the financial statements were estimated by independent petroleum consultants of Lee Keeling and Associates in accordance with guidelines established by the Securities and Exchange Commission and the FASB, 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, 2008 and 2009:

	2008	2009
	(In thousands)	
Cash Flows Relating to Proved Reserves:		
Future Cash Flows	$ 3,126,215	$ 2,774,542
Future Costs:		
Production	(1,161,911)	(1,091,305)
Development and Abandonment	(495,465)	(725,795)
Future Income Taxes	(328,649)	(99,572)
Future Net Cash Flows	1,140,190	857,870
10% Discount Factor	(503,899)	(431,280)
Standardized Measure of Discounted Future Net Cash Flows	$ 636,291	$ 426,590

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, 2007, 2008 and 2009:

	2007	2008	2009
		(In thousands)	
Standardized Measure, Beginning of Year	$ 747,494	$ 1,162,548	$ 636,291
Net Change in Sales Price, Net of Production Costs	256,216	(594,456)	(436,544)
Development Costs Incurred During the Year Which Were Previously Estimated	160,294	165,036	49,029
Revisions of Quantity Estimates	15,550	(90,587)	(176,742)
Accretion of Discount	98,128	157,781	82,011
Changes in Future Development and Abandonment Costs	(160,541)	(32,538)	144,388
Changes in Timing	(23,205)	83,223	52,762
Extensions, Discoveries and Improved Recovery	296,534	157,529	177,264
Purchases of Reserves in Place	220,372	—	—
Sales of Reserves in Place	—	(126,666)	(1,480)
Sales, Net of Production Costs	(266,822)	(477,019)	(221,684)
Net Changes in Income Taxes	(181,472)	231,440	121,295
Standardized Measure, End of Year	$ 1,162,548	$ 636,291	$ 426,590

New rules issued by the Securities and Exchange Commission relating to the estimation and disclosure of oil and natural gas reserves were adopted in 2009. The standardized measure of discounted future net cash flows at the end of 2009 were determined based on the simple average of the first of month market prices for oil and natural gas during 2009 which were $49.60 per barrel for oil and $3.54 per Mcf for natural gas. Under the prior rules the prices would have been based on the market prices at December 31, 2009, which would have been $64.43 per barrel for oil and $5.29 per Mcf for natural gas. In 2009 the average first of the month market prices for oil and natural gas were substantially lower than the year end market prices. The new rules also impacted the undeveloped proved reserves that were included in the Company's reserve estimates. The standardized measure of discounted future net cash flows would have been approximately $912.0 million under the previous rules.

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.

RESTRICTED STOCK AGREEMENT
UNDER THE COMSTOCK RESOURCES, INC.
2009 LONG-TERM INCENTIVE PLAN

AGREEMENT made as of __________, by and between Comstock Resources, Inc., a Nevada corporation (“Company”) and __________(“Award Recipient”):

WHEREAS, the Company maintains the Comstock Resources, Inc. 2009 Long-term Incentive Plan (the “Plan”) under which the Company’s Board of Directors (“Board”) may, among other things, award shares of restricted common stock to employees of the Company;

WHEREAS, pursuant to the Plan, the Board has awarded to the Award Recipient shares of restricted stock conditioned upon the execution by the Company and the Award Recipient of a Restricted Stock Agreement setting forth all the terms and conditions applicable to such award in accordance with the Plan;

THEREFORE, in consideration of the mutual promise(s) and covenant(s) contained herein, it is hereby agreed as follows:

1. AWARD OF STOCK. Under the terms of the Plan, the Board has awarded to the Award Recipient a restricted stock award on __________ (“Award Date”), covering Two hundred thousand (200,000) shares of common stock (the “Shares”) subject to the terms, conditions, and restrictions set forth in this Agreement.

2. CERTIFICATES. The certificate(s) evidencing the award shall be registered on the Company’s books in the name of the Award Recipient as of the Award Date. Physical possession or custody of such certificate(s) shall be retained by the Company until such time as they are vested (i.e., the restriction period lapses). While in its possession, the Company reserves the right to place a legend on the certificate(s) restricting the transferability of such certificate(s) and referring to the terms and conditions (including forfeiture) approved by the Board and applicable to the Shares represented by the certificate(s).

During the restriction period, except as otherwise provided in Paragraph 3 of this Agreement, the Award Recipient shall be entitled to all rights of a stockholder of the Company, including the right to receive dividends with respect to such Shares.

3. AWARD RESTRICTIONS. The restricted stock shall vest in accordance with the schedule set forth below, provided that the Award Recipient remains in the continuous employment of the Company on each vesting date:

Date	Percentage of Shares Vested
	100%

During the restriction period, the restricted Shares which are not vested are not transferable by the Award Recipient by means of sale, assignment, exchange, pledge, or otherwise.

4. TERMINATION OF EMPLOYMENT; CHANGE IN CONTROL. If the Award Recipient terminates employment with the Company due to Retirement, death or Disability during the restriction period, the restricted stock award, to the extent not already vested, shall vest in full as of the date of such termination. Termination of the Award Recipient's employment with the Company for any other reason shall result in forfeiture of the award on the date of termination to the extent not vested. The Award Recipient may designate a beneficiary(ies) to receive the certificate representing that portion of the award vested upon death. The Award Recipient has the right to change such beneficiary designation at will.

(i) In the event of a Change in Control of the Company during the restriction period, the restricted stock award shall vest in full upon the effective time of the Change in Control.

5. WITHHOLDING TAXES. The Company shall have the right to retain and withhold from any payment under the restricted stock awarded the amount of taxes required by any government to be withheld or otherwise deducted and paid with respect to such payment. At its discretion, the Company may require an Award Recipient receiving Shares to reimburse the Company for any such taxes required to be withheld by the Company and withhold any distribution in whole or in part until the Company is so reimbursed. In lieu thereof, the Company shall have the right to withhold from any other cash amounts due or to become due from the Company to the Award Recipient an amount equal to such taxes required to be withheld by the Company to reimburse the Company for any such taxes or retain and withhold a number of Shares having a market value not less than the amount of such taxes and cancel (in whole or in part) any such Shares so withheld in order to reimburse the Company for any such taxes.

6. ADMINISTRATION. The Board shall have full authority and discretion, (subject only to the express provisions of the Plan) to decide all matters relating to the administration and interpretation of the Plan and this Agreement. All such Board determinations shall be final, conclusive, and binding upon the Company, the Award Recipient, and any and all interested parties.

7. NO RIGHT TO CONTINUED EMPLOYMENT. Nothing in the Plan or this Agreement shall confer on an Award Recipient any right to continue in the employ of the Company or in any way affect the Company's right to terminate the Award Recipient's employment without prior notice at any time for any reason.

8. AMENDMENT(S). This Agreement shall be subject to the terms of the Plan as amended except that the award that is the subject of this Agreement may not in any way be

restricted or limited by any Plan amendment or termination approved after the date of the award without the Award Recipient's written consent.

9. FORCE AND EFFECT. The various provisions of this Agreement are severable in their entirety. Any determination of invalidity or unenforceability of any one provision shall have no effect on the continuing force and effect of the remaining provisions.

10. GOVERNING LAWS. This Agreement shall be construed and enforced in accordance with and governed by the laws of the State of Texas.

11. SUCCESSORS. This Agreement shall be binding upon and inure to the benefit of the heirs and permitted successors and assigns of the respective parties.

12. NOTICES. Unless waived by the Company, any notice to the Company required under or relating to this Agreement shall be in writing and addressed to:

Comstock Resources, Inc.
5300 Town and Country Blvd.
Suite 500
Frisco, TX 75034
Attention: President or Secretary;

or to such other address as the Company maintains as its principal executive offices.

13. ENTIRE AGREEMENT. This Agreement and the Plan contain the entire understanding of the parties and shall not be modified or amended except in writing and duly signed by the parties. In the event of any conflict between the terms and provisions of this Agreement and those of the Plan, the terms and provisions of the Plan including, without limitation, those with respect to powers of the Board, shall prevail and be controlling. No waiver by either party of any default under this Agreement shall be deemed a waiver of any later default. Any capitalized terms not otherwise defined herein shall have the meanings ascribed to them in the Plan.

IN WITNESS WHEREOF, the parties have signed this Agreement as of the date hereof.

COMSTOCK RESOURCES, INC.

By: ______________________________

Base Contract for Sale and Purchase of Natural Gas

This Base Contract is entered into as of the following date: November 7, 2008

The parties to this Base Contract are the following:

PARTY A	PARTY NAME	PARTY B
BP Energy Company		**Comstock Oil & Gas-Louisiana, LLC**
501 WestLake Park Blvd. Houston, TX 77079	***ADDRESS***	5300 Town & Country Blvd., Suite 500 Frisco, Texas 75034
www.bp.com	***BUSINESS WEBSITE***	**www.Comstockresources.com**
	CONTRACT NUMBER	
62-527-5755	***D-U-N-S® NUMBER***	**79-152-7807**
☑ US FEDERAL: **36-3421804** o OTHER:	***TAX ID NUMBERS***	☑ US FEDERAL: 75-2272352 o OTHER:
Delaware	***JURISDICTION OF ORGANIZATION***	
☑ Corporation o LLC o Limited Partnership o Partnership o LLP o Other: ______	***COMPANY TYPE***	o Corporation ☑ LLC o Limited Partnership o Partnership o LLP o Other: ______
	GUARANTOR (IF APPLICABLE)	
	CONTACT INFORMATION	
ATTN: ***TEL#:*** 281- 366-2000 ***FAX#:*** ______ ***EMAIL:*** ______	§ ***COMMERCIAL***	**Same as above** ***ATTN:*** ***Steve Neukom***______ ***TEL#:*** **972-668-8860** ***FAX#:*** **972-668-8865**___ ***EMAIL:*** ***sneukom@comstockresources.com***
ATTN: Gas Scheduling ***TEL#:*** 281-366-2000 ***FAX#:*** ______ ***EMAIL:***	§ ***SCHEDULING***	***ATTN:*** ***Lance McGinnis*** ***TEL#:*** **972-668-1736** ***FAX#:*** ______ ***EMAIL:*** ______
BP Energy Company P.O. Box 3092 Houston, TX 77253-3092 ***ATTN:*** Contract Services ***TEL#:*** 281-366-2000 *FAX#:* 281-366-0203 ***EMAIL:*** ______	§ ***CONTRACT AND LEGAL NOTICES***	______ ***ATTN:*** ***DiAne Jones*** ***TEL#:*** **972-668-8819** ***FAX#:*** ______ ***EMAIL:*** ______
ATTN: Credit Services ***TEL#:*** 281-366-2000 *FAX#:* 281-366-6335 ***EMAIL:*** ______	§ ***CREDIT***	***ATTN:*** ***Steve Neukom*** ______ ***TEL#:*** **972-668-1732**______ ***FAX#:*** ______ ***EMAIL:*** ***sneukom@comstockresources.com***
BP Energy Company P.O. Box 3092 Houston, TX 77253-3092 *ATTN:* Confirmations Dept. *TEL#:* 281-366-2000 *FAX#:* 281-366-1633 *EMAIL:* ______	§ ***TRANSACTION CONFIRMATIONS***	______ ***ATTN:*** ***DiAne Jones*** ***TEL#:*** **972-668-8819**______ ***FAX#:*** ______ ***EMAIL:*** ______
	ACCOUNTING INFORMATION	
P.O. Box 3092 Houston, TX 77253-3092 ***ATTN:*** Gas Accounting ***TEL#:*** 281-366-2000 ***FAX#:*** 281-366-5313 ***EMAIL:*** ______	§ ***INVOICES*** § ***PAYMENTS*** § ***SETTLEMENTS***	5300 Town & Country Blvd., Suite 500 Frisco, Texas 75034 ***ATTN:*** ***Gas Accounting*** ______ ***TEL#:*** **972-668-8819** ***FAX#:*** **972-668-8865** ***EMAIL:*** ______
BANK: JP Morgan Chase Bank, New York, NY ***ABA:*** **021000021** ***ACCT:*** **910-2-548097** ***OTHER DETAILS:*** For the Account of BP Energy	***WIRE TRANSFER NUMBERS (IF APPLICABLE)***	***BANK:*** ***Comerica*** ***ABA:*** **111000753** ______ ***ACCT:*** **1881118515** ***OTHER DETAILS:*** ______
BANK: JP Morgan Chase Bank, New York, NY ***ABA:*** **021000021** ***ACCT:*** **910-2-548097** ***OTHER DETAILS:*** For the Account of BP Energy Company	***ACH NUMBERS (IF APPLICABLE)***	***BANK:*** ______ ***ABA:*** ______ ***ACCT:*** ______ ***OTHER DETAILS:*** ______
ATTN: ______ ***ADDRESS:*** ______	***CHECKS (IF APPLICABLE)***	***ATTN:*** ______ ***ADDRESS:*** ______

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This Base Contract incorporates by reference for all purposes the General Terms and Conditions for Sale and Purchase of Natural Gas published by the North American Energy Standards Board. The parties hereby agree to the following provisions offered in said General Terms and Conditions. In the event the parties fail to check a box, the specified default provision shall apply. Select the appropriate box(es) from each section:

Section 1.2 Transaction Procedure	☑ OR o	Oral (default) Written	**Section 10.2** Additional Events of Default	☑ o o	No Additional Events of Default (default) Indebtedness Cross Default o Party A: ______ o Party B: ______ Transactional Cross Default Specified Transactions: ______
Section 2.7 Confirm Deadline	o OR ☑	2 Business Days after receipt (default) 5 Business Days after receipt			
Section 2.8 Confirming Party	o OR o ☑	Seller (default) Buyer BP Energy Company			
Section 3.2 Performance Obligation	☑ OR o	Cover Standard (default) Spot Price Standard	**Section 10.3.1** Early Termination Damages	☑ OR o	Early Termination Damages Apply (default) Early Termination Damages Do Not Apply
Note: The following Spot Price Publication applies to both of the immediately preceding.			**Section 10.3.2** Other Agreement Setoffs	☑ OR o	Other Agreement Setoffs Apply (default) o Bilateral (default) ☑ Triangular Other Agreement Setoffs Do Not Apply
Section 2.31 Spot Price Publication	☑ OR o	Gas Daily Midpoint (default) ______			
Section 6 Taxes	☑ OR o	Buyer Pays At and After Delivery Point (default) Seller Pays Before and At Delivery Point			
Section 7.2 Payment Date	☑ OR o	25th Day of Month following Month of delivery (default) Day of Month following Month of delivery	**Section 15.5** Choice Of Law		New York
Section 7.2 Method of Payment	o ☑ o	Wire transfer (default) Automated Clearinghouse Credit (ACH) Check	**Section 15.10** Confidentiality	☑ OR o	Confidentiality applies (default) Confidentiality does not apply
Section 7.7 Netting	☑ OR o	Netting applies (default) Netting does not apply			

☑ **Special Provisions** Number of sheets attached: 11
o **Addendum(s):** ______

IN WITNESS WHEREOF, the parties hereto have executed this Base Contract in duplicate.

BP ENERGY COMPANY	***PARTY NAME***	COMSTOCK OIL & GAS-LOUISIANA, LLC
By: /s/ GREGORY L. SHARP	***SIGNATURE***	By: /s/ STEPHEN E. NEUKOM
Name Gregory L. Sharp	***PRINTED NAME***	Name Stephen E. Neukom
Title Vice President	***TITLE***	Title Vice President of Marketing

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SECTION 1. PURPOSE AND PROCEDURES

1.1. These General Terms and Conditions are intended to facilitate purchase and sale transactions of Gas on a Firm or Interruptible basis. "Buyer" refers to the party receiving Gas and "Seller" refers to the party delivering Gas. The entire agreement between the parties shall be the Contract as defined in Section 2.9.

The parties have selected either the "Oral Transaction Procedure" or the "Written Transaction Procedure" as indicated on the Base Contract.

Oral Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Any Gas purchase and sale transaction may be effectuated in an EDI transmission or telephone conversation with the offer and acceptance constituting the agreement of the parties. The parties shall be legally bound from the time they so agree to transaction terms and may each rely thereon. Any such transaction shall be considered a "writing" and to have been "signed". Notwithstanding the foregoing sentence, the parties agree that Confirming Party shall, and the other party may, confirm a telephonic transaction by sending the other party a Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means within three Business Days of a transaction covered by this Section 1.2 (Oral Transaction Procedure) provided that the failure to send a Transaction Confirmation shall not invalidate the oral agreement of the parties. Confirming Party adopts its confirming letterhead, or the like, as its signature on any Transaction Confirmation as the identification and authentication of Confirming Party. If the Transaction Confirmation contains any provisions other than those relating to the commercial terms of the transaction (i.e., price, quantity, performance obligation, delivery point, period of delivery and/or transportation conditions), which modify or supplement the Base Contract or General Terms and Conditions of this Contract (e.g., arbitration or additional representations and warranties), such provisions shall not be deemed to be accepted pursuant to Section 1.3 but must be expressly agreed to by both parties; provided that the foregoing shall not invalidate any transaction agreed to by the parties.

Written Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Should the parties come to an agreement regarding a Gas purchase and sale transaction for a particular Delivery Period, the Confirming Party shall, and the other party may, record that agreement on a Transaction Confirmation and communicate such Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means, to the other party by the close of the Business Day following the date of agreement. The parties acknowledge that their agreement will not be binding until the exchange of nonconflicting Transaction Confirmations or the passage of the Confirm Deadline without objection from the receiving party, as provided in Section 1.3.

1.3. If a sending party's Transaction Confirmation is materially different from the receiving party's understanding of the agreement referred to in Section 1.2, such receiving party shall notify the sending party via facsimile, EDI or mutually agreeable electronic means by the Confirm Deadline, unless such receiving party has previously sent a Transaction Confirmation to the sending party. The failure of the receiving party to so notify the sending party in writing by the Confirm Deadline constitutes the receiving party's agreement to the terms of the transaction described in the sending party's Transaction Confirmation. If there are any material differences between timely sent Transaction Confirmations governing the same transaction, then neither Transaction Confirmation shall be binding until or unless such differences are resolved including the use of any evidence that clearly resolves the differences in the Transaction Confirmations. In the event of a conflict among the terms of (i) a binding Transaction Confirmation pursuant to Section 1.2, (ii) the oral agreement of the parties which may be evidenced by a recorded conversation, where the parties have selected the Oral Transaction Procedure of the Base Contract, (iii) the Base Contract, and (iv) these General Terms and Conditions, the terms of the documents shall govern in the priority listed in this sentence.

1.4. The parties agree that each party may electronically record all telephone conversations with respect to this Contract between their respective employees, without any special or further notice to the other party. Each party shall obtain any necessary consent of its agents and employees to such recording. Where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, the parties agree not to contest the validity or enforceability of telephonic recordings entered into in accordance with the requirements of this Base Contract.

SECTION 2. DEFINITIONS

The terms set forth below shall have the meaning ascribed to them below. Other terms are also defined elsewhere in the Contract and shall have the meanings ascribed to them herein.

2.1. "Additional Event of Default" shall mean Transactional Cross Default or Indebtedness Cross Default, each as and if selected by the parties pursuant to the Base Contract.

2.2. "Affiliate" shall mean, in relation to any person, any entity controlled, directly or indirectly, by the person, any entity that controls, directly or indirectly, the person or any entity directly or indirectly under common control with the person. For this purpose, "control" of any entity or person means ownership of at least 50 percent of the voting power of the entity or person.

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2.3. “Alternative Damages” shall mean such damages, expressed in dollars or dollars per MMBtu, as the parties shall agree upon in the Transaction Confirmation, in the event either Seller or Buyer fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer.

2.4. “Base Contract” shall mean a contract executed by the parties that incorporates these General Terms and Conditions by reference; that specifies the agreed selections of provisions contained herein; and that sets forth other information required herein and any Special Provisions and addendum(s) as identified on page one.

2.5. “British thermal unit” or “Btu” shall mean the International BTU, which is also called the Btu (IT).

2.6. “Business Day(s)” shall mean Monday through Friday, excluding Federal Banking Holidays for transactions in the U.S.

2.7. “Confirm Deadline” shall mean 5:00 p.m. in the receiving party’s time zone on the second Business Day following the Day a Transaction Confirmation is received or, if applicable, on the Business Day agreed to by the parties in the Base Contract; provided, if the Transaction Confirmation is time stamped after 5:00 p.m. in the receiving party’s time zone, it shall be deemed received at the opening of the next Business Day.

2.8. “Confirming Party” shall mean the party designated in the Base Contract to prepare and forward Transaction Confirmations to the other party.

2.9. “Contract” shall mean the legally-binding relationship established by (i) the Base Contract, (ii) any and all binding Transaction Confirmations and (iii) where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, any and all transactions that the parties have entered into through an EDI transmission or by telephone, but that have not been confirmed in a binding Transaction Confirmation, all of which shall form a single integrated agreement between the parties.

2.10. “Contract Price” shall mean the amount expressed in U.S. Dollars per MMBtu to be paid by Buyer to Seller for the purchase of Gas as agreed to by the parties in a transaction.

2.11. “Contract Quantity” shall mean the quantity of Gas to be delivered and taken as agreed to by the parties in a transaction.

2.12. “Cover Standard”, as referred to in Section 3.2, shall mean that if there is an unexcused failure to take or deliver any quantity of Gas pursuant to this Contract, then the performing party shall use commercially reasonable efforts to (i) if Buyer is the performing party, obtain Gas, (or an alternate fuel if elected by Buyer and replacement Gas is not available), or (ii) if Seller is the performing party, sell Gas, in either case, at a price reasonable for the delivery or production area, as applicable, consistent with: the amount of notice provided by the nonperforming party; the immediacy of the Buyer’s Gas consumption needs or Seller’s Gas sales requirements, as applicable; the quantities involved; and the anticipated length of failure by the nonperforming party.

2.13. “Credit Support Obligation(s)” shall mean any obligation(s) to provide or establish credit support for, or on behalf of, a party to this Contract such as cash, an irrevocable standby letter of credit, a margin agreement, a prepayment, a security interest in an asset, guaranty, or other good and sufficient security of a continuing nature.

2.14. “Day” shall mean a period of 24 consecutive hours, coextensive with a “day” as defined by the Receiving Transporter in a particular transaction.

2.15. “Delivery Period” shall be the period during which deliveries are to be made as agreed to by the parties in a transaction.

2.16. “Delivery Point(s)” shall mean such point(s) as are agreed to by the parties in a transaction.

2.17. “EDI” shall mean an electronic data interchange pursuant to an agreement entered into by the parties, specifically relating to the communication of Transaction Confirmations under this Contract.

2.18. “EFP” shall mean the purchase, sale or exchange of natural Gas as the “physical” side of an exchange for physical transaction involving gas futures contracts. EFP shall incorporate the meaning and remedies of “Firm”, provided that a party’s excuse for nonperformance of its obligations to deliver or receive Gas will be governed by the rules of the relevant futures exchange regulated under the Commodity Exchange Act.

2.19. “Firm” shall mean that either party may interrupt its performance without liability only to the extent that such performance is prevented for reasons of Force Majeure; provided, however, that during Force Majeure interruptions, the party invoking Force Majeure may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by the Transporter.

2.20. “Gas” shall mean any mixture of hydrocarbons and noncombustible gases in a gaseous state consisting primarily of methane.

2.21. “Guarantor” shall mean any entity that has provided a guaranty of the obligations of a party hereunder.

2.22. “Imbalance Charges” shall mean any fees, penalties, costs or charges (in cash or in kind) assessed by a Transporter for failure to satisfy the Transporter’s balance and/or nomination requirements.

2.23. “Indebtedness Cross Default” shall mean if selected on the Base Contract by the parties with respect to a party, that it or its Guarantor, if any, experiences a default, or similar condition or event however therein defined, under one or more agreements or instruments, individually or collectively, relating to indebtedness (such indebtedness to include any obligation whether present or future, contingent or otherwise, as principal or surety or otherwise) for the payment or repayment of borrowed money in an aggregate amount greater than the threshold specified in the Base Contract with respect to such party or its Guarantor, if any, which results in such indebtedness becoming immediately due and payable.

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2.24. “Interruptible” shall mean that either party may interrupt its performance at any time for any reason, whether or not caused by an event of Force Majeure, with no liability, except such interrupting party may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by Transporter.

2.25. “MMBtu” shall mean one million British thermal units, which is equivalent to one dekatherm.

2.26. “Month” shall mean the period beginning on the first Day of the calendar month and ending immediately prior to the commencement of the first Day of the next calendar month.

2.27. “Payment Date” shall mean a date, as indicated on the Base Contract, on or before which payment is due Seller for Gas received by Buyer in the previous Month.

2.28. “Receiving Transporter” shall mean the Transporter receiving Gas at a Delivery Point, or absent such receiving Transporter, the Transporter delivering Gas at a Delivery Point.

2.29. “Scheduled Gas” shall mean the quantity of Gas confirmed by Transporter(s) for movement, transportation or management.

2.30. “Specified Transaction(s)” shall mean any other transaction or agreement between the parties for the purchase, sale or exchange of physical Gas, and any other transaction or agreement identified as a Specified Transaction under the Base Contract.

2.31. “Spot Price “ as referred to in Section 3.2 shall mean the price listed in the publication indicated on the Base Contract, under the listing applicable to the geographic location closest in proximity to the Delivery Point(s) for the relevant Day; provided, if there is no single price published for such location for such Day, but there is published a range of prices, then the Spot Price shall be the average of such high and low prices. If no price or range of prices is published for such Day, then the Spot Price shall be the average of the following: (i) the price (determined as stated above) for the first Day for which a price or range of prices is published that next precedes the relevant Day; and (ii) the price (determined as stated above) for the first Day for which a price or range of prices is published that next follows the relevant Day.

2.32. “Transaction Confirmation” shall mean a document, similar to the form of Exhibit A, setting forth the terms of a transaction formed pursuant to Section 1 for a particular Delivery Period.

2.33. “Transactional Cross Default” shall mean if selected on the Base Contract by the parties with respect to a party, that it shall be in default, however therein defined, under any Specified Transaction.

2.34. “Termination Option” shall mean the option of either party to terminate a transaction in the event that the other party fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer for a designated number of days during a period as specified on the applicable Transaction Confirmation.

2.35. “Transporter(s)” shall mean all Gas gathering or pipeline companies, or local distribution companies, acting in the capacity of a transporter, transporting Gas for Seller or Buyer upstream or downstream, respectively, of the Delivery Point pursuant to a particular transaction.

SECTION 3. PERFORMANCE OBLIGATION

3.1. Seller agrees to sell and deliver, and Buyer agrees to receive and purchase, the Contract Quantity for a particular transaction in accordance with the terms of the Contract. Sales and purchases will be on a Firm or Interruptible basis, as agreed to by the parties in a transaction.

The parties have selected either the “Cover Standard” or the “Spot Price Standard” as indicated on the Base Contract.

Cover Standard:

3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the positive difference, if any, between the purchase price paid by Buyer utilizing the Cover Standard and the Contract Price, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller for such Day(s) excluding any quantity for which no replacement is available; or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in the amount equal to the positive difference, if any, between the Contract Price and the price received by Seller utilizing the Cover Standard for the resale of such Gas, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually taken by Buyer for such Day(s) excluding any quantity for which no sale is available; and (iii) in the event that Buyer has used commercially reasonable efforts to replace the Gas or Seller has used commercially reasonable efforts to sell the Gas to a third party, and no such replacement or sale is available for all or any portion of the Contract Quantity of Gas, then in addition to (i) or (ii) above, as applicable, the sole and exclusive remedy of the performing party with respect to the Gas not replaced or sold shall be an amount equal to any unfavorable difference between the Contract Price and the Spot Price, adjusted for such transportation to the applicable Delivery Point, multiplied by the quantity of such Gas not replaced or sold. Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party’s invoice, which shall set forth the basis upon which such amount was calculated.

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Spot Price Standard:

3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the Contract Price from the Spot Price; or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the applicable Spot Price from the Contract Price. Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

3.3. Notwithstanding Section 3.2, the parties may agree to Alternative Damages in a Transaction Confirmation executed in writing by both parties.

3.4. In addition to Sections 3.2 and 3.3, the parties may provide for a Termination Option in a Transaction Confirmation executed in writing by both parties. The Transaction Confirmation containing the Termination Option will designate the length of nonperformance triggering the Termination Option and the procedures for exercise thereof, how damages for nonperformance will be compensated, and how liquidation costs will be calculated.

SECTION 4. TRANSPORTATION, NOMINATIONS, AND IMBALANCES

4.1. Seller shall have the sole responsibility for transporting the Gas to the Delivery Point(s). Buyer shall have the sole responsibility for transporting the Gas from the Delivery Point(s).

4.2. The parties shall coordinate their nomination activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each party shall give the other party timely prior Notice, sufficient to meet the requirements of all Transporter(s) involved in the transaction, of the quantities of Gas to be delivered and purchased each Day. Should either party become aware that actual deliveries at the Delivery Point(s) are greater or lesser than the Scheduled Gas, such party shall promptly notify the other party.

4.3. The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. If the Imbalance Charges were incurred as a result of Buyer's receipt of quantities of Gas greater than or less than the Scheduled Gas, then Buyer shall pay for such Imbalance Charges or reimburse Seller for such Imbalance Charges paid by Seller. If the Imbalance Charges were incurred as a result of Seller's delivery of quantities of Gas greater than or less than the Scheduled Gas, then Seller shall pay for such Imbalance Charges or reimburse Buyer for such Imbalance Charges paid by Buyer.

SECTION 5. QUALITY AND MEASUREMENT

All Gas delivered by Seller shall meet the pressure, quality and heat content requirements of the Receiving Transporter. The unit of quantity measurement for purposes of this Contract shall be one MMBtu dry. Measurement of Gas quantities hereunder shall be in accordance with the established procedures of the Receiving Transporter.

SECTION 6. TAXES

The parties have selected either "Buyer Pays At and After Delivery Point" or "Seller Pays Before and At Delivery Point" as indicated on the Base Contract.

Buyer Pays At and After Delivery Point:

Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas at the Delivery Point(s) and all Taxes after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

Seller Pays Before and At Delivery Point:

Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s) and all Taxes at the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

SECTION 7. BILLING, PAYMENT, AND AUDIT

7.1. Seller shall invoice Buyer for Gas delivered and received in the preceding Month and for any other applicable charges, providing supporting documentation acceptable in industry practice to support the amount charged. If the actual quantity delivered is not known by the billing date, billing will be prepared based on the quantity of Scheduled Gas. The invoiced quantity will then be adjusted to the actual quantity on the following Month's billing or as soon thereafter as actual delivery information is available.

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7.2. Buyer shall remit the amount due under Section 7.1 in the manner specified in the Base Contract, in immediately available funds, on or before the later of the Payment Date or 10 Days after receipt of the invoice by Buyer; provided that if the Payment Date is not a Business Day, payment is due on the next Business Day following that date. In the event any payments are due Buyer hereunder, payment to Buyer shall be made in accordance with this Section 7.2.

7.3. In the event payments become due pursuant to Sections 3.2 or 3.3, the performing party may submit an invoice to the nonperforming party for an accelerated payment setting forth the basis upon which the invoiced amount was calculated. Payment from the nonperforming party will be due five Business Days after receipt of invoice.

7.4. If the invoiced party, in good faith, disputes the amount of any such invoice or any part thereof, such invoiced party will pay such amount as it concedes to be correct; provided, however, if the invoiced party disputes the amount due, it must provide supporting documentation acceptable in industry practice to support the amount paid or disputed without undue delay. In the event the parties are unable to resolve such dispute, either party may pursue any remedy available at law or in equity to enforce its rights pursuant to this Section.

7.5. If the invoiced party fails to remit the full amount payable when due, interest on the unpaid portion shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under “Money Rates” by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

7.6. A party shall have the right, at its own expense, upon reasonable Notice and at reasonable times, to examine and audit and to obtain copies of the relevant portion of the books, records, and telephone recordings of the other party only to the extent reasonably necessary to verify the accuracy of any statement, charge, payment, or computation made under the Contract. This right to examine, audit, and to obtain copies shall not be available with respect to proprietary information not directly relevant to transactions under this Contract. All invoices and billings shall be conclusively presumed final and accurate and all associated claims for under- or overpayments shall be deemed waived unless such invoices or billings are objected to in writing, with adequate explanation and/or documentation, within two years after the Month of Gas delivery. All retroactive adjustments under Section 7 shall be paid in full by the party owing payment within 30 Days of Notice and substantiation of such inaccuracy.

7.7. Unless the parties have elected on the Base Contract not to make this Section 7.7 applicable to this Contract, the parties shall net all undisputed amounts due and owing, and/or past due, arising under the Contract such that the party owing the greater amount shall make a single payment of the net amount to the other party in accordance with Section 7; provided that no payment required to be made pursuant to the terms of any Credit Support Obligation or pursuant to Section 7.3 shall be subject to netting under this Section. If the parties have executed a separate netting agreement, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 8. TITLE, WARRANTY, AND INDEMNITY

8.1. Unless otherwise specifically agreed, title to the Gas shall pass from Seller to Buyer at the Delivery Point(s). Seller shall have responsibility for and assume any liability with respect to the Gas prior to its delivery to Buyer at the specified Delivery Point(s). Buyer shall have responsibility for and assume any liability with respect to said Gas after its delivery to Buyer at the Delivery Point(s).

8.2. Seller warrants that it will have the right to convey and will transfer good and merchantable title to all Gas sold hereunder and delivered by it to Buyer, free and clear of all liens, encumbrances, and claims. EXCEPT AS PROVIDED IN THIS SECTION 8.2 AND IN SECTION 15.8, ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR OF FITNESS FOR ANY PARTICULAR PURPOSE, ARE DISCLAIMED.

8.3. Seller agrees to indemnify Buyer and save it harmless from all losses, liabilities or claims including reasonable attorneys’ fees and costs of court (“Claims”), from any and all persons, arising from or out of claims of title, personal injury (including death) or property damage from said Gas or other charges thereon which attach before title passes to Buyer. Buyer agrees to indemnify Seller and save it harmless from all Claims, from any and all persons, arising from or out of claims regarding payment, personal injury (including death) or property damage from said Gas or other charges thereon which attach after title passes to Buyer.

8.4. The parties agree that the delivery of and the transfer of title to all Gas under this Contract shall take place within the Customs Territory of the United States (as defined in general note 2 of the Harmonized Tariff Schedule of the United States 19 U.S.C. §1202, General Notes, page 3); provided, however, that in the event Seller took title to the Gas outside the Customs Territory of the United States, Seller represents and warrants that it is the importer of record for all Gas entered and delivered into the United States, and shall be responsible for entry and entry summary filings as well as the payment of duties, taxes and fees, if any, and all applicable record keeping requirements.

8.5. Notwithstanding the other provisions of this Section 8, as between Seller and Buyer, Seller will be liable for all Claims to the extent that such arise from the failure of Gas delivered by Seller to meet the quality requirements of Section 5.

SECTION 9. NOTICES

9.1. All Transaction Confirmations, invoices, payment instructions, and other communications made pursuant to the Base Contract (“Notices”) shall be made to the addresses specified in writing by the respective parties from time to time.

9.2. All Notices required hereunder shall be in writing and may be sent by facsimile or mutually acceptable electronic means, a nationally recognized overnight courier service, first class mail or hand delivered.

9.3. Notice shall be given when received on a Business Day by the addressee. In the absence of proof of the actual receipt date, the following presumptions will apply. Notices sent by facsimile shall be deemed to have been received upon the sending party’s receipt of its facsimile machine’s confirmation of successful transmission. If the day on which such facsimile is received is

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not a Business Day or is after five p.m. on a Business Day, then such facsimile shall be deemed to have been received on the next following Business Day. Notice by overnight mail or courier shall be deemed to have been received on the next Business Day after it was sent or such earlier time as is confirmed by the receiving party. Notice via first class mail shall be considered delivered five Business Days after mailing.

9.4. The party receiving a commercially acceptable Notice of change in payment instructions or other payment information shall not be obligated to implement such change until ten Business Days after receipt of such Notice.

SECTION 10. FINANCIAL RESPONSIBILITY

10.1. If either party ("X") has reasonable grounds for insecurity regarding the performance of any obligation under this Contract (whether or not then due) by the other party ("Y") (including, without limitation, the occurrence of a material change in the creditworthiness of Y or its Guarantor, if applicable), X may demand Adequate Assurance of Performance. "Adequate Assurance of Performance" shall mean sufficient security in the form, amount, for a term, and from an issuer, all as reasonably acceptable to X, including, but not limited to cash, a standby irrevocable letter of credit, a prepayment, a security interest in an asset or guaranty. Y hereby grants to X a continuing first priority security interest in, lien on, and right of setoff against all Adequate Assurance of Performance in the form of cash transferred by Y to X pursuant to this Section 10.1. Upon the return by X to Y of such Adequate Assurance of Performance, the security interest and lien granted hereunder on that Adequate Assurance of Performance shall be released automatically and, to the extent possible, without any further action by either party.

10.2. In the event (each an "Event of Default") either party (the "Defaulting Party") or its Guarantor shall: (i) make an assignment or any general arrangement for the benefit of creditors; (ii) file a petition or otherwise commence, authorize, or acquiesce in the commencement of a proceeding or case under any bankruptcy or similar law for the protection of creditors or have such petition filed or proceeding commenced against it; (iii) otherwise become bankrupt or insolvent (however evidenced); (iv) be unable to pay its debts as they fall due; (v) have a receiver, provisional liquidator, conservator, custodian, trustee or other similar official appointed with respect to it or substantially all of its assets; (vi) fail to perform any obligation to the other party with respect to any Credit Support Obligations relating to the Contract; (vii) fail to give Adequate Assurance of Performance under Section 10.1 within 48 hours but at least one Business Day of a written request by the other party; (viii) not have paid any amount due the other party hereunder on or before the second Business Day following written Notice that such payment is due; or ix) be the affected party with respect to any Additional Event of Default; then the other party (the "Non-Defaulting Party") shall have the right, at its sole election, to immediately withhold and/or suspend deliveries or payments upon Notice and/or to terminate and liquidate the transactions under the Contract, in the manner provided in Section 10.3, in addition to any and all other remedies available hereunder.

10.3. If an Event of Default has occurred and is continuing, the Non-Defaulting Party shall have the right, by Notice to the Defaulting Party, to designate a Day, no earlier than the Day such Notice is given and no later than 20 Days after such Notice is given, as an early termination date (the "Early Termination Date") for the liquidation and termination pursuant to Section 10.3.1 of all transactions under the Contract, each a "Terminated Transaction". On the Early Termination Date, all transactions will terminate, other than those transactions, if any, that may not be liquidated and terminated under applicable law ("Excluded Transactions"), which Excluded Transactions must be liquidated and terminated as soon thereafter as is legally permissible, and upon termination shall be a Terminated Transaction and be valued consistent with Section 10.3.1 below. With respect to each Excluded Transaction, its actual termination date shall be the Early Termination Date for purposes of Section 10.3.1.

The parties have selected either "Early Termination Damages Apply" or "Early Termination Damages Do Not Apply" as indicated on the Base Contract.

Early Termination Damages Apply:

10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, (i) the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract and (ii) the Market Value, as defined below, of each Terminated Transaction. The Non-Defaulting Party shall (x) liquidate and accelerate each Terminated Transaction at its Market Value, so that each amount equal to the difference between such Market Value and the Contract Value, as defined below, of such Terminated Transaction(s) shall be due to the Buyer under the Terminated Transaction(s) if such Market Value exceeds the Contract Value and to the Seller if the opposite is the case; and (y) where appropriate, discount each amount then due under clause (x) above to present value in a commercially reasonable manner as of the Early Termination Date (to take account of the period between the date of liquidation and the date on which such amount would have otherwise been due pursuant to the relevant Terminated Transactions).

For purposes of this Section 10.3.1, "Contract Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the Contract Price, and "Market Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the market price for a similar transaction at the Delivery Point determined by the Non-Defaulting Party in a commercially reasonable manner. To ascertain the Market Value, the Non-Defaulting Party may consider, among other valuations, any or all of the settlement prices of NYMEX Gas futures contracts, quotations from leading dealers in energy swap contracts or physical gas trading markets, similar sales or purchases and any other bona fide third-party offers, all adjusted for the length of the term and differences in transportation costs. A party shall not be required to enter into a replacement transaction(s) in order to determine the Market Value. Any extension(s) of the term of a transaction to which parties are not bound as of the Early Termination Date (including but not limited to "evergreen provisions") shall not be considered in determining Contract Values and

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Market Values. For the avoidance of doubt, any option pursuant to which one party has the right to extend the term of a transaction shall be considered in determining Contract Values and Market Values. The rate of interest used in calculating net present value shall be determined by the Non-Defaulting Party in a commercially reasonable manner.

Early Termination Damages Do Not Apply:

10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract.

The parties have selected either "Other Agreement Setoffs Apply" or "Other Agreement Setoffs Do Not Apply" as indicated on the Base Contract.

Other Agreement Setoffs Apply:

Bilateral Setoff Option:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party is hereby authorized to setoff any Net Settlement Amount against (i) any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract; and (ii) any amount(s) (including any excess cash margin or excess cash collateral) owed or held by the party that is entitled to the Net Settlement Amount under any other agreement or arrangement between the parties.

Triangular Setoff Option:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option, and without prior Notice to the Defaulting Party, the Non-Defaulting Party is hereby authorized to setoff (i) any Net Settlement Amount against any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract; (ii) any Net Settlement Amount against any amount(s) (including any excess cash margin or excess cash collateral) owed by or to a party under any other agreement or arrangement between the parties; (iii) any Net Settlement Amount owed to the Non-Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Non-Defaulting Party or its Affiliates to the Defaulting Party under any other agreement or arrangement; (iv) any Net Settlement Amount owed to the Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Defaulting Party to the Non-Defaulting Party or its Affiliates under any other agreement or arrangement; and/or (v) any Net Settlement Amount owed to the Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Defaulting Party or its Affiliates to the Non-Defaulting Party under any other agreement or arrangement.

Other Agreement Setoffs Do Not Apply:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party may setoff any Net Settlement Amount against any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract.

10.3.3. If any obligation that is to be included in any netting, aggregation or setoff pursuant to Section 10.3.2 is unascertained, the Non-Defaulting Party may in good faith estimate that obligation and net, aggregate or setoff, as applicable, in respect of the estimate, subject to the Non-Defaulting Party accounting to the Defaulting Party when the obligation is ascertained. Any amount not then due which is included in any netting, aggregation or setoff pursuant to Section 10.3.2 shall be discounted to net present value in a commercially reasonable manner determined by the Non-Defaulting Party.

10.4. As soon as practicable after a liquidation, Notice shall be given by the Non-Defaulting Party to the Defaulting Party of the Net Settlement Amount, and whether the Net Settlement Amount is due to or due from the Non-Defaulting Party. The Notice shall include a written statement explaining in reasonable detail the calculation of the Net Settlement Amount, provided that failure to give such Notice shall not affect the validity or enforceability of the liquidation or give rise to any claim by the Defaulting Party against the Non-Defaulting Party. The Net Settlement Amount as well as any setoffs applied against such amount pursuant to Section 10.3.2, shall be paid by the close of business on the second Business Day following such Notice, which date shall not be earlier than the Early Termination Date. Interest on any unpaid portion of the Net Settlement Amount as adjusted by setoffs, shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

10.5. The parties agree that the transactions hereunder constitute a "forward contract" within the meaning of the United States Bankruptcy Code and that Buyer and Seller are each "forward contract merchants" within the meaning of the United States Bankruptcy Code.

10.6. The Non-Defaulting Party's remedies under this Section 10 are the sole and exclusive remedies of the Non-Defaulting Party with respect to the occurrence of any Early Termination Date. Each party reserves to itself all other rights, setoffs, counterclaims and other defenses that it is or may be entitled to arising from the Contract.

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10.7. With respect to this Section 10, if the parties have executed a separate netting agreement with close-out netting provisions, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 11. FORCE MAJEURE

11.1. Except with regard to a party's obligation to make payment(s) due under Section 7, Section 10.4, and Imbalance Charges under Section 4, neither party shall be liable to the other for failure to perform a Firm obligation, to the extent such failure was caused by Force Majeure. The term "Force Majeure" as employed herein means any cause not reasonably within the control of the party claiming suspension, as further defined in Section 11.2.

11.2. Force Majeure shall include, but not be limited to, the following: (i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe; (ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe; (iii) interruption and/or curtailment of Firm transportation and/or storage by Transporters; (iv) acts of others such as strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections or wars, or acts of terror; and (v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of law promulgated by a governmental authority having jurisdiction. Seller and Buyer shall make reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance.

11.3. Neither party shall be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances: (i) the curtailment of interruptible or secondary Firm transportation unless primary, in-path, Firm transportation is also curtailed; (ii) the party claiming excuse failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; or (iii) economic hardship, to include, without limitation, Seller's ability to sell Gas at a higher or more advantageous price than the Contract Price, Buyer's ability to purchase Gas at a lower or more advantageous price than the Contract Price, or a regulatory agency disallowing, in whole or in part, the pass through of costs resulting from this Contract; (iv) the loss of Buyer's market(s) or Buyer's inability to use or resell Gas purchased hereunder, except, in either case, as provided in Section 11.2; or (v) the loss or failure of Seller's gas supply or depletion of reserves, except, in either case, as provided in Section 11.2. The party claiming Force Majeure shall not be excused from its responsibility for Imbalance Charges.

11.4. Notwithstanding anything to the contrary herein, the parties agree that the settlement of strikes, lockouts or other industrial disturbances shall be within the sole discretion of the party experiencing such disturbance.

11.5. The party whose performance is prevented by Force Majeure must provide Notice to the other party. Initial Notice may be given orally; however, written Notice with reasonably full particulars of the event or occurrence is required as soon as reasonably possible. Upon providing written Notice of Force Majeure to the other party, the affected party will be relieved of its obligation, from the onset of the Force Majeure event, to make or accept delivery of Gas, as applicable, to the extent and for the duration of Force Majeure, and neither party shall be deemed to have failed in such obligations to the other during such occurrence or event.

11.6. Notwithstanding Sections 11.2 and 11.3, the parties may agree to alternative Force Majeure provisions in a Transaction Confirmation executed in writing by both parties.

SECTION 12. TERM

This Contract may be terminated on 30 Day's written Notice, but shall remain in effect until the expiration of the latest Delivery Period of any transaction(s). The rights of either party pursuant to Section 7.6, Section 10, Section 13, the obligations to make payment hereunder, and the obligation of either party to indemnify the other, pursuant hereto shall survive the termination of the Base Contract or any transaction.

SECTION 13. LIMITATIONS

FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY. A PARTY'S LIABILITY HEREUNDER SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, A PARTY'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY. SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

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SECTION 14. MARKET DISRUPTION

If a Market Disruption Event has occurred then the parties shall negotiate in good faith to agree on a replacement price for the Floating Price (or on a method for determining a replacement price for the Floating Price) for the affected Day, and if the parties have not so agreed on or before the second Business Day following the affected Day then the replacement price for the Floating Price shall be determined within the next two following Business Days with each party obtaining, in good faith and from non-affiliated market participants in the relevant market, two quotes for prices of Gas for the affected Day of a similar quality and quantity in the geographical location closest in proximity to the Delivery Point and averaging the four quotes. If either party fails to provide two quotes then the average of the other party's two quotes shall determine the replacement price for the Floating Price. "Floating Price" means the price or a factor of the price agreed to in the transaction as being based upon a specified index. "Market Disruption Event" means, with respect to an index specified for a transaction, any of the following events: (a) the failure of the index to announce or publish information necessary for determining the Floating Price; (b) the failure of trading to commence or the permanent discontinuation or material suspension of trading on the exchange or market acting as the index; (c) the temporary or permanent discontinuance or unavailability of the index; (d) the temporary or permanent closing of any exchange acting as the index; or (e) both parties agree that a material change in the formula for or the method of determining the Floating Price has occurred. For the purposes of the calculation of a replacement price for the Floating Price, all numbers shall be rounded to three decimal places. If the fourth decimal number is five or greater, then the third decimal number shall be increased by one and if the fourth decimal number is less than five, then the third decimal number shall remain unchanged.

SECTION 15. MISCELLANEOUS

15.1. This Contract shall be binding upon and inure to the benefit of the successors, assigns, personal representatives, and heirs of the respective parties hereto, and the covenants, conditions, rights and obligations of this Contract shall run for the full term of this Contract. No assignment of this Contract, in whole or in part, will be made without the prior written consent of the non-assigning party (and shall not relieve the assigning party from liability hereunder), which consent will not be unreasonably withheld or delayed; provided, either party may (i) transfer, sell, pledge, encumber, or assign this Contract or the accounts, revenues, or proceeds hereof in connection with any financing or other financial arrangements, or (ii) transfer its interest to any parent or Affiliate by assignment, merger or otherwise without the prior approval of the other party. Upon any such assignment, transfer and assumption, the transferor shall remain principally liable for and shall not be relieved of or discharged from any obligations hereunder.

15.2. If any provision in this Contract is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Contract.

15.3. No waiver of any breach of this Contract shall be held to be a waiver of any other or subsequent breach.

15.4. This Contract sets forth all understandings between the parties respecting each transaction subject hereto, and any prior contracts, understandings and representations, whether oral or written, relating to such transactions are merged into and superseded by this Contract and any effective transaction(s). This Contract may be amended only by a writing executed by both parties.

15.5. The interpretation and performance of this Contract shall be governed by the laws of the jurisdiction as indicated on the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction.

15.6. This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any governmental authority having jurisdiction over the parties, their facilities, or Gas supply, this Contract or transaction or any provisions thereof.

15.7. There is no third party beneficiary to this Contract.

15.8. Each party to this Contract represents and warrants that it has full and complete authority to enter into and perform this Contract. Each person who executes this Contract on behalf of either party represents and warrants that it has full and complete authority to do so and that such party will be bound thereby.

15.9. The headings and subheadings contained in this Contract are used solely for convenience and do not constitute a part of this Contract between the parties and shall not be used to construe or interpret the provisions of this Contract.

15.10. Unless the parties have elected on the Base Contract not to make this Section 15.10 applicable to this Contract, neither party shall disclose directly or indirectly without the prior written consent of the other party the terms of any transaction to a third party (other than the employees, lenders, royalty owners, counsel, accountants and other agents of the party, or prospective purchasers of all or substantially all of a party's assets or of any rights under this Contract, provided such persons shall have agreed to keep such terms confidential) except (i) in order to comply with any applicable law, order, regulation, or exchange rule, (ii) to the extent necessary for the enforcement of this Contract , (iii) to the extent necessary to implement any transaction, (iv) to the extent necessary to comply with a regulatory agency's reporting requirements including but not limited to gas cost recovery proceedings; or (v) to the extent such information is delivered to such third party for the sole purpose of calculating a published index. Each party shall notify the other party of any proceeding of which it is aware which may result in disclosure of the terms of any transaction (other than as permitted hereunder) and use reasonable efforts to prevent or limit the disclosure. The existence of this Contract is not subject to this confidentiality obligation. Subject to Section 13, the parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with this confidentiality obligation. The terms of any transaction hereunder shall be kept confidential by the parties hereto for one year from the expiration of the transaction.

In the event that disclosure is required by a governmental body or applicable law, the party subject to such requirement may disclose the material terms of this Contract to the extent so required, but shall promptly notify the other party, prior to disclosure,

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and shall cooperate (consistent with the disclosing party's legal obligations) with the other party's efforts to obtain protective orders or similar restraints with respect to such disclosure at the expense of the other party.

15.11. The parties may agree to dispute resolution procedures in Special Provisions attached to the Base Contract or in a Transaction Confirmation executed in writing by both parties

15.12. Any original executed Base Contract, Transaction Confirmation or other related document may be digitally copied, photocopied, or stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidence on paper, the Transaction Confirmation, if introduced as evidence in automated facsimile form, the recording, if introduced as evidence in its original form, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings will be admissible as between the parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the recording, the Transaction Confirmation, or the Imaged Agreement on the basis that such were not originated or maintained in documentary form. However, nothing herein shall be construed as a waiver of any other objection to the admissibility of such evidence.

DISCLAIMER: The purposes of this Contract are to facilitate trade, avoid misunderstandings and make more definite the terms of contracts of purchase and sale of natural gas. Further, NAESB does not mandate the use of this Contract by any party. **NAESB DISCLAIMS AND EXCLUDES, AND ANY USER OF THIS CONTRACT ACKNOWLEDGES AND AGREES TO NAESB'S DISCLAIMER OF, ANY AND ALL WARRANTIES, CONDITIONS OR REPRESENTATIONS, EXPRESS OR IMPLIED, ORAL OR WRITTEN, WITH RESPECT TO THIS CONTRACT OR ANY PART THEREOF, INCLUDING ANY AND ALL IMPLIED WARRANTIES OR CONDITIONS OF TITLE, NON-INFRINGEMENT, MERCHANTABILITY, OR FITNESS OR SUITABILITY FOR ANY PARTICULAR PURPOSE (WHETHER OR NOT NAESB KNOWS, HAS REASON TO KNOW, HAS BEEN ADVISED, OR IS OTHERWISE IN FACT AWARE OF ANY SUCH PURPOSE), WHETHER ALLEGED TO ARISE BY LAW, BY REASON OF CUSTOM OR USAGE IN THE TRADE, OR BY COURSE OF DEALING. EACH USER OF THIS CONTRACT ALSO AGREES THAT UNDER NO CIRCUMSTANCES WILL NAESB BE LIABLE FOR ANY DIRECT, SPECIAL, INCIDENTAL, EXEMPLARY, PUNITIVE OR CONSEQUENTIAL DAMAGES ARISING OUT OF ANY USE OF THIS CONTRACT.**

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THIRD AMENDED AND RESTATED SPECIAL PROVISIONS ATTACHED TO AND FORMING PART OF THE BASE CONTRACT FOR SALE AND PURCHASE OF NATURAL GAS
Dated January 5, 2010
by and between

BP Energy Company ("BP Energy" or "Buyer")
And

Comstock Oil & Gas — Louisiana, LLC ("Comstock" or "Seller")

Collectively BP Energy and Comstock shall be referred to as the "Parties", and individually may be referred to as a "Party".

WHEREAS, BP Energy and Comstock are parties to that certain Base Contract for Sale and Purchase of Natural Gas dated November 7, 2008 as it was amended pursuant to the certain Amended and Restated Special Provisions on February 16, 2009 (the "Amended and Restated Provisions"), and further amended pursuant to the Second Amended and Restated Special Provisions on August 1, 2009 (the "Second Amended and Restated Provisions");

WHEREAS, the Parties desire to further amend the Base Contract pursuant to this Third Amended and Restated Provisions to (a) document the revised agreement of the Parties set forth in Section 3.7 of the Amended and Restated Provisions within a Transaction Confirmation, and (b) amend other various miscellaneous provisions in the Base Contract.

Section 1. Purpose & Procedures

Add the phrase "or other electronic means of communication" after "conversation" and before "with" in the second line of Section 1.2.

Delete Section 1.3 and replace it with the following:

"1.3 If a sending Party's Transaction Confirmation is materially different from the receiving Party's understanding of the agreement referred to in Section 1.2, such receiving Party shall notify the sending Party via facsimile, EDI or mutually agreeable electronic means by the Confirm Deadline, unless such receiving Party has previously sent a Transaction Confirmation to the sending Party. The failure of the receiving Party to so notify the sending Party in writing by the Confirm Deadline constitutes the receiving Party's agreement to the terms of the transaction described in the sending Party's Transaction Confirmation. If there are any material differences between timely sent Transaction Confirmations governing the same transaction, or if the receiving Party has timely objected to the terms of the sending Party's Transaction Confirmation, such transaction remains valid and the Parties remain legally bound thereby, however, both Parties shall in good faith attempt to resolve such differences. Once such material differences are resolved, the Confirming Party shall transmit a written Transaction Confirmation to the other Party, and such Transaction Confirmation shall be accepted (or disputed) pursuant to the provisions of this Section 1.3. The provisions of this Section 1.3 may be repeated as many times as necessary to produce a written Transaction Confirmation that is accepted or deemed accepted by the receiving Party. In the event of a conflict among the terms of (i) a binding Transaction Confirmation pursuant to Section 1.2, (ii) the oral agreement of the Parties (which may be evidenced by a recording of such transaction, oral testimony, data in a computer system, trade tickets, and/or notes), where the Parties have selected the Oral Transaction Procedure of the Base Contract, (iii) the Base Contract, and (iv) these General Terms and Conditions, the terms of the items shall govern in the priority listed in this sentence."

Add the following before the "." at the end of the second sentence in Section 1.4:

"; provided, further that the party responsible for obtaining the consent of its agents and employees to such recordings shall indemnify, defend and hold the other party harmless from any and all losses, liabilities, claims, damages, judgments, costs and expenses, including but not limited to reasonably attorney's fees and costs of court, arising from or out of such party's failure to obtain the consent of its agents and employees to such recordings."

Section 2. Definitions

Definition of "Payment Date" in Section 2.27 shall be deleted and replaced with the following: "Payment Date" shall mean a date, as indicated on the Base Contract, on or before which payment is due from one Party to the other as set forth in Section 7."

Definition of "Spot Price" in Section 2.31 shall be amended by deleting the last sentence.

Add the following at the end of Section 2:

"Dedicated Acreage" shall mean the acreage defined and described on Exhibits 1 and 2, which are attached hereto and incorporated herein for all purposes.

Section 3. Performance Obligation

Add the following at beginning of the sentence in Section 3.1: "Unless otherwise specifically agreed to in a Transaction Confirmation,"

Add the following as Section 3.5:

"3.5 In the event that the Contract Price for a transaction is a Fixed Price (as defined below), and such transaction (a) has a Firm performance obligation, and (b) a Delivery Period of at least one Month, then, notwithstanding anything to the contrary in this Contract, including, without limitation, anything in Sections 3.2 or 11 of this Contract:

(i) if, upon the occurrence of an event of Force Majeure, and as a result of the event of Force Majeure (a) Seller is unable to sell and deliver or (b) Buyer is unable to purchase and receive, the Contract Quantity of Fixed Price Gas, either in whole or in part, for such transaction,

(ii) then, for the duration of the event of Force Majeure, for each Day that Seller is unable to sell and deliver, or Buyer is unable to purchase and receive, such Fixed Price Gas, as set out in Section 3.5(i) above, the following settlement obligations between the parties shall apply:

   a. if the FOM Price (as defined below) exceeds the Fixed Price, Seller shall pay Buyer the difference between the FOM Price and the Fixed Price for each MMBtu of such Gas not delivered and/or received on that Day, or

   b. if the Fixed Price exceeds the FOM Price, Buyer shall pay Seller the difference between the Fixed Price and the FOM Price for each MMBtu of such Gas not delivered and/or received on that Day.

For the purpose of this Section 3.5:

"Fixed Price" means, a Contract Price for a transaction that is expressed as a flat dollar amount for the Month of delivery, excluding any transactions that have been entered into after the last trading day (as defined by the NYMEX) for the applicable Month. Subject to the foregoing exclusion, "Fixed Price" also includes any transaction containing a Contract Price that has been converted from a floating price mechanism (i.e., a

NYMEX/first of the month index basis component and a fixed price component, or a NYMEX/first of the month index priced component with a fixed basis component) to a flat dollar amount for the Month of delivery, either upon the mutual agreement of the Parties or as a result of a Party exercising a pricing "trigger" option in the Contract. "FOM Price" means the price per MMBtu, stated in the same currency as the transaction subject to such event of Force Majeure, for the first of the Month delivery, either as the NYMEX settlement price or as an index price published in the first issue of a publication commonly accepted by the natural gas industry (selected by the Seller in a commercially reasonable manner) for the Month of such event of Force Majeure for the geographic location closest in proximity to the point(s) of delivery for the relevant Day, adjusted for the basis differential between the point(s) of delivery and the NYMEX or such published geographic location as determined by the Seller in a commercially reasonable manner."

Add the following as Section 3.6:

"3.6 For the purposes of this Section, "Regulatory Event" means a government action requiring compliance, a court order, ruling, law, statute, ordinance, regulation or policy having the effect of law promulgated after the Effective Date of any transaction under this Contract, whether on a local, state or federal level, including but not limited to market rate caps (whether temporary or permanent), regulatory market requirements or the imposition of New Taxes. Regulatory Event shall not include a regulatory agency disallowing, in whole or in part, the pass through of costs resulting from this Contract. In the event a Regulatory Event occurs which renders a Party unable to continue to perform, either in whole or in part, under any transaction, or a Regulatory Event has a material adverse economic impact under this Contract on a Party (the "Affected Party") and the Affected Party is unable, after using commercially reasonable efforts, to avoid the inability to perform or the material economic impact, the Affected Party or other Party (the "Non-Affected Party"), shall be entitled to terminate and liquidate the transactions affected by such Regulatory Event (the "Affected Transactions") in accordance with Section 10, subject to the following conditions:

3.6.1 The Affected Party must give the Non-Affected Party at least twenty (20) Business Days prior written notice of its intent to terminate and liquidate the Affected Transaction(s). To the extent the Affected Party does not issue a Regulatory Event Notice to Terminate, the Non-Affected Party shall be entitled to provide at least twenty (20) Business Days notice to the Affected Party of its desire to terminate and liquidate the Affected Transactions under which performance by the Affected Party has been suspended, with such Notice being provided within five (5) Business Days from the date performance was suspended by the Affected Party. The Notice provided by the Affected Party, or the Non-Affected Party, as the case may be, shall be the "Regulatory Event Notice to Terminate". During the twenty (20) Business Day period following the Regulatory Event Notice to Terminate, the Parties shall attempt to reach mutual agreement, using the negotiation process set forth in Section 15.17., to resolve the material adverse economic impact on the Affected Party or the inability of the Affected Party to continue to perform.

3.6.2 If a mutual agreement using the negotiation process is not reached within the referenced twenty (20) Business Days notice period, the Affected Party or the Non-Affected Party, as the case may be, shall by written notice to the other Party specify an Early Termination Date (which must be a Business Day and which date shall be no more than ten (10) Days after the date of such notice) and on such Early Termination Date shall determine damages in accordance with Section10 of the Contract; provided however, that for purposes of determining the amounts owed with respect to the liquidation and termination of each Affected Transaction under Section 10, any and all costs otherwise allowed under Section 10.3.1. shall be excluded from the calculation, and provided further that for purposes of determining the resulting amount(s) owed for the termination and liquidation of each Affected Transaction, the Market Value for each Terminated Transaction shall be determined by using the mid-point, as it may be estimated, between the bid price and the ask price for each Terminated Transaction to reflect that neither Party is a Defaulting Party and accordingly the intent of the Parties is not to ascertain liquidated damages from a Non-Defaulting Party's perspective. The respective Parties shall have the same rights and remedies related to the calculation and dispute of the resulting Net Settlement Amount(s) owed with respect to the termination and liquidation of the Affected Transactions as those set forth in Section 10.

3.6.3 The Party owing the Net Settlement Amount shall pay the Net Settlement Amount to the other Party as provided under Section 10, provided that a Party shall not be entitled to receive a Net Settlement Amount if it initiated or supported the Regulatory Event.

3.6.4 For the purposes of this Section 3.6, "New Tax" or "New Taxes" means any or all governmental charges, licenses, fees, permits and assessments, or increases therein, that are imposed on a Party that (i) were not in effect on the date the Affected Transaction was entered into by the Parties, or (ii) were not imposed on a the Affected Transaction on the date the Affected Transaction was entered into by the Parties."

Add the following as Section 3.7:

"3.7 Any Gas sold and/or delivered by Seller to Buyer at the Delivery Point(s), and purchases made and/or received from Seller by Buyer at the Delivery Point(s), shall be deemed delivered in the following order, absent evidence to the contrary (i.e., Transporter's records):

(i) any Gas under that certain Transaction Confirmation No.4234667 dated July 30, 2009, as it has been amended thereafter ("CP1");

(ii) any Gas under that certain Transaction Confirmation No. 3617164 dated July 30, 2009 ("LIG1");

(iii) any Gas under that certain Transaction Confirmation No. 4700460 dated April 1, 2010 ("GSPL1");

(iv) any Gas under any future transactions related to the Dedicated Acreage for a fixed Contract Quantity (e.g., 10,000 MMBtus/Day, etc.) (collectively "Future Fixed Contract Quantity Transactions"), with the order of flow for such Future Fixed Contract Quantity Transactions flowing in the order that they were entered into by the Parties; or

(v) any Gas under that certain Transaction Confirmation dated July 16, 2009 ("DA1") (collectively CP1, LIG1, GSPL1, the Future Fixed Contract Quantity Transactions and DA1 shall be called the "Dedicated Acreage Transactions").

Provided further that (i) the Parties agree that with respect to any Gas delivered under a Transaction Confirmation, Gas shall be deemed delivered in the following order, (a) any Fixed Price Gas (as defined in Section 3.5) under such transaction; (b) the Baseload Volume under such transaction; and (c) any Swing Gas under such transaction, and (ii) absent evidence to the contrary, Baseload Volumes under the Dedicated Acreage Transactions shall flow before any Swing Gas under any of the Dedicated Acreage Transactions."

Add the following as Section 3.8:

Subject to the limitations set forth herein below, should BP Energy be unable to take and buy at least eight-five percent (85%) of the aggregated Contract Quantities of Gas made the subject of the Dedicated Acreage Transactions that are delivered to BP Energy at the respective Delivery Point(s) by Comstock for sixty (60) consecutive Days, other than due to an event of Force Majeure (such requirement being the "85% Termination Threshold"), then Comstock will have the right, but not the obligation, to terminate the Dedicated Acreage Transactions. In such event, Comstock will have BP Energy reassign the LIG capacity to Comstock as described in the Partial Assignment of Firm Transportation Agreement Between Comstock Oil and Gas —

Louisiana, LLC and Crosstex LIG, LLC, dated November 10, 2008; as well as the incremental LIG capacity as described in the Second Partial Assignment of Firm Transportation Agreement between Comstock and Crosstex LIG, LLC, dated February 16,2009, and any subsequent assignments of LIG capacity agreed to by the Parties that relates to transactions under this Contract. Provided further than in the event that an Event of Default results in the liquidation and termination of all transactions under the Contract, the capacity on LIG assigned by Comstock to BP Energy will be immediately reassigned to Comstock.

Section 5. Quality and Measurement

In the first line of Section 5, add the following short phrase after "Receiving Transporter" in the first sentence: "("Pipeline Requirements")".

Add the following after the first sentence in Section 5:

"The Transporter's equipment shall be utilized for purposes of determining whether Seller's Gas has satisfied the Pipeline Requirements, Notwithstanding the foregoing, the Parties acknowledge that the Gas delivered by Seller under any transaction governed by this Contract will be delivered in common stream with other sources of Gas. If (i) a Transporter refuses to receive or transport Gas nominated for delivery by Seller to Buyer because it claims that the Gas does not meet Pipeline Requirements and the Pipeline Requirements have changed since the date the subject transaction was entered into by the Parties, (ii) a Transporter refuses to receive or transport Gas nominated for delivery by Seller to Buyer because it claims that the Gas does not meet Pipeline Requirements and the Transporter previously accepted Gas from Seller from the same supply source; and/or (iii) Buyer refuses to accept Gas that is transported by Transporter based on a claim that the Gas does not meet Pipeline Requirements and (a) the Pipeline Requirements have changed since the date the subject transaction was entered into by the Parties and/or (b) the Transporter previously accepted Gas from Seller from the same supply source for deliveries to the Buyer, to the extent such event(s) prevents the Seller from delivering any Gas, in whole or in part, free from any claims of damages being made by Buyer for such Gas (i.e., the Buyer cannot accept such Gas and reserve damage claims against the Seller), the event will be considered an event of Force Majeure and Seller shall be released from its obligation to deliver (as well as any obligation to use reasonable efforts to avoid the adverse impact of such event) and Buyer will be released from its obligation to receive the Gas until the situation is remedied. Both Seller and Buyer will use commercially reasonable efforts to work with the applicable Transporter(s) to remedy the situation as soon as possible so that deliveries can resume. Notwithstanding anything else in this Agreement to the contrary, Seller will have no liability to Buyer if a Transporter delivers Gas that fails to meet the Pipeline Requirements, unless it can be demonstrated that Seller was the cause of the common stream not meeting Pipeline Requirements and Seller had direct control over ensuring that such Gas met the Pipeline Requirements."

Section 6. Taxes

Add the following as new Sections 6.2 and 6.3 to "Buyer Pays At and After the Delivery Point:" of Section 6:

"6.2 Gross Receipts and Consumption, and Compensating Taxes. For clarity, the Contract Price does not include any applicable state or local, gross receipts, compensating, utility, transaction privilege, sales or use tax which may be assessed as a result of sales of or use of Gas hereunder, whether measured by quantity or revenues ("Gross Receipts" or "Compensating Tax"). If there is such a Gross Receipts and/or Compensating Tax, either of which being applicable to that quantity of Gas sold to or used by Buyer hereunder, Seller will invoice Buyer and Buyer will pay Seller the amount of the Gross Receipts or Compensating Tax, and Seller will remit same as required by the applicable law.

6.3 Protest and Payment. If a Party is required to remit or pay Taxes that are the other Party's responsibility hereunder, the Party responsible for such Taxes shall promptly reimburse the other Party for such Taxes, except to the extent either Party has filed, or provides prior notice to the other Party that it will timely file, a good faith protest, contest, dispute or complaint with the taxing authority or applicable court with jurisdiction, which tolls the requirement to pay such Taxes. Any Party is entitled to make such good faith protests, contests, disputes or complaints with the applicable taxing authority or applicable court with jurisdiction or to file for a request for refund for such Taxes already paid in a timely manner as to any Taxes that it is responsible to pay or remit or for which it is responsible to pay or reimburse the other Party. In the event either Party makes such filings, the other Party shall cooperate with such filing Party by providing any relevant information within that Party's possession, which will support the filing Party's filing upon request by and as specified by the filing Party. Upon the issuance by the taxing authority or court of a final, non-appealable order, which lifts the tolling of an obligation to pay and requires payment of the applicable Taxes, and absent a stay of such order, the responsible Party shall either pay directly to the applicable taxing authority, or reimburse the other Party for, such Taxes and any other amounts (including interest) required by such order. Any Party entitled to an exemption from any such Taxes or charges shall furnish the other Party any necessary documentation thereof."

7. Billing, Payment and Audit

Delete Section 7.4 and replace it with the following:

"If the invoiced Party, in good faith, disputes the amount of any such invoice or any part thereof, such invoiced Party will pay such disputed amount into an escrow, trust or other account which will provide the other Party reasonable assurance that the amounts can be paid upon resolution of the dispute. Within ten (10) Days of the original Payment Date of the disputed amount, the Party disputing the amount shall provide the other Party with details of its dispute and any supporting documentation available. If the Parties are unable to resolve the dispute within ten (10) Days of delivery and receipt of such supporting documentation, the Parties shall use the negotiation process, failing which the arbitration process set forth in Sections 15.17 and 15.18, respectively."

In Section 7.7 add the following after the words "subject to netting under this Section" at the end of the first sentence:

"provided further, however, that the Party due payment under Section 7.3 may net all undisputed sums due thereunder against any amounts payable by it when making payments under Section 7."

Section 8. Title, Warranty, and Indemnity

Delete Section 8.4 in its entirety.

Section 9. Notices

In the first sentence of Section 9.4 delete the words "commercially acceptable".

Section 10. Financial Responsibility

Section 10.2 shall be amended by (i) deleting the words "or its Guarantor" in the first line of such Section; (ii) deleting the word "or" before "(ix)" in such Section; and (iii) adding the following immediately after the ";" in subclause (ix) of such Section:

> "(x) fail to perform or breach any other material obligation or representation under this Contract (except to the extent such failure constitutes a separate Event of Default, and except for such Party's obligations to deliver or receive Gas (the exclusive remedy for which is provided in Section 3)) if such failure is not remedied within three (3) Business Days after receipt of written notice; (xi) consolidate or amalgamate with, or merge with or into, or transfer all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under this Contract to which it or its predecessor was a Party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party; (xii) or with respect to a Party's guarantor, (A) any event referenced in clauses (i), (ii), (iii), (iv), or (v)

shall have occurred with respect to any Guarantor; (B) the failure of Guarantor's guaranty to be in full force and effect to cover all transactions entered into under this Contract prior to the satisfaction of all obligations of such Party under each transaction to which such guaranty shall relate without the prior written consent of the other Party; or (C) such Guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of any guaranty related to this Contract"

Add the following at the end before the "." in the last sentence of Section 10.2:

"provided that no suspension of performance shall continue for more than thirty (30) Days unless an Early Termination Date has been declared and the Defaulting Party given Notice thereof in accordance with Section 10.3."

In Section 10.3.1:

(i) Replace the words "whether or not then due" with the words "whether or not yet invoiced or due in the second line";

(ii) Insert the following: "(either firm or indicative)" after "physical gas trading markets" in the sixth line of the second paragraph of Section 10.3.1, and insert "any other information available to the Non-Defaulting Party, either internally or supplied to it by one or more third parties, including, without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data for the relevant markets", before "all adjusted for the length of term..." in the sixth line of the second paragraph of Section 10.3.1.;

(iii) Add the following provision at the end of the second paragraph:

"In determining the Early Termination Damages, damages shall be attributable only to Terminated Transactions for Firm Gas transactions. The Parties understand and appreciate that utilizing good faith and commercially reasonable efforts, the Non-Defaulting Party should obtain quotes or other reliable third party information authorized under the terms of this Contract for the purposes of calculating the Net Settlement Amount(s), and that to the extent such information is received from such third parties such information is to be preferred and utilized over internal information and valuations.";

(iv) Add the following as the third paragraph of Section 10.3.1. "Early Termination Damages Apply":

"The Non-Defaulting Party shall also aggregate the costs that the Non-Defaulting Party incurs in liquidating and accelerating each Terminated Transaction, or otherwise settling obligations arising from the cancellation and termination of each Terminated Transaction, including brokerage fees, commissions, and other similar transaction costs and expenses reasonably incurred by the Non-Defaulting Party including costs associated with hedging its obligations, transaction costs associated with obtaining replacement suppliers or markets (e.g. brokerage fees, or other such payments), additional transmission costs, ancillary services costs and like costs incurred in moving the replacement Gas to or from the Delivery Point, and reasonable attorneys' fees and other reasonable litigation costs incurred in connection with enforcing its rights under this Contract (collectively "Costs") and such Costs shall be due to the Non-Defaulting Party."; and

(v) Adding the following provision as the fourth paragraph:

“The purpose of calculating the Market Value with respect to a Terminated Transaction shall be the determination of the amount that would be incurred or realized by the Non-Defaulting Party to replace or to provide the economic equivalent of the remaining payments or deliveries in respect of the Terminated Transaction.”.

Delete the words “and without prior Notice to the Defaulting Party” in the second sentence of Section 10.3.2 “Other Agreements Setoffs Apply”.

Add the following at the end of Section 10.3.2. “Other Agreements Setoffs Apply”: “To the extent that amounts otherwise owed by the Non-Defaulting Party Affiliate to the Defaulting Party, have been setoff by the Non-Defaulting Party pursuant to this section, the Non-Defaulting Party Affiliate shall not be liable to, and shall be released by, the Defaulting Party; provided further that the Defaulting Party shall be forever estopped from asserting that the Non-Defaulting Party Affiliate owes the setoff amounts to the Defaulting Party. The obligations of the Non-Defaulting Party, the Non-Defaulting Party’s Affiliates, the Defaulting Party and the Defaulting Party’s Affiliates under this Contract or otherwise in respect of such amounts shall be deemed satisfied and discharged to the extent of any such setoff. For this purpose, the amounts subject to the setoff may be converted at the applicable prevailing exchange rate into U.S. Dollars by the Non-Defaulting Party. The Non-Defaulting Party will give the Defaulting Party Notice of any setoff effected under this section provided that failure to give such notice shall not affect the validity of the setoff. Nothing in this paragraph shall be deemed to create a charge or other security interest. The rights provided by this Section are in addition to and not in limitation of any other right or remedy (including any right to setoff, counterclaim, or otherwise withhold payment) to which a Party may be entitled (whether by operation of law, contract or otherwise). “Setoff” as used herein means setoff, offset, combination of accounts, right of retention or withholding or similar right or requirement to which the Non-Defaulting Party is entitled or subject to (whether arising under this Contract, another contract, applicable law or otherwise) that is exercised by, or imposed on, the Non-Defaulting Party.”

Section 10.4 is hereby amended by:

(i) Deleting the second sentence and replacing it with the following:

“The Notice shall include a written statement explaining in reasonable detail the calculation of the Net Settlement Amount, and the reduction of such amount(s) by (a) the application of any margin, collateral or security by the Non-Defaulting Party against such Net Settlement Amount, or (b) any setoffs allowed under the terms of this Contract (such adjusted amount after the exercise of rights under (a) or (b) being defined as the “Final Settlement Amount”)”;

(ii) Adding the following sentence after the insert in (i) above:

“The Non-Defaulting Party’s failure to give such Notice of the Net Settlement Amount/Final Settlement Amount calculations shall not affect the validity or enforceability of the liquidation and termination of the Terminated Transaction, or give rise to any claim by the Defaulting Party against the Non-Defaulting Party with respect to the Non-Defaulting Party becoming the Defaulting Party due to its failure to timely fulfill such obligation; however, such failure shall extend the start of the time period that the Defaulting Party may dispute the calculations as provided for in this Section 10.4.until such detailed Notice is appropriately given by the Non-Defaulting Party.";

(iii) Replacing "second" in the sixth line with "fifth";

(iv) Adding the following as Section 10.4.1.:

"10.4.1. Notwithstanding anything herein to the contrary, if the Non-Defaulting Party owes the Net Settlement Amount/Final Settlement Amount to the Defaulting Party, the Non-Defaulting Party shall not be required to pay to the Defaulting Party the Net Settlement Amount/Final Settlement Amount, nor shall interest be owed on such amount, until (i) the Non-Defaulting Party receives confirmation satisfactory to it, in its reasonable discretion, that all other obligations of any kind whatsoever of the Defaulting Party to make any payments to the Non-Defaulting Party under this Contract and transactions hereunder, or under any other agreements between the Parties, which are due and payable as of the Early Termination Date, have been paid (or netted, setoff, recouped, or the like) in full; and (ii) the Defaulting Party executes a release in a form satisfactory to the Non-Defaulting Party that acts as the final resolution of the amounts due and owing as the Net Settlement Amount/Final Settlement Amount under the terms of this Contract and transactions hereunder. To the extent that either Party believes that bankruptcy court approval of the release is required, the Non-Defaulting Party may withhold payment of the Net Settlement Amount/Final Settlement Amount until such time as appropriate court approval has been obtained and is final and non-appealable."; and

(v) Adding the following as Section 10.4.2.:

"10.4.2. Notwithstanding anything set forth in the Contract, nothing shall in any manner preclude the Defaulting Party from disputing the Non-Defaulting Party's calculation of the Net Settlement Amount or the Final Settlement Amount. In the event the Defaulting Party disputes the calculation of the Net Settlement Amount/Final Settlement Amount, such Party shall notify the other Non-Defaulting Party of such dispute within five (5) Business Days of the date the Non-Defaulting Party provides the Notice required under this Section 10.4 to the Defaulting Party; provided, further that as soon as commercially reasonable thereafter, the Defaulting Party shall provide a statement showing its calculation of the Net Settlement Amount/Final Settlement Amount. In the event of a dispute as to the Net Settlement Amount/Final Settlement Amount, the Defaulting Party shall, if applicable, within the time prescribed in Section 10.4, pay the undisputed amount of the Net Settlement Amount/Final Settlement Amount to the Non-Defaulting Party. If the Parties have not been able to resolve their dispute within five (5) Business Days of receipt of Notice of such dispute, such dispute relating to the calculation of the Net Settlement Amount/Final Settlement Amount shall be resolved by arbitration in accordance with Section 15.18 of this Contract. During the five (5) Business Day period, the Parties shall exchange, in addition to the detailed information otherwise required under the Contract supporting their initial Net Settlement Amount/Final Settlement Amount calculations, such other information, including quotations, that such Party is utilizing to justify its position. Each Party shall submit its detailed calculation of the Net Settlement Amount/Final Settlement Amount, as the same may be revised by the Parties after the exchange of the information required hereunder and as otherwise may be exchanged between the Parties prior to the initiation of the arbitration, to the arbitration panel. The Parties shall be entitled to appropriate discovery in the arbitration proceeding, which may be used to revise the Parties positions prior to submitting the final version of the Net Settlement Amount/Final Settlement Amount calculations for a decision by the arbitrators."

Delete Section 10.5 in its entirety and replace it with the following:

"10.5 The Parties specifically agree that this Contract and all transactions pursuant hereto are "forward contracts" as such term is defined in the United States Bankruptcy Code and that each Party is a "forward contract merchant" as such term is defined in the United States Bankruptcy Code. Each Party further agrees that the other Party is not a "utility" as such term is used in 11 U.S.C. Section 366, and each Party agrees to waive and not to assert the applicability of the provisions of 11 U.S.C. Section 366 in any bankruptcy proceeding involving such Party. In addition, each Party agrees that, for any Gas actually consumed (rather than resold) by such Party, if Gas is not delivered pursuant to this Contract, the local gas distribution utility for such Party is the provider of last resort and can supply such Party's Gas consumption needs."

Section 11. Force Majeure

In Section 11.2:

(i) Delete the "and" in front of "(v)";

(ii) Insert the following before the period at the end of the first sentence: "(vi)" the occurrence of a Regulatory Event that renders a Party unable to continue to perform, either in whole or in part, under any transaction, or the occurrence of a Regulatory Event that has a material adverse economic impact on a Party; and (vii) any of the events described in (i)-(iii) of Section 5. If a Party declares an event of Force Majeure based upon the event described in (vi), the event of Force Majeure shall terminate upon the earlier to occur of (a) the time a Party liquidates and terminates the affected transactions on the Early Termination Date in accordance with Section 3.6, or (b) the expiration of six (6) Business Days after the Notice of the event of Force Majeure is provided by the claiming Party unless a Regulatory Event Notice to Terminate has been declared by either Party in accordance with Section 3.6."; and

(iii) Insert the following at the end of Section 11.2 "To the extent an event of Force Majeure occurs,:

(a) prior to curtailing or interrupting any transaction for a Firm obligation, Seller/Buyer shall first curtail or interrupt its interruptible delivery or purchase obligations, as applicable, and

(b) Seller or Buyer will treat all similarly situated Firm customers in a fair and reasonable manner by allocating the supply or purchase of Firm Gas, as applicable, on a pro rata basis."

Delete Section 11.4 and replace it with the following:

"Notwithstanding anything to the contrary in this Section 11, the Parties agree that the settlement of strikes, lockouts, or other industrial disturbances shall be within the sole discretion of the Party experiencing such disturbance; and further agree that, upon the occurrence and continuance of any event of Force Majeure, neither Party shall be obligated to purchase or sell Gas hereunder if such purchase or sale would result in material economic impact to such Party under this Contract."

Add the following as Section 11.7:

"11.7 Without restricting the generality of foregoing, if an event of Force Majeure occurs, the Party affected may, in its sole discretion and without notice to the other Party, determine not to make a claim of Force Majeure and to waive its rights hereunder as they would apply to such event. Such determination or waiver shall not preclude the affected Party from claiming Force Majeure in respect of any subsequent event, including any event that is substantially similar to the event in respect of which such determination or waiver is made."

Add the following as Section 11.8:

"11.8 If an event of Force Majeure impairs or prevents Seller from delivering or Buyer from purchasing Gas under this Contract and such event of Force Majeure continues (i) for a continuous period of time greater than ninety (90) Days or (ii) for more than one hundred and eighty (180) cumulative Days during any calendar year, the Party not claiming the event of Force Majeure may terminate and liquidate the transactions affected by such event of Force Majeure utilizing the same methodology (including rights and remedies) set forth under Section 3.6 for terminating and liquidating Affected Transactions with respect to Regulatory Events. Notwithstanding the foregoing, (a) if the Party claiming an event of Force Majeure proceeded with reasonable efforts to resolve the event or occurrence once it occurred in order to resume performance but performance under the Contract cannot resume until after the time periods set forth in (i), the Party not claiming the event of Force Majeure may not terminate and liquidate the transactions affected by such event of Force Majeure unless performance is not resumed within one hundred and eighty (180) Days from the event of Force Majeure; and (b) to the extent the event of Force Majeure relates to the events described in any of the events described in (i)-(iii) of Section 5, any affected transactions shall be terminated between the Parties without either Party being liable to the other Party for any damages under the Contract."

Section 12. Term

Delete the second sentence and replace it with the following:

"The rights of either Party pursuant to: (i) Section 7, (ii) Section 10, (iii) Section 13, (iv) Section 14, (v) Section 15, (vi) Waiver of Jury Trial provisions (if applicable), (vii) Arbitration provisions (if applicable), (viii) the obligations to make payment hereunder, and (ix) the obligation of either Party to indemnify the other pursuant hereto, shall survive the termination of the Base Contract or any transaction."

Section 14. Market Disruption

Delete Section 14. and replace it with the following:

"If a Market Disruption Event has occurred then the Parties shall negotiate in good faith to agree on a replacement price for the Floating Price (or on a method for determining a replacement price for the Floating Price) for the affected Day, and if the Parties have not so agreed on or before the second Business Day following the affected Day then the replacement price for the Floating Price shall be determined within the next two following Business Days with each Party attempting to obtain, in good faith and from non-affiliated market participants in the relevant market, at least four quotes for prices of Gas for the affected Day of a similar quality and quantity in the geographical location closest in proximity to the Delivery Point and averaging the four quotes. Once the Parties obtain the quotes, the following methodology shall be used to determine the replacement price for the Floating Price: (i) if each Party obtains four or more quotes, the arithmetic mean of the quotations, excluding the highest and lowest values, shall be utilized; (ii) if one Party obtains four or more quotes and the other Party obtains less four, the highest and lowest values of all obtained quotes shall be excluded and the arithmetic mean of the remaining quotations shall be utilized; or (iii) if both Parties obtain less than three quotes, the Parties shall resort to the negotiation process set out in Section 15.17 to resolve the dispute with the quotes being only indicative of an illiquid market which shall allow both Parties to utilize other industry information, including internal valuations to resolve the dispute, and to the extent necessary, the

Parties shall resolve the dispute utilizing the arbitration process set forth in Section 15.18 using the American Arbitration Association's ("AAA") Expedited Procedures. For purposes of the foregoing sentence, if more than one quotation is the same as another quotation, and such quotations are the highest and/or lowest values, only one of the quotations shall be excluded. "Floating Price" means the price or a factor of the price agreed to in the transaction as being based upon a specified index. "Market Disruption Event" means, with respect to an index specified for a transaction, any of the following events: (a) the failure of the index to announce or publish information necessary for determining the Floating Price; (b) the failure of trading to commence or the permanent discontinuation or material suspension of trading on the exchange or market acting as the index; (c) the temporary or permanent discontinuance or unavailability of the index; (d) the temporary or permanent closing of any exchange acting as the index; or (e) a material change in the formula for or the method of determining the Floating Price has occurred. For the purposes of the calculation of a replacement price for the Floating Price, all numbers shall be rounded to three decimal places. If the fourth decimal number is five or greater, then the third decimal number shall be increased by one and if the fourth decimal number is less than five, then the third decimal number shall remain unchanged."

Section 15. Miscellaneous

Delete Section 15.3 in its entirety and replace it with the following:

"15.3 No waiver of any breach of this Contract, or delay, failure or refusal to exercise or enforce any rights under this Contract, shall be held to be a waiver of any other or subsequent breach, or be construed as a waiver of any such right then existing or arising in the future."

Add the following as third paragraph of Section 15.10:

"15.10 Notwithstanding anything in the foregoing, Buyer and Seller agree to keep the Exhibit A confidential as proprietary information. Any limited disclosure required by Buyer to obtain necessary approvals of the Contract will only be permitted if expressly agreed to by Seller in advance and Seller is satisfied that appropriate obligations of confidentiality have been imposed on the third parties receiving such information. Buyer acknowledges that earlier disclosure of the commercially sensitive information on Exhibit A may cause Seller significant damage and loss for which Buyer will be held accountable if such disclosure was made by Buyer and caused such damage."

Add the following as Section 15.13:

"15.13 To the extent, if any, that a transaction does not qualify as a "first sale" as defined by the Natural Gas Act and §§ 2 and 601 of the Natural Gas Policy Act, each Party irrevocably waives its rights, including its rights under §§ 4-5 of the Natural Gas Act, unilaterally to seek or support a change to any terms and conditions of the Contract, including but not limited to the rate(s), charges, or classifications set forth therein. By this provision, each Party expressly waives its right to seek or support, either directly or indirectly, and by whatever means: (i) an order from the U.S. Federal Energy Regulatory Commission ("FERC") seeking to change any of the terms and conditions of the Contract agreed to by the Parties; and (ii) any refund from the other Party with respect to the Contract. Each Party further agrees that this waiver and covenant shall be binding upon it notwithstanding any regulatory or market changes that may occur after the date of the Base Contract or any transaction entered into between the Parties. Absent the agreement of both Parties to the proposed change, the standard of review for changes to any terms and conditions of the Contract proposed by (a) a Party, to the extent that the waiver set forth in this Section 15.13 is unenforceable or ineffective as to such Party due to a final determination being made under applicable law that precludes the Party from waiving its rights to seek or support changes from the FERC to the terms and conditions of this Contract, (b) a non-party, or (c) the FERC acting sua sponte, shall solely be the "public interest" application of the "just and reasonable" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra Doctrine"), as the

Mobile-Sierra Doctrine has been clarified by Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish 128 S.Ct. 2733 (2008)."

Add the following as Section 15.14:

"15.14 This Contract shall be considered for all purposes as prepared through the joint efforts of the Parties and shall not be construed against one Party or the other as a result of the manner in which this Contract was negotiated, prepared, drafted or executed."

Add the following as Section 15.15:

"15.15 Each Party will be deemed to represent to the other Party each time a transaction is entered into that: (a) it is acting for its own account, and it has made its own independent decisions to enter that transaction and as to whether that transaction is appropriate or proper for it based upon its own judgment and upon advice from such advisors as it has deemed necessary; (b) it is not relying on any communication (written or oral) of the other Party as investment advice or as a recommendation to enter into that transaction; it being understood that information and explanations related to the terms and conditions of a transaction shall not be considered investment advice or a recommendation to enter into that transaction; (c) no communication (written or oral) received from the other Party shall be deemed to be an assurance or guarantee as to the expected results of that transaction; (d) it is capable of assessing the merits (on its own behalf or through independent professional advice), and understands and accepts, the terms, conditions and risks of that transaction; (e) it is capable of assuming, and assumes, the risks of that transaction; and (f) the other Party is not acting as a fiduciary for, or an advisor to, it in respect of that transaction."

Add the following as Section 15.16:

"15.16 Buyer acknowledges that Seller is engaged, and will continue to be engaged, in the business of buying and selling Gas for its own account and for the account of others, in contracting with pipelines and others for transportation of Gas for its own account and for the account of others, and in contracting with pipelines and others for services the same or similar to one or more of the services furnished to Buyer hereunder. Nothing in this Contract shall be construed to restrict Seller's ability to engage in the foregoing business activities even to the extent such activities directly or indirectly compete with Buyer. Nothing is this section shall be construed as detracting from the warranties, covenants and obligations of Seller in this Contract."

Add the following as Section 15.17:

"15.17 Where the negotiation process is specifically prescribed to resolve a dispute under this Contract, the Parties shall seek to resolve the dispute by negotiations between senior executives who have authority to settle the controversy. Either Party may initiate this negotiation process by written Notice to the other Party outlining that Party's position regarding the dispute ("Negotiation Notice"). The senior executives shall meet at a mutually acceptable time and place within fifteen (15) Business Days after the date of the Negotiation Notice to exchange relevant information concerning the dispute and to attempt to resolve the dispute. If a senior executive intends to be accompanied at a meeting by an attorney, the other Party's senior executive shall be given at least three Business Days' Notice of such intention and may also be accompanied by an attorney. All negotiations are confidential and shall be treated as compromise and settlement negotiations under the Federal Rules of Evidence."

Add the following as Section 15.18 et. seq.:

"15.18 Where arbitration is specifically provided for under this Contract, or if otherwise mutually agreed, a Party may submit the dispute to binding arbitration, by providing the other Party with written Notice, by certified mail return receipt requested, initiating arbitration. The Notice shall set forth the nature of the dispute, the support for the Party's position, and a proposed arbitrator ("Arbitration Notice").

15.18.1 Within ten (10) Business Days of receipt of the Arbitration Notice, the Parties shall attempt to agree upon a single neutral arbitrator. In the event the Parties are unable to agree upon a single neutral arbitrator within that period, within ten (10) Business Days of the Arbitration Notice each Party shall select an arbitrator and notify the other Party of such selection. Within ten (10) Business Days following their selection, the two (2) arbitrators shall select a third neutral arbitrator who shall have no prior affiliation or representation of either Party, or if such arbitrators fail to select a third arbitrator within such time period, the AAA shall select the third arbitrator and the time for that process will be extended as necessary to accommodate the AAA. Unless otherwise mutually agreed the Parties will direct the AAA to select an arbitrator with the experience and expertise specified in Section 15.18.2. Where there are three (3) arbitrators, all decisions of the arbitrators will be by simple majority. The arbitrator(s) may extend the foregoing time deadlines in their reasonable discretion keeping in mind that the Parties' intention is to have the dispute resolved expeditiously.

15.18.2 The arbitration shall be governed by the Federal Arbitration Act (9 U.S.C., Section 1, et. seq.) and conducted in accordance with the Commercial Arbitration Rules of the AAA ("AAA Rules"). All arbitrators shall be and remain at all times wholly impartial and shall decide the case impartially. All arbitrators shall make the disclosures required by the AAA Rules. No arbitrator shall have any financial interest (directly or indirectly) in the dispute or any financial dependence (directly or indirectly) upon or an interest in any of the Parties (other than de minimus common stock ownership in the ultimate parent company of such Seller). All arbitrators shall be knowledgeable of the natural gas business and have the relevant experience.

15.18.3 The validity, construction, and interpretation of this covenant to arbitrate, and all procedural aspects, including time deadlines or extensions of time deadlines, of the arbitration conducted pursuant hereto shall be decided by the arbitrator(s). The Parties shall be entitled to appropriate discovery in the arbitration proceeding, which may also be used to revise the Parties positions prior to submitting the final version of the Final Settlement Amount calculations for decision by the arbitrators. It is the intent of the Parties that the arbitrator(s) shall, if practicable, render a final decision within forty-five (45) days after agreement on the single arbitrator or the appointment of a third arbitrator, as the case may be. The arbitration proceeding shall be conducted at a location to be mutually agreed upon, or if not mutually agreed to, at the location specified by the arbitrator(s). The arbitrator(s) are authorized, if they consider it appropriate, to decide any disputes by summary disposition on the documents and written testimony without hearing oral testimony. Prior to rendering the final award, the arbitrators shall submit to the Parties an unsigned draft of the proposed award and each Party, within ten (10) Business days after receipt of such draft decision, may serve on the other Party and file with the arbitrator(s) a written statement commenting upon any alleged errors of fact, law, computation, or otherwise. The arbitrator(s) shall render a final binding award within ten (10) Business Days after the receipt of the later of the written statements of the Parties.

15.18.4 Each of the Parties will bear their own costs of the arbitration, but the costs of the arbitrator(s), facilities, hearing and any other charges of the AAA will be shared equally. Penal, punitive, treble, multiple, consequential, incidental or similar damages may not be recovered or awarded unless expressly authorized by the Contract, and any such limitation on any and all such damages shall survive termination of the Contract.

15.18.5 To the fullest extent permitted by law, the Parties and the arbitrator shall maintain the arbitration and the award resulting from the arbitration in confidence.

15.18.6 The Parties agree that judgment on an arbitration decision and award may be entered by any court of competent jurisdiction, and that all arbitration decisions and awards shall be enforceable under the Federal Arbitration Act and any other applicable federal or state law governing the enforcement of such decisions and awards. Any right to appeal from, or to cause judicial review of, any arbitration decision and award shall be subject to and limited by the provisions concerning appeals set forth in the Federal Arbitration Act. If a Party files a complaint in any court with respect to any matter subject to arbitration hereunder, the defendant in such court action shall be entitled to recover its reasonable attorneys' fees in connection with the court action."

Add the following as Section 15.19:

"15.19 To the extent applicable, Buyer is not entitled to claim on the grounds of sovereignty or other similar grounds with respect to itself or its revenues or assets (irrespective of their use or intended use) immunity from (i) suit, (ii) jurisdiction of any court, (iii) relief by way of injunction, mandamus, order for specific performance or for recovery of property, (iv) attachment of its assets (whether before or after judgment) or (v) execution or enforcement of any judgment to which it or its revenues or assets might otherwise be made subject to in any proceedings in the courts of any jurisdiction, and no such immunity (whether or not claimed) may be attributed to Buyer or its revenues or assets."

Add the following as Section 15.20:

"15.20 WAIVER OF RIGHTS: **SELLER AND BUYER (A) CERTIFY THAT THEY ARE NOT "CONSUMERS" WITHIN THE MEANING OF THE TEXAS DECEPTIVE TRADE PRACTICES-CONSUMER PROTECTION ACT, SUBCHAPTER E OF CHAPTER 17, SECTIONS 17.41 ET SEQ., AS AMENDED (THE "DTPA"), A LAW THAT GIVES CONSUMERS SPECIAL RIGHTS AND PROTECTIONS, AND (B) EACH WAIVES ITS RIGHTS UNDER THE DTPA. AFTER CONSULTATION WITH AN ATTORNEY OF ITS OWN SELECTION, EACH PARTY VOLUNTARILY CONSENTS TO THIS WAIVER. BY THIS PROVISION, EACH PARTY INTENDS TO WAIVE ANY RIGHT TO SUE UNDER THE DTPA FOR ANY CLAIM ARISING FROM OR RELATING IN ANY WAY TO THIS CONTRACT, INCLUDING BUT NOT LIMITED TO THE NEGOTIATION, PERFORMANCE OR BREACH OF THE CONTRACT. THIS WAIVER IS IN ADDITION TO ANY OTHER DEFENSE THAT EITHER PARTY MAY HAVE TO A DTPA CLAIM, INCLUDING BUT NOT LIMITED TO A DEFENSE THAT THE PARTIES ARE NOT "CONSUMERS" WITHIN THE MEANING OF THE STATUTE OR THAT THE CLAIM IS SUBJECT TO THE EXEMPTIONS ENUMERATED IN THE STATUTE."**

Add the following as Section 15.21:

"15.21 To the extent that a Transporter materially modifies the rates charged for the transportation services utilized by the Seller to transport the Gas to the Delivery Point(s) under a particular transaction governed by this Contract, the Contract Price for such transaction shall be modified to reflect the increase in the rates charged by the Transporter."

Second Amendment and Restatement. The Second Amended and Restated Special Provisions is hereby superseded and replaced in its entirety and shall have no further force and effect.

IN WITNESS WHEREOF, the Parties hereto have caused this Third Amended and Restated Special Provisions to be executed by their respective authorized representatives intending to be legally bound thereby on November 7, 2008.

BP ENERGY COMPANY

By: /s/ JAMES A. TAYLOR
Name: James A. Taylor
Title: Senior Vice President
South Marketing & Origination

Date: 1/6/2010

COMSTOCK OIL & GAS — LOUISIANA, LLC

By: /s/ STEPHEN E. NEUKOM
Name: Stephen E. Neukom
Title: Vice President of Marketing

Date: 1/5/2010

Exhibit 21

SUBSIDIARIES OF COMSTOCK RESOURCES, INC.

Name	Incorporation	Business Name
Comstock Oil & Gas GP, LLC	Nevada	Comstock Oil & Gas GP, LLC
Comstock Oil & Gas Investments, LLC	Nevada	Comstock Oil & Gas Investments, LLC
Comstock Oil & Gas, LP(1)	Nevada	Comstock Oil & Gas, LP
Comstock Oil & Gas Holdings, Inc.(2)	Nevada	Comstock Oil & Gas Holdings, Inc.
Comstock Oil & Gas — Louisiana, LLC(3)	Nevada	Comstock Oil & Gas — Louisiana, LLC

(1) Comstock Oil & Gas GP, LLC is the general partner and Comstock Oil & Gas Investments, LLC is the limited partner of this partnership

(2) 100% owned by Comstock Oil & Gas, LP

(3) Subsidiary of Comstock Oil & Gas Holdings, Inc.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements (Nos. 333-36854, 33-88962 and 333-159332 filed on Form S-8 and No. 333-162328 on Form S-3) of Comstock Resources, Inc. and the related Prospectuses of our reports dated February 26, 2010 with respect to the consolidated financial statements of Comstock Resources, Inc. and the effectiveness of internal control over financial reporting of Comstock Resources, Inc. included in this Annual Report (Form 10-K) for the year ended December 31, 2009.

/s/ ERNST & YOUNG LLP

Dallas, Texas

February 26, 2010

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We consent to the incorporation by reference in the Registration Statements (Nos. 333-36854, 33-88962 and 333-159332 filed on Form S-8 and No. 333-162328 on Form S-3) of Comstock Resources, Inc. and the related Prospectuses of the reference of our firm and to the reserve estimates as of December 31, 2009 and our report thereon in the Annual Report on Form 10-K for the year ended December 31, 2009 of Comstock Resources, Inc., filed with the Securities and Exchange Commission.

/s/ LEE KEELING AND ASSOCIATES, INC.

Tulsa, Oklahoma

February 26, 2010

Section 302 Certification

I, M. Jay Allison, certify that:

1. I have reviewed this December 31, 2009 Form 10-K of Comstock Resources, Inc;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2010

/s/ M. JAY ALLISON
President and Chief Executive Officer

Section 302 Certification

I, Roland O. Burns, certify that:

1. I have reviewed this December 31, 2009 Form 10-K of Comstock Resources, Inc;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2010	/s/ ROLAND O. BURNS
	Sr. Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Comstock Resources, Inc. (the “Company”) on Form 10-K for the year ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, M. Jay Allison, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ M. JAY ALLISON
M. Jay Allison
Chief Executive Officer
February 26, 2010

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Comstock Resources, Inc. (the “Company”) on Form 10-K for the year ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Roland O. Burns, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ ROLAND O. BURNS
Roland O. Burns
Chief Financial Officer
February 26, 2010

Exhibit 99.1

LEE KEELING AND ASSOCIATES, INC.

PETROLEUM CONSULTANTS

TULSA OFFICE
First Place Tower
15 East Fifth Street • Suite 3500
Tulsa, Oklahoma 74103-4350
(918) 587-5521 • Fax: (918) 587-2881

HOUSTON OFFICE
Kellog Brown and Root Tower
601 Jefferson Ave. • Suite 3790
Houston, Texas 77002-7912
(713) 651-8006 • Fax: (281) 754-4934

February 9, 2010

Comstock Resources, Inc.
5300 Town and Country Boulevard, Ste. 500
Frisco, Texas 75034

Attention: Mr. M. Jay Allison
President and C.E.O.

RE: Estimated Reserves and
Future Net Revenue
Comstock Resources, Inc.
Constant Prices and Expenses
(Revised 2009 SEC Pricing)

Gentlemen:

In accordance with your request, we have prepared an estimate of net reserves and future net revenue to be realized from the interests owned by Comstock Resources, Inc. (Comstock) for 2009 year end reporting. These interests are in oil and gas properties located in the states of Arkansas, Kansas, Kentucky, Louisiana, Mississippi, New Mexico, Oklahoma, Texas, and Wyoming. Reserves estimated by us reflect all of Comstock's corporate reserves. The effective date of this estimate is December 31, 2009. It was completed February 9, 2010, and the results are summarized as follows:

RESERVE CLASSIFICATION	ESTIMATED REMAINING NET RESERVES Oil (Barrels)	Gas (MCF)	NET GAS* EQUIVALENT (MCFE)	FUTURE NET REVENUE Total (M$)	Present Worth Disc.@10% (M$)
Proved Developed					
Producing	3,220.284	301,149.438	320,471.125	504,073.000	425,366.406
Non-Producing	1.980	22,987.037	22,998.920	56,363.695	37,984.148
Behind-Pipe	1,672.187	42,965.676	52,998.793	140,988.953	48,952.852
Sub-Total	4,894.451	367,102.151	396,468.838	701,425.648	512,303.406
Proved Undeveloped	2,319.926	315,286.625	329,206.219	256,017.344	-23,189.504
Total All Reserves	7,214.377	682,388.776	725,675.057	957,442.992	489,113.902

* Net Gas Equivalent is calculated based on a conversion factor of 6 MCF of Gas per BBL of Oil.

Future net revenue is the amount, exclusive of state and federal income taxes, which will accrue to Comstock's interest from continued operation of the properties to depletion. It should not be construed as a fair market or trading value.

No attempt has been made to quantify or otherwise account for any accumulative gas production imbalances that may exist. Neither has an attempt been made to determine whether the wells and facilities are in compliance with various governmental regulations, nor have costs been included in the event they are not.

This report consists of various summaries. Schedule No. 1 presents summary forecasts of annual gross and net production, severance and ad valorem taxes, operating income, and net revenue by reserve type. Schedule No. 2 is a sequential listing of the individual properties based on discounted future net revenue. Schedule No. 3 is a sequential listing of the individual properties based on discounted future net revenue by reserve category. An alphabetical one-line summary by property is presented on Schedule No. 4. A one-line listing of the individual properties, ordered by reserve category, state and project, is presented on Schedule No. 5. A geographical one-line summary by state, project and lease is shown on Schedule No. 6.

CLASSIFICATION OF RESERVES

Reserves assigned to the various leases and/or wells have been classified as either "proved developed" or "proved undeveloped" in accordance with the definitions of the proved reserves as promulgated by the Securities and Exchange Commission (SEC). These are as follows:

Proved Developed Oil and Gas Reserves are 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 should 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 Undeveloped Oil and Gas Reserves are 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 should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Proved Developed Oil and Gas Reserves attributed to the subject leases have been further classified as "proved developed producing," "proved developed non-producing" and "proved developed behind-pipe."

Proved Developed Producing Reserves are those reserves expected to be recovered from currently producing zones under continuation of present operating methods.

Proved Developed Non-Producing Reserves are those reserves expected to be recovered from zones that have been completed and tested but are not yet producing due to situations including, but not limited to, lack of market, minor completion problems that are expected to be corrected, or reserves expected from future stimulation treatments based on analogy to nearby wells.

Proved Developed Behind-Pipe Reserves are those reserves currently behind the pipe in existing wells that are considered proved by virtue of successful testing or production in offsetting wells.

ESTIMATION OF RESERVES

The majority of the subject wells have been producing for a considerable length of time. Reserves attributable to wells with a well-defined production and/or pressure decline trend were based upon extrapolation of that trend to an economic limit and/or abandonment pressure.

Reserves anticipated from new wells were based upon volumetric calculations or analogy with similar properties, which are producing from the same horizons in the respective areas. Structural position, net pay thickness, well productivity, gas/oil ratios, water production, pressures, and other pertinent factors were considered in the estimation of these reserves.

Reserves assigned to behind-pipe zones and undeveloped locations have been estimated based on volumetric calculations and/or analogy with other wells in the area producing from the same horizon.

There are proved undeveloped reserves assigned to locations that will not be developed within five years because company resources are focused on developing the deeper Haynesville zone and deferring development of the shallower Cotton Valley zones in the same area.

FUTURE NET REVENUE

Oil Income

Income from the sale of oil was estimated using the average price received for oil sold from the subject properties the first day of each month during 2009. These prices were provided by the staff of Comstock. The average price, $61.18 per barrel, was held constant throughout the life of each property. Provisions were made for state severance and ad valorem taxes where applicable.

Gas Income

Income from the sale of gas was also estimated using the average price received for gas sold from the subject properties the first day of each month during 2009. These prices were provided by the staff of Comstock. In certain instances, it was necessary to adjust prices to reflect the difference between gas sales volumes and produced volumes. The average price, $3.87 per million cubic feet, was held constant throughout the life of each property. Provisions were also made for state severance and ad valorem taxes where applicable.

Projected produced gas volumes from Double "A" Wells Field wells were reduced to sales volumes based on actual shrinkage data as provided by Comstock.

Operating Expenses

Operating expenses were based upon actual operating costs charged by the respective operators as supplied by the staff of Comstock or were based upon the actual experience of the operators in the respective areas. For leases operated by Comstock, monthly lease operating expenses do not include overhead charges. All expenses have been held constant throughout the life of each lease.

Future Expenses and Abandonment Costs

As provided by Comstock, provisions have been made for future expenses required for drilling, recompletion and/or abandonment costs. These costs have been held constant from current estimates.

QUALIFICATIONS OF LEE KEELING AND ASSOCIATES, INC.

Lee Keeling and Associates, Inc. has been offering consulting engineering and geological services to integrated oil companies, independent operators, investors, financial institutions, legal firms, accounting firms and governmental agencies since 1957. Its professional staff is experienced in all productive areas of the United States, Canada, Latin America and many other foreign countries. The firm's reports are recognized by major financial institutions and used as the basis for oil company mergers, purchases, sales, financing of projects and for registration purposes with financial and regulatory authorities throughout the world.

GENERAL

Information upon which this estimate of net reserves and future net revenue has been based was furnished by the staff of Comstock or was obtained by us from outside sources we consider to be reliable. This information is assumed to be correct. No attempt has been made to verify title or ownership of the subject properties. Interests attributed to wells to be drilled at undeveloped locations are based on current ownership. Leases were not inspected by a representative of this firm, nor were the wells tested under our supervision; however, the performance of the majority of the wells was discussed with employees of Comstock.

This report has been prepared utilizing all methods and procedures regularly used by petroleum engineers to estimate oil and gas reserves for properties of this type and character, and we have used all methods and procedures necessary to prepare this report. The recovery of oil and gas reserves and projection of producing rates are dependent upon many variable factors including prudent operation, compression of gas when needed, market demand, installation of lifting equipment, and remedial work when required. The reserves included in this report have been based upon the assumption that the wells will be operated in a prudent manner under the same conditions existing on the effective date. Actual production results and future well data may yield additional facts, not presently available to us, which may require an adjustment to our estimates. The assumptions, data, methods and procedures used in connection with the preparation of this report are appropriate for the purpose served by this report.

The reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered and if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts. As in all aspects of oil and gas estimation, there are uncertainties inherent in the interpretation of engineering data and, therefore, our conclusions necessarily represent only informed professional judgments.

The projection of cash flow has been made assuming constant prices. There is no assurance that prices will not vary. For this reason and those listed in the previous paragraph, the future net cash from the sale of production from the subject properties may vary from the estimates contained in this report.

It should be pointed out that regulatory authorities could, in the future, change the allocation of reserves allowed to be produced from a particular well in any reservoir, thereby altering the material premise upon which our reserve estimates may be based.

The information developed during the course of this investigation, basic data, maps and worksheets showing recovery determinations are available for inspection in our office.

We appreciate this opportunity to be of service to you.

Very truly yours,

/s/ LEE KEELING AND ASSOCIATES, INC.
LEE KEELING AND ASSOCIATES, INC.