CARRIZO OIL & GAS INC
Form 10-K/A
August 17, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K/A
(Amendment No. 1)

Annual Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

For the Fiscal Year Ended December 31, 2008

Commission No. 0-22915

Carrizo Oil & Gas, Inc.
(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	76-0415919 (I.R.S. Employer Identification No.)
1000 Louisiana Street, Suite 1500, Houston, Texas (Principal executive offices)	77002 (Zip Code)

Registrant's telephone number, including area code: (713) 328-1000

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

Common Stock, $0.01 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

YES £ NO R

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

YES £ NO R

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 R 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 R	Accelerated filer £	Non-accelerated filer £ (Do not check if a smaller reporting company)	Smaller reporting company £

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

YES £ NO R

At June 30, 2008, the aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $1,876.6 million based on the closing price of such stock on such date of $68.09.

At March 2, 2009, the number of shares outstanding of the registrant's Common Stock was 30,888,635.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 2009 Annual Meeting of Shareholders are incorporated by reference in Part III of this Form 10-K. Such definitive proxy statement will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2008.

EXPLANATORY NOTE

We hereby amend and restate in their entirety the following items of our Annual Report on Form 10-K for the year ended December 31, 2008 as originally filed with the Securities and Exchange Commission on March 13, 2009: (i) Item 1A of Part I “Risk Factors,” (ii) Item 6 of Part II, “Selected Financial Data,” (iii) Item 7 of Part II, “Management’s Discussion and Analysis of Financial Condition and Results of Operations”(iv) Item 8 of Part II, “Financial Statements and Supplementary Data,” (v) Item 9A of Part II, “Controls and Procedures,” and (vi) Item 15 of Part IV, “Exhibits and Financial Statement Schedules.” We have also updated the signature page and the certifications of our Chief Executive Officer and Chief Financial Officer in Exhibits 31.1, 31.2, 32.1 and 32.2. No other sections were affected.

Upon further review of our December 31, 2008 ceiling test impairment, we determined that there were errors in our impairment calculation, including (1) failure to properly consider certain deferred tax amounts and (2) the incorrect classifications of cost between unevaluated costs and the full cost pool. As a result, we are restating in this Form 10-K/A our consolidated financial information for the year ended December 31, 2008. The effect of this adjustment is an increase in the ceiling test impairment of $39.9 million, an increase in the net loss of $25.9 million, and a reduction in the property and equipment balance of $39.9 million.

In addition, we have adjusted our financial statement and disclosures to reflect the retrospective adoption of Financial Accounting Standards Board (“FASB”) Staff Position (“FSP”) No. APB 14-1, “Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlements)” (“APB 14-1”) and FSP Emerging Issues Task Force 03-6-1, “Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities” (“EITF 03-6-1”).

APB 14-1 requires issuers to account separately for the liability and equity components of certain convertible debt instruments in a manner that reflects the issuer’s nonconvertible debt borrowing rate when interest cost is recognized. The adoption of APB 14-1 affects the accounting for our 4.375% Senior Convertible Notes due 2028 (“the “Senior Convertible Note”) and the retrospective application of the new accounting guidelines will impact the full year 2008 and the second, third and fourth quarters of 2008. As a result of the retrospective application of APB 14-1, we have decreased the carrying value of the Senior Convertible Notes to $316.5 million, increased our equity by $40.2 million to record the conversion premium at December 31, 2008 and increased our net loss by $1.2 million for the year ended December 31, 2008.

EITF 03-6-1 provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents, whether paid or unpaid, are participating securities and shall be included in the computation of both basic and diluted earnings per share. EITF 03-6-1 requires retroactive application for all periods presented. We determined that our restricted shares of common stock are participating securities as defined in EITF 03-6-1 and applied EITF 03-6-1 retroactively to all periods presented.

Please read Note 2 of the Notes to Consolidated Financial Statements in Item 8 of Part II of this Form 10-K/A for more information related to the restatement and retrospective application of APB 14-1 and EITF 03-6-1.

No attempt has been made in this Form 10-K/A to modify or update other disclosures as presented in the original Form 10-K to reflect events occurring after the original filing date, except as required to reflect the effects of the restatement and retrospective application of APB 14-1 and EITF 03-6-1.

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Forward-Looking Statements.

The statements contained in all parts of this document, including, but not limited to, those relating to our schedule, targets, estimates or results of future drilling, including the number, timing and results of wells, budgeted wells, increases in wells, the timing and risk involved in drilling follow-up wells, expected working or net revenue interests, planned expenditures, prospects budgeted and other future capital expenditures, risk profile of natural gas and oil exploration, acquisition of 3-D seismic data (including number, timing and size of projects), planned evaluation of prospects, probability of prospects having natural gas and oil, expected production or reserves, increases in reserves, acreage, working capital requirements, hedging activities, the ability of expected sources of liquidity to implement our business strategy, future exploration activity, production rates, financing for our 2009 exploration and development program, growth in production, development of new drilling programs, participation of our industry partners, funding for our Marcellus Shale operations, hedging of production and exploration and development expenditures, Camp Hill steam injection and development, all and any other statements regarding future operations, financial results, business plans and cash needs and other statements that are not historical facts are forward looking statements. When used in this document, the words “anticipate,” “budgeted,” “planned,” “targeted,” “potential,” “estimate,” “expect,” “may,” “project,” similar expressions are intended to be among the statements that identify forward looking statements. Such statements involve risks and uncertainties, including, but not limited to, those relating to the current economic downturn and credit crisis, our dependence on our exploratory drilling activities, the volatility of natural gas and oil prices, the need to replace reserves depleted by production, operating risks of natural gas and oil operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, technological changes, our significant capital requirements, the potential impact of government regulations, adverse regulatory determinations, litigation, competition, the uncertainty of reserve information and future net revenue estimates, property acquisition risks, availability of equipment, access to pipelines and gathering systems, weather, availability of financing, financial condition of our industry partners and the counterparties to our hedges, ability to obtain permits and other factors detailed herein and in our other filings with the Securities and Exchange Commission (the “Commission”). Some of the factors that could cause actual results to differ from those expressed or implied in forward-looking statements are described under “Item 1A. Risk Factors” and in other sections of this report. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation to update or revise any forward-looking statement.

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PART I

Item 1A. Risk Factors

The global financial and credit crisis may have impacts on our liquidity and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have a material impact on our liquidity and our financial condition, and we may ultimately face major challenges if conditions in the financial markets do not improve. Our ability to access the capital markets or borrow money may be restricted or made more expensive at a time when we would like, or need, to raise capital, which could have an adverse impact on our flexibility to react to changing economic and business conditions and on our ability to fund our operations and capital expenditures in the future. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us, and on the liquidity of our operating partners, resulting in delays in operations or their failure to make required payments. Also, market conditions could have an impact on our natural gas and oil derivatives transactions if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, the current economic situation could lead to further reductions in the demand for natural gas and oil, or further reductions in the prices of natural gas and oil, or both, which could have a negative impact on our financial position, results of operations and cash flows. While the ultimate outcome and impact of the current financial crisis cannot be predicted, it may have a material adverse effect on our future liquidity, results of operations and financial condition.

Natural gas and oil prices are highly volatile and have declined significantly since mid 2008, and lower prices will negatively affect our financial condition, planned capital expenditures and results of operations.

Since mid 2008, publicly quoted spot natural gas and oil prices have declined significantly from record levels in July 2008 of approximately $145.31 per Bbl (West Texas Intermediate) and $11.87 per Mcfe (WAHA) to approximately $40.07 per Bbl and $2.92 per Mcfe as of March 2, 2009. In the past, some oil and gas companies have curtailed production to mitigate the impact of low natural gas and oil prices. We may determine to shut in a portion of our production as a result of the decrease in prices. The decrease in natural gas and oil prices has had a significant impact on our financial condition, planned capital expenditures and results of operations. Further declines in natural gas and oil prices or a prolonged period of low natural gas and oil prices may materially adversely affect our financial condition, liquidity (including our borrowing capacity under our senior credit facility), ability to finance planned capital expenditures and results of operations.

Our revenue, profitability, cash flow, future growth and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent on prevailing prices of natural gas and oil. Historically, the markets for natural gas and oil prices have been volatile, and those markets are likely to continue to be volatile in the future. It is impossible to predict future natural gas and oil price movements with certainty. Prices for natural gas and oil are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors beyond our control. These factors include:

- the level of consumer product demand;
- overall economic conditions;
- weather conditions;

- domestic and foreign governmental relations, regulations and taxes;
- the price and availability of alternative fuels;
- political conditions;
- the level and price of foreign imports of oil and liquefied natural gas; and
- the ability of the members of the Organization of Petroleum Exporting Countries to agree upon and maintain production constraints and oil price controls.

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Natural gas and oil drilling is a speculative activity and involves numerous risks and substantial and uncertain costs that could adversely affect us.

Our success will be largely dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control, including:

- unexpected or adverse drilling conditions;
- elevated pressure or irregularities in geologic formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs, crews and equipment.

Because we identify the areas desirable for drilling in the onshore Gulf Coast area from 3-D seismic data covering large areas, we may not seek to acquire an option or lease rights until after the seismic data is analyzed or until the drilling locations are also identified; in those cases, we may not be permitted to lease, drill or produce natural gas or oil from those locations.

Even if drilled, our completed wells may not produce reserves of natural gas or oil that are economically viable or that meet our earlier estimates of economically recoverable reserves. Our overall drilling success rate or our drilling success rate for activity within a particular project area may decline. Unsuccessful drilling activities could result in a significant decline in our production and revenues and materially harm our operations and financial condition by reducing our available cash and resources. Because of the risks and uncertainties of our business, our future performance in exploration and drilling may not be comparable to our historical performance described in this Annual Report on Form 10-K/A.

We may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of our exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by the other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability and prices of drilling rigs and crews; and
- the availability of leases and permits on reasonable terms for the prospects.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame or at all. Wells that are currently part of our capital budget may be based on statistical results of drilling activities in other 3-D project areas that we believe are geologically similar rather than on analysis of seismic or other data in the prospect area, in which case actual drilling and results are likely to vary, possibly materially, from those statistical results. In addition, our drilling schedule may vary from our expectations because of future uncertainties.

Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future.

There are uncertainties inherent in estimating natural gas and oil reserves and their estimated value, including many factors beyond the control of the producer. The reserve data set forth in this Form 10-K/A represents only estimates. Reservoir engineering is a

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subjective and inexact process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner and is based on assumptions that may vary considerably from actual results.

Accordingly, reserve estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates. Additionally, there recently has been increased debate and disagreement over the classification of reserves, with particular focus on proved undeveloped reserves. Changes in interpretations as to classification standards or disagreements with our interpretations could cause us to write down these reserves.

As of December 31, 2008, approximately 58.6% of our proved reserves were proved undeveloped and proved nonproducing. Moreover, some of the producing wells included in our reserve reports as of December 31, 2008 had produced for a relatively short period of time as of that date. Because most of our reserve estimates are calculated using volumetric analysis, those estimates are less reliable than estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure based on seismic analysis. In addition, realization or recognition of our proved undeveloped reserves will depend on our development schedule and plans. Lack of certainty with respect to development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved. Although, since 2005, we have increased our development of the Camp Hill Field in East Texas, we have in the past chosen to delay development of our proved undeveloped reserves in the Camp Hill Field in favor of pursuing shorter-term exploration projects with higher potential rates of return, adding to our lease position in this field and further evaluating additional economic enhancements for this field's development.

The discounted future net cash flows included in this Form 10-K/A are not necessarily the same as the current market value of our estimated natural gas and oil reserves. As required by the Commission, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of the date of the estimate. Actual future net cash flows also will be affected by factors such as:

- the actual prices we receive for natural gas and oil;
- our actual operating costs in producing natural gas and oil;
- the amount and timing of actual production;
- supply and demand for natural gas and oil;
- increases or decreases in consumption of natural gas and oil; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board Statement of Financial Accounting Standards No. 69 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

We depend on successful exploration, development and acquisitions to maintain reserves and revenue in the future.

In general, the volume of production from natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we conduct successful exploration and development activities or acquire properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Our future natural gas and oil production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. In addition, we are dependent on finding partners for our exploratory activity. To the extent that others in the industry do not have the financial resources or choose not to participate in our exploration activities, we will be adversely affected.

We participate in oil and natural gas leases with third parties and these third parties may not be able to fulfill their commitments to our projects.

We may own less than 100% of the working interest in certain leases acquired by us, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of the other working interest

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owners such as nonpayment of costs and liabilities arising from the actions of the other working interest owners. In addition, the current economic downturn, the credit crisis and the decline in natural gas and oil prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. Many of our project partners are experiencing liquidity and cash flow problems. These problems may lead our partners to attempt to delay the pace of drilling or project development in order to preserve cash. A partner may be unable or unwilling to pay its share of project costs. In some cases, an example of which recently occurred in our Huntington Field, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial condition.

We have substantial capital requirements that, if not met, may hinder operations.

We have experienced and expect to continue to experience substantial capital needs as a result of our active exploration, development and acquisition programs. We expect that additional external financing will be required in the future to fund our growth. We may not be able to obtain additional financing, and financing under our existing senior credit facility or new credit facilities may not be available in the future. The current credit crisis has had an adverse impact on our ability to obtain additional financing. Even if additional capital becomes available, it may not be on terms acceptable to us. Without additional capital resources, we may be forced to limit or defer our planned natural gas and oil exploration and development drilling program by releasing rigs or deferring fracturing, completion and hookup of the wells to pipelines and thereby adversely affect our production, cash flow, and the recoverability and ultimate value of our natural gas and oil properties, in turn negatively affecting our business, financial condition and results of operations.

Our senior credit facility contains operating restrictions and financial covenants, and we may have difficulty obtaining additional credit.

Over the past few years, increases in commodity prices and our successful drilling program led to increased proved reserve amounts, and the resulting increase in our estimated discounted future net revenue allowed us to increase the borrowing base under our senior credit facility. However, as a result of the significant decline in natural gas and oil prices that began in mid 2008, or other factors, the lenders under our senior credit facility may adjust our borrowing base downward, thereby reducing our borrowing capacity. Our senior credit facility is secured by a pledge of substantially all of our producing natural gas and oil properties and assets, guaranteed by our subsidiaries CCBM, Inc., CLLR, Inc., Hondo Pipeline, Inc., Carrizo (Marcellus) LLC and Carrizo Marcellus Holding Inc. and contains covenants that limit additional borrowings, dividends, the incurrence of liens, investments, sales or pledges of assets, changes in control, repurchases or redemptions for cash of our common stock, speculative commodity transactions and other matters. The senior credit facility also requires that specified financial ratios be maintained. Although we currently believe that we can meet all of our financial covenants with the business plan that we have put in place, our business plan is based on a number of assumptions, the most important of which is a relatively stable natural gas price at economically sustainable levels. If the price that we receive for our natural gas production deteriorates significantly from current levels, it could lead to lower revenues, cash flow and earnings, which in turn could lead to a default under certain financial covenants contained in our senior credit facility, including the covenants related to working capital and the ratio of EBITDA to debt coverage. In order to provide a further margin of comfort with regards to these financial covenants, we may seek to further reduce our capital and exploration budget, sell non-strategic assets, opportunistically modify or increase our natural gas hedges, or approach our lenders under our senior credit facility for modification of either or both of the financial covenants discussed above. There can be no assurance that we will be able to successfully execute any of these strategies, or if executed, that they will be sufficient to avoid a default under our senior credit facility if a precipitous decline in natural gas prices were to occur in the future. We may not be able to refinance our debt or obtain additional financing, particularly in view of the restrictions of our senior credit facility on our ability to incur additional debt and the fact that substantially all of our assets are currently pledged to secure obligations under the senior credit facility. The restrictions of our senior credit facility and our difficulty in obtaining additional debt financing may have adverse consequences on our operations and financial results including:

- our ability to obtain financing for working capital, capital expenditures, our drilling program, purchases of new technology or other purposes may be impaired;

- the covenants in our senior credit facility that limit our ability to borrow additional funds and dispose of assets may affect our flexibility in planning for, and reacting to, changes in business conditions;

- because our indebtedness is subject to variable interest rates, we are vulnerable to increases in interest rates;

- any additional financing we obtain may be on unfavorable terms;

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- we may be required to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for operations and future business opportunities;

- a substantial decrease in our operating cash flow or an increase in our expenses could make it difficult for us to meet debt service requirements and could require us to modify our operations, including by curtailing portions of our drilling program, selling assets, reducing our capital expenditures, refinancing all or a portion of our existing debt or obtaining additional financing; and

- we may become more vulnerable to downturns in our business or the economy.

In addition, under the terms of our senior credit facility, our borrowing base is subject to redeterminations at least semi-annually based in part on prevailing natural gas and oil prices. In the event the amount outstanding exceeds the redetermined borrowing base, we could be forced to repay a portion of our borrowings. We may not have sufficient funds to make any required repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell a portion of our assets.

We have limited experience drilling wells in the Marcellus Shale and less information regarding reserves and decline rates in the Marcellus Shale than in other areas of our operations. We may face difficulties in securing and operating under authorizations and permits to drill and/or operate our Marcellus Shale wells.

We have limited exploration experience and no development experience in the Marcellus Shale. As of February 15, 2009, we have participated in the drilling of only two wells in the Marcellus Shale area. Other operators in the Marcellus Shale area also have limited experience drilling in the area. As a result, we have less information with respect to the ultimate recoverable reserves and the production decline rate in the Marcellus Shale than we have in other areas in which we operate. Moreover, the recent growth in exploration in the Marcellus Shale has drawn intense scrutiny from environmental interest groups, regulatory agencies and other governmental entities. As a result, we may face significant opposition to our operations that may make it difficult or impossible to obtain permits and other needed authorizations to operate or otherwise make operating more costly or difficult than operating elsewhere.

We face strong competition from other natural gas and oil companies.

We encounter competition from other natural gas and oil companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Our competitors include major integrated natural gas and oil companies and numerous independent natural gas and oil companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies that have been engaged in the natural gas and oil business much longer than we have and possess substantially larger operating staffs and greater capital resources than we do. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry. Such competitors may also be in a better position to secure oilfield services and equipment on a timely basis or on favorable terms. We may not be able to conduct our operations, evaluate and select suitable properties and consummate transactions successfully in this highly competitive environment.

We may not be able to keep pace with technological developments in our industry.

The natural gas and oil industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other natural gas and oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

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We are subject to various governmental regulations and environmental risks.

Natural gas and oil operations are subject to various federal, state, local and foreign government regulations that may change from time to time. Matters subject to regulation include discharge permits for drilling operations, plug and abandonment bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of natural gas and oil wells below actual production capacity in order to conserve supplies of natural gas and oil. Other federal, state and local laws and regulations relating primarily to the protection of human health and the environment apply to the development, production, handling, storage, transportation and disposal of natural gas and oil, by-products thereof and other substances and materials produced or used in connection with natural gas and oil operations. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. As a result, we may incur substantial liabilities to third parties or governmental entities and may be required to incur substantial remediation costs. We also are subject to changing and extensive tax laws, the effects of which cannot be predicted. Compliance with existing, new or modified laws and regulations could have a material adverse effect on our business, financial condition and results of operations.

We are subject to various operating and other casualty risks that could result in liability exposure or the loss of production and revenues.

The natural gas and oil business involves operating hazards such as:

- well blowouts;
- mechanical failures;
- explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- fires;
- geologic formations with abnormal pressures;
- pipeline ruptures or spills;
- releases of toxic gases; and
- other environmental hazards and risks.

Any of these hazards and risks can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our properties and the property of others.

Offshore operations are subject to a variety of operating risks, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can and have caused substantial damage to facilities and interrupt production. Our operations in the U.K. North Sea are dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. Any significant change affecting these infrastructure facilities could materially harm our business. We deliver crude oil and natural gas through gathering systems and pipelines that we do not own. These facilities may be temporarily unavailable due to adverse weather conditions or may not be available to us in the future. As a result, we could incur substantial liabilities or experience reductions in revenue that could reduce or eliminate the funds available for our exploration and development programs and acquisitions, or result in the loss of properties.

A substantial portion of our operations is exposed to the additional risk of tropical weather disturbances.

A substantial portion of our production and reserves is located onshore South Louisiana and Texas. Operations in this area are subject to tropical weather disturbances. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production. For example, some of our wells in the Gulf Coast were shut in following Hurricanes Katrina and Rita in 2005 and Hurricanes Gustav and Ike in 2008. In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks.

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Losses could occur for uninsured risks or in amounts in excess of existing insurance coverage. We cannot assure you that we will be able to maintain adequate insurance in the future at rates we consider reasonable or that any particular types of coverage will be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

We may not have enough insurance to cover all of the risks we face.

We maintain insurance against losses and liabilities in accordance with customary industry practices and in amounts that management believes to be prudent; however, insurance against all operational risks is not available to us. We do not carry business interruption insurance. We may elect not to carry insurance if management believes that the cost of available insurance is excessive relative to the risks presented. In addition, we cannot insure fully against pollution and environmental risks. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition and results of operations.

We cannot control the activities on properties we do not operate.

We do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, operations of these properties. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interests could reduce our production and revenues or could create liability for us for the operator's failure to properly maintain the well and facilities and to adhere to applicable safety and environmental standards. With respect to properties that we do not operate:

- the operator could refuse to initiate exploration or development projects;
- if we proceed with any of those projects the operator has refused to initiate, we may not receive any funding from the operator with respect to that project;
- the operator may initiate exploration or development projects on a different schedule than we would prefer;
- the operator may propose greater capital expenditures than we wish, including expenditures to drill more wells or build more facilities on a project than we have funds for, which may mean that we cannot participate in those projects or participate in a substantial amount of the revenues from those projects; and
- the operator may not have sufficient expertise or resources.

Any of these events could significantly and adversely affect our anticipated exploration and development activities.

The marketability of our natural gas production depends on facilities that we typically do not own or control, which could result in a curtailment of production and revenues.

The marketability of our production depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. Historically, we have generally delivered natural gas through gas gathering systems and gas pipelines that we do not own under interruptible or short-term transportation agreements. Under the interruptible transportation agreements, the transportation of our gas may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system, or for other reasons as dictated by the particular agreements. Due to the lack of available pipeline capacity in the Barnett Shale, we have recently begun entering into firm transportation agreements in the Barnett Shale, which are more costly to us than the interruptible or short-term transportation agreements. Our ability to produce and market natural gas on a commercial basis could be harmed by any significant change in the cost or availability of such markets, systems or pipelines.

Our future acquisitions may yield revenues or production that varies significantly from our projections.

In acquiring producing properties, we assess the recoverable reserves, future natural gas and oil prices, operating costs, potential liabilities and other factors relating to the properties. Our assessments are necessarily inexact and their accuracy is inherently uncertain. Our review of a subject property in connection with our acquisition assessment will not reveal all existing or potential problems or permit us to become sufficiently familiar with the property to assess fully its deficiencies and capabilities. We may not inspect every well, and we may not be able to observe structural and environmental problems even when we do inspect a well. If problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of those

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problems. Any acquisition of property interests may not be economically successful, and unsuccessful acquisitions may have a material adverse effect on our financial condition and future results of operations.

Our business may suffer if we lose key personnel.

We depend to a large extent on the services of certain key management personnel, including our executive officers and other key employees, the loss of any of whom could have a material adverse effect on our operations. We have entered into employment agreements with many of our key employees as a way to assist in retaining their services and motivating their performance. We do not maintain key-man life insurance with respect to any of our employees. Our success will be dependent on our ability to continue to employ and retain skilled technical personnel.

We may experience difficulty in achieving and managing future growth.

We have experienced growth in the past primarily through the expansion of our drilling program. Future growth may place strains on our financial, technical, operational and administrative resources and cause us to rely more on project partners and independent contractors, possibly negatively affecting our financial condition and results of operations. Our ability to grow will depend on a number of factors, including:

- our ability to obtain leases or options on properties, including those for which we have 3-D seismic data;
- our ability to acquire additional 3-D seismic data;
- our ability to identify and acquire new exploratory prospects;
- our ability to develop existing prospects;
- our ability to continue to retain and attract skilled personnel;
- our ability to maintain or enter into new relationships with project partners and independent contractors;
- the results of our drilling program;
- hydrocarbon prices; and
- our access to capital.

We may not be successful in upgrading our technical, operations and administrative resources or in increasing our ability to internally provide certain of the services currently provided by outside sources, and we may not be able to maintain or enter into new relationships with project partners and independent contractors. Our inability to achieve or manage growth may adversely affect our financial condition and results of operations.

We may continue to enter into derivative transactions to manage the price risks associated with our production. Our derivative transactions may result in our making cash payments or prevent us from benefiting from increases in prices for natural gas and oil.

Because natural gas and oil prices are unstable, we periodically enter into price-risk-management transactions such as swaps, collars, futures and options to reduce our exposure to price declines associated with a portion of our natural gas and oil production and thereby to achieve a more predictable cash flow. The use of these arrangements limits our ability to benefit from increases in the prices of natural gas and oil. Our derivative arrangements may apply to only a portion of our production, thereby providing only partial protection against declines in natural gas and oil prices. These arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which production is less than expected, our customers fail to purchase contracted quantities of natural gas and oil or a sudden, unexpected event materially impacts natural gas or oil prices. In addition, the counterparties under our derivatives contracts may fail to fulfill their contractual obligations to us.

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Periods of high demand for field services and equipment and the ability of suppliers to meet that demand may limit our ability to drill and produce our oil and natural gas properties.

During periods when natural gas and oil prices are relatively high, which was recently the case until mid 2008, well service providers and related equipment and personnel may be in short supply. These shortages can cause escalating prices, delays in drilling and other exploration activities and the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries. Such pressures may increase the actual cost of services, extend the time to secure such services and add costs for damages due to any accidents sustained from the overuse of equipment and inexperienced personnel.

We may record ceiling limitation write-downs that would reduce our shareholders' equity.

We use the full-cost method of accounting for investments in natural gas and oil properties. Accordingly, we capitalize all the direct costs of acquiring, exploring for and developing natural gas and oil properties. Under the full-cost accounting rules, the net capitalized cost of natural gas and oil properties may not exceed a "ceiling limit" that is based on the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or the fair market value of unproved properties. If net capitalized costs of natural gas and oil properties exceed the ceiling limit, we must charge the amount of the excess to operations through depreciation, depletion and amortization expense. This charge is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities but does reduce our shareholders' equity. The risk that we will be required to write down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are low or volatile. In addition, write-downs would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues, as further discussed in "Item 1A. Risk Factors—Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future." Once incurred, a write-down of natural gas and oil properties is not reversible at a later date. We recorded a ceiling test limitation write-down at the end of 2008, and we subsequently increased the amount of that write-down, as reflected in this Form 10-K/A. We could incur additional write-downs in the future, particularly as a result of a continuation in the decline of natural gas and oil prices. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Summary of Critical Accounting Policies" for additional information on these matters.

We may incur losses as a result of title deficiencies.

We purchase working and revenue interests in the natural gas and oil leasehold interests upon which we will perform our exploration activities from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. Title insurance covering mineral leaseholds is not generally available and, in all instances, we forego the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled. Even then, particularly in urban settings, the cost of performing detailed title work can be expensive. We may choose to forgo detailed title examination by title lawyers on a portion of the mineral leases that we place in a drilling unit or conduct less title work than we have traditionally performed. As is customary in our industry, we generally rely upon the judgment of natural gas and oil lease brokers or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and before drilling a well on a leased tract. We, in some cases, perform curative work to correct deficiencies in the marketability or adequacy of the title to us. The work might include obtaining affidavits of heirship or causing an estate to be administered. In cases involving more serious title problems, the amount paid for affected natural gas and oil leases can be generally lost, and the target area can become undrillable. The failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

We have risks associated with our foreign operations.

We currently have international activities and we continue to evaluate and pursue new opportunities for international expansion in select areas. Ownership of property interests and production operations in areas outside the United States is subject to the various risks inherent in foreign operations. These risks may include:

- currency restrictions and exchange rate fluctuations;
- loss of revenue, property and equipment as a result of expropriation, nationalization, war or insurrection;
- increases in taxes and governmental royalties;

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- renegotiation of contracts with governmental entities and quasi-governmental agencies;
- changes in laws and policies governing operations of foreign-based companies;
- labor problems; and
- other uncertainties arising out of foreign government sovereignty over our international operations.

Our international operations also may be adversely affected by the laws and policies of the United States affecting foreign trade, taxation and investment. In addition, if a dispute arises with respect to our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts of the United States.

The threat and impact of terrorist attacks or similar hostilities may adversely impact our operations.

We cannot assess the extent of either the threat or the potential impact of future terrorist attacks on the energy industry in general, and on us in particular, either in the short-term or in the long-term. Uncertainty surrounding such hostilities may affect our operations in unpredictable ways, including the possibility that infrastructure facilities, including pipelines and gathering systems, production facilities, processing plants and refineries, could be targets of, or indirect casualties of, an act of terror or war.

PART II

Item 6. Selected Financial Data

Our financial information set forth below for each of the five years in the period ended December 31, 2008, has been derived from our audited consolidated financial statements. The information should be read in conjunction with such section and our consolidated financial statements and related notes included in "Item 8. Financial Statements and Supplementary Data."

As further discussed in Note 2 to our consolidated financial statements, our consolidated financial statements for each period presented in the table below have been adjusted for the restatement of the 2008 ceiling test impairment and the retrospective application of Financial Accounting Standards Board Staff Positions No. APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (including Partial Cash Settlement) and Emerging Issues Task Force No. 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities."

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	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands, except per share data)				
Statements of Operations Data:					
Oil and natural gas revenues	$216,677	$125,789	$82,945	$78,155	$52,397
Costs and expenses:					
Oil and natural gas operating expenses	37,885	24,662	16,428	10,437	8,392
Impairment of oil and natural gas properties	178,470	-	-	-	-
Depreciation, depletion and amortization	58,311	41,899	31,129	21,374	15,464
Third party gas purchase	6,570	-	-	-	-
General and administrative	23,425	18,912	14,909	11,243	8,255
Accretion expense related to asset retirement	154	374	496	70	23
Total costs and expenses	304,815	85,847	62,962	43,124	32,134
Operating income (loss)	(88,138)	39,942	19,983	35,031	20,263
Gain (loss) on derivatives	37,499	(1,366)	16,457	(5,882)	(625)
Loss on extinguishment of debt	(5,689)	-	(294)	(3,721)	-
Equity in net income/(loss) of Pinnacle Gas Resources, Inc.	-	-	35	(2,542)	(1,399)
Interest (expense) income, net of amounts capitalized and interest income	(9,461)	(13,994)	(8,127)	(4,295)	(622)
Other income and expenses, net	17	130	427	(457)	506
Income (loss) before income taxes	(65,772)	24,712	28,481	18,134	18,123
Income tax expense (benefit)	(20,725)	9,243	10,233	7,500	7,009
Income (loss) before cumulative effect of change in accounting principle	(45,047)	15,469	18,248	10,634	11,114
Dividends and accretion of discount on preferred stock	-	-	-	-	350
Net income (loss) available to common shareholders	$(45,047)	$15,469	$18,248	$10,634	$10,764
Basic earnings (loss) per common share	$(1.49)	$0.58	$0.73	$0.45	$0.54
Diluted earnings (loss) per common share	$(1.49)	$0.57	$0.71	$0.44	$0.49
Basic weighted average shares outstanding	30,326	26,641	25,081	23,539	19,958
Diluted weighted average shares outstanding	30,326	27,120	25,565	24,361	21,818
Statements of Cash Flow Data:					
Net cash provided by operating activities	$148,754	$95,231	$65,437	$38,839	$32,501
Net cash used in investing activities	(555,345)	(227,724)	(161,576)	(111,417)	(80,294)
Net cash provided by (used in) financing activities	403,749	135,111	72,822	95,635	50,139
Other Operating Data:					
Capital expenditures	$571,291	$247,003	$201,773	$135,156	$83,891
Debt repayments(1)	498,239	108,258	40,536	101,021	13,737
Balance Sheet Data:					
Working capital (deficit)	$(57,602)	$(50,053)	$(17,014)	$10,307	$(8,937)
Property and equipment, net	986,629	646,810	445,447	314,074	205,482
Total assets	1,071,702	709,670	494,795	383,101	234,345
Long-term debt, including current maturities	475,961	254,501	188,758	149,294	62,974
Total equity	440,085	310,721	212,274	155,385	121,060

(1) Debt repayments include amounts refinanced.

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

As further discussed in Note 2 to our consolidated financial statements, our consolidated financial statements for each period presented, as well as the financial information in the following discussion, have been adjusted for restatement of the 2008 ceiling test impairment and the retrospective application of Financial Accounting Standards Board (“FASB”) Staff Position (“FSP”) No. APB 14-1, “Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)” (“APB 14-1”), and FSP Emerging Issues Task Force 03-6-1, “Determining Whether Instruments Granted in Share-Based Payment

Transactions are Participating Securities" ("EITF 03-6-1"). The financial information contained in the discussion below reflects only the adjustments described in Note 2 to our consolidated financial statements and does not reflect events occurring after March 13, 2009, the date of the original filing of our 2008 Annual Report on Form 10-K, or modify or update those disclosures that may have been affected by subsequent events. You should read this discussion together with the consolidated financial statements.

General Overview

In 2008, we recognized record revenues from oil and natural gas production of $209.8 million, record production of 25.6 Bcfe and a record level of oil and gas proved reserves, at December 31, 2008, of 502.6 Bcfe. The key drivers to our success for 2008 included the following:

Drilling program. Our success is largely dependent on the results of our drilling program. During the year ended December 31, 2008, we drilled 119 gross wells (87.6 net wells) with an apparent success rate of 96% that was comprised of: (1) 80 of 80 gross wells (62.8 net wells) in the Barnett Shale area, (2) five of six gross wells (3.0 of 3.3 net wells) in the onshore Gulf Coast area, (3) 17 of 17 gross wells (17.0 net wells) in the Camp Hill Field and (4) 12 of 16 gross wells (1.4 of 4.4 net wells) in other areas. We also drilled 13 gross service wells (13.0 net wells) in the Camp Hill area and one gross appraisal well (0.2 net) in the U.K. North Sea. At December 31, 2008, 56 of these gross wells were awaiting completion or pipeline connections.

Reserve Growth. As a result of our drilling program discussed above, our reserves increased 45 percent to 502.6 Bcfe at December 31, 2008, replacing 705% of 2008 production.

Production. Our 2008 annual production of 25.6 Bcfe, or 70.0 MMcfe/d was a record high. The 2008 production increased 47% from 2007 production of 17.5 Bcfe. The increase was primarily due to the addition of new Barnett Shale wells.

Commodity prices. Our average natural gas price during 2008 was $7.80 per Mcf (excluding the impact of our hedges), $1.03 per Mcf higher than the 2007 price of $6.77. Our average oil price in 2008 was $99.74 per Bbl, or $28.32 higher than in 2007. Commodity prices are affected by changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Our financial results are largely dependent on commodity prices, particularly natural gas prices, which are beyond our control and have been and are expected to remain volatile. These prices have declined significantly since mid-2008.

Capital funding. In order to fund our growth, we have taken steps to enhance our liquidity. In February 2008, we received approximately $135.1 million in net proceeds from an underwritten public offering of 2.59 million shares of our common stock. The net proceeds were used in part to pay down the $85.0 million then outstanding under our senior credit facility. In May 2008, we received net proceeds of approximately $365.3 million from the issuance of convertible notes. Part of the proceeds from the convertible notes offering were used to repay $75.0 million of outstanding debt under our senior credit facility and the $219.9 million then outstanding under our second lien credit facility. In December 2008, the borrowing base under our senior credit facility was also increased to $250.0 million. In connection with the formation of our joint venture in the Marcellus Shale play in August 2008, Avista agreed to fund 100% of the joint venture's next approximately $71.5 million of expenditures related to the play. As of December 31, 2008, Avista still had approximately $40.0 million in funding commitments remaining before we are required to fund any of our Marcellus Shale joint venture capital expenditures. After this amount has been funded, the parties will share all costs on joint venture projects in accordance with their participating interests in the properties, which we expect will be generally 50/50. We currently expect that substantially all of our capital and exploration expenditures of our joint venture in the Marcellus Shale during 2009 will be met through Avista's funding obligation.

Outlook for 2009

Our outlook for 2009 is challenging, primarily as a result of the decline in natural gas and oil prices that began in mid 2008, but our outlook for the long-term future remains positive. Production growth and stable upward movement in commodity prices are key to our future success, and we believe the following measures will have a positive impact on our results in 2009:

Control capital costs and maintain financial flexibility. In response to reduced demand for natural gas and lower natural gas prices as a result of the current economic downturn and the current cost of accessing the capital markets, we have reduced our approved capital and exploration budget for 2009 to $105.0 million, and we are striving to maintain our financial flexibility and a positive production growth profile. Further deterioration in commodity prices may cause us to reduce our capital and exploration budget for 2009 even further.

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2009 drilling and capital program. In 2009 we plan to drill 45 gross (30.0 net) wells in the Barnett Shale area, 12 gross (4.0 net) wells in the Marcellus Shale play area, three gross (1.0 net) wells in the Gulf Coast area and to complete 44 gross (44.0 net) wells in the Camp Hill Field. As mentioned above, our 2009 capital and exploration budget has been reduced to approximately $105 million and includes approximately $90.0 million for drilling, comprised in Barnett Shale ($85.0 million), Gulf Coast ($3.0 million) and Camp Hill ($2.0 million). We also plan to spend $3.0 million in the U.K. North Sea, largely for pre-development project costs, and approximately $12.0 million for land and seismic activities, most of it in the Barnett Shale. We currently expect that our land acquisition, exploration and drilling program in the Marcellus will be funded by Avista under our joint venture agreement. The actual number of wells we drill will vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow, success of drilling programs, weather delays and other factors.

Results of Operations

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

Revenues from oil and natural gas production for 2008 increased 67% to $209.8 million from $125.8 million in 2007. Production volumes for oil and natural gas in 2008 increased 47% to 25.6 Bcfe from 17.5 Bcfe in 2007. Realized average natural gas sales price for 2008 increased 15% to $7.80 per Mcf compared to $6.77 per Mcf in 2007, and the average oil sales price for 2008 increased 40% to $99.74 per barrel from $71.42 per barrel in 2007. The increase in natural gas production was primarily due to the production from new wells in the Barnett Shale area.

The following table summarizes production volumes, average sales prices and operating revenues for our oil and natural gas operations for the years ended December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007	2008 Period Compared to 2007 Period Increase (Decrease)	2008 Period Compared to 2007 Period % Increase (Decrease)
Production volumes-				
Oil and condensate (Mbbls)	186	241	(55)	(23)%
Natural gas (MMcf)(1)	24,513	16,042	8,471	53 %
Average sales prices-				
Oil and condensate (per Bbl)	$ 99.74	$ 71.42	$ 28.32	40 %
Natural gas (per Mcf)	7.80	6.77	1.03	15 %
Operating revenues (In thousands) -				
Oil and condensate	$ 18,598	$ 17,197	$ 1,401	8 %
Natural gas	191,231	108,592	82,639	76 %
Other	6,848	-	6,848	100 %
Total	$ 216,677	$ 125,789	$ 90,888	72 %

(1) Includes 2,467.6 and 1,316.3 MMcfe of natural gas liquids in 2008 and 2007, respectively.

Oil and natural gas operating expenses for 2008 increased 54% to $37.9 million (or $1.48 per Mcfe) from $24.7 million (or $1.41 per Mcfe) in 2007. The increase in total operating expenses was primarily due to (i) higher transportation gathering and treating costs of $4.5 million, (ii) higher saltwater disposal costs of $1.4 million, (iii) increased compression costs of $1.4 million and (iv) higher ad valorem taxes of $2.9 million.

The significant decline in oil and natural gas prices, indicated by average prices of $4.99 per Mcf for natural gas and $40.12 per Bbl for oil on December 31, 2008, caused the discounted present value (discounted at ten percent) of future net cash flows from proved oil and gas reserves to fall below the net book basis in the proved oil and gas properties. This resulted in a non-cash ceiling test write-down at the end of the fourth quarter of 2008 of $178.5 million ($116.0 million after tax).

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Depreciation, depletion and amortization ("DD&A") expense for 2008 increased to $58.3 million from $41.9 million in 2007. This increase was primarily due to an increase in production volumes partially offset by a decrease in the DD&A rate primarily due to lower overall finding cost of new reserves added in 2008.

General and administrative ("G&A") expense for 2008 increased 24% to $23.4 million from $18.9 million for 2007. The increase in G&A was due primarily to (i) increased employee related and contractor costs of $1.2 million, (ii) increased stock-based compensation expense of $1.0 million and (iii) increased legal and professional fees of $0.8 million.

The net gain on derivatives of $37.5 million for the year ended December 31, 2008 was comprised of a $41.4 million of unrealized mark-to-market net gain on derivatives that was partially offset by $3.9 million of net realized losses.

In May 2008, we repaid our outstanding borrowings under the Second Lien Facility and terminated the facility. As a result, we recorded a $5.7 million loss associated with the early extinguishment of debt consisting of a $4.6 million non-cash write-off of deferred loan costs and $1.1 million in penalties paid for early retirement. In connection with the early termination, we settled the interest rate swaps and realized a $3.3 million loss, included in our net loss on derivatives.

Interest expense and capitalized interest in 2008 were $30.3 million and $20.5 million, respectively, as compared to $26.4 million and $11.7 million in 2007. These increases were largely attributable to approximately $6.9 million in non-cash interest expense associated with the amortization of the debt discount on the Senior Convertible Notes as prescribed by FSP No. APB 14-1 and by increased debt outstanding during 2008. These increases were partially offset by the pay off of the higher cost Second Lien Credit Facility with the proceeds from the issuance of the Convertible Notes, which bore interest at a lower rate, and due to higher capitalized interest as a result of increased unproved leasehold costs in 2008.

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006

Oil and natural gas revenues for 2007 increased 52% to $125.8 million from $82.9 million in 2006. Production volumes for oil and natural gas in 2007 increased 49% to 17.5 Bcfe from 11.7 Bcfe in 2006. Realized average natural gas sales price for 2007 increased 3% to $6.77 per Mcf compared to $6.56 per Mcf in 2006, and the average oil sales price for 2007 increased 12% to $71.42 per barrel from $63.62 per barrel in 2006. The increase in natural gas production was primarily due to the production from new wells in the Barnett Shale area and the Baby Ruth and Doberman #1 wells in the Gulf Coast area.

The following table summarizes production volumes, average sales prices and operating revenues for our oil and natural gas operations for the years ended December 31, 2007 and 2006:

	December 31,		2007 Period Compared to 2006 Period	
	2007	2006	Increase (Decrease)	% Increase (Decrease)
Production volumes-				
Oil and condensate (Mbbls)	241	255	(14)	(5)%
Natural gas (MMcf)(1)	16,042	10,176	5,866	58 %
Average sales prices-				

Oil and condensate (per Bbl)	$	71.42	$	63.62	$	7.80	12	%
Natural gas (per Mcf)		6.77		6.56		0.21	3	%
Operating revenues (In thousands) -								
Oil and condensate	$	17,197	$	16,217	$	980	6	%
Natural gas		108,592		66,728		41,864	63	%
Total	$	125,789	$	82,945	$	42,844	52	%

(1) Includes 1,316.3 MMcfe of natural gas liquids in 2007.

Oil and natural gas operating expenses for 2007 increased 50% to $24.7 million (or $1.41 per Mcfe) from $16.4 million (or $1.40 per Mcfe) in 2006. While total costs increased primarily due to increased production, costs per Mcfe remained relatively unchanged from 2006 to 2007. The increase in total operating expenses was due to (i) approximately $3.3 million in higher transportation gathering and treating costs in the Barnett Shale, (ii) higher saltwater disposal costs of $2.2 million, (iii) increased compression costs of $1.1 million, (iv) higher severance taxes of $0.9 million and (v) increased workover expenses of $0.4 million.

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DD&A expense for 2007 increased 35% to $41.9 million from $31.1 million in 2006. This increase was primarily due to an increase in production volumes partially offset by a decrease in the DD&A rate primarily due to lower overall finding cost of new reserves added in 2007.

G&A expense for 2007 increased 27% to $18.9 million from $14.9 million for 2006. The increase in G&A was due primarily to (i) increased employee related costs of $2.5 million, (ii) increased stock-based compensation expense of $2.0 million due to additional restricted shares issued in 2007 and higher stock prices (iii) increased office expense of $0.6 million and (iv) increased legal and professional fees of $0.3 million. These increases were partially offset by decreased bad debt expense of $1.4 million primarily related to a 2006 outside operator bankruptcy filing.

The net loss on derivatives was $1.4 million for the year ended December 31, 2007, comprised of (i) $7.4 million of unrealized mark-to-market net losses on derivatives ($4.6 million loss on oil and gas derivatives and $2.8 million loss on interest rate swaps) and (ii) $6.0 million of net realized gains ($5.8 million gain from oil and gas derivatives and $0.2 million gain from interest rate swaps).

Interest expense and capitalized interest in 2007 were $26.4 million and $11.7 million, respectively, as compared to $19.1 million and $10.0 million in 2006. These increases were attributable to the $75.0 million increase in borrowings under the Second Lien Credit Facility in January 2007, increased borrowings under our senior credit facility and higher effective interest rates.

Liquidity and Capital Resources

2009 Capital Budget and Funding Strategy. For 2009, our Board has established a capital and exploration expenditures budget of $105 million, including (i) $90 million for our drilling program (including $85 million for the Barnett Shale development), (ii) $3 million for pre-development project costs in the U.K. North Sea (iii) $6 million for lease acquisitions, primarily in the Barnett Shale and (iv) $6 million for seismic data acquisition. We intend to finance our 2009 capital and exploration budget primarily from oil and natural gas production sales revenue, supplemented by borrowings under our senior credit facility and the possible selective sale of non-core assets. We may be required to reduce or defer part of our 2009 capital expenditures program if we are unable to obtain sufficient financing from these sources.

Sources and Uses of Cash. During the year ended December 31, 2008, capital expenditures, net of proceeds from property sales, exceeded our net cash provided by operations. During 2008, we funded our capital expenditures with cash generated from operations, proceeds from the issuance of our common stock and convertible notes, and net additional borrowings under our senior credit facility. Potential primary sources of future liquidity include the following:

- Cash on hand and cash generated by operations. Cash flows from operations are highly dependent on commodity prices and market conditions for oil and gas field services. We hedge a portion of our production to reduce the downside risk of declining natural gas and oil prices.

- Available borrowings under our senior credit facility. During the fourth quarter of 2008, the borrowing base under our senior credit facility increased to $250.0 million. At March 2, 2009, $71.0 million was available for borrowing under our senior credit facility. The next borrowing base redetermination is currently scheduled for March 31, 2009.

- Other debt and equity offerings. In February 2008, we received $135.1 million of net proceeds from an underwritten public offering of 2,587,500 shares of our common stock priced at $54.50 per share. In May 2008, we received $365.3 million of net proceeds from the issuance of our convertible notes. As situations or conditions arise, we may need to issue debt, equity or other instruments to supplement our cash flows. However, we may not be able to obtain such financing on terms that are acceptable to us, or at all.

- Asset sales. In order to fund our capital and exploration budget, we may consider the sale of certain properties or assets that are not part of our core business, can be monetized at a price we find acceptable, or are no longer deemed essential to our future growth.

- Project financing in certain limited circumstances.

- Lease option agreements and land banking arrangements, such as those we have entered into regarding the Marcellus Shale, the Barnett Shale and other plays.

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- Joint ventures with third parties through which such third parties fund a portion of our exploration activities to earn an interest in our exploration acreage, such as our recent joint venture in the Marcellus Shale play.

- We may consider sale/leaseback transactions of certain capital assets, such as pipelines and compressors, which are not part of our core oil and gas exploration and production business.

Our primary use of cash is capital expenditures related to our drilling and development programs and, to a lesser extent, our lease and seismic acquisition programs. Our capital expenditures budget in 2009 provides for approximately $90 million for drilling, and approximately $12 million for lease and seismic acquisitions. In 2009 we currently plan to drill 45 gross (30.0 net) wells in the Barnett Shale area, three gross (1.0 net) wells in the Gulf Coast area, and to complete 44 gross (44.0 net) wells in the Camp Hill Field, and to spend approximately $3.0 million on project development in the Huntington Field in the U.K. North Sea and in other areas. The actual number of wells drilled and capital expended is dependent upon our available financing, cash flow, availability and cost of drilling rigs, land and partner issues and other factors. Capital expenditures do not include operating costs such as the steam costs that will be required for the multi-year development of our Camp Hill project. In addition to our capital expenditure program, we have contractual obligations as discussed below.

Overview of Cash Flow Activities. Cash flows provided by operating activities were $148.8 million, $95.2 million and $65.4 million for the years ended December 31, 2008, 2007 and 2006, respectively. The increase from 2007 to 2008 was primarily due to an increase in revenues largely attributable to a 47% increase in production. Natural gas prices have fallen since the third quarter of 2008 and have generally continued to decline into 2009, having a negative impact on our cash flow from operations and on our 2009 drilling plans. Despite our increase in natural gas production a continued fall in natural gas prices could have a further negative impact on our cash flow from operations and on our 2009 drilling plans.

Cash flows used in investing activities were $555.3 million for the year ended December 31, 2008 and related primarily to oil and gas property expenditures. Cash flows used in investing activities were $227.7 million for the year ended December 31, 2007 and related primarily to oil and gas property expenditures. Cash flows used in investing activities of $161.6 million for the year ended December 31, 2006 were largely attributable to capital expenditures for oil and gas properties of $201.8 million partially offset by proceeds from the sale of properties of $38.3 million.

Net cash provided by financing activities for the year ended December 31, 2008 was $403.7 million and related primarily to net proceeds of $135.1 million from the issuance of common stock in February 2008, net proceeds of $365.3 million from the issuance of senior convertible notes and $401.0 million in additional borrowings under the senior credit facility. These cash proceeds were partially offset by the payoff and termination of the second lien credit facility and partial paydown of the senior credit facility. Net cash provided by financing activities for the year ended December 31, 2007 was $135.1 million and related primarily to the additional borrowings of $75.0 million under our second lien credit facility in January 2007 and net proceeds of $71.9 million from the issuance of common stock in September 2007. These cash proceeds were partially offset by the repayment of borrowings under our senior credit facility. Net cash provided by financing activities for the year ended December 31, 2006 was $72.8 million and related primarily to additional borrowings under our senior credit facility of $80.0 million and net proceeds of $33.5 million from the issuance of common stock, partially offset by $40.5 million of debt repayments.

Liquidity/Cash Flow Outlook.

We currently believe that cash generated from operations, supplemented by borrowings under our senior credit facility will be sufficient to fund our immediate needs. Cash generated from operations is primarily driven by production and commodity prices. While we have steadily increased production over the last few years oil and natural gas prices have declined since third quarter of 2008. In an effort to mitigate declining prices, we hedge a portion of our production and, as of March 3, 2009, we have hedged approximately 25,570,000 MMBtu (70 MMcf per day for the year, or 85% of our estimated production from April through December 2009) of our 2009 natural gas production at a weighted average floor or swap price of $6.20 per MMBtu relative to WAHA and Houston Ship Channel prices. We believe the funds available to us under our senior credit facility, $71.0 million at March 2, 2009, will be accessible to us. We are scheduled for a borrowing base redetermination on March 31, 2009 at which time our borrowing base may change. We currently expect that our borrowing base will increase based upon the increase to our proved reserves during the fourth quarter of 2008. However, the borrowing base is also affected by the future sales price assumptions for our oil and natural gas production that our banks use in their calculations and these may result in a lower borrowing base if our banks believe that the price we will receive for our oil and natural gas production is substantially less than what their current assumptions are.

If cash from operations and funds available under our senior credit facility are insufficient to fund our 2009 capital and exploration budget, we may need to reduce our capital and exploration budget or seek other financing alternatives to fund it. We may not be able

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to obtain financing needed in the future on terms that would be acceptable to us, or at all. If we cannot obtain adequate financing, we may be required to limit or defer our planned 2009 natural gas and oil exploration and development program, thereby adversely affecting the recoverability and ultimate value of our natural gas and oil properties. The recent worldwide financial and credit crisis has adversely affected our ability to access the capital markets.

Contractual Obligations

The following table sets forth estimates of our contractual obligations as of December 31, 2008:

	Payments Due by Year (In thousands)					
	Total	2009	2010	2011	2012	2013 and Thereafter
Long-term Debt	$ 533,230	$ 173	$ 148	$ 159	$ 159,000	$ 373,750
Operating Leases	3,212	1,008	1,102	1,102	-	-
Drilling Contracts	58,937	25,294	25,295	8,348	-	-
Pipeline Volume Commitment(1)	46,976	6,273	7,144	6,479	5,857	21,223
Total Contractual Cash Obligations	$ 642,355	$ 32,748	$ 33,689	$ 16,088	$ 164,857	$ 394,973

(1) Includes a seven firm year transportation agreement for 80,000 MMBtus/d with an estimated starting date in October 2009.

Off Balance Sheet Arrangements

We currently do not have any off balance sheet arrangements.

Financing Arrangements

Senior Secured Revolving Credit Facility

On May 25, 2006, we entered into a Senior Secured Revolving Credit Facility ("Senior Credit Facility") with JPMorgan Chase Bank, National Association, as administrative agent. The Senior Credit Facility provided for a revolving credit facility up to the lesser of the borrowing base and $200.0 million. It is secured by substantially all of our proved oil & gas assets and is guaranteed by our subsidiaries CCBM, Inc., CCLR, Inc., Carrizo (Marcellus) LLC and Carrizo Marcellus Holding Inc.

In the fourth quarter of 2008, we amended the Senior Credit Facility to (1) increase the borrowing base to $250.0 million; (2) extend the maturity date to October 29, 2012; (3) increase the maximum total net debt to Consolidated EBITDAX to 4.0 to 1.0; (4) change the semi-annual borrowing base redetermination dates to March 31 and September 30; (5) change the interest rate provisions; and (6) replace JPMorgan Chase with Guaranty Bank as the administrative agent bank.

If the outstanding principal balance of the revolving loans under the Senior Credit Facility exceeds the borrowing base at any time, we have the option within 30 days to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, pledge additional collateral sufficient in the lenders' opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the ensuing six-month period. Those payments would be in addition to any payments that may come due as a result of the quarterly borrowing base reductions. Otherwise, any unpaid principal or interest will be due at maturity.

The annual interest rate on each base rate borrowing is (a) the greatest of the agent's Prime Rate, the Base CD Rate plus 1.0% and the Federal Funds Effective Rate plus 0.5%, plus (b) a margin between 0.75% and 2.25% (depending on the then-current level of borrowing base usage), but such interest rate can never be lower than the adjusted Daily LIBO rate on such day plus a margin between 2.0% to 3.5% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar loan is the adjusted daily LIBO rate plus a margin between 2.0% to 3.5% (depending on the then-current level of borrowing base usage). At February 17, 2009, the average interest rate for amounts outstanding under the Senior Credit Facility was 3.4%.

We are subject to certain covenants under the amended terms of the Senior Credit Facility which include, but are not limited to, the maintenance of the following financial ratios: (1) a minimum current ratio of 1.0 to 1.0; and (2) a maximum total net debt to

Consolidated EBITDAX (as defined in the Senior Credit Facility) of 4.0 to 1.0. Although we currently believe that we can comply with all of our financial covenants with the business plan that we have put in place, our business plan is based on a number of assumptions, the most important of which is a relatively stable, natural gas price at economically sustainable levels. If the price that we receive for our natural gas production deteriorates significantly from current levels, it could lead to lower revenues, cash flow and earnings, which in turn could lead to a default under certain financial covenants in our Senior Credit Facility, including the financial covenants discussed above. In order to provide a further margin of comfort with regards to these financial covenants, we may seek to further reduce our capital and exploration budget, sell non-strategic assets, opportunistically modify or increase our natural gas hedges or approach the lenders under our Senior Credit Facility for modifications of either or both of the financial covenants discussed above. There can be no assurance that we will be able to successfully execute any of these strategies, or if executed, that they will be sufficient to avoid a default under our Senior Credit Facility if a precipitous decline in natural gas prices were to occur in the future. The Senior Credit Facility also places restrictions on indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of our common stock, speculative commodity transactions, transactions with affiliates and other matters.

The Senior Credit Facility is subject to customary events of default, the occurrence and continuation of which could result in the acceleration of amounts due under the facility by the agent or the lenders.

At December 31, 2008, we were in compliance with all of our debt covenants.

As of March 2, 2009, we had $179.0 million of borrowings outstanding and a borrowing base availability of $71.0 million.

Convertible Senior Notes

In May 2008, we issued $373.8 million aggregate principal amount of 4.375% convertible senior notes due 2028 (“Convertible Senior Notes”). Interest is payable on June 1 and December 1 each year, commencing December 1, 2008. The notes will be convertible, using a net share settlement process, into a combination of cash and our common stock that entitles holders of the Convertible Senior Notes to receive cash up to the principal amount ($1,000 per note) and common stock in respect of the remainder, if any, of our conversion obligation in excess of such principal amount. The notes are convertible into our common stock at a ratio of 9.9936 shares per $1,000 principal amount of notes, equivalent to a conversion price of approximately $100.06. This conversion rate is subject to adjustment upon certain corporate events. In addition, if certain fundamental changes occur on or before June 1, 2013, we will in some cases increase the conversion rate for a holder electing to convert notes in connection with such fundamental change; provided, that in no event will the total number of shares issuable upon conversion of a note exceed 14.7406 per $1,000 principal amount of notes (subject to adjustment in the same manner as the conversion rate). Holders may convert the notes only under the following conditions: (a) during any calendar quarter if the last reported sale price of our common stock exceeds 130 percent of the conversion price for at least 20 trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter, (b) during the five business days after any five consecutive trading day period in which the trading price per $1,000 principal amount of the notes is equal to or less than 97% of the conversion value of such notes, (c) during specified periods if specified distributions to holders of our common stock are made or specified corporate transactions occur, (d) prior to the close of business on the business day preceding the redemption date if the notes are called for redemption or (e) on or after March 31, 2028 and prior to the close of business on the business day prior to the maturity date of June 1, 2028. The holders of the Convertible Senior Notes may require us to repurchase the notes on June 1, 2013, 2018 and 2023, or upon a fundamental corporate change at a repurchase price in cash equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any. We may redeem notes at any time on or after June 1, 2013 at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any.

The Convertible Senior Notes are subject to customary non-financial covenants and events of default, including a cross default under the Senior Credit Facility, the occurrence and continuation of which could result in the acceleration of amounts due under the Convertible Senior Notes.

The Convertible Senior Notes are unsecured obligations and rank equal to all future senior unsecured debt but rank second in priority to the Senior Credit Facility.

As prescribed by APB 14-1, on the date of issuance we valued the Convertible Senior Notes as $309.6 million of debt and $64.2 million of equity, representing the fair value of the conversion premium. The resulting debt discount will be amortized to interest expense through June 1, 2013, the first date on which the holders may require the Company to repurchase the Convertible Senior Notes, resulting in an effective interest rate of approximately 8% for the Convertible Senior Notes.

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Second Lien Credit Facility

On July 21, 2005, we entered into a Second Lien Credit Agreement with Credit Suisse, as administrative agent and collateral agent and the lenders party thereto (the “Second Lien Credit Facility”). The Second Lien Credit Facility, as amended, provided for a term loan facility in an aggregate principal amount of $225.0 million. In May 2008, we repaid in full the $219.9 million outstanding under the Second Lien Credit Facility and terminated the facility in connection with the issuance of the Convertible Senior Notes.

Public Offerings in 2008 and 2007; and Private Placement of Common Stock in 2006.

In February 2008, we sold 2,587,500 shares of our common stock in an underwritten public offering at a price of $54.50 per share, raising $135.1 million of net proceeds. With a portion of the proceeds we repaid $85.0 million of borrowings then outstanding under the Senior Credit Facility. We used the remaining proceeds to fund in part our 2008 capital expenditure program.

In September 2007, we sold 1,800,000 shares of our common stock to certain qualified investors in a registered direct offering at a price of $41.40 per share, raising $72.0 million of net proceeds. We used the net proceeds to repay $54 million of outstanding borrowings under the Senior Credit Facility and to fund in part our 2007 capital expenditure program.

In July 2006, we sold 1,350,000 shares of our common stock to institutional investors at a price of $26.00 per share in a private placement (the “2006 Private Placement”). The net proceeds, after deducting placement agents’ fees but before paying offering expenses, of approximately $33.7 million were principally used to fund a portion of our 2006 capital expenditures program. In connection with the 2006 Private Placement, we entered into Subscription and Registration Rights Agreements (the “Subscription and Registration Rights Agreements”) with the investors in the 2006 Private Placement. The Subscription and Registration Rights Agreements provide registration rights with respect to the shares purchased in the 2006 Private Placement. We filed a resale shelf registration statement in connection with the 2006 Private Placement that has been declared effective by the Commission. We are generally subject to specified penalties in the event we do not maintain the effectiveness of the registration statement. We are subject to certain covenants under the terms of the Subscription and Registration Rights Agreements, including the requirement that the registration statement be kept effective for resale of shares for two years. In certain situations, we are required to indemnify the investors in the 2006 Private Placement, including without limitation, for certain liabilities under the Securities Act.

Lease Option Arrangements

Due to the limited capital available at times to fund all of our ongoing lease acquisition efforts in the Barnett Shale, Marcellus Shale, Fayetteville Shale and other plays, we elect from time to time to enter into various lease purchase option agreements with a number of third parties, including, in 2006, Steven A. Webster, who is the Chairman of our Board of Directors. The lease purchase option arrangement with Mr. Webster expired at the end of 2006. The terms and conditions of the lease purchase option arrangement with Mr. Webster were consistent with the lease purchase option arrangements we entered into with unrelated third parties. These lease purchase option arrangements provide us the option to purchase leases from the counterparties, over an option period, generally 90 days, for the counterparties’ original cost of the leases plus an option fee. We paid Mr. Webster fees totaling approximately $250,000 in 2006. In accordance with the lease purchase option agreement, we also assigned to him an overriding royalty interest on any lease we acquired from Mr. Webster under the lease purchase option agreement with him, which overriding royalty interest varied from one-half to one percent of 8/8ths, proportionally reduced to the actual net interest in any given lease acquired from Mr. Webster. We paid Mr. Webster approximately $430 and $50 in 2008 and 2007, respectively, for overriding royalties under these arrangements.

In order to expand our lease acquisition efforts in the Marcellus Shale play, the Company elected to enter into a lease option agreement effective August 1, 2008 with Avista, our partner in the Marcellus Shale play. See "Business and Properties—Significant Project Areas; Marcellus Shale Area." The terms and conditions of the lease purchase option arrangement with Avista were generally consistent with lease option arrangements that we have traditionally entered into with other third parties. Avista paid approximately $27.5 million for the oil and gas leases under the lease purchase option agreement and subsequently contributed these properties at their cost to our Marcellus joint venture, effective August 1, 2008.

We have continued to enter into lease purchase option arrangements with third parties from time to time. We currently have one lease purchase option arrangement with an unrelated third party. Strategically, these leasing arrangements have allowed us to temporarily control important acreage positions during periods that we have lacked sufficient capital to directly acquire such oil and gas leases. We may continue to use these arrangements as a strategic alternative in the future.

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Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing natural gas and oil prices. The dramatic drop in natural gas and oil prices in 2008 has resulted in a significant drop in revenue per unit of production. Although operating costs have come down slightly in recent months, the rate of decline in natural gas and oil prices has been substantially greater. Historically, inflation has had a minimal effect on us. However, with interest rates at historic lows and the government attempting to stimulate the economy through rapid expansion of the money supply in recent months, inflation could become a significant issue in the future.

Recently Issued Accounting Pronouncements

In March 2008, the Financial Accounting Standards Board ("FASB") issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities ("SFAS No. 161"). This standard is intended to improve financial reporting by requiring transparency about the location and amounts of derivative instruments in an entity's financial statements, how derivative instruments and related hedged items are accounted for under SFAS No. 133, and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We do not believe the adoption of SFAS No. 161 will have a significant effect on our consolidated financial position, results of operations or cash flows.

On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revision to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies to report the independence and qualification of the person primarily responsible for the preparation or audit of reserve estimates, and to file reports when a third party is relied upon to prepare or audit reserves estimates. The new rules also require that the present value of oil and gas reserves be reported and to be used in the full-cost ceiling test calculation be based upon an average price for the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. The Company is in the process of assessing the impact of these new requirements on its financial position, results of operations and financial disclosures.

Recently Adopted Accounting Pronouncements

We adopted the Statement of Financial Accounting Standards No. 157, "Fair Value Measurement" ("SFAS No. 157"), effective January 1, 2008. SFAS No. 157 provides a framework for measuring fair value and enhances related disclosures. The implementation of SFAS No. 157 did not change our current valuation method and did not have a material effect on our consolidated financial position or results of operations. We included additional disclosures in the Notes to Consolidated Financial Statements with respect to the measurement of our assets and liabilities at fair value on the balance sheet date.

We adopted FSP APB 14-1 effective January 1, 2009. This FSP clarifies that convertible debt instruments that may be settled in cash upon conversion, including partial cash settlement, are not addressed by paragraph 12 of APB Opinion No. 14, "Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants." Additionally, this FSP specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. The FSP requires retrospective application. We valued the 4.375% Senior Convertible Notes due 2028 as $309.6 million of debt and $64.2 million of equity, representing the fair value of the conversion premium on the date of issuance, and recognized an additional $1.8 million in interest expense (net of $4.9 million of capitalized interest) during 2008, resulting in an effective interest rate of approximately 8% for 2008.

We adopted EITF 03-6-1 effective January 1, 2009. This FSP provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents, whether paid or unpaid, are participating securities and shall be included in the computation of both basic and diluted earnings per share. We determined that our shares of restricted stock qualified as participating securities and included these shares in both the basic and diluted earnings per share for all periods presented.

Summary of Critical Accounting Policies

The following summarizes several of our critical accounting policies. See a complete list of significant accounting policies in Note 2 to our consolidated financial statements.

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Use of Estimates

The preparation of financial statements in conformity with U.S. 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 periods. Actual results could differ from these estimates. The use of these estimates significantly affects our natural gas and oil properties through depletion and the full cost ceiling test, as discussed in more detail below.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of undeveloped properties, future income taxes and related assets/liabilities, the collectability of outstanding accounts receivable, fair value of derivatives, stock-based compensation expense, contingencies and the results of future and current litigation. Oil and natural gas reserve estimates, which are the basis for unit-of-production depletion and the ceiling test, have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Subsequent drilling results, testing and production may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. In addition, reserve estimates are vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

The significant estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates, the market value of our common stock and corresponding volatility and our ability to generate future taxable income. Future changes to these assumptions may affect these significant estimates materially in the near term.

Oil and Natural Gas Properties

We account for investments in natural gas and oil properties using the full-cost method of accounting. All costs directly associated with the acquisition, exploration and development of natural gas and oil properties are capitalized. These costs include lease acquisitions, seismic surveys, and drilling and completion equipment. We proportionally consolidate our interests in natural gas and oil properties. We capitalized compensation costs and other costs for employees working directly on exploration activities of $7.8 million, $4.5 million and $3.5 million in 2008, 2007 and 2006, respectively. We expense maintenance and repairs as they are incurred.

We amortize natural gas and oil properties based on the unit-of-production method using estimates of proved reserve quantities. Costs not subject to amortization include costs of unevaluated leaseholds, seismic costs associated with specific unevaluated properties and exploratory wells in progress. These costs are periodically evaluated, on a property-by-property basis, for impairment. If the results of an assessment indicate that the properties are impaired, we add the amount of impairment to the proved natural gas and oil property costs to be amortized. The amortizable base includes estimated future development costs and, where significant, dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for 2008, 2007 and 2006 was $2.23, $2.36 and $2.61, respectively.

We account for dispositions of natural gas and oil properties as adjustments to capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves. We have not had any transactions that significantly alter that relationship.

The net capitalized costs of proved oil and natural gas properties are limited to a “ceiling test” based on the estimated future net revenues, discounted at a 10% per annum, from proved oil and natural gas reserves based on current economic and operating conditions (the “Full Cost Ceiling”). If net capitalized costs exceed this limit, the excess is charged to earnings.

The Full Cost Ceiling impairment at the end of 2008 of approximately $178.5 million was based upon average realized oil, natural gas liquids and natural gas prices of $40.12 per Bbl, $19.62 per Bbl and $4.99 per Mcf, respectively, or a volume weighted average price of $29.86 per BOE. We would not have had a Full Cost Ceiling write-down at an estimated volume weighted average price of $35.25 per BOE. The Full Cost Ceiling impairment was primarily the result of the decline in commodity prices. The prices used in the ceiling test impairment were the prices in effect at December 31, 2008, as contemplated by current Commission rules that require the use of prices in effect on the last day of the relevant financial period. These rules are expected to change in the future to require the use of an average price over a twelve-month period.

Under the full cost method of accounting, the depletion rate is the current period production as a percentage of the total proved reserves. Total proved reserves include both proved developed and proved undeveloped reserves. The depletion rate is applied to the net book value of our oil and natural gas properties (excluding unevaluated costs) and estimated future development costs less net salvage value to calculate the depletion expense. Proved reserves materially impact depletion expense. If the proved reserves decline, then the depletion rate (the rate at which we record depletion expense) increases, reducing net income.

We have a significant amount of proved undeveloped reserves. We had 239.1 Bcfe, 185.8 Bcfe and 126.2 Bcfe of proved undeveloped reserves, representing 48%, 53% and 60% of our total proved reserves at December 31, 2008, 2007 and 2006, respectively. As of December 31, 2008, less than 13% of these proved undeveloped reserves, or approximately, 29.9 Bcfe, were attributable to our Camp Hill properties that we acquired in 1994. See “Business and Properties Significant Project Areas — Camp Hill Area” for further discussion of the Camp Hill properties. The estimated future development costs to develop our proved undeveloped reserves on our Camp Hill properties are relatively low, on a per Mcfe basis, when compared to the estimated future development costs to develop our proved undeveloped reserves on our other oil and natural gas properties. Furthermore, the average depletable life (the estimated time that it will take to produce all recoverable reserves) of our Camp Hill properties is considerably longer, or approximately 15 years, when compared to the depletable life of our remaining oil and natural gas properties of approximately 10 years. Accordingly, the combination of a relatively low ratio of future development costs and a relatively long depletable life on our Camp Hill properties has resulted in a relatively low overall historical depletion rate and DD&A expense. This has resulted in a capitalized cost basis associated with producing properties being depleted over a longer period than the associated production and revenue stream, causing the build-up of non-depleted capitalized costs associated with properties that have been completely depleted. This combination of factors, in turn, has had a favorable impact on our earnings, which have been higher than they would have been had the Camp Hill properties not resulted in a relatively low overall depletion rate and DD&A expense and longer depletion period. As a hypothetical illustration of this impact, the removal of our Camp Hill proved undeveloped reserves starting January 1, 2002 would have reduced our net income by, (1) an estimated $11.2 million in 2002 (comprised of after-tax charges for a $7.1 million full cost ceiling impairment and a $4.1 million depletion expense increase), (2) an estimated $5.9 million in 2003 (due to higher depletion expense), (3) an estimated $3.4 million in 2004 (due to higher depletion expense), (4) an estimated $6.9 million in 2005 (due to higher depletion expense), (5) an estimated $0.7 million in 2006 (due to higher depletion expense), (6) an estimated $2.0 million in 2007 (due to higher depletion expenses) and (7) an estimated $9.2 million in 2008 (comprised of after-tax charges for a $8.5 million full cost ceiling impairment and a $0.7 million depletion expense increase).

We expect our relatively low historical depletion rate to continue until the high level of nonproducing reserves to total proved reserves is reduced and the life of our proved developed reserves is extended through development drilling and/or the significant addition of new proved producing reserves through acquisition or exploration. If our level of total proved reserves, finding cost and current prices were all to remain constant, this continued build-up of capitalized costs increases the probability of a ceiling test write-down.

We depreciate other property and equipment using the straight-line method based on estimated useful lives ranging from five to 10 years.

Oil and Natural Gas Reserve Estimates

The proved reserve data as of December 31, 2008 included in this document are estimates prepared by Ryder Scott Company, LaRoche Petroleum Consultants, Ltd., and Fairchild & Wells, Inc., Independent Petroleum Engineers. Reserve engineering is a subjective process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact manner. The process relies on judgment and the interpretation of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions regarding drilling and operating expense, capital expenditures, taxes and availability of funds. The Commission mandates some of these assumptions such as oil and natural gas prices and the present value discount rate.

Proved reserve estimates prepared by others may be substantially higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve quantities actually recovered may be significantly different than estimated. Material revisions to reserve estimates may be made depending on the results of drilling, testing, and rates of production.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with Commission requirements, we based the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate, using a discount rate of 10%.

Our rate of recording depreciation, depletion and amortization expense for proved properties is dependent on our estimate of proved reserves. If these reserve estimates decline, the rate at which we record these expenses will increase. A 10% increase or decrease in our proved reserves would have increased or decreased our depletion expense by nine percent for the year ended December 31, 2008.

As of December 31, 2008, approximately 58% of our proved reserves were proved undeveloped and proved nonproducing. Moreover, some of the producing wells included in our reserve reports as of December 31, 2008 had produced for a relatively short period of time as of that date. Because most of our reserve estimates are calculated using volumetric analysis, those estimates are less reliable than estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure based on seismic analysis. In addition, realization or recognition of our proved undeveloped reserves will depend on our development schedule and plans. Lack of certainty with respect to development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved. We have from time to time chosen to delay development of our proved undeveloped reserves in the Camp Hill Field in East Texas in favor of pursuing shorter-term exploration projects with higher potential rates of return, adding to our lease position in this field and further evaluating additional economic enhancements for this field's development. The average life of the Camp Hill proved undeveloped reserves is approximately 15 years, with 50% of these reserves being booked over ten years ago. Although we have increased the pace of the development of the Camp Hill project, there can be no assurance that the aforementioned discontinuance will not occur.

Derivative Instruments

We use derivatives, typically fixed-rate swaps and costless collars, to manage price risk underlying our oil and gas production. We also used derivatives to manage the variable interest rate on the Second Lien Credit Facility prior to its termination in May 2008. We have elected to account for our derivative contracts as non-designated derivatives that will be marked-to-market. For a discussion of the impact of changes in the prices of oil and gas on our hedging transactions, see "Volatility of Oil and Natural Gas Prices" below.

Our Board of Directors sets all of our risk management policies and reviews volume limitations, types of instruments and counterparties, on a quarterly basis. These policies require that derivative instruments be executed only by either the President or Chief Financial Officer after consultation and concurrence by the President, Chief Financial Officer and Chairman of the Board. The master contracts with the approved counterparties identify the President and Chief Financial Officer as the only representatives authorized to execute trades. The Board of Directors also reviews the status and results of derivative activities quarterly.

Upon entering into a derivative contract, we either designate the derivative instrument as a hedge of the variability of cash flow to be received (cash flow hedge) or the derivative must be accounted for as a non-designated derivative. All of our derivative instruments at December 31, 2008, 2007 and 2006 were treated as non-designated derivatives and the unrealized gains related to the mark-to-market valuation was included in our earnings.

Income Taxes

Under Statement of Financial Accounting Standards No. 109 ("SFAS No. 109"), "Accounting for Income Taxes," deferred income taxes are recognized at each year end for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. We routinely assess the realizability of our deferred tax assets. We consider future taxable income in making such assessments. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, it is reduced by a valuation allowance. However, despite our attempt to make an accurate estimate, the ultimate utilization of our deferred tax assets is highly dependent upon our actual production and the realization of taxable income in future periods.

Contingencies

Liabilities and other contingencies are recognized upon determination of an exposure, which when analyzed indicates that it is both probable that an asset has been impaired or that a liability has been incurred and that the amount of such loss is reasonably estimable.

Volatility of Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial condition and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and natural gas. See

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"Item 1A. Risk Factors—Natural gas and oil prices are highly volatile, and have declined significantly since mid-2008, and lower prices will negatively affect our financial condition planned, capital expenditures and results of operations."

We periodically review the carrying value of our oil and natural gas properties under the full cost accounting rules of the Commission. See "—Summary of Critical Accounting Policies—Oil and Natural Gas Properties" and "Item 1A. Risk Factors— We may record ceiling limitation write-downs that would reduce our shareholders' equity."

To mitigate some of our commodity price risk, we engage periodically in certain other limited derivative activities including price swaps, costless collars and, occasionally, put options, in order to establish some price floor protection. We do not hold or issue derivative instruments for trading purposes.

The following table includes oil and natural gas derivative positions settled during the years ended December 31, 2008, 2007 and 2006 and the unrealized gain (loss) associated with the outstanding oil and natural gas derivatives at December 31, 2008, 2007 and 2006.

	December 31,		
	2008	2007	2006
Oil positions settled (Bbls)	64,100	52,000	82,200
Natural gas positions settled (MMBtu)	15,733,000	7,846,000	5,481,000
Realized gain ($ millions) (1)	$ 0.6	$ 5.8	$ 6.8
Unrealized gain (loss) ($ millions) (1)	$ 38.6	$ (4.6)	$ 8.7

(1) Included in gain (loss) on derivatives, net in the Consolidated Statements of Operations.

At December 31, 2008, approximately 69% of our open natural gas hedges were with Credit Suisse and the remaining 31% were with Shell Energy North America (US), L.P. The open oil hedges were with Credit Suisse.

While the use of hedging arrangements limits the downside risk of adverse price movements, it may also limit our ability to benefit from increases in the prices of natural gas and oil. We enter into the majority of our derivative transactions with two counterparties and have a netting agreement in place with those counterparties. We do not obtain collateral to support the agreements but monitor the financial viability of counterparties and believe our credit risk is minimal on these transactions. Under these arrangements, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at expiration or exchanged for physical delivery contracts. In the event of nonperformance, we would again be exposed to price risk. We have additional risk of financial loss because the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the hedging transaction. Moreover, our derivative arrangements generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our hedges will vary from time to time.

Our natural gas derivative transactions are generally settled based upon the average of the reporting settlement prices on the Houston Ship Channel or WAHA index for the last three trading days of a particular contract month. Our oil derivative transactions are generally settled based on the average reporting settlement prices on the West Texas

Intermediate index for each trading day of a particular calendar month.

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At December 31, 2008 we had the following open derivative positions:

	Natural Gas Swaps		Natural Gas Collars			Basis Differential Swaps(2)	
Quarter	MMbtu	Average Fixed Price(1)	MMBtu	Average Floor Price(1)	Average Ceiling Price(1)	MMBtu	Price
First Quarter 2009	2,803,000	$ 6.13	2,520,000	$ 7.37	$ 9.10	310,000	$ 0.31
Second Quarter 2009	1,547,000	5.40	2,548,000	7.12	8.85	-	-
Third Quarter 2009	-	-	2,576,000	7.16	8.88	920,000	0.31
Fourth Quarter 2009	-	-	2,576,000	7.17	8.90	-	-
First Quarter 2010	-	-	1,620,000	7.92	9.63	-	-
Second Quarter 2010	-	-	1,638,000	7.18	8.89	-	-
Third Quarter 2010	-	-	1,656,000	7.35	9.06	-	-
Fourth Quarter 2010	-	-	1,656,000	7.45	9.16	-	-
First Quarter 2011	-	-	450,000	9.70	11.70	-	-
Second Quarter 2011	-	-	455,000	8.25	10.25	-	-
Third Quarter 2011	-	-	460,000	8.65	10.65	-	-
Fourth Quarter 2011	-	-	460,000	8.85	10.85	-	-
First Quarter 2012	-	-	455,000	9.55	11.55	-	-
Second Quarter 2012	-	-	455,000	8.35	10.35	-	-

TOTAL	4,350,000	19,525,000	1,230,000

Quarter	Bbls	Oil Collars Average Floor Price(3)	Average Ceiling Price(3)
First Quarter 2009	9,000	$ 131.65	$ 151.65
Second Quarter 2009	9,100	131.40	151.40
Third Quarter 2009	9,200	130.85	150.85
Fourth Quarter 2009	9,200	130.35	150.35
TOTAL	36,500		

(1) Based on Houston Ship Channel and WAHA spot prices.

(2) Basis differential swaps cover the price differential for natural gas between NYMEX and HSC.

(3) Based on West Texas intermediate index prices.

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In the first quarter of 2009, in order to monetize some profitable hedge positions, we sold down a portion of our oil hedge positions, receiving $2.2 million in proceeds. We also converted a 2010 natural gas costless collar position into a 2009 natural gas fixed price swap to further mitigate the risk of declining natural gas prices in 2009. As of March 2, 2009, we had the following open derivative positions:

	Natural Gas Swaps		Natural Gas Collars			Basis Differential Swaps(2)	
Quarter	MMbtu	Average Fixed Price(1)	MMBtu	Average Floor Price(1)	Average Ceiling Price(1)	MMBtu	Price
First Quarter 2009	2,803,000	$ 6.13	2,520,000	$ 7.37	$ 9.10	-	$ -
Second Quarter 2009	5,187,000	5.34	2,548,000	7.12	8.85	-	-
Third Quarter 2009	3,680,000	5.31	2,576,000	7.16	8.88	920,000	0.31
Fourth Quarter 2009	3,680,000	5.58	2,576,000	7.17	8.90	-	-
First Quarter 2010	1,800,000	5.57	1,620,000	7.92	9.63	-	-
Second Quarter 2010	1,820,000	5.57	182,000	7.35	9.15	-	-
Third Quarter 2010	1,840,000	5.57	184,000	7.35	9.15	-	-
Fourth Quarter 2010	1,840,000	5.57	184,000	7.35	9.15	-	-
First Quarter 2011	1,800,000	5.64	450,000	9.70	11.70	-	-
Second Quarter 2011	1,820,000	5.64	455,000	8.25	10.25	-	-
Third Quarter 2011	1,840,000	5.64	460,000	8.65	10.65	-	-
Fourth Quarter 2011	1,840,000	5.64	460,000	8.85	10.85	-	-
First Quarter 2012	910,000	5.88	455,000	9.55	11.55	-	-

Second Quarter 2012	910,000	5.88	455,000	8.35	10.35	-	-
Third Quarter 2012	920,000	5.88	-	-	-	-	-
Fourth Quarter 2012	920,000	5.88	-	-	-	-	-
TOTAL	33,610,000		15,125,000			920,000	

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(1) Based on Houston Ship Channel and WAHA spot prices.

(2) Basis differential swaps cover the price differential for natural gas between NYMEX and HSC.

Item 8. Financial Statements and Supplementary Data

The response to this item is included elsewhere in this report.

Item 9A. Controls and Procedures (Restated)

(a) Disclosure Controls and Procedures. We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission (the “Commission”) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), is recorded, processed, summarized and reported within the time periods specified by the Commission's rules and forms, and that information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

In accordance with Exchange Act Rules 13a-15(b) and 15d-15(b), we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined by Exchange Act Rules 13a-15(e) and 15d-15(e) as of the end of the period covered by this report. As described below under paragraph (b) within Management's Annual Report on Internal Control over Financial Reporting, we identified a material weakness in our internal control over financial reporting. As a result of this material weakness, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this Annual Report on Form 10-K/A, our disclosure controls and procedures were not effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the Commission under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified by the Commission's rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate

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to allow timely decisions regarding required disclosure. We have outlined a number of initiatives designed to address this material weakness, as discussed below under paragraph (b) of this Item 9A. In addition, we were required to seek relief under Rule 12b-25 in connection with the filing of our Annual Report on Form 10-K for the year ended December 31, 2008 ("2008 Form 10-K") to obtain additional time to complete the financial statements and secondary reviews needed to finalize the 2008 Form 10-K due to an impairment to oil and gas properties resulting from a decline in prices for natural gas and oil.

The audit report of Pannell Kerr Forster of Texas, P.C., which is included in this 2008 Form 10-K/A, expressed an unqualified opinion on our consolidated financial statements.

(b) Management's Annual Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of our assets;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

While "reasonable assurance" is a high level of assurance, it does not mean absolute assurance. Because of its inherent limitations, internal control over financial reporting may not prevent or detect every misstatement and instance of fraud. Controls are susceptible to manipulation, especially in instances of fraud caused by collusion of two or more people, including our senior management. 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.

Under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, our management conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2008. In making this evaluation, management used the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on the results of our evaluation, our management concluded that our internal control over financial reporting was not effective as of December 31, 2008 for the reason identified below.

Subsequent to the issuance of the 2008 Form 10-K, we identified an error resulting from the presence of certain computational deficiencies in our standard ceiling test computation format, most notably the absence of the pre-tax, gross-up computation and a reconciling proof of the oil and gas property and related deferred tax amounts to the financial statements (in the event of an after-tax, ceiling test write-down). Upon further review, we also discovered additional errors which partially offset the impact of the pre-tax, gross-up error. These offsetting errors included: (1) the incorrect classification of a portion of the capitalized interest in the full cost pool that related to unevaluated properties, (2) the failure to properly consider certain deferred tax amounts and (3) the incorrect classification of certain unevaluated costs in the full cost pool.

These errors and/or omissions resulted in a restatement of the 2008 consolidated financial statements and were an indication that a material weakness was present at December 31, 2008, increasing the likelihood to more than remote that a material misstatement of our annual or interim financial statements would not be prevented or detected. These deficiencies ultimately affect the accuracy of our financial statement reporting and disclosures. As a result, management has concluded that our internal controls over financial reporting were not effective as of December 31, 2008. We have outlined certain procedures, discussed below, that are designed to prevent these specific errors from occurring in the future.

We have taken or plan to take the following initiatives in the third quarter of 2009: (1) delegate preparation of certain critical workpapers to our financial reporting staff allowing our financial reporting manager to perform more qualitative review analysis, (2) remove the computational deficiencies from our standard ceiling test workpaper format, (3) improve workpaper formats and implement comparative analysis within these critical workpapers to enhance qualitative analysis and (4) prepare a reconciliation of the

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quarter-to-quarter changes in costs associated with unevaluated property and proved undeveloped locations that will be used to determine the reclassification of costs to the full cost pool.

We have discussed this material weakness and our planned remediation steps with our Audit Committee and believe that such enhanced procedures and workpaper formats, once fully implemented, will prospectively mitigate this material weakness.

Pannell Kerr Forster of Texas, P.C., our former independent registered public accounting firm that audited our consolidated financial statements, has also issued its own report on the effectiveness of our internal control over financial reporting as of December 31, 2008, which is filed herewith.

(c) Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting during the fiscal quarter ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. As described above in paragraph (b) of this Item 9A under Management's Annual Report on Internal Control over Financial Reporting, we identified a material weakness in our internal control over financial reporting and have described a number of planned changes to our internal control over financial reporting that are expected to be fully implemented by the end of the third quarter 2009 and once fully implemented, should remediate this weakness.

PART IV

Item 15. Exhibits

(a)(1) Financial Statements

The response to this item is submitted in a separate section of this report.

(a)(3) Exhibits

EXHIBIT INDEX

Exhibit Number		Description
†2.1	–	Combination Agreement by and among the Company, Carrizo Production, Inc., Encinitas Partners Ltd., La Rosa Partners Ltd., Carrizo Partners Ltd., Paul B. Loyd, Jr., Steven A. Webster, S.P. Johnson IV, Douglas A.P. Hamilton and Frank A. Wojtek dated as of September 6, 1997 (incorporated herein by reference to Exhibit 2.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).
†3.1	–	Amended and Restated Articles of Incorporation of the Company (incorporated herein by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 1998).
†3.2	–	Articles of Amendment to Amended and Restated Articles of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on June 25, 2008).
†3.3	–	Amended and Restated Bylaws of the Company (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on January 3, 2008).
†4.1	–	Indenture among Carrizo Oil & Gas, Inc., the subsidiaries named therein and Wells Fargo Bank, National Association, as trustee, dated May 28, 2008 (incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on May 28, 2008).
†4.2	–	First Supplemental Indenture dated May 28, 2008 between Carrizo Oil & Gas, Inc. and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company's

Current Report on Form 8-K filed on May 28, 2008).

†10.1 – Amendment No. 1 to the Letter Agreement Regarding Participation in the Company's 2001 Seismic and Acreage Program, dated June 1, 2001 (incorporated herein by reference to Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).

*†10.2 – Amended and Restated Incentive Plan of the Company effective as of February 17, 2000 (incorporated herein by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2000).

*†10.3 – Amendment No. 1 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).

*†10.4 – Amendment No. 2 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Exhibit 10.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002).

*†10.5 – Amendment No. 3 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Appendix A to the Company's Proxy Statement dated April 21, 2003).

*†10.6 – Amendment No. 4 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Appendix B to the Company's Proxy Statement dated April 26, 2004).

*†10.7 – Amendment No. 5 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 16, 2005).

*†10.8 – Amendment No. 6 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on August 19, 2005).

*†10.9 – Amendment No.7 to the Amended and Restated Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on May 30, 2006).

*†10.10 – Employment Agreement between the Company and S.P. Johnson IV (incorporated herein by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).

*†10.11 – Employment Agreement between the Company and J. Bradley Fisher (incorporated herein by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-2 (Registration No. 333-111475)).

*†10.12 – Employment Agreement between the Company and Paul F. Boling (incorporated herein by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-2 (Registration No. 333-111475)).

*†10.13 – Employment Agreement between the Company and Gregory E. Evans dated March 21, 2005 (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 22, 2005).

*†10.14 – Employment Agreement between Carrizo Oil & Gas, Inc. and Richard Smith dated September 18, 2006, and effective as of August 23, 2006 (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 22, 2006).

*†10.15 – Form of Indemnification Agreement between the Company and each of its directors and executive officers (incorporated herein by reference to Exhibit 10.6 to the Company's Annual Report on Form 10-K for the year ended December 31, 1998).

*†10.16 – Form of Amendment to Executive Officer Employment Agreement (incorporated herein by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K dated January 8, 1998).

*†10.17 – Form of Amendment to Executive Officer Employment Agreement (incorporated herein by reference to Exhibit 99.7 to the Company's Current Report on Form 8-K dated December 15, 1999).

*†10.18 – Form of Amendment to Director Indemnification Agreement (incorporated herein by reference to Exhibit 99.8 to the Company's Current Report on Form 8-K dated December 15, 1999).

*†10.19 – Form of Amendment to Executive Officer Employment Agreement (incorporated herein by reference to Exhibit 99.7 to the Company's Current Report on Form 8-K dated February 20, 2002).

*†10.20 – Form of Amendment to Director Indemnification Agreement (incorporated herein by reference to Exhibit 99.8 to the Company's Current Report on Form 8-K dated February 20, 2002).

*†10.21 – Amendment to the Employment Agreement between the Company and S.P. Johnson IV (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 27, 2006).

*†10.22 – Amendment to the Employment Agreement between the Company and Paul F. Boling (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on January 27, 2006).

*†10.23 – Amendment to the Employment Agreement between the Company and Gregory E. Evans (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8- K filed on January 27, 2006).

*†10.24 – Amendment to the Employment Agreement between the Company and J. Bradley Fisher (incorporated herein by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on January 27, 2006).

*†10.25 –

Amendment to the Employment Agreement between Carrizo Oil & Gas, Inc. and S.P. Johnson IV effective December 19, 2008 (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 23, 2008).

*†10.26 – Amendment to the Employment Agreement between Carrizo Oil & Gas, Inc. and Paul F. Boling effective December 19, 2008 (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on December 23, 2008).

*†10.27 – Amendment to the Employment Agreement between Carrizo Oil & Gas, Inc. and J. Bradley Fisher effective December 19, 2008 (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on December 23, 2008).

*†10.28 – Amendment to the Employment Agreement between Carrizo Oil & Gas, Inc. and Gregory E. Evans effective December 19, 2008 (incorporated herein by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on December 23, 2008).

*†10.29 – Amendment to the Employment Agreement between Carrizo Oil & Gas, Inc. and Richard H. Smith effective December 19, 2008 (incorporated herein by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on December 23, 2008).

*†10.30 – Form of Stock Option Award Agreement (incorporated herein by reference to Exhibit 10.43 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004).

*†10.31 – Form of Director Restricted Stock Award Agreement under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 19, 2005).

*†10.32 – Form of Director Restricted Stock Award Agreement under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on April 19, 2005).

*†10.33 – Form of Employee Restricted Stock Award Agreement under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on April 19, 2005).

*†10.34 – Form of Employee Restricted Stock Award under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on January 27, 2006).

*†10.35 – Form of Employee Restricted Stock Award Agreement (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).

*†10.36 – Form of Employee Stock Option Award Agreement (incorporated herein by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).

*†10.37 – Form of Independent Contractor Restricted Stock Award Agreement (incorporated herein by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on May 30, 2006).

*†10.38 – Form of Employee Restricted Stock Award Agreement (with performance-based vesting) (incorporated herein by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on December 23, 2008).

†10.39 – S Corporation Tax Allocation, Payment and Indemnification Agreement among the Company and Messrs. Loyd, Webster, Johnson, Hamilton and Wojtek (incorporated herein by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).

†10.40 – S Corporation Tax Allocation, Payment and Indemnification Agreement among Carrizo Production, Inc. and Messrs. Loyd, Webster, Johnson, Hamilton and Wojtek (incorporated herein by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).

†10.41 – Amended and Restated Registration Rights Agreement dated December 15, 1999 among the Company, Paul B. Loyd Jr., Douglas A. P. Hamilton, Steven A. Webster, S.P. Johnson IV, Frank A. Wojtek and DAPHAM Partnership, L.P. (incorporated herein by reference to Exhibit 99.5 to the Company's Current Report on Form 8-K dated December 15, 1999).

†10.42 – Registration Rights Agreement dated February 20, 2002 among the Company, Mellon Ventures, L.P. and Steven A. Webster (incorporated herein by reference to Exhibit 99.5 to the Company's Current Report on Form 8-K dated February 20, 2002).

†10.43 – Credit Agreement dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, the Lenders party thereto, JPMorgan Chase Bank, National Association, as Administrative Agent, and J.P. Morgan Securities Inc., as Sole Bookrunner and Lead Arranger (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 30, 2006).

†10.44 – First Lien Stock Pledge and Security Agreement dated as of May 25, 2006, by Carrizo Oil & Gas, Inc., in favor of JPMorgan Chase Bank, National Association, as Administrative Agent (incorporated herein by

reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on May 30, 2006).

†10.45 – Second Amendment effective as of September 11, 2007 to Credit Agreement dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, JPMorgan Chase Bank, National Association, as Administrative Agent and Lender, and Guaranty Bank as Lender (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 11, 2007).

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†10.46 – Third Amendment effective as of December 20, 2007 to Credit Agreement dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, JPMorgan Chase Bank, National Association, as Administrative Agent and Lender, and Guaranty Bank as Lender (incorporated by reference to Exhibit 10.48 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008).

†10.47 – Fourth Amendment to Credit Agreement, dated as of May 20, 2008, by and among Carrizo Oil & Gas, Inc. and certain subsidiaries thereof, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 22, 2008).

†10.48 – Fifth Amendment to Credit Agreement dated as of June 11, 2008 to Credit Agreement dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on July 11, 2008).

†10.49 – Sixth Amendment dated as of July 7, 2008 to Credit Agreement dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on July 11, 2008).

†10.50 – Seventh Amendment dated as of October 29, 2008 to Credit Agreement dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, the Lenders party thereto, JPMorgan Chase Bank, N.A., as resigning administrative agent and as resigning issuing bank, and Guaranty Bank, as successor administrative agent and as successor issuing bank (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 4, 2008).

†10.51 – Lender Certificate dated December 16, 2008 of Union Bank of California, N.A. regarding joinder as Lender to Credit Agreement, as amended, dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, Guaranty Bank, as Administrative Agent and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 22, 2008).

*10.52 – Base Salaries for certain Executive Officers.

*21.1 – Subsidiaries of the Company.

**23.1 – Consent of Pannell Kerr Forster of Texas, P.C.

**23.2 – Consent of Ryder Scott Company Petroleum Engineers.

**23.3 – Consent of Fairchild & Wells, Inc.

**23.4 – Consent of LaRoche Petroleum Consultants, Ltd.

**31.1 – CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

**31.2 – CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

**32.1 – CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

**32.2 – CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*99.1 – Summary of Reserve Report of Ryder Scott Company Petroleum Engineers as of December 31, 2008.

*99.2 – Summary of Reserve Report of Fairchild & Wells, Inc. as of December 31, 2008.

*99.3 – Summary of Reserve Report of LaRoche Petroleum Consultants, Ltd. as of December 31, 2008.

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* Previously filed

** Filed herewith.

CARRIZO OIL & GAS, INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Carrizo Oil & Gas, Inc.

We have audited the accompanying consolidated balance sheets of Carrizo Oil & Gas, Inc. as of December 31, 2008 and 2007 and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule included on page 61. 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 financial position of Carrizo Oil & Gas, Inc. at December 31, 2008 and 2007 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2, the Company has restated its previously issued consolidated financial statements for 2008 to correct a misstatement in the amount of their ceiling test impairment and have adjusted the 2008 financial statements for the retroactive application of APB No. 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlements)" and have adjusted all years presented for the retroactive application of FSP Emerging Issues Task Force No. 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities."

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Carrizo Oil & Gas, Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 12, 2009, except for the restatement of Management's Annual Report on Internal Control Over Financial Reporting, for which the date is August 17, 2009, expressed an adverse opinion on the Company's internal control over financial reporting.

/s/ Pannell Kerr Forster of Texas, P.C.

Houston, Texas
March 12, 2009

(Except for Notes 2, 4, 5, 6 and 13 for which
the date is August 17, 2009.)

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REPORT OF INDEPENENT REGISTERED PUBLIC ACCOUNTING FIRMS

Board of Directors and Shareholders
Carrizo Oil & Gas, Inc.
Houston, Texas

We have audited the internal control over financial reporting of Carrizo Oil & Gas, Inc. (the "Company") as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company'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 by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. 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 U.S. 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As stated in Management's Annual Report on Internal Control over Financial Reporting, management's assessment of the effectiveness of the Company's internal control over financial reporting has been restated to reflect the impact of a material weakness in internal control over financial reporting.

In our opinion, because of the effect of the aforementioned material weakness on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the December 31, 2008 consolidated financial statements of the Company. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the December 31, 2008 consolidated financial statements, and this report does not affect our report dated March 12, 2009, except for Notes 2, 4, 5, 6 and 13 for which the date is August 17, 2009, which expressed an unqualified opinion on those consolidated financial statements.

/s/ Pannell Kerr Forster of Texas, P.C.

Houston, Texas
March 12, 2009

(Except for the restatement of Management's Annual Report on Internal
Control Over Financial Reporting, for which the date is August 17, 2009)

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CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
(As Restated and Adjusted (See Note 2))

	December 31, 2008	December 31, 2007
	(In thousands, except per share amount)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$5,184	$8,026
Accounts receivable, trade (net of allowance for doubtful accounts of $1,264 and $1,430 at December 31, 2008 and 2007, respectively)	24,675	27,114
Advances to operators	336	1,113
Fair value of derivative financial instruments	22,791	1,126
Prepayments and deposits	3,335	3,913
Deferred tax asset	-	324
Total current assets	56,321	41,616
PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil and natural gas properties (including costs not subject to amortization of $378,634 and $170,586 at December 31, 2008 and 2007, respectively)	986,629	646,810
DEFERRED FINANCING COSTS, NET	8,430	5,921
INVESTMENTS	3,274	11,071
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	15,876	-
OTHER ASSETS	1,172	3,245
TOTAL ASSETS	$1,071,702	$708,663
LIABILITIES AND SHAREHOLDERS’ EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$46,683	$49,700
Accrued liabilities	54,149	36,091
Advances for joint operations	3,815	872
Current maturities of long-term debt	173	2,251
Fair value of derivative financial instruments	-	2,755
Deferred tax liability	9,103	-
Total current liabilities	113,923	91,669
LONG-TERM DEBT, net of current maturities and debt discount	475,788	252,250
ASSET RETIREMENT OBLIGATION	6,503	5,869
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	-	1,050
DEFERRED INCOME TAXES	34,778	46,321
DEFERRED CREDITS	625	783
COMMITMENTS AND CONTINGENCIES	-	-
SHAREHOLDERS’ EQUITY:		
Common stock, par value $0.01 (90,000 shares authorized with 30,860 and 28,009 issued and outstanding at December 31, 2008 and 2007, respectively)	309	280
Additional paid in capital	420,778	239,672
Retained earnings	20,297	65,344
Accumulated other comprehensive income (loss), net of tax	(1,299)	5,425
Total shareholders’ equity	440,085	310,721
TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY	$1,071,702	$708,663

The accompanying notes are an integral part of these consolidated financial statements.

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CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(As Restated and Adjusted (See Note 2))

	For the Years Ended December 31,		
	2008	2007	2006
	(In thousands, except per share amounts)		
OIL AND NATURAL GAS REVENUES	$216,677	$125,789	$82,945
COSTS AND EXPENSES:			
Oil and natural gas operating expenses (exclusive of depletion, depreciation and amortization, shown separately below)	37,885	24,662	16,428
Third party gas purchases	6,570	-	-
Depreciation, depletion and amortization	58,311	41,899	31,129
Impairment of oil and natural gas properties	178,470	-	-
General and administrative	23,425	18,912	14,909
Accretion expenses related to asset retirement obligation	154	374	496
Total costs and expenses	304,815	85,847	62,962
OPERATING INCOME (LOSS)	(88,138)	39,942	19,983
OTHER INCOME AND EXPENSES:			
Gain (loss) on derivatives, net	37,499	(1,366)	16,457
Loss on extinguishment of debt	(5,689)	-	(294)
Equity in income of Pinnacle Gas Resources, Inc.	-	-	35
Interest income	269	691	969
Interest expense	(30,257)	(26,403)	(19,071)
Capitalized interest	20,527	11,718	9,975
Other income, net	17	130	427
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (BENEFIT)	(65,772)	24,712	28,481
INCOME TAX EXPENSE (BENEFIT)	(20,725)	9,243	10,233
NET INCOME (LOSS)	$(45,047)	$15,469	$18,248
OTHER COMPREHENSIVE INCOME (LOSS):			
Increase (decrease) in market value of investment in Pinnacle Gas Resources, Inc., net of taxes	(6,724)	5,425	-
COMPREHENSIVE INCOME (LOSS)	$(51,771)	$20,894	$18,248
BASIC EARNINGS (LOSS) PER COMMON SHARE	$(1.49)	$0.58	$0.73
DILUTED EARNINGS (LOSS) PER COMMON SHARE	$(1.49)	$0.57	$0.71
WEIGHTED AVERAGE SHARES OUTSTANDING:			
BASIC	30,326	26,641	25,081
DILUTED	30,326	27,120	25,565

The accompanying notes are an integral part of these consolidated financial statements.

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CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(As Restated and Adjusted (See Note 2))

	Common Stock	
	Shares	Amount
	(Dollars in thousands)	
BALANCE, January 1, 2006	24,251,430	$243
Common stock issued, net of offering cost	1,350,000	13
Common stock issued for property	2,000	-
Stock options exercised for cash	101,800	1
Stock-based compensation	-	-
Capitalization of repriced stock options of adoption of SFAS 123(R)	-	-
Restricted stock awards, net of forfeitures	277,436	3
Common stock repurchased for tax withholding obligations	(2,061)	-
Net income	-	-
BALANCE, December 31, 2006	25,980,605	$260
Common stock issued, net of offering cost	1,800,000	18
Stock options exercised for cash	124,148	1
Stock-based compensation	-	-
Restricted stock awards, net of forfeitures	111,839	1
Common stock repurchased for tax withholding obligations	(7,440)	-
Other comprehensive income:	-	-
Fair value adjustment to investment in Pinnacle Gas Resources, Inc., net of tax		
Net income	-	-
Total other comprehensive income	-	-
BALANCE, December 31, 2007	28,009,152	$280
Common stock issued, net of offering cost	2,587,500	26
Bifurcation of equity premium related to Senior Secured Notes	-	-
Stock options exercised for cash	65,400	1
Stock-based compensation	-	-
Restricted stock awards, net of forfeitures	203,306	2
Common stock repurchased to settle tax withholding obligations	(5,711)	-
Other comprehensive loss:		
Fair value adjustment to investment in Pinnacle Gas Resources, Inc., net of tax	-	-
Net loss	-	-
Total other comprehensive loss	-	-
BALANCE, December 31, 2008	30,859,647	$309

The accompanying notes are an integral part of these consolidated financial statements.

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CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(As Restated and Adjusted (See Note 2))

	Additional Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Shareholders' Equity
	(Dollars in thousands)			
BALANCE, January 1, 2006	$123,515	$31,627	$ -	$ 155,385
Common stock issued, net of offering cost	33,403	-	-	33,416
Common stock issued for property	55	-	-	55
Stock options exercised for cash	601	-	-	602
Stock-based compensation	3,007	-	-	3,007
Capitalization of repriced stock options at adoption of SFAS 123(R)	1,696	-	-	1,696
Restricted stock awards, net of forfeitures	(80)	-	-	(77)
Common stock repurchased to settle tax withholding obligations	(58)	-	-	(58)
Net income	-	18,248	-	18,248
BALANCE, December 31, 2006	$162,139	$49,875	$ -	$ 212,274
Common stock issued, net of offering cost	71,908	-	-	71,926
Stock options exercised for cash	1,030	-	-	1,031
Stock-based compensation	5,041	-	-	5,041
Restricted stock awards, net of forfeitures	(136)	-	-	(135)
Common stock repurchased to settle tax withholding obligations	(310)	-	-	(310)
Other comprehensive income:				
Fair value adjustment to investment in Pinnacle Gas Resources,	-	-	5,425	5,425
Inc., net of tax				
Net income	-	15,469	-	15,469
Total other comprehensive income	-	-	-	20,894
BALANCE, December 31, 2007	$239,672	$65,344	$ 5,425	$ 310,721
Common stock issued, net of offering cost	135,049	-	-	135,075
Bifurcation of equity premium related to Senior Secured Notes	40,207	-	-	40,207
Stock options exercised for cash	261	-	-	262
Stock-based compensation	6,013	-	-	6,013
Restricted stock awards, net of forfeitures	(63)	-	-	(61)
Common stock repurchased to settle tax withholding obligations	(361)	-	-	(361)
Other Comprehensive income:				
Fair value adjustment to investment in Pinnacle Gas Resources,		-	(6,724)	(6,724)
Inc., net of tax	-			
Net loss	-	(45,047)	-	(45,047)
Total other comprehensive loss	-	-	-	(51,771)
BALANCE, December 31, 2008	$420,778	$20,297	$ (1,299)	$ 440,085

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CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(As Restated and Adjusted (See Note 2))

	For the Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (Loss)	$(45,047)	$15,469	$18,248
Adjustments to reconcile net income (loss) to net cash provided by operating activities —			
Depreciation, depletion and amortization	58,311	41,899	31,129
Impairment of oil and natural gas properties	178,470	-	-
Fair value (gain) loss on derivative financial instruments	(41,345)	7,377	(8,069)
Provision for allowance for doubtful accounts	(166)	(209)	1,386
Accretion of discounts on asset retirement obligations and debt	154	374	496
Loss on extinguishment of debt	4,601	-	294
Stock-based compensation	5,952	4,907	2,930
Equity in income of Pinnacle Gas Resources, Inc.	-	-	(35)
Deferred income taxes	(20,920)	8,329	9,829
Amortization of equity premium associated with Senior Convertible Notes	1,825	-	-
Other	5,272	1,623	1,237
Changes in operating assets and liabilities —			
Accounts receivable	2,605	316	(2,178)
Other assets	(3,661)	(210)	2,037
Accounts payable	(1,476)	15,463	5,560
Accrued liabilities	4,179	(107)	2,573
Net cash provided by operating activities	148,754	95,231	65,437
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(571,291)	(247,003)	(201,773)
Change in capital expenditure accrual	11,808	17,079	7,791
Proceeds from the sale of oil and natural gas properties	3,259	1,505	38,319
Advances to operators	776	994	(517)
Advances for joint operations	2,943	(229)	(4,786)
Other	(2,840)	(70)	(610)
Net cash used in investing activities	(555,345)	(227,724)	(161,576)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from common stock issuances:			
Private placements, net of offering costs	135,075	71,926	33,525
Stock option exercises	262	1,031	602
Net proceeds from debt issuance and borrowings	778,182	174,000	80,000
Debt repayments	(498,923)	(108,258)	(40,536)
Deferred loan costs and other	(10,847)	(3,588)	(769)
Net cash provided by financing activities	403,749	135,111	72,822
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(2,842)	2,618	(23,317)
CASH AND CASH EQUIVALENTS, beginning of year	8,026	5,408	28,725
CASH AND CASH EQUIVALENTS, end of year	$5,184	$8,026	$5,408
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid for interest (net of amounts capitalized)	$4,160	$12,217	$7,211

Cash paid for income taxes	$30	$-	$-

The accompanying notes are an integral part of these consolidated financial statements.

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CARRIZO OIL & GAS, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS

Carrizo Oil & Gas, Inc., a Texas corporation ("Carrizo" or the "Company") is an independent energy company engaged in the exploration, development and production of natural gas and oil. Our current operations are principally focused in proven, producing natural gas plays known as "shale plays" or "resource plays". The Company's primary core area is the Barnett Shale area in North Texas ("Barnett Shale" or "Fort Worth Barnett Shale"), with a focus on Southeast Tarrant County, Texas. Through its wholly-owned subsidiary Carrizo (Marcellus) LLC, the Company is also actively seeking to establish a core area in another emerging resource play, the Marcellus Shale play in Pennsylvania, New York, West Virginia and Virginia. In addition to the Barnett and the Marcellus, we are active in other shale plays, including the Fayetteville in Arkansas, Barnett/Woodford in West Texas/New Mexico, Floyd/Neal in Mississippi, and the New Albany in Kentucky/Illinois. We also explore for, develop and produce natural gas and oil from traditional geologic trends along the onshore Gulf Coast area in Texas, Louisiana and Alabama, primarily in the Miocene, Wilcox, Frio and Vicksburg trends. The Company's other interests include properties in the U.K. North Sea.

2. ADJUSTMENTS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Restatement for 2008 Ceiling Test Impairment and Adjustment for Retrospective Application of FSP APB 14-1 and FSP EITF 03-6-1

Subsequent to filing the Company's Annual Report on Form 10-K for the year ended December 31, 2008, an error was discovered in the ceiling test computation. The Company determined that its impairment calculation did not take into account correctly certain deferred tax amounts and the classification of costs between the unevaluated costs and the full cost pool. As a result, the Company is restating its consolidated financial information for the year ended December 31, 2008 in this Form 10-K/A. The effect of this restatement is an increase of the ceiling test impairment from $138.6 million to $178.5 million as of December 31 2008.

Furthermore, the Company has adjusted its consolidated financial statements for the years ended December 31, 2008 to reflect the adoption of the Financial Accounting Standards Board's ("FASB") Staff Position ("FSP") No. APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlements)" ("APB 14-1"), and FSP Emerging Issues Task Force No. 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities ("EITF 03-6-1") for all periods presented.

Effective on January 1, 2009, the Company adopted APB 14-1, which clarifies the accounting for convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. APB 14-1 requires that issuers of convertible debt separately account for the liability and equity components in a manner that reflects the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. Once adopted, APB 14-1 requires retrospective application to the terms of instruments as they existed for periods presented. The adoption of APB 14-1 affects the accounting for the Company's 4.375% Senior Convertible Notes due 2028. The retrospective application of this accounting pronouncement affects the Company's balance sheet as of December 31, 2008, and statements of operations, shareholders' equity and cash flows for the year ended December 31, 2008.

On January 1, 2009, the Company adopted and retroactively applied EITF 03-6-1. This FSP provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents, whether paid or unpaid, are participating securities and shall be included in the computation of both basic and diluted earnings per share. This FSP requires retroactive application for all periods presented. The Company determined that its restricted shares of common stock are participating securities as defined in this FSP and applied this FSP retroactively to all periods presented.

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The following table sets forth the effect of the restatement of the 2008 ceiling test impairment and the retrospective application of APB 14-1 and EITF 03-6-1 on certain previously reported items:

	For the Years Ended December 31,					
	2008		2007		2006	
	Originally Reported	As Adjusted	Originally Reported	As Adjusted(1)	Originally Reported	As Adjusted(1)
	(In thousands, except per share amounts)					
Impairment of oil and natural gas properties	$ 138,591	$ 178,470				
Interest expense	(23,546)	(30,257)				
Capitalized interest	15,641	20,527				
LOSS BEFORE INCOME TAX EXPENSE	(24,068)	(65,772)				
INCOME TAX BENEFIT	(6,129)	(20,725)				
NET LOSS	(17,939)	(45,047)				
COMPREHENSIVE LOSS	(24,663)	(51,771)				
Basic Income (Loss) Per Share	$ (0.60)	$ (1.49)	$ 0.59	$ 0.58	$ 0.74	$ 0.73
Diluted Income (Loss) Per Share	$ (0.60)	$ (1.49)				
Weighted Average Common Shares Oustanding						
Basic	30,010	30,326	26,287	26,641	24,827	25,081
Diluted	30,010	30,326				

(1) Adjusted for the retrospective adoption of EITF 03-6-1 only, as discussed above.

Consolidated Balance Sheet:

	December 31, 2008	
	Originally Reported	As Adjusted
	(In thousands)	
Property and Equipment	$ 1,021,621	$ 986,629
Deferred Financing Costs, net	9,750	8,430
Long-Term Debt, net of current	533,057	475,788

maturities and debt discount		
Deferred Income Taxes	26,920	34,778
Additional Paid-In Capital	380,571	420,778
Retained Earnings	47,405	20,927
Total Shareholders' Equity	426,986	440,085

In addition, the restatement and retrospective application resulted in changes to our consolidated statement of cash flows for the year ended December 31, 2008 and Notes 4, 5, 6 and 13.

Principles of Consolidation

The consolidated financial statements are presented in accordance with U.S. generally accepted accounting principles. The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries after elimination of all significant intercompany transactions and balances. The financial statements reflect necessary adjustments, all of which were of a recurring nature and are in the opinion of management necessary for a fair presentation.

Unconsolidated Investments

Prior to April 2006, the Company's investment in Pinnacle Gas Resources, Inc. ("Pinnacle") was recorded using the equity method of accounting and was adjusted for the Company's equity in the subsidiary's profit or loss. In April 2006, the Company changed its accounting for Pinnacle to the cost method of accounting and adjusts the carrying amount of its investment for contributions to and distributions from the subsidiary.

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In 2007, Pinnacle became a publicly traded entity on the Nasdaq Global Market. For accounting purposes, the Pinnacle common stock now has a readily determinable fair market value. The Company classifies the investment as available-for-sale and adjusts the book value to fair market value through other comprehensive income, net of taxes. This fair value adjustment is assessed quarterly for other than temporary impairment based upon publicly available information. If the loss is deemed other than temporary, it will be recognized in earnings.

The Company accounts for its investment in Oxane Materials, Inc. using the cost method of accounting and adjusts the carrying amount of its investment for contributions to and distributions from the entity.

Reclassifications

Certain reclassifications have been made to prior periods' financial statements to conform to the current presentation. These reclassifications had no effect on total assets, total liabilities, shareholders' equity or net income.

Use of Estimates

The preparation of financial statements in conformity with U.S. 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 consolidated financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of undeveloped properties, future income taxes and related assets/liabilities, the collectability of outstanding accounts receivable, fair values of derivatives, stock-based compensation expense, contingencies and the results of current and future litigation. Oil and natural gas reserve estimates, which are the basis for unit-of-production depletion and the ceiling test, have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Subsequent drilling results, testing and production may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. In addition, reserve estimates are vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

The significant estimates are based on current assumptions that may be materially effected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates, the market value of the Company's common stock and corresponding volatility and the Company's ability to generate future taxable income. Future changes in these assumptions may affect these significant estimates materially in the near term.

Oil and Natural Gas Properties

Investments in oil and natural gas properties are accounted for using the full-cost method of accounting. All costs directly associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Such costs include lease acquisitions, seismic surveys, and drilling and completion equipment. The Company proportionally consolidates its interests in oil and natural gas properties. The Company capitalized compensation costs and other costs of employees working directly on exploration activities of $7.8 million, $4.5 million and $3.5 million in 2008, 2007 and 2006, respectively. Maintenance and repairs are expensed as incurred.

Depreciation, depletion and amortization ("DD&A") of proved oil and natural gas properties are based on the unit-of-production method using estimates of proved reserve quantities. Costs not subject to amortization include costs of unevaluated leaseholds, seismic costs associated with specific unevaluated properties and exploratory wells in progress. These costs are evaluated periodically for impairment on a property-by-property basis. If the results of an assessment indicate that the properties have been impaired, the amount of such impairment is determined and added to the proved oil and natural gas property costs subject to DD&A. The depletable base includes estimated future development costs and, where significant, dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for 2008, 2007 and 2006 was $2.23, $2.36 and $2.61, respectively.

Dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves.

The net capitalized costs are limited to a “ceiling test” based on the estimated future net revenues from proved reserves, discounted at a 10% rate per annum, based on current economic and operating conditions (“full cost ceiling”). If net capitalized costs exceed this limit, the excess is charged to earnings. During 2008, the Company recorded an impairment of $178.5 million associated with its year end 2008 ceiling test analysis.

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Depreciation of other property and equipment is provided using the straight-line method based on estimated useful lives ranging from five to 10 years.

Oil and Natural Gas Reserve Estimates

The process of estimating quantities of proved reserves is inherently uncertain, and the reserve data included in this document are estimates prepared by Ryder Scott Company Petroleum Engineers, Fairchild & Wells, Inc. and LaRoche Petroleum Consultants, Ltd., independent petroleum engineers. Reserve engineering is a subjective process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact manner. The process relies on interpretation of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions regarding drilling and operating expense, capital expenditures, taxes and availability of funds. The SEC mandates some of these assumptions such as oil and natural gas prices and the present value discount rate.

Proved reserve estimates prepared by others may be substantially higher or lower than the Company's estimates. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve quantities actually recovered may be significantly different than estimated. Material revisions to reserve estimates may be made depending on the results of drilling, testing, and rates of production.

You should not assume that the present value of future net cash flows is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the estimated discounted future net cash flows from proved reserves on market prices and costs on the date of the estimate.

The Company's rate of recording depreciation, depletion and amortization expense for proved properties is dependent on the Company's estimate of proved reserves. If these reserve estimates decline, the rate at which the Company records these expenses will increase.

The Company's full cost ceiling test also depends on the Company's estimate of proved reserves. If these reserve estimates decline, the Company may be subjected to a full cost ceiling write-down. The Company recorded a full cost ceiling test write-down in 2008.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with maturities of three months or less when purchased.

Revenue Recognition and Natural Gas Imbalances

The Company follows the sales method of accounting for revenue recognition and natural gas imbalances, which recognizes over and under lifts of natural gas when sold, to the extent sufficient natural gas reserves or balancing agreements are in place. Natural gas, natural gas liquids and oil sales volumes are not significantly different from the Company's share of production.

The Company purchases natural gas at the well head from a third-party operator under a purchase and sales agreement whereby the Company recognizes revenue at the redelivery point, which is the point at which title to the natural gas transfers to the purchaser. The Company then remits the sales proceeds received less a fixed fee per unit of production (MMBtu) transported which is recorded at the cost of the natural gas purchased.

Financing Costs, net

Net long-term debt financing costs of $8.4 million (net of $10.4 million accumulated amortization) and $5.9 million (net of $4.0 million accumulated amortization) were capitalized as of December 31, 2008 and 2007, respectively, and are being amortized using the effective yield method over the term of the debt, which is through May 2013 for the Convertible Senior Notes and through October 2012 for the Senior Secured Revolving Credit Facility.

Supplemental Cash Flow Information

The Statement of Cash Flows for the year ended December 31, 2008 does not include the adjustment of the investment in Pinnacle of $(6.7) million, net of tax. The Statement of Cash Flows for the year ended December 31, 2007 does not include the adjustment of the investment in Pinnacle of $5.4 million, net of tax. The Statement of Cash Flows for the year ended December 31, 2006 does not include the acquisition of $55,000 of oil and gas properties in exchange for the Company's common stock and the capitalization of stock-based compensation associated with the adoption of SFAS 123(R) of $1.7 million, net of tax.

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Financial Instruments

The Company's financial instruments consist of cash, receivables, payables and long-term debt. The carrying amount of cash, receivables and payables approximates fair value because of the short-term nature of these items. The carrying amounts of long-term debt under the Senior Credit Facility approximate fair value as these borrowings bear interest at variable interest rates. The carrying amount of the Convertible Senior Notes does not approximate fair value because the notes are fixed rate debt.

Stock-Based Compensation

In June of 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the "Incentive Plan"), which authorizes the granting of stock options and stock awards to directors, employees and independent contractors. The Company recognized the following stock-based compensation expenses for the years ended December 31:

	2008	2007	2006
		(In millions)	
Stock Option	$ 0.1	$ 0.3	$ 0.5
Restricted Stock	5.9	4.6	2.4
Total Stock-Based Compensation	$ 6.0	$ 4.9	$ 2.9

Stock Options. Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 123 (revised 2004), "Share-Based Payment" ("SFAS No. 123(R)"), which requires companies to measure all stock-based compensation awards using the fair value method and record such expense in the financial statements over the vesting period of the options, which is generally three years. The Company implemented SFAS No. 123(R) using the modified prospective transition method.

The Company recognizes compensation expense for all unvested options outstanding as of January 1, 2006, options issued after January 1, 2006, and those options that are subsequently modified, repurchased or cancelled. The compensation expense is based on the grant-date fair value of the options and expensed over the vesting period.

The Company uses the Black-Scholes option pricing model to compute the fair value of stock options, which requires the Company to make the following assumptions:

- The risk-free interest rate is based on the five-year Treasury bond at date of grant.
- The dividend yield on the Company's common stock is assumed to be zero since the Company does not pay dividends and has no current plans to do so in the future.
- The market price volatility of the Company's common stock is based on daily, historical prices for the last three years.
- The term of the grants is based on the simplified method as described in Staff Accounting Bulletin No. 107.

In addition, the Company estimates a forfeiture rate at the inception of the option grant based on historical data and adjusts this prospectively as new information regarding forfeitures becomes available.

Restricted Stock. The Company grants shares of restricted stock and measures deferred compensation based on the price of the Company's stock on the grant date. The deferred compensation is amortized to stock-based compensation expense ratably over the vesting period of the restricted shares (generally one to three years), using either the straight-line or graded vesting method as prescribed in SFAS 123(R). Restricted stock issued to other than employees that vests over time as services are provided is adjusted to fair value at each reporting period with the change in fair value being recorded to expense until vested.

Taxes. Upon settlement of stock awards, the Company recognizes any difference between book compensation expense and tax compensation expense as a tax windfall or shortfall. The difference is charged to equity in the case of a windfall. In the case of shortfalls, the difference is charged to equity to the extent of previously recognized windfall tax benefits and any remaining shortfall is recognized as additional income tax expense. When the settlement of an award results in a net operating loss (NOL), or increases an NOL carryforward, SFAS 123(R) prescribes that no windfall should be recognized until the deduction reduces income tax payable. At December 31, 2008, the Company had an NOL of approximately $67.5 million. The Company has postponed the recognition of approximately $5.7 million in windfall tax benefits associated with its stock-based compensation until a tax cash savings is realized.

Derivative Instruments

The Company uses derivatives to manage price risk underlying its oil and natural gas production. The Company also used derivatives to manage the variable interest rate on its Second Lien Credit Facility that was terminated in May 2008.

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Upon entering into a derivative contract, the Company either designates the derivative instrument as a hedge of the variability of cash flow to be received (cash flow hedge) or the derivative must be accounted for as a non-designated derivative. All of the Company’s derivative instruments during the years ended December 31, 2008, 2007 and 2006 were treated as non-designated derivatives and the unrealized gain/(loss) related to the change in mark-to-market valuation was included in the Company’s earnings.

The Company typically uses fixed-rate swaps, costless collars and basis differential swaps to hedge its exposure to material changes in the price of oil and natural gas and variable interest rates on long-term debt.

The Company’s Board of Directors sets all risk management policies and reviews volumes, types of instruments and counterparties on a quarterly basis. These policies require that derivative instruments be executed only by either the President or Chief Financial Officer after consultation and concurrence by the President, Chief Financial Officer and Chairman of the Board. The master contracts with approved counterparties identify the President and Chief Financial Officer as the only Company representatives authorized to execute trades. The Board of Directors also reviews the status and results of derivative activities quarterly.

Income Taxes

Under SFAS No. 109 “Accounting for Income Taxes,” deferred income taxes are recognized at each reporting period for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. The Company routinely assess the realizability of its deferred tax assets and considers future taxable income in making such assessments. If the Company concludes that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, it is reduced by a valuation allowance. However, despite the Company’s attempt to make an accurate estimate, the ultimate utilization of the deferred tax assets is highly dependent upon actual production and the realization of taxable income in future periods.

Concentration of Credit Risk

Substantially all of the Company’s accounts receivable result from oil and natural gas sales, joint interest billings to third parties in the oil and natural gas industry or drilling and completion advances to third-party operators for development costs of in-progress wells. This concentration of customers and joint interest owners may impact the Company’s overall credit risk in that these entities may be similarly affected by changes in economic and other industry conditions. The Company does not require collateral from its customers. The Company generally has the right to offset revenue against related billings to joint interest owners.

Derivative contracts subject the Company to a concentration of credit risk. At December 31, 2008, approximately 69% of the Company’s open natural gas hedges were with Credit Suisse, and the remaining 31% were with Shell Energy North America (US), L.P. The open oil hedge positions were all arranged with Credit Suisse. The Company maintains its cash with major U.S. banks and one bank in the United Kingdom. From time to time, cash amounts may exceed the FDIC insured limit of $250,000. The terms of these deposits are on demand to minimize risk. Historically, the Company has not incurred losses related to these deposits.

Allowance for Doubtful Accounts

The Company establishes provisions for losses on accounts receivable when it determines that it will not collect all or a part of the outstanding balance. The Company reviews collectability quarterly and adjusts the allowance as necessary using the specific identification method.

During the fourth quarter of 2006, Reichmann Petroleum filed for bankruptcy. At the time, the Company had outstanding receivable balances of approximately $1.5 million for October 2006 production and advances to Reichmann for the drilling of wells in which Reichmann was the operator. The Company expects to recover approximately five percent of the receivable balance due at the time of bankruptcy. Accordingly, the Company increased the allowance by approximately $1.5 million during the fourth quarter of 2006. During 2007, the Company collected the receivable associated with October 2006 production and reduced the reserve for the Reichmann bankruptcy to $0.9 million.

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Major Customers

The Company sold oil and natural gas production representing more than 10% of its oil and natural gas revenues as follows:

	Year Ended December 31,		
	2008	2007	2006
DTE Energy Trading, Inc.	39 %	-	-
Cokinos Natural Gas Company	11 %	11 %	-
Crosstex Energy	10 %	15 %	-
Houston Pipeline Company	-	11 %	-
Energy Transfer	-	10 %	-
Reichmann Petroleum	-	-	10 %
Chevron/Texaco	-	-	11 %

Earnings Per Share

Supplemental earnings per share information is provided below:

	Year Ended December 31,		
	2008	2007	2006
		Adjusted	
	(In thousands, except per share amounts)		
Net income (loss) available to common shareholders	$ (45,047)	$ 15,469	$ 18,248
Basic weighted average common shares outstanding	30,326	26,641	25,081
Stock options	-	479	484
Diluted weighted average shares outstanding	30,326	27,120	25,565
Earnings (loss) per share			
Basic	$ (1.49)	$ 0.58	$ 0.73
Diluted	$ (1.49)	$ 0.57	$ 0.71

Basic earnings (loss) per common share is based on the weighted average number of shares of common stock outstanding during the periods including unvested restricted shares subject to the provisions of EITF 03-6-1. Diluted earnings per common share is based on the weighted average number of common shares and all dilutive potential common shares outstanding during the periods. The Company had outstanding 685,854 stock options at December 31, 2008 that were antidilutive due to the net loss for 2008. Shares subject to potential issuance upon conversion of the Convertible Senior Notes did not have any impact on the calculation for 2008. The Company had 2,500 stock options at December 31, 2006 that were antidilutive as the exercise price of the options was greater than the then current market price of the Company's stock.

Contingencies

Liabilities and other contingencies are recognized upon determination of an exposure, which when analyzed indicates that it is both probable that an asset has been impaired or that a liability has been incurred and that the amount of such loss is reasonably estimable.

Asset Retirement Obligation

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143"). SFAS No. 143 requires that an asset retirement obligation (ARO) associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying amount of the associated asset. The ARO is recorded at fair value, excluding salvage values, and accretion expense will be recognized over time as the discounted liability is accreted to its expected settlement value. The fair value of the ARO is measured using expected future cash outflows discounted at the Company's credit-adjusted risk-free interest rate. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the cost of the ARO is recognized over the useful life of the asset.

In accordance with the provisions of SFAS No. 143, the Company records an abandonment liability associated with its oil and natural gas wells when those assets are placed in service. Under SFAS No. 143, depletion expense is reduced since a discounted ARO is depleted in the property balance rather than the undiscounted value previously depleted under the old rules. The lower depletion expense under SFAS No. 143 is offset, however, by accretion expense, which is recognized over time as the discounted liability is accreted to its expected settlement value.

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Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance. Settlements greater than or less than amounts accrued as ARO are recovered as a gain or loss upon settlement.

The following table is a reconciliation of the asset retirement obligation liability for the years ended December 31:

	2008	2007
	(In thousands)	
Asset retirement obligation at beginning of year	$ 5,869	$ 3,625
Liabilities incurred	1,004	1,251
Liabilities settled	(177)	(234)
Accretion expense	154	374
Revisions to previous estimates	(347)	853
Asset retirement obligation at end of year	$ 6,503	$ 5,869

Foreign Currency

The company has foreign activities related to its operations in the U.K. North Sea. Accordingly, assets and liabilities related to these operations are translated into United States dollars at exchange rates in effect at the balance sheet date. Income and expense items are translated at average exchange rates throughout the year. Translation adjustments are charged or credited to other comprehensive income (loss) and are recorded net of applicable taxes. Transaction gains or losses that occur due to the realization of assets and the settlement of liabilities using a currency denominated in other than the functional currency are charged to earnings.

Recently Issued Accounting Pronouncements

In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities” (“SFAS No. 161”). This standard is intended to improve financial reporting by requiring transparency about the location and amounts of derivative instruments in an entity’s financial statements, how derivative instruments and related hedged items are accounted for under SFAS No. 133, and how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company does not believe the adoption of SFAS No. 161 will have a significant effect on its consolidated financial position, results of operations or cash flows.

On December 31, 2008, the Securities and Exchange Commission (SEC) adopted a major revision to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies to report the independence and qualification of the person primarily responsible for the preparation or audit of reserve estimates, and to file reports when a third party is relied upon to prepare or audit reserves estimates. The new rules also require that the net present value of oil and gas reserves to be reported and used in the full-cost ceiling test calculation should be based upon an average price for the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. The Company is in the process of assessing the impact of these new requirements on its financial position, results of operations and financial disclosures.

Recently Adopted Accounting Pronouncements

The Company adopted the Financial Accounting Standards Statement No. 157, "Fair Value Measurement" ("SFAS No. 157"), effective January 1, 2008. SFAS No. 157 provides a framework for measuring fair value and enhances related disclosures. The implementation of SFAS No. 157 did not change the Company's current valuation method and did not have a material effect on the Company's consolidated financial position or results of operations. The Company included additional disclosures in the Notes to Consolidated Financial Statements with respect to the measurement of its assets and liabilities at fair value on the balance sheet date.

The Company adopted APB 14-1 effective January 1, 2009. This FSP clarifies that convertible debt instruments that may be settled in cash upon conversion, including partial cash settlement, are not addressed by paragraph 12 of APB Opinion No. 14, "Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants." Additionally, this FSP specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. The Company valued the 4.375% Senior Convertible Notes due 2028 as $309.6 million of debt and $64.2 million of equity, representing the fair value of the

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conversion premium on the date of issuance, and recognized an additional $1.8 million in interest expense (net of $4.9 million capitalized to oil and natural gas properties) during 2008, resulting in an effective interest rate of approximately 8% for 2008.

The Company adopted EITF 03-6-1 effective January 1, 2009. This FSP provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents, whether paid or unpaid, are participating securities and shall be included in the computation of both basic and diluted earnings per share. The Company determined that some of its shares of restricted stock qualified as participating securities and included them in both basic and diluted earnings per share calculation for all periods presented.

3. INVESTMENTS

Investments consisted of the following at December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
	(In thousands)	
Pinnacle Gas Resources, Inc.	$ 751	$ 11,071
Oxane Materials, Inc.	2,523	-
	$ 3,274	$ 11,071

Pinnacle Gas Resources, Inc.

In 2003, the Company’s wholly-owned subsidiary CCBM, Inc. (“CCBM”) contributed its interests in certain natural gas and oil leases in Wyoming and Montana in areas prospective for coalbed methane to a newly formed entity, Pinnacle Gas Resources, Inc. (“Pinnacle”).

The Company classifies the Pinnacle investment as available-for-sale and adjusts the investment to fair value through Other Comprehensive Income. At December 31, 2008, the Company reported the fair value of the stock at $0.8 million (based on the closing price of Pinnacle’s common stock on December 31, 2008), which is approximately $2.0 million below original cost. The fair value of this investment based on quoted market prices, was in excess of or equal to the original cost in October 2008. Management believes that this recent decrease in value that commenced in October of 2008 is temporary.

In June 2007, the Company sold 41,894 shares of Pinnacle stock for net proceeds of $0.4 million and recognized a $0.3 million gain, which is included in other income and expenses, net on the Consolidated Statements of Operations. As of December 31, 2008, the Company owned 2,422,238 shares of Pinnacle common stock.

Oxane Materials, Inc.

In May 2008, the Company entered into a strategic alliance agreement with Oxane Materials, Inc. (“Oxane”) in connection with the development of a proppant product to be used in the Company’s exploration and production program. The Company contributed approximately $2.0 million to Oxane in exchange for warrants to purchase Oxane common stock and for certain exclusive use and preferential purchase rights with respect to the proppant. The Company simultaneously invested an additional $500,000 in a convertible promissory note from Oxane. The convertible promissory note accrued interest at a rate of 6% per annum. During the fourth quarter of 2008, the Company converted the promissory note into 630,371 shares of Oxane preferred stock. The Company accounts for the investment using the cost method.

4. PROPERTY AND EQUIPMENT

At December 31, 2008 and 2007, property and equipment consisted of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
Proved oil and natural gas properties	$ 821,238	$ 655,308
Costs not subject to amortization	378,634	170,586
Land, building and other equipment	6,363	2,853
Total property and equipment	1,206,235	828,747
Accumulated depreciation, depletion and amortization	(219,606)	(181,937)
Property and equipment, net	$ 986,629	$ 646,810

Oil and natural gas properties not subject to amortization consist of the cost of unevaluated leaseholds, seismic costs associated with specific unevaluated properties and exploratory wells in progress. These costs are reviewed periodically by

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management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include drilling results by the Company and other operators, the terms of oil and natural gas leases not held by production, production response to secondary recovery activities and available funds for exploration and development. The Company expects it will complete its evaluation of the properties representing the majority of these costs within the next two to five years.

The significant decline in oil and natural gas prices caused the discounted present value (discounted at 10 percent) of future net cash flows from proved oil and gas reserves to fall below the net book basis of the proved oil and gas properties. This resulted in a non-cash ceiling test write-down at the end of the fourth quarter of 2008 of $178.5 million ($116.0 million after tax).

5. INCOME TAXES

All of the Company's income is derived from domestic activities. Actual income tax expense (benefit) differs from income tax expense (benefit) computed by applying the U.S. federal statutory corporate rate of 35% to pretax income as follows:

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Provision at the statutory tax rate	$ (23,020)	$ 8,649	$ 9,968
Preferred dividend on Pinnacle	-	-	141
Increase in valuation allowance for equity in income of Pinnacle	-	-	(153)
State taxes	123	594	277
Nondeductible expenses	1,930	-	-
Other	242	-	-
Income tax expense (benefit)	$ (20,725)	$ 9,243	$ 10,233

Deferred income taxes result from temporary differences in the recognition of income and expenses for financial reporting purposes and for tax purposes. At December 31, 2008 and 2007, the tax effects of these temporary differences resulted principally from the following:

	December 31,	
	2008	2007
	(In thousands)	
Deferred income tax assets:		
Net operating loss carryforward	$ 23,547	$ 17,430
Stock based compensation	1,549	1,675
Fair value derivative instruments	-	1,332
Allowance for doubtful accounts	442	500
Equity in income of Pinnacle	385	385
Valuation allowance	(385)	(385)
Adjustmennt to fair value of investment in Pinnacle	699	-

		26,237		20,937
Deferred income tax liabilities:				
Oil and gas acquisition, exploration and development		12,740		48,010
costs deducted for tax purposes in excess of financial statement DD&A				
Conversion premium on convertible debt		20,044		-
Capitalized interest		22,520		15,335
Adjustment to fair value of investment in Pinnacle		-		2,921
Fair value derivative instruments		14,659		668
Other		155		-
		70,118		66,934
Net deferred income tax liability	$	43,881	$	45,997

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At December 31, 2008 and 2007, the net deferred income tax liability is classified as follows:

	December 31, 2008		December 31, 2007	
	(In thousands)			
Current deferred tax asset	$	-	$	(324)
Current deferred tax liability		9,103		-
Deferred income taxes		34,778		46,321
Deferred income tax liability, net	$	43,881	$	45,997

The realization of deferred tax assets is dependent on the Company's ability to generate taxable earnings in the future. The Company believes it will generate taxable income in the NOL carryforward period. As such management believes that it is more likely than not that its deferred tax assets other than the deferred tax asset attributable to Pinnacle will be fully realized. A full valuation allowance has been established for the equity in loss of Pinnacle's tax asset as the realization of the deferred tax asset is dependent on generating sufficient taxable income in Pinnacle in future periods, which management believes is unlikely. The Company has a net operating loss carryforward totaling approximately $67.3 million, which is scheduled to expire over a period from 2019 through 2028.

On January 1, 2007, the Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109" ("FIN 48"). FIN 48 prescribes a measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return. Additionally, FIN 48 provides guidance regarding uncertain tax positions relating to derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company classifies interest and penalties associated with income taxes as interest expense. At December 31, 2008, the Company had no material uncertain tax positions and the tax years 2003 through 2007 remained open to review by federal and various state tax jurisdictions.

6. LONG-TERM DEBT

At December 31, 2008 and 2007, long-term debt consisted of the following:

	December 31, 2008		December 31, 2007	
	(In thousands)			
Convertible Senior Notes	$	373,750	$	-
Unamortized discount for Convertible Senior Notes		(57,269)		-
		159,000		34,000

Senior Secured Revolving Credit Facility		
Second Lien Credit Facility	-	220,500
Other	480	1
	475,961	254,501
Less: current maturities	(173)	(2,251)
	$ 475,788	$ 252,250

Convertible Senior Notes

In May 2008, the Company issued $373.8 million aggregate principal amount of 4.375% convertible senior notes due 2028 ("Convertible Senior Notes"). Interest is payable on June 1 and December 1 each year, commencing December 1, 2008. The notes will be convertible, using a net share settlement process, into a combination of cash and Carrizo common stock that entitles holders of the Convertible Senior Notes to receive cash up to the principal amount ($1,000 per note) and common stock in respect of the remainder, if any, of Carrizo's conversion obligation in excess of such principal amount. The notes are convertible into Carrizo's common stock at a ratio of 9.9936 shares per $1,000 principal amount of notes, equivalent to a conversion price of approximately $100.06. This conversion rate is subject to adjustment upon certain corporate events. In addition, if certain fundamental changes occur on or before June 1, 2013, the Company will in some cases increase the conversion rate for a holder electing to convert notes in connection with such fundamental change; provided, that in no event will the total number of shares issuable upon conversion of a note exceed 14.7406 per $1,000 principal amount of notes (subject to adjustment in the same manner as the conversion rate). Holders may convert the notes only under the following conditions: (a) during any calendar quarter if the last reported sale price of Carrizo common stock exceeds 130 percent of the conversion price for at least 20 trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter, (b) during the five business days after any five consecutive trading day period in which the trading price per $1,000 principal amount of the notes is equal to or less than 97% of the conversion value of such notes, (c) during specified periods if specified distributions to holders of Carrizo common stock are made or specified corporate transactions occur, (d) prior to the close of

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business on the business day preceding the redemption date if the notes are called for redemption or (e) on or after March 31, 2028 and prior to the close of business on the business day prior to the maturity date of June 1, 2028. The holders of the Convertible Senior Notes may require the Company to repurchase the notes on June 1, 2013, 2018 and 2023, or upon a fundamental corporate change at a repurchase price in cash equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any. The Company may redeem notes at any time on or after June 1, 2013 at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any.

The Convertible Senior Notes are subject to customary, non-financial covenant and events of default, including a cross default under the Senior Credit Facility, the occurrence and continuation of which could result in the acceleration of amounts due under the Convertible Senior Notes.

The Convertible Senior Notes are unsecured obligations of the Company and rank equal to all future senior unsecured debt but rank second in priority to the Senior Secured Revolving Credit Facility.

As prescribed by APB 14-1, on the date of issuance the Company valued the Convertible Senior Notes as $309.6 million of debt and $64.2 million of equity, representing the fair value of the conversion premium. The resulting debt discount will be amortized to interest expense through June 1, 2013, the first date on which the holders may require the Company to repurchase the Convertible Senior Notes, resulting in an effective interest rate of approximately 8% for the Convertible Senior Notes.

Senior Secured Revolving Credit Facility

On May 25, 2006, the Company entered into a Senior Secured Revolving Credit Facility (“Senior Credit Facility”) with JPMorgan Chase Bank, National Association, as administrative agent. The Senior Credit Facility provided for a revolving credit facility up to the lesser of the borrowing base and $200.0 million. It is secured by substantially all of the Company’s proved oil & gas assets and is guaranteed by the Company’s subsidiaries, CCBM, Inc., CLLR, Inc., Carrizo (Marcellus) LLC and Carrizo Marcellus Holdings, Inc.

In the fourth quarter of 2008, the Company amended the Senior Credit Facility to (1) increase the borrowing base to $250.0 million; (2) extend the maturity date to October 29, 2012; (3) increase the maximum total net debt to Consolidated EBITDAX to 4.0 to 1.0; (4) change the semi-annual borrowing base redetermination dates to March 31 and September 30; (5) change the interest rate provisions; and (6) replace JPMorgan Chase Bank with Guaranty Bank as the administrative agent bank.

If the outstanding principal balance of the revolving loans under the Senior Credit Facility exceeds the borrowing base at any time, the Company has the option within 30 days to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, pledge additional collateral sufficient in the lenders’ opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the ensuing six-month period. Those payments would be in addition to any payments that may come due as a result of the quarterly borrowing base reductions. Otherwise, any unpaid principal or interest will be due at maturity.

The annual interest rate on each base rate borrowing is (a) the greatest of the agent’s Prime Rate, the Base CD Rate plus 1.0% and the Federal Funds Effective Rate plus 0.5%, plus (b) a margin between 0.75% and 2.25% (depending on the then-current level of borrowing base usage), but such interest rate can never be lower than the adjusted Daily LIBO rate on such day plus a margin between 2.0% to 3.5% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar loan will be the adjusted daily LIBO rate plus a margin between 2.0% to 3.5% (depending on the then-current level of borrowing base usage). At December 31, 2008, the average interest rate for amounts outstanding under the Senior Credit Facility was 3.0%.

The Company is subject to certain covenants under the amended terms of the Senior Credit Facility which include, but are not limited to, the maintenance of the following financial ratios: (1) a minimum current ratio of 1.0 to 1.0; and (2) a maximum total net debt to Consolidated EBITDAX (as defined in the Senior Credit Facility) of 4.0 to 1.0. Although the Company currently believes that it can comply with all of the financial covenants with the business plan that it has put in place, the business plan is based on a number of assumptions, the most important of which is a relatively stable, natural gas price at economically sustainable levels. If the price that the Company receives for our natural gas production deteriorates significantly from current levels, it could lead to lower revenues, cash flow and earnings, which in turn could lead to a default under certain financial covenants in the Senior Credit Facility, including the financial covenants discussed above. In order to provide a further margin of comfort with regards to these financial covenants, the Company may seek to further reduce its capital and exploration budget, sell non-strategic assets, opportunistically modify or increase its natural gas hedges or approach the lenders under our Senior Credit Facility for modifications of either or both of the financial covenants discussed above. There can be no assurance that the Company will be able to successfully execute any of these strategies, or if executed, that they will be sufficient to avoid a default under our Senior Credit Facility if a precipitous decline in natural gas prices were to occur in the future. The Senior Credit Facility also places restrictions on indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of our common stock, speculative commodity transactions, transactions with affiliates and other matters.

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The Senior Credit Facility is subject to customary events of default, the occurrence and continuation of which could result in the acceleration of amounts due under the facility by the agent or the lenders.

At December 31, 2008, the Company was in compliance with all of our debt covenants.

At December 31, 2008, the Company had $159.0 million of borrowings outstanding under the Senior Credit Facility and the borrowing base availability was $91.0 million.

Second Lien Credit Facility

On July 21, 2005, the Company entered into a Second Lien Credit Agreement with Credit Suisse, as administrative agent and collateral agent and the lenders party thereto (the “Second Lien Credit Facility”). The Second Lien Credit Facility, as amended, provided for a term loan facility in an aggregate principal amount of $225.0 million. In May 2008, the Company repaid in full the $219.9 million outstanding under the Second Lien Credit Facility and terminated the facility in connection with the issuance of its Convertible Senior Notes. The Company recorded a loss on extinguishment of approximately $5.7 million during 2008.

7. COMMITMENTS AND CONTINGENCIES

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

The operations and financial position of the Company continue to be affected from time to time in varying degrees by domestic and foreign political developments as well as legislation and regulations pertaining to restrictions on oil and natural gas production, imports and exports, natural gas regulation, tax increases, environmental regulations and cancellation of contract rights. Both the likelihood and overall effect of such occurrences on the Company vary greatly and are not predictable.

The Company has a long-term operating lease agreement for its corporate offices that expires in December 2011. Under the terms of the lease agreement, the Company received a rent abatement equal to six months of lease payments and a build out allowance that is being amortized to expense over the term of the lease. In July 2006, the Company amended its lease agreement to expand the leased office space by an additional floor. The lease term for the additional floor also expires in December 2011. Rent expense for the years ended December 31, 2008, 2007 and 2006 was $0.9 million, $0.9 million and $0.6 million, respectively, and includes rent expense for the Company’s corporate office and a field office in the Barnett Shale area.

Minimum office rentals, drilling rig obligations and pipeline volume commitments for each of the five years subsequent to December 31, 2008 are as follows (in thousands):

	Amount (in thousands)
2009	$ 32,575
2010	33,540
2011	15,929
2012	5,858
2013 and Thereafter	21,223

$ 109,125

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8. SHAREHOLDERS' EQUITY AND STOCK INCENTIVE PLAN

Shareholders' Equity

The following is a summary of changes in the Company's common stock shares for the years ended December 31,:

	2008	2007	2006
		(In thousands)	
Shares outstanding at January 1	28,009	25,981	24,251
Common stock issued	2,588	1,800	1,350
Restricted stock issued, net of forfeitures	203	112	278
Stock options exercised	65	124	102
Common stock issued for property	-	-	2
Common stock repurchased and retired for tax withholding obligation	(5)	(8)	(2)
Shares outstanding at December 31	30,860	28,009	25,981

In February 2008, the Company completed an underwritten public offering of 2,587,500 shares of its common stock at a price of $54.50 per share. The number of shares sold was approximately 9.2% of the Company's outstanding shares before the offering. The Company received proceeds of approximately $135.1 million, net of expenses, which were used to fund a portion of the Company's 2008 capital expenditure program.

In September 2007, the Company sold 1.8 million shares of its common stock to certain qualified investors in a registered direct offering at a price of $41.40 per share. The number of shares sold was approximately 6.8% of the Company's fully diluted shares outstanding before the offering. The Company used substantially all of the net proceeds to fund in part its capital expenditure program, including its drilling and leasing programs in the Barnett Shale and appraisal well drilling in the North Sea. Pending those uses, the Company used a portion of the net proceeds of approximately $72.0 million to repay $54 million of outstanding borrowings under the Senior Credit Facility.

In July 2006, the Company sold 1.35 million shares of the Company's common stock to institutional investors at a price of $26.00 per share in a private placement. The number of shares sold was approximately 5.4% of the Company's fully diluted shares outstanding before the offering. The net proceeds, after deducting placement agents' fees but before paying offering expenses, of approximately $33.7 million were principally used to fund a portion of the Company's 2006 capital expenditures program.

Stock Incentive Plan

In June 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the "Incentive Plan"), which authorizes the granting of stock options and restricted stock awards to directors, employees and independent contractors. The Company may grant awards of up to 2,800,000 shares under the Incentive Plan and has granted options, restricted stock and restricted stock units covering 2,559,658 shares through December 31, 2008, net of forfeitures.

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Stock Options. Prior to 2006, the Company issued stock options that become exercisable ratably over a three year period and expire ten years from the date of the grant. The table below summarizes stock option activity for the three years ended December 31, 2008:

	Shares	Weighted-Average Exercise Prices	Weighted-Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)
For the Year Ended December 31, 2006				
Outstanding, beginning of period	1,025,204	$ 5.53		
Granted	-	-		
Exercised	(101,800)	5.91		
Forfeited	(32,335)	12.63		
Outstanding, end of period	891,069	$ 5.25		
Exercisable, end of period	834,799	$ 4.65		
For the Year Ended December 31, 2007				
Outstanding, beginning of period	891,069	$ 5.25		
Granted	-	-		
Exercised	(124,148)	8.30		
Forfeited	(5,000)	16.35		
Outstanding, end of period	761,921	$ 4.67		
Exercisable, end of period	731,808	$ 4.23		
For the Year Ended December 31, 2008				
Outstanding, beginning of period	761,921	$ 4.67		
Granted	-			
Exercised	(65,400)	4.01		
Forfeited	(10,667)	6.72		
Outstanding, end of period	685,854	$ 4.71	3.0	$ 7.0
Exercisable, end of period	685,854	$ 4.71	3.0	$ 7.0

At December 31, 2008, the Company had no unrecognized expense associated with nonvested stock option awards. The total intrinsic value (current market price less the option strike price) of options exercised during the years ended December 31, 2008, 2007 and 2006 was $2.5 million, $4.5 million and $2.5 million, respectively, and the Company received $0.3 million, $1.0 million and $0.6 million in cash in connection with these exercises for the years ended December 31, 2008, 2007 and 2006, respectively.

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Restricted Stock Shares. The Company began issuing shares of restricted common stock in 2005 and restricted stock units in 2008. A restricted stock unit is an obligation to issue shares of stock upon their vesting. Unvested restricted stock awards are deemed issued and outstanding based on the terms of the award. Restricted stock shares and units are accounted for as deferred compensation based on the closing price of the Company's common stock on the grant date and are amortized to stock-based compensation expense over the vesting period (generally one to three years). The unamortized deferred compensation obligation amounted to $7.8 million as of December 31, 2008 and will be amortized to expense over the next three years. The table below summarizes restricted stock activity for the three years ended December 31, 2008:

	Shares/ Units	Weighted-Average Price
Unvested restricted stock shares at December 31, 2005	87,585	$ 15.98
Granted	303,968	27.42
Vested	(38,812)	17.35
Forfeited	(26,532)	23.31
Unvested restricted stock shares at December 31, 2006	326,209	25.87
Granted	132,719	40.26
Vested	(86,199)	25.13
Forfeited	(20,880)	31.21
Unvested restricted stock shares at December 31, 2007	351,849	31.15
Granted	215,469	35.43
Vested	(217,113)	28.65
Forfeited	(8,507)	42.00
Unvested restricted stock shares at December 31, 2008	341,698	$ 34.93

9. RELATED-PARTY TRANSACTIONS

Marcellus Shale Joint Venture. Effective as of August 1, 2008, a wholly-owned subsidiary Carrizo (Marcellus) LLC entered into a joint venture arrangement with Avista, a private equity fund. Under the terms of the joint venture, the Company and Avista each committed to contribute up to $150 million in cash and properties to acquire and develop acreage within an area of mutual interest located in the Marcellus Shale play, including the dedication of all of their respective Marcellus leasehold owned at the time of the formation of the joint venture.

The Company serves as operator of the joint venture with Avista under a joint operating agreement with Avista and provides all geotechnical, land, engineering and accounting support to the joint venture. The Company has also agreed to perform specified management services for the Avista affiliate that is the Company's partner in the joint venture on the same cost and reimbursement bases provided for in the joint operating agreement. An operating committee composed of one representative of each party provides overall supervision and direction of joint operations. Each representative has a vote equal to the participating interest in the properties and operations of the party it represents. Avista or its designee has the right to become a co-operator of the properties if all of its membership interests or substantially all of its assets are sold to an unaffiliated third party or if the Company defaults under the terms of any pledge of its interest in the properties.

Under the terms of the joint venture, each party committed to contribute up to $150 million in cash and properties to acquire and develop acreage in the Marcellus Shale play, including the dedication of all of its Marcellus Shale leasehold owned at the time of the formation of the joint. In connection with formation of the joint venture, Avista contributed certain leasehold interests (costing approximately $27.5 million) and agreed to fund 100% of the joint venture's next approximately $71.5 million of expenditures related to the Marcellus Shale play (the "Initial Cash Contribution"). After the Initial Cash Contribution has been funded by Avista, the parties will share all costs of joint venture operations in accordance with their participating interests, which the Company expects will generally be 50/50. As a result of Avista's obligation to fund the Initial Cash Contribution, the Company does not currently expect that it will be required to contribute any cash to fund capital and exploration expenditures in the Marcellus Shale during 2009.

Subject to specified exceptions, net cash flow from hydrocarbon production from the Marcellus joint venture properties and related sales proceeds, if the properties are sold, will be allocated first to the joint venture partners in proportion to their respective investments (with property dedications generally valued on a cost basis) until Avista has recovered its investment, then 100% to the Company until it recovers approximately $33.5 million, and thereafter in accordance with the parties' participating interests, which the Company expects will generally be 50/50. The Company has also agreed to jointly market Avista's share of the production from the properties with its own until the cash flows and sale proceeds are allocated in accordance with the parties' participating interests under the joint operating agreement. In addition to the Company's share in the production and sale proceeds from joint venture properties, the Company also acquired as part of the transaction (through a wholly-owned subsidiary) an interest in the Avista joint venture entity that entitles the Company to increasing percentages of the Avista entity's profits if that entity's members receive a return of their investment and specified internal rates of return on these investments are achieved.
The

Company's interest in the Avista entity provides consent rights only in limited, specified circumstances and generally does not entitle the Company to vote or participate in the management of the Avista entity, which is controlled by its members and affiliates.

As part of the transaction, and subject to certain exceptions, the parties agreed to enter into an area of mutual interest covering the Marcellus Shale play, wherein any lease, royalty or mineral rights acquired by one party within the area must be proportionately offered to the other on the same terms and conditions. The area of mutual interest will remain in place until the earliest to occur of the following events, at which time the area of mutual interest will only continue to apply to those areas where the joint venture is active: (1) December 31, 2010, (2) the date on which the parties' collective investment reaches $300 million, (3) upon Avista's request to be designated (or have its designee designated) as a co-operator of the properties in connection with the sale to an unaffiliated third party of all of its membership interests or substantially all of its assets and (4) upon the required designation of Avista (or its designee) as a co-operator of the properties in connection with the Company's default under the terms of any pledge of the Company's interest in the properties.

The parties have limited rights to transfer their respective interests in the properties until the Initial Cash Contribution has been satisfied. After that time, each party's ability to transfer its interest in the joint venture to third parties is subject in most instances to preferential purchase rights for transfers of less than 10% of its interest in joint venture properties, or to "tag along" rights for most other transfers. Avista's tag along rights do not apply upon a change of control of Carrizo.

Steven A. Webster, Chairman of the Company's Board of Directors, serves as Co-Managing Partner and President of Avista Capital Holdings, LP, which has the ability to control Avista. As previously disclosed, the Company has been a party to prior arrangements with affiliates of Avista Capital Holdings, LP in respect of the Company's investment in Pinnacle Gas Resources, Inc.

Avista Land Bank Agreement. In order to expand the Company's lease acquisition efforts in the Marcellus Shale play, the
Company elected to enter into a lease option agreement effective August 1, 2008 with Avista, the Company's partner in the Marcellus Shale play. See "Business and Properties—Significant Project Areas; Marcellus Shale Area." The terms and conditions of the lease purchase option arrangement with Avista were generally consistent with lease option arrangements that the Company has traditionally entered into with other third parties. Avista paid approximately $27.5 million for the oil and gas leases under the lease purchase option agreement and subsequently contributed these properties at their cost to the Company's Marcellus joint venture, effective August 1, 2008.

Other Transactions. The Company's Chairman of the Board, Mr. Steven A. Webster serves on the Board of Directors for Basic Energy Services, Inc., Grey Wolf Inc., Hercules Offshore L.L.C., Pinnacle Gas Resources, Inc. and Geokinetics, Inc., the parent of Quantum Geophysical, Inc., and previously served on the Board of Directors of each of Goodrich Petroleum and Brigham Exploration. The Company's Chief Executive Officer, Mr. S.P. Johnson serves as member on the Board of Directors of Basic Energy Services, Inc. and Pinnacle Gas Resources, Inc. Mr. Thomas L. Carter, Jr., a member of the Company's Board of Directors, is the Chief Executive Officer and owner of a significant interest in Black Stone Minerals Company, L.P. ("Black Stone Minerals"). Mr. F. Gardner Parker serves on the Board of Directors for Hercules Offshore, L.L.C. Due to these relationships, the Company has deemed these companies to be related parties. The Company incurred the following costs with these related parties:

Year Ended December 31,		
2008	2007	2006
(In millions)		
$ 0.4	$ 0.2	$ 0.5

Basic Energy Services			
Grey Wolf Drilling	7.1	6.8	6.7
Brigham Exploration(1)	-	(0.3)	(0.6) (2)
Quantum Geophysical Inc.	-	-	0.2
Hercules Offshore, L.L.C.	3.2	-	-

(1) At the end of the first quarter of 2007, Mr. Webster resigned from the Board of Directors of Goodrich Petroleum and Brigham Exploration. As such, these companies are no longer deemed related parties after the first quarter of 2007.

(2) Includes $1.2 million of net revenues related to wells operated by Brigham Exploration and $0.6 million of net revenues related to wells operated by the Company.

It is management's opinion that the transactions with these entities were executed at prevailing market rates. At December 31, 2008 and 2007, the Company had an outstanding related-party net receivable balance of approximately $66,000 and net payable balance of approximately $22,000, respectively.

In January 2006, the Company acquired certain oil and gas leases for approximately $1.1 million from Black Stone Acquisitions Partners I L.P., the general partner of which is Black Stone Minerals. Black Stone Acquisition Partners also retains

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a royalty interest in the acquired leases, which are located in Mississippi. During 2007, the Company acquired additional acreage located in Texas from Black Stone for approximately $0.2 million. During 2008, the Company did not acquire any additional acreage from Black Stone. The terms and conditions of the lease agreement with Black Stone Acquisitions Partners I L.P. and Black Stone are generally consistent with the lease agreements that the Company has entered into with other third parties. Additionally, the Company operates four producing wells in which affiliates of Black Stone Minerals hold a royalty interest for which the Company paid approximately $0.6 and $0.8 million in 2008 and 2007, respectively.

Due to the limited capital available at times to fund all of the Company's ongoing lease acquisition efforts in the Barnett Shale, Marcellus Shale, Fayetteville Shale and other plays, the Company elects from time to time to enter into various lease purchase option agreements with a number of third parties, including, in 2006, Steven A. Webster, the Company's Chairman of the Board. The lease purchase option arrangement with Mr. Webster expired at the end of 2006. The terms and conditions of the lease purchase option arrangement with Mr. Webster were consistent with the lease purchase option arrangements the Company entered into with unrelated third parties. These lease purchase option arrangements provide the Company the option to purchase leases from the counterparties, over an option period, generally 90 days, for the counterparties' original cost of the leases plus an option fee. The Company paid Mr. Webster fees totaling approximately $250,000 in 2006. In accordance with the lease purchase option agreement, the Company also assigned to Mr. Webster an overriding royalty interest on any lease the Company acquired from Mr. Webster under the lease purchase option agreement with him, which overriding royalty interest varied from one-half to one percent of 8/8ths, proportionally reduced to the actual net interest in any given lease acquired from Mr. Webster. We paid Mr. Webster approximately $430 and $50 in 2008 and 2007, respectively, in overriding royalties under these arrangements.

See Note 3 for a discussion of the investment in Pinnacle.

Mr. Webster is also Co-Managing Partner and President of Avista Capital Holdings, L.P. and is therefore a related party to the Pinnacle transaction.

10. DERIVATIVE FINANCIAL INSTRUMENTS

The Company enters into swaps, options, collars and other derivative contracts to manage price risks associated with a portion of anticipated future oil and natural gas production. While the use of derivative financial instruments limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. Under these agreements, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at termination, expiration or exchanged for physical delivery contracts. The Company enters into the majority of its derivative transactions with two counterparties and netting agreements are in place with those counterparties. The Company does not obtain collateral to support the agreements but monitors the financial viability of counterparties and believes its credit risk is minimal on these transactions. In the event of nonperformance, the Company would be exposed to price risk. The Company has some risk of accounting loss since the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the financial instruments. The Company used interest rate swap agreements to manage the Company's exposure to interest rate fluctuations on borrowings under the Second Lien Credit Facility, which was terminated during 2008.

The Company accounts for its oil and natural gas derivatives and interest rate swap agreements as non-designated hedges. These derivatives are marked-to-market at each balance sheet date and the unrealized gains (losses) are reported in the net gain (loss) on derivatives in Other Income and Expenses in the Consolidated Statement of Operations. In addition, the Company records the realized gains (losses) associated with the cash settlements of these derivative instruments in the net gain (loss) on derivatives in Other Income and Expenses in the Consolidated

Statement of Operations. For the years ended December 31, 2008, 2007 and 2006, the Company recorded the following related to its derivatives:

	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Realized gain (loss)			
Natural gas and oil derivatives	$ 0.6	$ 5.8	$ 6.8
Interest rate swaps	(1.2)	0.2	1.0
Gain (loss) on interest rate swap sell down	(3.3)	-	0.6
	(3.9)	6.0	8.4
Unrealized gain (loss)			
Natural gas and oil derivatives	38.6	(4.6)	8.7
Interest rate swaps	2.8	(2.8)	(0.6)
	41.4	(7.4)	8.1
Net Gain (Loss) on Derivatives	$ 37.5	$ (1.4)	$ 16.5

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At December 31, 2008 the Company had the following outstanding derivative positions:

	Natural Gas Swaps		Natural Gas Collars			Basis Differential Swaps(2)	
Quarter	Mmbtus	Average Fixed Price(1)	MMBtus	Average Floor Price(1)	Average Ceiling Price(1)	MMBtus	Price
First Quarter 2009	2,803,000	$ 6.13	2,520,000	$ 7.37	$ 9.10	310,000	$ 0.31
Second Quarter 2009	1,547,000	5.40	2,548,000	7.12	8.85	-	-
Third Quarter 2009	-	-	2,576,000	7.16	8.88	920,000	0.31
Fourth Quarter 2009	-	-	2,576,000	7.17	8.90	-	-
First Quarter 2010	-	-	1,620,000	7.92	9.63	-	-
Second Quarter 2010	-	-	1,638,000	7.18	8.89	-	-
Third Quarter 2010	-	-	1,656,000	7.35	9.06	-	-
Fourth Quarter 2010	-	-	1,656,000	7.45	9.16	-	-
First Quarter 2011	-	-	450,000	9.70	11.70	-	-
Second Quarter 2011	-	-	455,000	8.25	10.25	-	-
Third Quarter 2011	-	-	460,000	8.65	10.65	-	-
Fourth Quarter 2011	-	-	460,000	8.85	10.85	-	-
First Quarter 2012	-	-	455,000	9.55	11.55	-	-
Second Quarter 2012	-	-	455,000	8.35	10.35	-	-

TOTAL	4,350,000	19,525,000	1,230,000

Quarter	Bbls	Oil Collars Average Floor Price(3)	Average Ceiling Price(3)
First Quarter 2009	9,000	$ 131.65	$ 151.65
Second Quarter 2009	9,100	131.40	151.40
Third Quarter 2009	9,200	130.85	150.85
Fourth Quarter 2009	9,200	130.35	150.35
TOTAL	36,500		

(1) Based on Houston Ship Channel (HSC) and WAHA spot prices.

(2) Basis differential swaps cover the price differential for natural gas between NYMEX and HSC.

(3) Based on West Texas intermediate index prices.

The fair value of the outstanding oil and natural gas derivatives at December 31, 2008 and 2007 was an asset of $38.7 million and $0.1 million, respectively.

At December 31, 2008, approximately 69% of the Company's open natural gas hedges were with Credit Suisse, and the remaining 31% were with Shell Energy North America (US), L.P. The open oil hedge positions were all arranged with Credit Suisse.

During the third quarter of 2005, the Company entered into interest rate swap agreements with respect to amounts outstanding under the Second Lien Credit Facility. These arrangements were designed to manage the Company's exposure to interest rate fluctuations during the period beginning January 1, 2006 through June 30, 2007 by effectively exchanging existing obligations to pay interest based on floating rates for obligations to pay interest based on fixed LIBO rates. In connection with an amendment to the Second Lien Credit Facility, the remaining open derivative positions on interest rate swaps were cash settled, resulting in a realized gain of $0.6 million on December 21, 2006.

During the first and second quarter of 2007, the Company entered into interest swap agreements covering amounts outstanding under the Second Lien Credit Facility. These arrangements were designed to manage the Company's exposure to interest rate fluctuations through December 31, 2008 by effectively exchanging existing obligations to pay interest based on floating rates with obligations to pay interest based on fixed LIBOR. In connection with the Company's repayment of borrowings under and termination of the Second Lien Credit Facility, following the issuance of the Convertible Senior Notes in May 2008, the remaining open derivative positions on interest rates were cash settled, resulting in a realized loss of $3.3 million on the remaining positions covering the period from May 28, 2008 to December 31, 2008.

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11. FAIR VALUE MEASUREMENTS

Effective January 1, 2008, the Company adopted FASB Statement No. 157, “Fair Value Measurements” (“SFAS No. 157”), which defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements. The implementation of SFAS No. 157 did not cause a change in the method of calculating fair value of assets or liabilities, with the exception of incorporating a measure of the Company’s own nonperformance risk or that of its counterparties as appropriate, which was not material. The primary impact from adoption was additional disclosures.

The Company elected to implement SFAS No. 157 with the one-year deferral permitted by FASB Staff Position No. FAS 157-2, “Effective Date of FASB Statement No. 157,” issued February 2008, which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis.

SFAS No. 157 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1 — Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2 — Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3 — Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

The following table presents information about the Company’s assets and liabilities measured at fair value on a recurring basis as of December 31, 2008, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value:

	Level 1	Level 2	Level 3	Total
		(in thousands)		
Assets:				
Investment in Pinnacle Gas Resources, Inc.	$ 751	$ -	$ -	$ 751
Oil and natural gas derivatives	-	38,667	-	38,667
Total	$ 751	$ 38,667	$ -	$ 39,418

Oil and natural gas derivatives are valued by a third-party consultant using valuation models that are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Effective January 1, 2008 the Company adopted SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of SFAS No. 115” (“SFAS No. 159”). SFAS No. 159 allows companies to choose to measure financial instruments and other items at fair value that previously were not required to be measured at fair value. The Company elected not to present any financial instruments or other items at fair value that were not required to be presented at fair value prior to the adoption of SFAS No. 159.

12. SUPPLEMENTARY FINANCIAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

The following disclosures provide unaudited information required by SFAS No. 69, “Disclosures About Oil and Gas Producing Activities.”

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Costs Incurred

Costs incurred in oil and natural gas property acquisition, exploration and development activities are summarized below:

	Year Ended December 31, 2008	2007	2006
	(In thousands)		
Property acquisition costs			
Unproved	$ 271,618	$ 54,467	$ 48,409
Proved	-	-	-
Exploration costs	235,382	144,402	104,473
Development costs	49,626	30,562	37,889
Asset retirement obligation	630	1,961	299
Total costs incurred(1)	$ 557,256	$ 231,392	$ 191,070

(1) Excludes capitalized interest on unproved properties of $20.5 million, $11.7 million and $10.0 million for the years ended December 31, 2008, 2007 and 2006, respectively, and includes capitalized overhead of $7.8 million, $4.5 million and $3.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Oil And Natural Gas Reserves

Proved reserves are estimated quantities of 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 proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Proved oil and natural gas reserve quantities at December 31, 2008, 2007 and 2006, and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company Petroleum Engineers, LaRoche Petroleum Consultants, Ltd., and Fairchild & Wells, Inc. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

The Company's net ownership interests in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves, all of which are located in the continental United States, are summarized below:

	Millions of Cubic Feet of Natural Gas at December 31, 2008	2007	2006
Proved developed and undeveloped reserves —			
Beginning of year	248,433	166,798	103,058
Purchase of oil and natural gas properties in place	-	-	-

Discoveries and extensions	146,189	131,836	91,090
Revisions	21,661	(34,017)	(11,026)
Sales of oil and gas properties in place	-	(142)	(6,148)
Production	(23,547)	(16,042)	(10,176)
End of year	392,736	248,433	166,798
Proved developed reserves at beginning of year	122,598	73,912	44,681
Proved developed reserves at end of year	216,229	122,598	73,912

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	Thousands of Barrels of Oil, Condensate and Natural Gas Liquids at December 31,		
	2008	2007	2006
Proved developed and undeveloped reserves -			
Beginning of year	16,531	7,195	7,925
Purchase of oil and natural gas properties in place	-	796	-
Discoveries and extensions	2,088	3,536	359
Revisions	36	5,245	(823)
Sales of oil and gas properties in place	-	-	(11)
Production	(347)	(241)	(255)
End of year	18,308	16,531	7,195
Proved developed reserves at beginning of year	6,536	1,638	1,343
Proved developed reserves at end of year	7,869	6,536	1,638

During 2008, 2007 and 2006, the Company reported considerable discoveries and extensions to the Company's natural gas reserves primarily due to the Company's drilling program in the Barnett Shale play. In 2007, the Company recorded significant oil discoveries and extensions due to drilling and development activity in the Barnett Shale region and additional formation evaluation in the Camp Hill field. In 2008, the Company included a large natural gas revision primarily due to actual performance of wells in the Barnett Shale. In 2007, the Company reported a large natural gas revision largely attributable to the reclass of natural gas liquids, previously presented as natural gas equivalents, to the reserve category of oil and condensate. During 2007, the Company increased production of natural gas liquids as a result of an increase in processed gas sales. In prior years, any natural gas liquid production was deemed immaterial. The Company reported significant downward revisions to its natural gas reserves in 2006 due to a decline in natural gas prices.

Standardized Measure

The standardized measure of discounted future net cash flows relating to the Company's ownership interests in proved oil and natural gas reserves as of year-end is shown below:

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Future cash inflows	$ 2,501,460	$ 2,663,281	$ 1,356,118
Future oil and natural gas operating expenses	868,027	618,479	350,076
Future development costs	315,837	277,070	193,245
Future income tax expenses	407,897	394,569	202,685
Future net cash flows	909,699	1,373,163	610,112
	468,445	710,793	311,401

Less 10% annual discount for estimating timing of cash flows			
Standard measure of discounted future net cash flows	$ 441,254	$ 662,370	$ 298,711

Future cash flows are computed by applying year-end prices of oil and natural gas to year-end quantities of proved oil and natural gas reserves. Average prices used in computing year end 2008, 2007 and 2006 future cash flows were $29.61, $74.45 and $54.73 for oil, respectively, and $4.99, $5.99 and $5.77 for natural gas, respectively. Future operating expenses and development costs are computed primarily by the Company's petroleum engineers by estimating the expenditures to be incurred in developing and producing the Company's proved oil and natural gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions.

Future income taxes are based on year-end statutory rates, adjusted for the tax basis of oil and gas properties and available applicable tax assets. A discount factor of 10% was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair market value of the Company's oil and natural gas properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

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Change in Standardized Measure

Changes in the standardized measure of future net cash flows relating to proved oil and natural gas reserves are summarized below:

	Year Ended December 31, 2008	2007	2006
	(In thousands)		
Changes due to current-year operations -			
Sales of oil and natural gas, net of oil and natural gas operating expenses	$ (171,944)	$ (101,127)	$ (72,077)
Extensions and discoveries	228,037	340,503	139,657
Purchases of oil and gas properties	-	20,625	-
Changes due to revisions in standardized variables			
Prices and operating expenses	(371,924)	142,126	(71,814)
Income taxes	22,307	(89,158)	16,422
Future development costs, net	11,052	57,126	64,166
Revision of quantities	44,643	(7,614)	(43,362)
Sales of reserves in place	-	(351)	(15,518)
Accretion of discount	83,931	38,718	40,423
Production rates, timing and other	(67,218)	(37,189)	(58,527)
Net change	(221,116)	363,659	(630)
Beginning of year	662,370	298,711	299,341
End of year	$ 441,254	$ 662,370	$ 298,711

Sales of oil and natural gas, net of oil and natural gas operating expenses, are based on historical pretax results. Sales of oil and natural gas properties, extensions and discoveries, purchases of minerals in place and the changes due to revisions in standardized variables are reported on a pretax discounted basis, while the accretion of discount is presented on a before tax basis.

13. SUPPLEMENTAL QUARTERLY FINANCIAL DATA (UNAUDITED)

The sum of the individual quarterly basic and diluted earnings (loss) per share amounts may not agree to year-to-date basic and diluted earnings (loss) per share amounts as a result of each period's computation being based on the weighted average number of common shares outstanding during the period.

2008	First	Second	Third	Fourth
	(In thousands, except per share amounts)			
Revenues	$ 53,560	$ 67,388	$ 58,527	$ 37,202
Costs and expenses, net	58,856	80,168 (1)	(7,188) (1)	129,888 (2)

Net income (loss)	$ (5,296)	$ (12,780)	$ 65,715	$ (92,686)
Basic net income (loss) per share	$ (0.18)	$ (0.42)	$ 2.14	$ (3.01)
Diluted net income (loss) per share	$ (0.18)	$ (0.42)	$ 2.11	$ (3.01)

2007	First	Second	Third	Fourth
	(In thousands, except per share amounts)			
Revenues	$ 22,612	$ 32,891	$ 30,305	$ 39,981
Costs and expenses, net	25,157	24,754	26,072	34,337
Net income (loss)	$ (2,545)	$ 8,137	$ 4,233	$ 5,644
Basic net income (loss) per share	$ (0.10)	$ 0.31	$ 0.16	$ 0.20
Diluted net income (loss) per share	$ (0.10)	$ 0.31	$ 0.16	$ 0.20

(1) Includes a before tax $48.2 million loss and $77.7 million gain associated with derivatives for the second and third quarter, respectively.

(2) Includes a before tax $178.5 million impairment of oil and gas properties.

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SIGNATURES

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

CARRIZO OIL & GAS, INC.

By: /s/Paul F. Boling
Paul F. Boling
Chief Financial Officer, Vice President,
Secretary and Treasurer

Date: August 17, 2009