CARRIZO OIL & GAS INC
Form 10-K/A
June 12, 2006

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

FORM 10-K/A
Amendment No. 2 to Form 10-K filed March 31, 2005

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2004
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(g) of the Act:
COMMON STOCK, $.01 PAR VALUE

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

YES [X] NO [ ]

Indicate by check mark 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 an accelerated filer.

YES [X] NO [ ]

At June 30, 2004, the aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $159.4 million based on the closing price of such stock on such date of $10.21.

At January 31, 2005, the number of shares outstanding of the registrant's Common Stock was 22,456,007.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 2005 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, 2004.

EXPLANATORY NOTE

We hereby amend the following items of the Form 10-K of Carrizo Oil & Gas, Inc. ("Carrizo," the "Company" or "We") for the year ended December 31, 2004 (the "Form 10-K"), which was originally filed on March 31, 2005: (1) Part I - Item 1 "Business;" (2) Part I - Item 2 "Properties;" (3) Part II - Item 6 "Selected Financial Data;" (4) Part II - Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations;" (5) Part II - Item 8 "Financial Statements and Supplementary Data;" (6) Part II - Item 9A "Controls and Procedures;" and Part IV - Item 15 "Exhibit and Financial Statement Schedules." No other sections were affected.

This Amendment No. 2 does not modify or update the disclosures in the Form 10-K in any way other than as required to reflect the amendments as described above and set forth below.

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PART I

ITEM 1. AND ITEM 2. BUSINESS AND PROPERTIES

GENERAL

Carrizo Oil & Gas, Inc. ("Carrizo," the "Company" or "We") is an independent energy company engaged in the exploration, development and production of natural gas and oil. Our current operations are focused in proven, producing natural gas and oil geologic trends along the onshore Gulf Coast area in Texas and Louisiana, primarily in the Miocene, Wilcox, Frio and Vicksburg trends, and, since mid-2003, in the Barnett Shale area in North Texas. Our other interests include properties in East Texas, and a coalbed methane investment in the Rocky Mountains. Additionally, in 2003 we obtained licenses to explore in the U.K. North Sea.

We have traditionally grown our production through our 3-D seismic-driven exploratory drilling program. Our compound production growth rate for the period December 31, 1999 through December 31, 2004 on an annualized basis was 14%. From our inception through December 31, 2004, we participated in the drilling of 373 wells (119.7 net) with a success rate of approximately 70% in our onshore Gulf Coast area and 100% in the Barnett Shale area in North Texas. Exploratory wells accounted for 86% of the total wells we drilled. Our total proved reserves as of December 31, 2004 were an estimated 109.3 Bcfe with a PV-10 Value of $208.6 million. During 2004, we added a record 47.3 Bcfe to proved reserves and produced a record 8.3 Bcfe. We have traditionally financed the majority of our drilling activity through internal cash flow generated primarily from oil and natural gas production sales revenue.

As a main component of our business strategy, we have acquired licenses for over 9,200 square miles of 3-D seismic data for processing and evaluation. Historically, we either (1) sought to acquire seismic permits from landowners that included options to lease the acreage prior to conducting proprietary surveys or (2) participated in 3-D group shoots in which we typically sought to obtain leases or farm-ins rather than lease options. Since 2001, we have been able to increase the size of our 3-D seismic holdings in our onshore Gulf Coast area by approximately 84% to over 7,500 square miles, in large part by taking advantage of very favorable pricing available for nonproprietary data from libraries of seismic companies. Since 2003, we have also grown our 3-D seismic holdings in the Barnett Shale area to over 123 square miles.

One of our primary strengths is the experience of our management and technical staff in the development, processing and analysis of this 3-D seismic data to generate and drill natural gas and oil prospects. Our technical and operating employees have an average of over 20 years of industry experience, in many cases with major and large independent oil and gas companies, including Shell Oil, Ocean Energy, ARCO, Conoco, Burlington Resources, Vastar, Pennzoil and Tenneco. Analyzing and reprocessing our 3-D seismic database, our highly qualified technical staff is continually adding to and refining our substantial inventory of drilling locations.

We believe that our utilization of large-scale 3-D seismic surveys and related technology allows us to create and maintain a multiyear inventory of high-quality exploration prospects in the Gulf Coast area. As of December 31, 2004, we had 159,496 gross acres in Texas and Louisiana under lease or lease option (all references to acres under lease in this Form 10-K/A also include lease option acres unless otherwise indicated), including 109,129 net acres in our onshore Gulf Coast area, predominantly all covered by 3-D seismic data, and 44,835 gross acres in our Barnett Shale area. On this leased acreage, we have identified: (1) over 155 potential exploratory drilling locations in our onshore Gulf Coast area, including over 78 additional extension opportunities, depending on the success of our initial drilling activities on those locations and (2) over 200 potential exploratory and development horizontal drilling locations in the Barnett Shale area. The vast majority of our 3-D seismic data covers productive geological trends in our onshore Gulf Coast area, where we have made 223 completions as a result of our utilization and evaluation of this data.

In our onshore Gulf Coast area, most of our drilling targets prior to 2000 were shallow (from 4,000 to 7,000 feet), normally pressured reservoirs that generally involved moderate cost (typically $0.3 million to $0.4 million per completed well) and risk. Since then, the depth of many of the wells that we have drilled, as well as our current drilling prospects, are deeper, over-pressured targets with greater economic potential but generally higher cost (typically $1.0 million to $4.0 million per completed well) and risk. We seek to sell a portion of these deeper prospects to reduce our exploration risk and financial exposure while retaining significant upside potential. More recently, we have begun to retain larger percentages of, and increased our exposure to, higher cost, higher potential wells. We used a portion of the $23.3 million of net proceeds from our February 2004 public offering to increase our percentage of and exposure to these wells.

In mid-2003, we became active in the Barnett Shale area in North Texas (primarily in the Tarrant, Parker, Denton, Johnson, Hill and Erath counties). Improvements in fracture techniques in recent years have dramatically changed the economics of producing reserves in the Barnett Shale, which is now considered one of the most active natural gas plays in North America. The reserve profile

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from the typical productive wells we drill in the Barnett Shale area is noteably longer-lived compared to the typical reserve profile from our wells drilled in our onshore Gulf Coast area.

We are drilling both vertical and horizontal wells in the Barnett Shale area. Typical costs to drill and complete are $550,000 for vertical wells and $1.5 to $2.5 million for horizontal wells. Our Barnett wells generally have target depths of 6,000 to 8,000 feet. During 2004, we held an average 40 percent, usually non-operated, working interest participation in the Barnett wells drilled. For wells drilled in 2005, we plan to retain larger working interests, generally ranging between 50 and 100 percent, and to operate a majority of the wells drilled.

Accordingly, we believe that continued development of producing reserves in the Barnett Shale play will have the potential to lengthen our overall average reserve life and, on balance, add a long-lived cash flow stream to help fund our future capital exploration and development program. In our Barnett Shale area through December 31, 2004, we had acquired approximately 30,717 net acres, drilled 33 gross (13.7 net) wells and increased our total proved reserves in the Barnett Shale area to 31.7 Bcfe. As of March 1, 2005, our current net production in the Barnett Shale area was estimated at 4.0 MMcfe/d and we had increased our leasehold and option position to over 35,000 net acres.

As of December 31, 2004, we operated 92 producing oil and gas wells, which accounted for 50% of the onshore Gulf Coast area producing wells in which we had an interest.

During 2001, through our wholly-owned subsidiary, CCBM, Inc. (“CCBM”), we acquired 50% of the working interests held by Rocky Mountain Gas, Inc. (“RMG”) in approximately 107,000 net mineral acres prospective for coalbed methane located in the Powder River Basin in Wyoming and Montana. Subsequently, we participated in the acquisition and/or drilling of 77 gross wells (21 net) before jointly contributing with RMG a majority of our coalbed methane property interests and operations into a newly, formed company, Pinnacle Gas Resources, Inc. (“Pinnacle”). In exchange for the assets contributed, CCBM and RMG each received a 37.5% common stock ownership in Pinnacle and options to purchase additional common stock, or on a fully diluted basis, CCBM and RMG each received a 26.9% interest in Pinnacle. Simultaneously with the contribution of these assets, Credit Suisse First Boston Private Equity entities (the “CSFB Parties”) contributed $17.6 million cash along with a future cash commitment to Pinnacle in exchange for common stock, warrants and preferred stock equal to a 46.2% interest on a fully diluted basis. In February 2004, the CSFB Parties contributed additional funds of $11.8 million into Pinnacle to continue funding the 2004 development program which increased their ownership to 66.7% on a fully diluted basis should we and RMG each elect not to exercise our available options. See “The Pinnacle Transaction” for more information on this transaction.

Historically, the business operations and development program of Pinnacle has not required us to provide any further capital infusion. In March 2005, Pinnacle acquired additional undeveloped acreage with an undisclosed company which would also significantly increase Pinnacle’s development program budget in 2005. Accordingly, CCBM and the other Pinnacle shareholders have the option to participate in the equity contribution into Pinnacle needed to finance the acquisition and the related development program in 2005. Should we elect to maintain our proportionate ownership interest in Pinnacle, we estimate that we would be required to contribute $2.5 million. If CCBM opts not to contribute any or all of its share of the equity contribution, its fully diluted ownership in Pinnacle would be reduced. CCBM plans to contribute $2.5 million in April 2005, its share of the equity capital needed to close the acquisition and fund part of the additional development program. There can be no assurance regarding CCBM’s level of participation in future equity contributions needed, if any. On March 29, 2005, we elected to participate and contribute $2.5 million to Pinnacle in exchange for warrants and preferred stock.

In addition to our interest in Pinnacle, CCBM has maintained interests in approximately 162,489 gross acres at the end of 2004 in the Castle Rock coalbed methane project area in Montana and the Oyster Ridge project area in Wyoming. During 2004, we opted to exercise our right to cancel one-half of the remaining note payable to RMG, or approximately $300,000, in exchange for assigning one-half of our mineral interest in the Oyster Ridge leases to RMG.

Certain terms used herein relating to the oil and natural gas industry are defined in “Glossary of Certain Industry Terms” below.

BUSINESS STRATEGY

Growth Through the Drillbit

Our objective is to create shareholder value through the execution of a business strategy designed to capitalize on our strengths. Key elements of our business strategy include:

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· Grow Primarily Through Drilling. We are pursuing an active technology-driven exploration drilling program. We generate exploration prospects through geological and geophysical analysis of 3-D seismic and other data. Our ability to successfully define and drill exploratory prospects is demonstrated by our exploratory drilling success rate in the onshore Gulf Coast area of 84% over the last three years and a 100% drilling success rate in our Barnett Shale area since inception in 2003. During 2005, we are drilling or plan to drill approximately 34 wells (14.4 net) in the onshore Gulf Coast area and 37 wells (24.0 net) in the Barnett Shale area. We have planned approximately $85.0 to $90.0 million for capital expenditures in 2005, $70.0 million of which we expect to use for drilling activities in the onshore Gulf Coast and Barnett Shale areas.

· Focus on Prolific and Industry-Proven Trends. We focus our activities both in the prolific onshore Gulf Cost area where our management, our technical staff and our field operations teams have significant prior experience and in the industry-proven Barnett Shale trend in which our wells have generally longer-lived reserves. Although we have broadened our areas of operations to include the Rocky Mountains and the U.K. North Sea, we plan to focus a majority of our near-term capital expenditures in the onshore Gulf Coast area, where we believe our accumulated data and knowledge base provide a competitive advantage, and in the Barnett Shale area where we have acquired a significant acreage position and accumulated a large drillsite inventory.

· Aggressively Evaluate 3-D Seismic Data and Acquire Acreage to Maintain a Large Drillsite Inventory. We have accumulated and continue to add to a multiyear inventory of 3-D seismic and geologic data along the prolific producing trend of the onshore Gulf Coast area and industry-proven trend of the Barnett Shale area. In 2004, we added approximately 463 square miles of newly released 3-D and seismic data. We believe our utilization of large-scale 3-D seismic surveys and related technology provides us with the opportunity to maximize our exploration success in both the onshore Gulf Coast and Barnett Shale areas. As of December 31, 2004, we had accumulated licenses for approximately 9,200 square miles of 3-D seismic data and identified over 355 drilling locations and extension opportunities (comprised of 155 locations in the onshore Gulf Coast area, and approximately 200 locations in the Barnett Shale area) including 277 locations currently under lease or in the process of being leased (comprised of 77 locations in the onshore Gulf Coast area and 200 locations in the Barnett Shale area). We believe our use of 3-D seismic surveys reduces, but does not eliminate, the risk of drilling.

· Maintain a Balanced Exploration Drilling Portfolio. We seek to balance our drilling program between projects with relatively lower risk and moderate potential and drilling prospects that have relatively higher risk and substantial potential. We believe we have furthered this strategy through the expansion of the Barnett Shale operations in which our wells generally have longer-lived reserves and generally lower risk/lower reward than our average onshore Gulf Coast area wells. We will continue to expand our exploratory drilling portfolio, including lease acquisitions with exploration potential.

  · Manage Risk Exposure by Market Testing Prospects and Optimizing Working Interests. We seek to limit our financial and operating risks by varying our level of participation in drilling prospects with differing risk profiles and by seeking additional technical input and economic review from knowledgeable industry participants regarding our prospects. Additionally, we rely on advanced technologies, including 3-D seismic analysis, to better define geologic risks, thereby enhancing the results of our drilling efforts. The use of 3-D seismic analysis does not guarantee that hydrocarbons are present or, if present, that they can be recovered economically. We also seek to operate our projects in order to better control drilling costs and the timing of drilling.

· Retain and Incentivize a Highly Qualified Technical Staff. We employ 18 natural gas and oil professionals, including geophysicists, petrophysicists, geologists, petroleum engineers and production and reservoir engineers and technical support staff, who have an average of over 20 years of experience. This level of expertise and experience gives us an in-house ability to apply advanced technologies to our drilling and production activities, including our extensive experience in fracturing and horizontal drilling technologies. Our technical staff is granted stock options and participates in an incentive bonus pool based on production resulting from our exploratory successes.

EXPLORATION APPROACH

In the onshore Gulf Coast area, our exploration strategy has generally been to accumulate large amounts of 3-D seismic data along primarily prolific, producing trends after obtaining options to lease areas covered by the data. In the case of our Barnett Shale area, our exploration strategy has been to accumulate significant leasehold positions in the proximity of known or emerging pipeline infrastructures, followed by the acquisition and processing of 3-D seismic data. We use 3-D seismic data to identify or evaluate

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prospects before drilling the prospects that fit our risk/reward criteria. We typically seek to explore in locations within our areas of expertise that we believe have (1) longer-lived, reserve-proven trends, such as the Barnett Shale trend, (2) numerous accumulations of normally pressured reserves at shallow depths and in geologic traps that are difficult to define without the interpretation of 3-D seismic data or (3) the potential for large accumulations of deeper, over-pressured reserves.

As a result of the increased availability of economic onshore 3-D seismic surveys and the improvement and increased affordability of data interpretation technologies, we have relied almost exclusively on the interpretation of 3-D seismic data in our exploration strategy. We generally do not invest any substantial portion of the drilling costs for an exploration well without first interpreting 3-D seismic data. The principal advantage of 3-D seismic data over traditional 2-D seismic analysis is that it affords the geoscientist the ability to interpret a three dimensional cube of data as compared to interpreting between widely separated two dimensional vertical profiles. Consequently, the geoscientist is able to more fully and accurately evaluate prospective areas, improving the probability of drilling commercially successful wells in both exploratory and development drilling.

Even in the relatively lower-risk, reserve-proven trends, such as the Barnett Shale trend, 3-D seismic data interpretation is instrumental in our exploration approach, significantly reducing geologic risk and allowing optimized reserve development.

Historically, we sought to obtain large volumes of 3-D seismic data by participating in large seismic data acquisition programs either alone or pursuant to joint venture arrangements with other energy companies, or through “group shoots” in which we shared the costs and results of seismic surveys. By participating in joint ventures and group shoots, we were able to share the up-front costs of seismic data acquisition and interpretation, thereby enabling us to participate in a larger number of projects and diversify exploration costs and risks. Most of our operations are conducted through joint operations with industry participants.

We have also participated in 3-D data licensing swaps, whereby we transfer license rights to certain proprietary 3-D data we own in exchange for license rights to other 3-D data within our areas, thus allowing us to obtain access to additional 3-D data within our onshore Gulf Coast area at either minimal or no out-of-pocket cash cost. Since 2001, we also have made significant purchases of 3-D data from the libraries of seismic companies at favorable pricing.

In more recent years, we have focused less on conducting proprietary 3-D surveys and have focused instead on (1) the continual interpretation and evaluation of our existing 3-D seismic database and the drilling of identified prospects on such acreage and (2) the acquisition of existing non-proprietary 3-D data at reduced prices, in many cases contiguous to or near existing project areas where we have extensive knowledge and subsequent acquisition of related acreage as we deem to be prospective based upon our interpretation of such 3-D data.

In late 2002, we acquired (or obtained the right to acquire) an additional 2,750 square miles of 3-D seismic data in our onshore Gulf Coast area. This data was primarily either recently merged and reprocessed data sets or former proprietary data sets newly released to industry. Specific operating areas to which new data were added as a result of the late 2002 data acquisition include (1) 450 square miles of newly reprocessed 3-D data to the Matagorda project area, (2) 167 square miles of newly released 3-D data to the Liberty Project area, (3) 239 square miles to the Wilcox project area and (4) 826 square miles of newly reprocessed 3-D data to the South Louisiana project area. These data acquisitions consist of existing nonproprietary data sets obtained from seismic companies at what we believe to be attractive pricing.

In late 2004, we entered into a 3-D seismic data acquisition program, which includes a joint venture partner that shares in a portion of the costs and results of the seismic shoot, covering an approximate 95 square mile area in our onshore Gulf Coast area located in Liberty County, Texas. This seismic survey project and the related processed data are expected to be completed in the second quarter of 2005. We also entered into a 3-D seismic data acquisition program in late 2004 to complete seismic shoots over significant acreage positions in our Barnett Shale area, covering an estimated 195 square miles by year-end 2005.

We maintain a flexible and diversified approach to project identification by focusing on the estimated financial results of a project area rather than limiting our focus to any one method or source for obtaining leads for new project areas. Our current project areas result from leads developed primarily by our internal staff. Additionally, we monitor competitor activity and review outside prospect generation by small, independent “prospect generators,” or our joint venture partners. We complement our exploratory drilling portfolio through the use of these outside sources of project generation and typically retain operation rights. Specific drill-sites are typically chosen by our own geoscientists.

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OPERATING APPROACH

Our management team has extensive experience in the development and management of exploration projects along the Texas and Louisiana Gulf Coast. We believe that the experience of our management in the development, processing and analysis of 3-D projects and data in the onshore Gulf Coast area is a core competency to our continued success. Additionally, we believe that the experience we have gained in the Barnett Shale area, along with our extensive experience in fracturing and horizontal drilling technologies, will play a significant part in our future success.

We generally seek to obtain lease operator status and control over field operations, and in particular seek to control decisions regarding 3-D survey design parameters and drilling and completion methods. As of December 31, 2004, we operated 92 producing oil and natural gas wells. Although we initially did not act as operator for most of our projects in the Barnett Shale area, we now generally seek to control operations for most new exploration and development in that area, taking advantage of our technical staff experience in horizontal drilling and hydraulic fracturing.

We emphasize preplanning in project development to lower capital and operational costs and to efficiently integrate potential well locations into the existing and planned infrastructure, including gathering systems and other surface facilities. In constructing surface facilities, we seek to use reliable, high quality, used equipment in place of new equipment to achieve cost savings. We also seek to minimize cycle time from drilling to hook-up of wells, thereby accelerating cash flow and improving ultimate project economics.

We seek to use advanced production techniques to exploit and expand our reserve base. Following the discovery of proved reserves, we typically continue to evaluate our producing properties through the use of 3-D seismic data to locate undrained fault blocks and identify new drilling prospects and perform further reserve analysis and geological field studies using computer aided exploration techniques. We have integrated our 3-D seismic data with reservoir characterization and management systems through the use of geophysical workstations which are compatible with industry standard reservoir simulation programs.

SIGNIFICANT PROJECT AREAS

This section is an explanation and detail of some of the relevant project groupings from our overall inventory of productive wells, seismic data and prospects. Our operations are focused primarily in the onshore Gulf Coast area extending from South Louisiana to South Texas and the Barnett Shale trend in North Texas. Our other areas of interest are in East Texas, the Rocky Mountains and the U.K. North Sea. The table below highlights our main areas of activity:

3-D PROJECT SUMMARY CHART

AS OF DECEMBER 31, 2004

	PRODUCTIVE WELLS		**3-D SEISMIC DATA**	**NET OPTIONS/ LEASED**	**DRILLING CAPITAL EXPENDITURES**	
	GROSS	**NET**	**(SQ. MILES)**	**ACRES**	**2004**	**2005 PLAN**
Onshore Gulf Coast:						
Wilcox	28	8.2	2,066	17,966	$ 9.2	$ 4.9
Frio/Vicksburg	91	27.5	2,166	7,750	8.7	6.3
Southeast Texas	11	4.4	881	17,275	7.0	4.8

South Louisiana	10	3.0	1,887	4,752	8.9	17.4
Barnett Shale	38	13.8	123	30,717	15.1	35.0
East Texas	45	43.9	503	1,449	1.7	1.6
Rocky Mountain	--	--	473	16,709	0.6	--
North Sea	--	--	153	209,613	--	--
Other Areas	--	--	1,005	7,151	--	--
Total	223	100.8	9,257	313,382	$ 51.2	$ 70.0

(1) We expect to seek additional financing to partially fund our exploration and development program in 2005. Accordingly, our 2005 capital spending program could decrease significantly if we do not obtain such financing. --See “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources.”

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ONSHORE GULF COAST AREA

For purposes of presentation, we divide our onshore Gulf Coast area into four main producing areas: Wilcox, Frio/Vicksburg, Southeast Texas and South Louisiana. Our onshore Gulf Coast area generally contains geologically complex natural gas objectives well-suited for drilling using 3-D seismic evaluation.

In our onshore Gulf Coast area, we have identified over 155 exploratory drilling opportunities on acreage we have under lease or have an option to lease, including over 78 additional extension opportunities, depending on the success of our initial drilling activities on those locations. We plan to spend approximately $35.0 million on drilling expenditures in 2005, comprised of approximately 34 wells (14.4 net). We also plan to spend $5 million to purchase and reprocess 3-D seismic surveys during 2005.

TEXAS - WILCOX AREAS

We have licenses for approximately 2,066 square miles of 3-D seismic data and 17,966 net acres of leasehold in the Wilcox trend in Texas. From January 1, 2001 through December 31, 2004, we drilled and completed 33 wells (10.9 net) on 39 attempts in this area. We incurred capital expenditures of $9.2 million and drilled 11 wells (4.6 net) in the Texas Wilcox area in 2004 and expect to devote approximately $4.9 million to drill nine wells (3.5 net) in this area in 2005. As of March 1, 2005, we have identified over 25 exploratory drilling locations, with an additional 37 potential extension opportunities, in the Wilcox trend over which we have licenses for 3-D seismic data and leased acreage. Approximately 12 of the 25 exploratory locations we have identified are relatively lower risk and generally shallower with the remainder being relatively higher risk and deeper with greater upside potential.

TEXAS FRIO/VICKSBURG/YEGUA AREAS

This combined trend area sometimes overlaps but is generally closer to the Texas Gulf Coast than the Wilcox areas discussed above. In any particular target or prospect in this area, the Frio is the shallower formation, above the deeper Vicksburg and still deeper Yegua formations. We have licenses for a total of over 2,166 miles of 3-D seismic data and 7,750 net leasehold acres over this trend. Since 1999, we have focused primarily in Matagorda County, the location of the Providence Field, and in Brooks County, the location of the Encinitas Field.

As of March 1, 2005, we have identified over 21 exploratory drilling locations with an additional 19 potential extension opportunities (depending on the success of our initial drilling activities on those locations) in the Frio/ Vicksburg trend area over which we have licenses for 3-D seismic data and leased acreage. Approximately 14 of the 21 exploratory locations we have identified are relatively lower risk and generally shallower with the remaining seven being relatively higher risk and deeper with greater upside potential.

From January 1, 2001 through December 31, 2004, we drilled and completed 41 wells (9.3 net) in 46 attempts in this trend. We incurred capital expenditures of $8.7 million and drilled 16 wells (4.5 net) in the Frio/Vicksburg trend area in 2004 and expect to devote approximately $6.3 million to drill nine wells (2.7 net) in this area in 2005.

Providence Field. We have licenses for over 540 square miles of 3-D data in and surrounding the Providence Field we discovered in 2001. Since the discovery well commenced production in January 2002, six wells have been drilled and successfully completed. Four of the wells had average production rates ranging from 14,339 to 17,669 Mcfe per day per well during the first 90 full days of production. The field has cumulative production as of December 31, 2004 of 18.0 Bcfe. We have working interests ranging from 35% to 45% in the leases in this field and operate four of the six wells.

Encinitas Field. This field, the site of our first 3-D seismic survey in 1995, has 32 wells currently producing. Since 1996, we have participated in the drilling of 29 wells (5.4 net) in this area, 27 (4.9 net) of which were successfully completed. During 2004, we participated in the drilling of five wells, all of which were successfully completed. We expect to drill four wells (1.1 net) in 2005, with an additional eight well locations to be drilled thereafter. We expect to have a 27.5% working interest in those wells.

SOUTHEAST TEXAS AREAS

The Southeast Texas area contains similar objective levels found in the Frio/Vicksburg/Yegua trend area. We separate this as a focus area because of the geographic concentration of our 3-D seismic data and because reservoirs in this area can display seismic amplitude anomalies. Seismic amplitude anomalies can be interpreted as an indicator of hydrocarbons, although these anomalies are not necessarily reliable as to hydrocarbon presence or productivity. We have acquired licenses for approximately 881 square miles of

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3-D data over our Southeast Texas project area which is focused primarily on the Frio, Yegua, Cook Mountain and Vicksburg formations.

As of March 1, 2005, we have identified over 22 exploratory drilling locations with an additional 12 potential extension locations in the Southeast Texas area over which we have licenses for 3-D seismic data. Approximately 18 of the 22 exploratory locations we have identified are relatively lower risk and generally shallower with the remaining four being relatively higher risk and deeper with greater upside potential.

From January 1, 2001 to December 31, 2004, we participated in the drilling and completion of 13 wells (4.5 net) in 17 attempts in this area. We incurred capital expenditures of $7.0 million and drilled six wells (2.4 net) in the Southeast Texas area in 2004 and expect to devote approximately $4.8 million and drill five wells (1.7 net) in this area in 2005. The Liberty Project Area and Cedar Point Project Area have proven to be successful for us, and we expect that the Liberty Project Area will constitute a significant portion of our drilling program for 2005.

Liberty

We have identified and leased prospects ranging from the Frio to the Cook Mountain formations within the 500 square miles of 3-D seismic data in the Liberty Project Area which now covers significant areas of Liberty and Hardin Counties, Texas. Since January 1, 2001, we have been successful on nine of 12 wells drilled. In late 2002, we completed a significant well in the area, which produced an average of 9,787 Mcfe per day during the first 90 full days of production when it was placed on line in the spring of 2003. We operate this well and own a 40% working interest. In 2003, we had another significant drilling success in this area with a well producing an average of 13,030 Mcfe per day during the first 90 full days of production when placed on line in mid-June 2003. We operate this well and own a 46.3% working interest. Average daily net production from our Liberty Project area was 3.3 Mmcfe, 4.5 Mmcfe and 0.5 Mmcfe during the calendar years 2004, 2003 and 2002, respectively.

As of March 1, 2005, we had identified 20 exploratory drilling locations and an additional two potential extension locations in the Liberty Project Area. We have since generated an additional eight exploratory drilling locations from our 2005 seismic survey project, and we expect additional exploratory drilling locations will be generated from our 2005 seismic survey project during the second half of 2005. As a result, our 2005 drilling budget provides for drilling of five of these exploratory locations. Accordingly, we expect to continue significant drilling activity in the Liberty Project area in 2006.

SOUTH LOUISIANA AREA

The South Louisiana area primarily contains objectives in the Middle and Lower Miocene intervals. We have acquired licenses for approximately 1,887 square miles of 3-D data and approximately 4,752 net acres of leasehold. The 3-D seismic data sets are concentrated in one general area including St. Mary, Terrebonne and LaFourche Parishes.

Currently, we have identified over nine exploratory drilling locations with an additional ten potential extension locations in the South Louisiana area over which we have licenses for 3-D seismic data. Four of the nine exploratory locations we have identified are relatively lower risk and generally shallower with the other five being relatively higher risk and deeper with greater upside potential.

From January 1, 2001 to December 31, 2004, we drilled and completed nine wells (2.5 net) on 14 attempts in this area. In 2004, we incurred capital expenditures of $8.9 million and drilled four wells (1.7 net) in the South Louisiana area, successfully completing three of the four wells. The aggregate initial and current (as of October 31, 2004) from these three successful wells drilled in 2004 were 11,350 Mcfe/d (4,459 Mcfe/d net) and 8,220 Mcfe/d (4,111 Mcfe/d net), respectively. We expect to devote approximately $17.8 million to drill ten wells (6.0 net) in this area in 2005.

LaRose

During 2002, we successfully drilled and completed an offset well to the discovery well in this area. We operate the two wells and own a 40% working interest. The discovery well produced at an average of 15,581 Mcfe per day during the first 90 full days of production. We plan to participate in one additional well (0.2 net) in the general area during 2005.

BARNETT SHALE TREND

We began active participation in the Barnett Shale play in the Fort Worth Basin on acreage located west of the city of Fort Worth,

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Texas in mid-2003. In 2003, we acquired leases on approximately 4,100 net acres and invested $0.9 million to drill six wells (2.6 net), two of which were completed and producing and four of which were awaiting pipeline hookup at year end. Net production from the two online wells (0.6 net) was a combined 380 Mcfe per day at year end in 2003.

In February 2004 we purchased specified wells and leases in the Barnett Shale trend in Denton County, Texas from a private company for $8.2 million. These non-operated properties have an average 39 percent working interest. The acquisition included 21 existing gross wells (6.7 net) and interests in approximately 1,500 net acres, which we expect to provide another 31 gross drill sites.

During 2004, we drilled 33 additional wells (13.7 net) and acquired an additional 26,617 net acres, increasing our acreage at the end of 2004 to 30,717 net acres (primarily in Tarrant, Parker, Denton, Johnson, Hill and Erath counties). 17 out of those gross wells were on-line producing at year-end and the remaining 16 wells are awaiting completion and pipeline hookup. 28 of the drilled wells in 2004 were non-operated, with relatively low working interests. In the second half of 2004, we initiated our operated drilling program and we anticipate the majority of our activity going forward will focus on company operated acreage.

We are continuing to expand our leasehold acquisition in this trend. Production at the end of 2004 and at March 1, 2005 was approximately 2,800 Mcfe/d and 3,500 Mcfe/d, respectively. Net proved reserves have grown from 1.6 Bcfe in December 31, 2003 to 31.7 Bcfe at December 31, 2004.

EAST TEXAS AREA

The East Texas area encompasses multiple objectives, including the Wilcox and Cotton Valley intervals. We are focused on the Camp Hill Field, a Wilcox steam flood project in Anderson County, and the Tortuga Grande Prospect, a Cotton Valley sand opportunity. We have licenses for over 500 square miles of 3-D seismic data in the East Texas area and 1,449 net acres under lease.

We expect to invest $1.6 million to drill nine (7.7 net) wells in this region in 2005.

Camp Hill Project. From January 1, 2001 to December 31, 2004, we drilled and completed nine wells (2.5 net) on 14 attempts in this area. WeIn 2004, we incurred capital expenditures of $8.9 million and drilled four wells (1.7 net) in the South Louisiana area in 2004 and, successfully completing three of the four wells. The aggregate initial and current (as of October 31, 2004) from these three successful wells drilled in 2004 were 11,350 Mcfe/d (4,459 Mcfe/d net) and 8,220 Mcfe/d (4,111 Mcfe/d net), respectively. We expect to devote approximately $17.8 million to drill ten wells (6.0 net) in this area in 2005. We own interests in approximately 600 gross acres in the Camp Hill field in Anderson County, Texas. We currently operate all of these leases. During the year ended December 31, 2004, the project produced an average of 56 Bbls/d of 19 API gravity oil. The wells produce from a depth of 500 feet and utilize a tertiary steam drive as an enhanced oil recovery process. Although efficient at maximizing oil recovery, the steam drive process is relatively expensive to operate because natural gas or produced crude is burned to create the steam injectant. Lifting costs during the year ended December 31, 2004 averaged $19.87 per barrel ($3.31 per Mcfe). We have in the past used, and plan in the future to use, a tertiary steam drive. In response to high fuel gas prices, steam injection was suspended in mid-2000. The oil produced, although viscous, commands a higher price (an average premium of $1.00 per Bbl during the year ended December 31, 2004) than West Texas intermediate crude due to its suitability as a lube oil feedstock. As of December 31, 2004, we had 8.6 MMBbls of proved oil reserves in this project, with 969 MBbls of oil reserves currently developed. 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 (1) pursuing shorter-term exploration projects with potentially higher rates of return, (2) adding to our lease position in this field and (3) further evaluating additional economic enhancements for this field's development. "See 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." The proved undeveloped reserves at the Camp Hill Field constitute 41.8% of our proved reserves and account for 27.7% of our present value of net future revenues from proved reserves as of December 31, 2004. We anticipate drilling additional wells and increasing steam injection to develop the proved undeveloped reserves in this project, with the timing and amount of expenditures dependent on the relative prices of oil and natural gas. We are currently drilling with one rig and plan to spend approximately $0.6 million drilling eight gross (7.2 net) wells in 2005. The planned Camp Hill development expenditures represent a relatively small portion of the Company's total capital expenditures budgeted in 2005. We continue to invest the majority of our 2005 budgeted capital expenditures in our Barnett Shale and onshore Gulf Coast areas where the rates of return are traditionally higher. This is due in large measure to significantly higher lifting costs associated with Camp Hill oil production. We have an average working interest of approximately 90% in this field and an approximate net revenue interest of 73%.

Tortuga Grande Prospect. In March 2004 we finalized an agreement to operate the re-entry of an abandoned Cotton Valley test well that calculates on logs to have over 230 feet of sands with possible production. At the time the well was originally drilled, the

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predecessor owner/operator perforated the objective interval and tested gas but in uneconomic volumes. This well was drilled before newer fracturing technologies were developed that could have increased flow rates and during a period when gas prices were significantly lower. Although this attempted completion flowed gas at uneconomic rates, we expect to drill another exploratory well in 2005 in a better structural position. We believe there are over ten potential extension development locations on our acreage that may be prospective.

WYOMING/MONTANA COALBED METHANE PROJECT AREA

Rocky Mountain Region

As discussed below under "--Pinnacle Transaction," in the second quarter of 2003, we contributed to Pinnacle our Powder River Basin properties in the Clearmont, Kirby, Arvada and Bobcat project areas located in Wyoming and Montana. At the end of 2004, we also own direct interests in approximately 162,489 gross acres of coalbed methane properties in the Castle Rock project area in Montana and the Oyster Ridge project area in Wyoming that were not contributed to Pinnacle, but we currently have no proved reserves of, and are no longer receiving revenue from, coalbed methane gas other than through Pinnacle.

In February 2004, the CSFB Parties contributed additional funds of $11.8 million into Pinnacle to continue funding the 2004 development program which will increase their ownership to 66.7% on a fully diluted basis should we and RMG each elect not to exercise our available options. See "-The Pinnacle Transaction" for more information on this transaction.

By 2004 year end, Pinnacle had completed the acquisition and/or drilling of 486 wells (or approximately 276 net). Of those wells, 484 encountered coal accumulations. Coalbed methane wells typically first produce water in a process called dewatering and then, as the water production declines, begin producing methane gas at an increasing rate. As the wells mature, the production peaks and begins declining.

As of August 31, 2005, Pinnacle had drilled 345 wells; of these 345 wells, (1) 256 are producing gas; (2) 18 remain in the completion/hook-up phase; (3) 46 are in the dewatering phase with no early indication as to gas production; (4) 22 are waiting on or being evaluated for workovers or redrill or plugging and abandonment; and (5) three of these wells did encounter coal accumulations.

As of August 31, 2005, of the 241 wells that Pinnacle had acquired, (1) 71 are producing gas, (2) 108 remain in the completion/hook-up phase; (3) 27 are in the dewatering phase with no early indication as to gas production; (4) 12 are waiting on or being evaluated for workovers or redrill or plugging and abandonment; (5) 18 that are producing gas at uneconomic rates are currently shut in; and (6) five have been plugged and abandoned.

The dewatering process may require significant time and resources, and there can be no assurance that a well that encounters coal accumulations will in fact produce gas in commercial quantities. The ultimate commercial success of the well will depend upon several factors, including the establishment of gas and/or water inflow, the presence of pipelines and infrastructure, the satisfaction of engineering or production issues and other risks and uncertainties associated with drilling activities.

See "Regulation - Coalbed Methane Proceedings in Montana" for a description of certain regulatory proceedings affecting coalbed methane drilling in Montana.

OTHER PROJECT AREAS

U.K. North Sea Region

We have been awarded seven acreage blocks, consisting of one “Traditional” and three “Promote” licenses, in the United Kingdom’s 21st Round of Licensing. The awarded blocks, to explore for natural gas and oil totaling 209,613 acres, are located within mature producing areas of the Central and Southern North Sea in water depths of 30 to 350 feet. The Promote licenses do not have drilling commitments and have two-year terms. The Traditional license will be canceled after four years if we or our assignee elects not to commit to drilling a well. We believe our U.K. North Sea interest is a natural extension to our technical analyses, portfolio and business plan. The U.K. North Sea includes proven hydrocarbon trends with established technological expertise, available large 3-D seismic datasets and significant exploration potential. We plan to promote our interests to other parties experienced in drilling and operating in this region. Geological and geophysical costs will be incurred in an attempt to maximize the value of our retained interest. Our estimated project commitments for 2005 are $0.2 million, largely for data processing.

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WORKING INTEREST AND DRILLING IN PROJECT AREAS

The actual working interest we will ultimately own in a well will vary based upon several factors, including the depth, cost and risk of each well relative to our strategic goals, activity levels and budget availability. From time to time some fraction of these wells may be sold to industry partners either on a prospect by prospect basis or a program basis. In addition, we may also contribute acreage to larger drilling units thereby reducing prospect working interest. We have, in the past, retained less than 100% working interest in our drilling prospects. References to our interests are not intended to imply that we have or will maintain any particular level of working interest.

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 final determination of whether to drill any scheduled or budgeted wells will be dependent on a number of factors, including (1) the results of our exploration efforts and the acquisition, review and analysis of the seismic data; (2) the availability of sufficient capital resources to us and the other participants for the drilling of the prospects; (3) the approval of the prospects by the other participants after additional data has been compiled; (4) 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 (5) the availability of leases and permits on reasonable terms for the prospects. There can be no assurance that these projects can be successfully developed or that any identified drillsites or budgeted wells discussed will, if drilled, encounter reservoirs of commercially productive oil or natural gas. We may seek to sell or reduce all or a portion of our interest in a project area or with respect to prospects or wells within a project area.

Our success will be materially dependent upon the success of our exploratory drilling program, which is an activity that involves numerous risks. See "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors--Natural gas and oil drilling is a speculative activity and involves numerous risks and substantial and uncertain costs that could adversely affect us."

OIL AND NATURAL GAS RESERVES

The following table sets forth our estimated net proved oil and natural gas reserves and the PV-10 Value of such reserves as of December 31, 2004. The reserve data and the present value as of December 31, 2004 were prepared by Ryder Scott Company, DeGolyer and MacNaughton and Fairchild & Wells, Inc., Independent Petroleum Engineers. For further information concerning Ryder Scott's, DeGolyer and MacNaughton's and Fairchild's estimate of our proved reserves at December 31, 2004, see the reserve reports included as exhibits to this Annual Report on Form 10-K/A. The PV-10 Value was prepared using constant prices as of the calculation date, discounted at 10% per annum on a pretax basis, and is not intended to represent the current market value of the estimated oil and natural gas reserves owned by us. For further information concerning the present value of future net revenue from these proved reserves, see Note 15 of Notes to Consolidated Financial Statements.

	PROVED RESERVES		
	Developed	**Undeveloped** (dollars in thousands)	**Total**
Oil and condensate (MBbls)	1,459	7,658	9,117

Natural gas (MMcf)	28,066	26,555	54,621
Total proved reserves (MMcfe)	36,823	72,505	109,328
PV-10 Value(1)(2)	$ 116,413	$ 92,197	$ 208,610

(1) The PV-10 Value as of December 31, 2004 is pre-tax and was determined by using the December 31, 2004 sales prices, which averaged $41.18 per Bbl of oil, $5.68 per Mcf of natural gas. This measure is common in our industry and is a market indicator of performance.

(2) Future income taxes and present value discounted (10%) future income taxes were $108.3 and $58.9 million, respectively. Accordingly, the after-tax PV-10 Value of Total Proved Reserves (or "Standardized Measure of Discounted Future Net Cash Flows") is $149.7 million.

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No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the Securities and Exchange Commission (the "Commission"). The reserve data set forth in this Annual Report on Form 10-K/A represent only estimates. See "Management's Discussion and Analysis of Financial Condition and Results of Operations-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."

Our future oil and natural gas production is highly dependent upon our level of success in finding or acquiring additional reserves. See "Management's Discussion and Analysis of Financial Condition and Results of Operations-Risk Factors-We depend on successful exploration, development and acquisitions to maintain reserves and revenue in the future." Also, the failure of an operator of our wells to adequately perform operations, or such operator's breach of the applicable agreements, could adversely impact us. See "Management's Discussion and Analysis of Financial Condition and Results of Operations-Risk Factors-We cannot control the activities on properties we do not operate and are unable to ensure their proper operation and profitability."

DeGolyer and MacNaughton determined 29% of our proved reserves for the year ended December 31, 2004, which reserves were located on our Barnett Shale properties. Fairchild & Wells, Inc. determined 47% of our proved reserves for the year ended December 31, 2004, which reserves were located on our properties in the Camp Hill field. Ryder Scott Company Petroleum Engineers determined 24% of our proved reserves for the year ended December 31, 2004, which reserves were located on our Gulf Coast and all other remaining properties.

OIL AND NATURAL GAS RESERVE REPLACEMENT

Finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to our long-term success. Given the inherent decline of hydrocarbon reserves resulting from the production of those reserves, it is important for an exploration and production company to demonstrate a long-term trend of more than offsetting produced volumes with new reserves that will provide for future production. Management uses the reserve replacement ratio, as defined below, as an indicator of our ability to replenish annual production volumes and grow our reserves, thereby providing some information on the sources of future production. We believe reserve replacement information is frequently used by analysts, investors and others in the industry to evaluate the performance of companies like ours. The reserve replacement ratio is calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries, and other additions and acquisitions) by the actual production for the corresponding period. The values for these reserve additions are derived directly from the proved reserves table above. We do not use unproved reserve quantities in calculating our reserve replacement ratio. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not take into consideration the cost of timing of future production of new reserves, it cannot be used as a measure of value creation. The ratio does not distinguish between changes in reserve quantities that are producing and those that will require additional time and funding to begin producing In that regard, it might be noted that percentage of reserves that were producing varied from 13.6% in 2002, to 11.2% in 2003 to 17.2% in 2004. Set forth below is our reserve replacement ratio for the year ended December 31, 2004, 2003 and 2002.

	FOR THE YEAR ENDED DECEMBER 31,		
	2002	**2003**	**2004**
Reserve Replacement Ratio	163%	203%	568%

VOLUMES, PRICES AND OIL & NATURAL GAS OPERATING EXPENSE

The following table sets forth certain information regarding the production volumes of, average sales prices received for and average production costs associated with our sales of oil and natural gas for the periods indicated. The table includes the cash impact of hedging activities.

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	YEAR ENDED DECEMBER 31, 2002	2003	2004
Production volumes			
Oil (MBbls)	401	450	309
Natural gas (MMcf)	4,801	4,763	6,462
Natural gas equivalent (MMcfe)	7,207	7,463	8,319
Average sales prices			
Oil (per Bbl)	$ 24.94	$ 28.90	$ 41.00
Natural gas (per Mcf)	3.50	5.35	6.14
Natural gas equivalent (per Mcfe)	3.72	5.16	6.30
Average costs (per Mcfe)			
Camp Hill operating expenses	$ 2.50	$ 3.45	$ 3.31
Other operating expenses	0.44	0.58	0.59
Total operating expenses(1)	0.68	0.90	1.01

(1) Includes direct lifting costs (labor, repairs and maintenance, materials and supplies), workover costs and the administrative costs of production offices, insurance and property and severance taxes.

FINDING AND DEVELOPMENT COSTS

The table below reconciles our calculation of finding cost to our costs incurred in the purchase of proved and unproved properties and in development and exploration activities, excluding capitalized interest on unproved properties of $3.1 million, $2.9 million and $2.9 million for the years ended December 31, 2002, 2003 and 2004, respectively. We have also included capitalized overhead in our finding cost of $1.0 million, $1.4 million and $1.7 million for the years ended December 31, 2002, 2003 and 2004, respectively. We have also included non-cash asset retirement obligations of $0.7 and $0.5 million for the years ended December 31, 2003 and 2004, respectively.

	YEAR ENDED DECEMBER 31, 2002	2003 (in thousands)	2004
Acquisition costs:			
Unproved properties contributed to Pinnacle	$ 1,323	$ --	$ --
Other unproved properties	5,079	7,280	21,831
Proved properties	660	--	8,357
Exploration	14,194	23,745	39,181
Development	2,351	112	12,697
Asset retirement obligation	--	744	529
Total costs incurred	23,607	31,881	82,595
Less unproved properties contributed to Pinnacle	1,323	--	--
Adjusted costs	$ 22,284	$ 31,881	$ 82,595
Total proved reserves added	11,761	15,138	47,294

Average all-sources finding cost (per Mcfe) (1)	$	1.89	$	2.11	$	1.75

(1) Our all-sources finding cost excludes the coalbed methane unproved property costs we contributed as a minority investment to Pinnacle Gas Resources, Inc. in June 2003 and, accordingly, is no longer included in our consolidated operations.

For the three year period ended December 31, 2004, our total adjusted costs for development, exploration and acquisition activities was approximately $136.8 million. Total exploration, development and acquisition activities for the three year period ended December 31, 2004 have added approximately 74.2 Bcfe of net proved reserves at an all-sources finding cost of $1.84 per Mcfe.

Our finding and development cost computation excludes net additions/reductions to total future development costs with respect to proved undeveloped properties necessary to convert those properties into proved developed properties of ($0.8), $0.7 and $39.8 million at December 31, 2002, 2003 and 2004, respectively, and includes total additions to proved undeveloped reserves of 3.7, 2.9 and 27.6 Bcfe for the years ended December 31, 2002, 2003 and 2004, respectively. Accordingly, had we included future development costs in our computations, the average all-sources finding costs would have been $1.82, $2.15 and $2.59 for the years ended December 31, 2002, 2003 and 2004, respectively.

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In order to maintain continued growth and profitability, our annual goal is to add new reserves exceeding our yearly production at a finding and development cost that contributes to an acceptable profit margin. Accordingly, we use the finding and development cost in combination with our reserve replacement ratio, as previously defined, to measure our operating and financial performance.

Our all-source finding cost measure is a measure with limitations. Consistent with industry practice, our finding and development costs have historically fluctuated on a year-to-year basis based on a number of factors including the extent and timing of new discoveries and property acquisitions. Due to the timing of proved reserve additions and timing of the related costs incurred to find and develop our reserves, our all-sources finding cost measure often includes quantities of reserves for which a majority of the costs of development have not yet been incurred. Conversely, the measure also often includes costs to develop proved reserves that had been added in earlier years. Finding and development costs, as measured annually, may not be indicative of our ability to economically replace oil and natural gas reserves because the recognition of costs may not necessarily coincide with the addition of proved reserves. Our all-sources finding costs may also be calculated differently than the comparable measure for other oil and gas companies.

DEVELOPMENT, EXPLORATION AND ACQUISITION CAPITAL EXPENDITURES

The following table sets forth certain information regarding the gross costs incurred in the purchase of proved and unproved properties and in development and exploration activities.

	YEAR ENDED DECEMBER 31,		
	2002	**2003**	**2004**
		(in thousands)	
Acquisition costs			
Unproved prospects	$ 6,402	$ 7,280	$ 21,831
Proved properties	660	--	8,357
Exploration	14,194	23,745	39,181
Development	2,351	112	12,697
Asset retirement obligation	--	744	529
Total costs incurred(1)	$ 23,607	$ 31,881	$ 82,595

(1) Excludes capitalized interest on unproved properties of $3.1 million, $2.9 million and $2.9 million for the years ended December 31, 2002, 2003, and 2004, respectively, and includes capitalized overhead of $1.0 million, $1.4 million and $1.7 million for the years ended December 31, 2002, 2003 and 2004 respectively. The table also includes non-cash asset retirement obligations of $0.7 and $0.5 million, respectively, for the year ended December 31, 2003 and 2004, respectively.

DRILLING ACTIVITY

The following table sets forth our drilling activity for the years ended December 31, 2002, 2003 and 2004. In the table, “gross” refers to the total wells in which we have a working interest and “net” refers to gross wells multiplied by our working interest therein. Our drilling activity from January 1, 1996 to December 31, 2004 has resulted in a commercial success rate of approximately 73%.

YEAR ENDED DECEMBER 31,

	2002		2003		2004	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory Wells						
Productive	16	5.6	33	9.2	39	14.9
Nonproductive	3	1.1	5	0.8	6	3.7
Total	19	6.7	38	10.0	45	18.6
Development Wells						
Productive	1	0.4	1	0.2	26	8.7
Nonproductive	--	--	--	--	--	--
Total	1	0.4	1	0.2	26	8.7

At December 31, 2003 and 2004, we had ownership in 12 and 11 gross (3.2 and 2.7 net) wells, respectively, with dual completion in single bore holes. The above table excludes 77 gross (29 net) wells drilled or acquired by CCBM through 2003, a majority of which were contributed to Pinnacle during 2003. The table also excludes 12 gross (2.3 net) wells drilled by CCBM during 2004. The wells contributed to Pinnacle are in various stages of development and/or stages of production. See “Wyoming/Montana Coalbed Methane Project Area” above.

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PRODUCTIVE WELLS

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2004. This table excludes all wells drilled or acquired by CCBM through 2003, a majority of which were contributed to Pinnacle in that year.

	COMPANY OPERATED		OTHER		TOTAL	
	Gross	Net	Gross	Net	Gross	Net
Oil	53	36.6	10	3.7	63	40.3
Natural gas	39	19.8	143	42.3	182	62.1
Total	92	56.4	153	46.0	245	102.4

ACREAGE DATA

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of December 31, 2004. Developed acres refers to acreage on which wells have been drilled or completed to a point that would permit production of oil and gas in commercial quantities. Undeveloped acreage refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and gas in commercial quantities whether or not the acreage contains proved reserves.

	DEVELOPED ACREAGE		UNDEVELOPED ACREAGE		TOTAL	
	Gross	Net	Gross	Net	Gross	Net
North Sea	--	--	209,613	209,613	209,613	209,613
Louisiana	3,027	986	4,845	3,766	7,872	4,752
Texas	36,656	12,674	112,881	51,489	149,537	64,163
Montana/Wyoming	--	--	138,705	10,763	138,705	10,763
Other	--	--	7,618	1,143	7,618	1,143
Total	39,683	13,660	473,662	276,774	513,345	290,434

The table does not include 32,809 gross and 17,002 net acres under lease option that we had a right to acquire in Texas, pursuant to various seismic and lease option agreements at December 31, 2004. Under the terms of our option agreements, we typically have the right for a period of one year, subject to extensions, to exercise our option to lease the acreage at predetermined terms. Our lease agreements generally terminate if producing wells have not been drilled on the acreage within a period of three years. Further, the table does not include 23,784 gross and 5,946 net acres under lease option in Wyoming that CCBM has the right to earn pursuant to certain drilling obligations and other predetermined terms.

MARKETING

Our production is marketed to third parties consistent with industry practices. Typically, oil is sold at the wellhead at field-posted prices plus a bonus and natural gas is sold under contract at a negotiated price based upon factors normally considered in the industry, such as distance from the well to the pipeline, well pressure, estimated reserves, quality of natural gas and prevailing supply and demand conditions.

Our marketing objective is to receive the highest possible wellhead price for our product. We are aided by the presence of multiple outlets near our production in the Texas and Louisiana onshore Gulf Coast area and the Barnett Shale area. We take an active role in determining the available pipeline alternatives for each property based on historical pricing, capacity, pressure, market relationships, seasonal variances and long-term viability.

There are a variety of factors that affect the market for natural gas and oil, including:

- the extent of domestic production and imports of natural gas and oil;

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- the proximity and capacity of natural gas pipelines and other transportation facilities;
- demand for natural gas and oil;
- the marketing of competitive fuels; and
- the effects of state and federal regulations on natural gas and oil production and sales.

See “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Risk Factors--Natural gas and oil prices are highly volatile, and lower prices will negatively affect our financial results,” “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Risk Factors--We are subject to various governmental regulations and environmental risks” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Risk Factors--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.”

We from time to time market our own production where feasible with a combination of market-sensitive pricing and forward-fixed pricing. We utilize forward pricing to take advantage of anomalies in the futures market and to hedge a portion of our production deliverability at prices exceeding forecast. All of these hedging transactions provide for financial rather than physical settlement. For a discussion of these matters, our hedging policy and recent hedging positions, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations--Critical Accounting Policies and Estimates--Derivative Instruments and Hedging Activities,” “Qualitative and Quantitative Disclosures About Market Risk--Derivative Instruments and Hedging Activities,” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors--We may continue to hedge the price risks associated with our production. Our hedge transactions may result in our making cash payments or prevent us from benefiting to the fullest extent possible from increases in prices for natural gas and oil.”

COMPETITION AND TECHNOLOGICAL CHANGES

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. Many of our competitors are large, well-established companies that have been engaged in the natural gas and oil business for much longer than we have and possess substantially larger operating staffs and greater capital resources than we do. We may not be able to conduct our operations, evaluate and select suitable properties and consummate transactions successfully in this highly competitive environment.

The natural gas and oil industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. 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.

REGULATION

Natural gas and oil operations are subject to various federal, state and local environmental regulations that may change from time to time, including regulations governing natural gas and oil production, federal and state regulations governing environmental quality and pollution control and state limits on allowable rates of production by well or proration unit. These regulations may affect the amount of natural gas and oil available for sale, the availability of adequate pipeline and other regulated transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be “shut-in” because of an oversupply of natural gas or lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of natural gas and oil, protect rights to produce natural gas and oil between owners in a common reservoir, control the amount of natural gas and oil produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted.

The following discussion summarizes the regulation of the United States oil and gas industry. We believe we are in substantial compliance with the various statutes, rules, regulations and governmental orders to which our operations may be subject, although we cannot assure you that this is or will remain the case. Moreover, those statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and any such changes or reinterpretations could materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Natural Gas and Oil Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels that:

- require permits for the drilling of wells;

- mandate that we maintain bonding requirements in order to drill or operate wells; and

- regulate the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations.

Our operations are also subject to various conservation laws and regulations. These regulations govern the size of drilling and spacing units or proration units, the density of wells that may be drilled in natural gas and oil properties and the unitization or pooling of natural gas and oil properties. In this regard, some states (including Louisiana) allow the forced pooling or integration of tracts to facilitate exploration while other states (including Texas) rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is primarily or exclusively voluntary, it may be more difficult to form units and therefore more difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas and impose specified requirements regarding the ratability of production. The effect of these regulations may limit the amount of natural gas and oil we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the natural gas and oil industry increases our costs of doing business and, consequently, affects our profitability. Because these laws and regulations are frequently expanded, amended and reinterpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

Federal legislation and regulatory controls have historically affected the price of natural gas we produce and the manner in which our production is transported and marketed. Under the Natural Gas Act of 1938 (“NGA”), the Federal Energy Regulatory Commission (“FERC”) regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act (the “Decontrol Act”) deregulated natural gas prices for all “first sales” of natural gas, including all of our sales of our own production. As a result, all of our domestically produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. The FERC’s jurisdiction over interstate natural gas transportation, however, was not affected by the Decontrol Act.

Under the NGA, facilities used in the production or gathering of natural gas are exempt from the FERC’s jurisdiction. We own certain natural gas pipelines that we believe satisfy the FERC’s criteria for establishing that these are all gathering facilities not subject to FERC jurisdiction under the NGA. State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirements but does not generally entail rate regulation.

Although we therefore do not own or operate any pipelines or facilities that are directly regulated by the FERC, its regulations of third-party pipelines and facilities could indirectly affect our ability to market our production. Beginning in the 1980s the FERC initiated a series of major restructuring orders that required pipelines, among other things, to perform open access transportation, “unbundle” their sales and transportation functions, and allow shippers to release their pipeline capacity to other shippers. As a result of these changes, sellers and buyers of natural gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. It remains to be seen, however, what effect the FERC’s other activities will have on access to markets, the fostering of competition and the cost of doing business. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities.

In the past, Congress has been very active in the area of natural gas regulation. However, the more recent trend has been in favor of deregulation or “lighter handed” regulation and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the federal and state legislatures which, if enacted, would significantly affect the petroleum industry.

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At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas, cannot be predicted.

Oil Price Controls and Transportation Rates

Our sales of oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to specified conditions and limitations. These regulations may tend to increase the cost of transporting natural gas and oil liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. These regulations generally have been approved on judicial review. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. The first such review was completed in 2000 and on December 14, 2000, the FERC reaffirmed the current index. Following a successful court challenge of these orders by an association of oil pipelines, on February 24, 2003 the FERC increased the index slightly for the current five-year period, effective July 2001. The next review is scheduled in July 2005. Another FERC proceeding, that may impact oil pipeline transportation costs, relates to an ongoing proceeding to determine whether and to what extent oil pipelines should be permitted to include in their transportation rates an allowance for income taxes attributable to non-corporate partnership interests. We are not able at this time to predict the effects, if any, of these regulations on the transportation costs associated with oil production from our oil-producing operations.

Environmental Regulations

Our operations are subject to numerous federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on specified lands within wilderness, wetlands and other protected areas, require remedial measures to mitigate pollution from former operations, such as pit closure and plugging abandoned wells, and impose substantial liabilities for pollution resulting from production and drilling operations. The failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of investigatory or remedial obligations or the issuance of injunctions prohibiting or limiting the extent of our operations. Public interest in the protection of the environment has increased dramatically in recent years. The trend of applying more expansive and stricter environmental legislation and regulations to the natural gas and oil industry could continue, resulting in increased costs of doing business and consequently affecting our profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

We generate waste that may be subject to the federal Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes. The U.S. Environmental Protection Agency (“EPA”) and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous waste. Furthermore, certain waste generated by our natural gas and oil operations that are currently exempt from treatment as “hazardous waste” may in the future be designated as “hazardous waste” and therefore become subject to more rigorous and costly operating and disposal requirements.

We currently own or lease numerous properties that for many years have been used for the exploration and production of natural gas and oil. Although we believe that we have implemented appropriate operating and waste disposal practices, prior owners and operators of these properties may not have used similar practices, and hydrocarbons or other waste may have been disposed of or released on or under the properties we own or lease or on or under locations where such waste have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other waste was not under our control. These properties and the waste disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), RCRA and analogous state laws as well as state laws governing the management of natural gas and oil waste. Under these laws, we could be required to remove or remediate previously disposed waste (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination. See "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Factors--We are subject to various governmental

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regulations and environmental risks."

CERCLA, also known as the "Superfund" law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on specified classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These classes of persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Our operations may be subject to the Clean Air Act ("CAA") and comparable state and local requirements. In 1990 Congress adopted amendments to the CAA containing provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have developed and continue to develop regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe our operations will be materially adversely affected by any such requirements.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as us, to prepare and implement spill prevention, control, countermeasure ("SPCC") and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. The OPA also requires owners and operators of offshore facilities that could be the source of an oil spill into federal or state waters, including wetlands, to post a bond, letter of credit or other form of financial assurance in amounts ranging from $10 million in specified state waters to $35 million in federal outer continental shelf waters to cover costs that could be incurred by governmental authorities in responding to an oil spill. These financial assurances may be increased by as much as $150 million if a formal risk assessment indicates that the increase is warranted. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Our operations are also subject to the federal Clean Water Act ("CWA") and analogous state laws. In accordance with the CWA, the State of Louisiana issued regulations prohibiting discharges of produced water in state coastal waters effective July 1, 1997. Pursuant to other requirements of the CWA, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits or seek coverage under an EPA general permit. Like OPA, the CWA and analogous state laws relating to the control of water pollution provide varying civil and criminal penalties and liabilities for releases of petroleum or its derivatives into surface waters or into the ground.

We also are subject to a variety of federal, state and local permitting and registration requirements relating to protection of the environment. We believe we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse effect on us.

As further described in "--Significant Areas--Other Areas of Interest--Rocky Mountain Region," the issuance of new coalbed methane drilling permits and the continued viability of existing permits in Montana have been challenged in lawsuits filed in state and federal court.

Coalbed Methane Proceedings in Montana

The issuance of new coalbed methane drilling permits in Montana was halted temporarily pending the Federal Bureau of Land Management's ("BLM") approval of a final record of decision on Montana's Resource Management Plan environmental impact statement and the Montana Department of Environmental Quality's approval of a statewide oil and gas environmental impact statement. These two program approvals were obtained in April and August of 2003, respectively. Environmental groups initiated six lawsuits, challenging these program approvals. On February 22, 2005, the Federal District Court for the District of Montana issued an opinion in Northern Plains Resource Council v. BLM and a companion case vacating BLM's approval of the state plan and remanding the plan to BLM for further consideration. The Court left open the issue of what, if any, injunctive relief should be granted in light of this ruling. Although this decision could result in a suspension of the state's authority to issue new drilling permits or could effect the continued viability of existing permits in Montana, we believe that the decisions by the Federal Bureau of Land Management and the State of Montana ultimately will be upheld on appeal and/or BLM's reconsideration will address the Court's concerns and new coalbed methane development will continue to be authorized in Montana. There can be no assurance that any new permits will be

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obtained in a given time period or at all.

OPERATING HAZARDS AND INSURANCE

The natural gas and oil business involves a variety of operating hazards and risks that could result in substantial losses to us from, among other things, injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, cleanup responsibilities, regulatory investigation and penalties and suspension of operations.

In addition, we may be liable for environmental damages caused by previous owners of property we purchase and lease. As a result, we may incur substantial liabilities to third parties or governmental entities, the payment of which could reduce or eliminate the funds available for exploration, development or acquisitions or result in the loss of our properties.

In accordance with customary industry practices, we maintain insurance against some, but not all, potential losses. We do not carry business interruption insurance or protect against loss of revenues. We cannot assure you that any insurance we obtain will be adequate to cover any losses or liabilities. We cannot predict the continued availability of insurance or the availability of insurance at premium levels that justify its purchase. We may elect to self-insure if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. 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 participate in a substantial percentage of our wells on a nonoperated basis, and may be accordingly limited in our ability to control the risks associated with natural gas and oil operations.

TITLE TO PROPERTIES; ACQUISITION RISKS

We believe we have satisfactory title to all of our producing properties in accordance with standards generally accepted in the natural gas and oil industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect the value of these properties. As is customary in the industry in the case of undeveloped properties, we make little investigation of record title at the time of acquisition (other than a preliminary review of local records). Investigations, including a title opinion of local counsel, are generally made before commencement of drilling operations. Our revolving credit facility is secured by substantially all of our natural gas and oil properties.

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 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. See “Risk Factors -- Our future acquisitions may yield revenues or production that varies significantly from our projections.”

CUSTOMERS

We sold oil and natural gas production representing more than 10% of our oil and natural gas revenues for the year ended December 31, 2004 to Cokinos Natural Gas Company (17%), Texon L.P. (13%) and WMJ Investments Corp. (12%); for the year ended December 31, 2003 to WMJ Investments Corp. (16%), Cokinos Natural Gas Company (15%) and Gulfmark Energy, Inc. (14%); and for the year ended December 31, 2002 to Cokinos Natural Gas Company (12%) and Discovery Producer Services, LLC (10%). Because alternate purchasers of oil and natural gas are readily available, we believe that the loss of any of our purchasers would not have a material adverse effect on our financial results.

EMPLOYEES

At December 31, 2004, we had 38 full-time employees, including six geoscientists, six engineers and six landmen. We believe that our relationships with our employees are good.

In order to optimize prospect generation and development, we utilize the services of independent consultants and contractors to

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perform various professional services, particularly in the areas of 3-D seismic data mapping, acquisition of leases and lease options, construction, design, well site surveillance, permitting and environmental assessment. Independent contractors generally provide field and on-site production operation services, such as pumping, maintenance, dispatching, inspection and testings. We believe that this use of third-party service providers has enhanced our ability to contain general and administrative expenses.

We depend to a large extent on the services of certain key management personnel, the loss of, any of which could have a material adverse effect on our operations. We do not maintain key-man life insurance with respect to any of our employees.

PINNACLE TRANSACTION

Formation and Operations

During the second quarter of 2003, we and Rocky Mountain Gas, Inc. ("RMG") each contributed our interests in certain natural gas and oil leases in Wyoming and Montana in areas prospective for coalbed methane to a newly formed joint venture, Pinnacle Gas Resources, Inc. In exchange for the contribution of these assets, we each received 37.5% of the common stock of Pinnacle and options to purchase additional Pinnacle common stock, or on a fully diluted basis, we each received an ownership interest in Pinnacle of 26.9%. At the end of 2004, we retained our interests in approximately 139,000 gross acres in the Castle Rock project area in Montana and the Oyster Ridge project area in Wyoming. We no longer have a drilling obligation in connection with the oil and natural gas leases contributed to Pinnacle. During 2004, we opted to exercise our right to cancel one-half of a remaining note payable to RMG, or approximately $300,000 in exchange for assigning one-half of our interest in the Oyster Ridge project area to RMG.

Simultaneously with the contribution of these assets, affiliates and related parties of CSFB Private Equity ("CSFB") contributed approximately $17.6 million of cash to Pinnacle in return for redeemable preferred stock of Pinnacle, 25% of Pinnacle's common stock as of the closing date and warrants to purchase Pinnacle common stock. The CSFB parties currently have greater than 50% of the voting power of the Pinnacle capital stock through their ownership of Pinnacle common and preferred stock. Our Chairman, Steven A. Webster, is also Chairman of Global Energy Partners, Ltd., an affiliate of CSFB.

In February 2004, the CSFB parties contributed additional funds of $11.8 million to continue funding the 2004 development program of Pinnacle. Assuming that we and RMG exercise our Pinnacle options, the CSFB parties' ownership interest in Pinnacle would be 54.6%, and we and RMG each would own 22.7%, on a fully diluted basis. On the other hand, assuming we and RMG each elect not to exercise our Pinnacle options, our interest, on a fully diluted basis, would each decline to 16.7%, and, concurrently, CSFB parties' ownership interest would increase to 66.7%. Our options are exercisable as long as we own Pinnacle common stock, but the exercise price increases by 15% every year.

Immediately following its formation, Pinnacle acquired an approximate 50% working interest in existing leases and approximately 36,529 gross acres prospective for coalbed methane development in the Powder River Basin of Wyoming from an unaffiliated party for $6.2 million. At the time of the Pinnacle transaction, these wells were producing at a combined gross rate of approximately 2.5 MMcfd, or an estimated 1 MMcfd net to Pinnacle. At the end of 2004 Pinnacle's production was approximately 13 MMcfe/d gross (5.6 MMcfe/d net). In June 2004, Pinnacle fulfilled, $14.5 million funding commitment for future drilling and development costs on these properties on behalf of the third party prior to December 31, 2005. The drilling and development work will be done under the terms of an earn-in joint venture agreement between Pinnacle and Gastar. As of December 31, 2004, Pinnacle owned interests in approximately 170,000 gross acres (79,000 net) in the Powder River Basin.

Historically, the business operations and development program of Pinnacle has not required us to provide any further capital infusion. In March 2005, Pinnacle acquired additional undeveloped acreage with an undisclosed company which would also significantly increase Pinnacle's development program budget in 2005. Accordingly, CCBM and the other Pinnacle shareholders have the option to participate in the equity contribution into Pinnacle needed to finance the acquisition and the related development program in 2005. Should we elect to maintain our proportionate ownership interest in Pinnacle, we estimate that we would be required to contribute $2.5 million. If CCBM opts not to contribute any or all of its share of the equity contribution, its fully diluted ownership in Pinnacle would be reduced. CCBM plans to contribute $2.5 million in April 2005, its share of the equity capital needed to close the acquisition and fund part of the additional development program. There can be no assurance regarding CCBM's level of participation in future equity contributions needed, if any. On March 29, 2005, we elected to participate and contribute $2.5 million to Pinnacle in exchange for warrants and preferred stock.

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AVAILABLE INFORMATION

Our website address is www.carrizo.cc. We make our website content available for informational purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Form 10-K/A. We make available on this website, through a direct link to Securities and Exchange Commission's website at www.sec.gov, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file those materials.

You may also find information related to our corporate governance, board committees and company code of ethics at our website. Among the information you can find there is the following:

- Audit Committee Charter;
- Compensation Committee Charter;
- Nominating Committee Charter;
- Code of Ethics and Business Conduct; and
- Compliance Employee Report Line.

We intend to satisfy the requirement under Item 5.05 of Form 8-K to disclose any amendments to our Code of Ethics and any waiver from a provision of our Code of Ethics by posting such information in our Corporate Governance section of our website at www.carrizo.cc.

GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below shall apply to the indicated terms as used herein. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

After payout. With respect to an oil or gas interest in a property, refers to the time period after which the costs to drill and equip a well have been recovered.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to oil or other liquid hydrocarbons.

Bbls/d. Stock tank barrels per day.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Before payout. With respect to an oil or gas interest in a property, refers to the time period before which the costs to drill and equip a well have been recovered.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

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

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale

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of such production exceed production expenses and taxes.

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

Farm-in or farm-out. An agreement where under the owner of a working interest in an oil and natural gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a “farm-in” while the interest transferred by the assignor is a “farm-out.”

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding costs. Costs associated with acquiring and developing proved oil and natural gas reserves which are capitalized by us pursuant to generally accepted accounting principles, including all costs involved in acquiring acreage, geological and geophysical work and the cost of drilling and completing wells.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

MBbls/d. One thousand barrels of oil or other liquid hydrocarbons per day.

Mcf. One thousand cubic feet of natural gas.

Mcf/d. One thousand cubic feet of natural gas per day.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

MMBbls. One million barrels of oil or other liquid hydrocarbons.

MMBtu. One million British Thermal Units.

MMcf. One million cubic feet.

MMcf/d. One million cubic feet per day.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids, which approximates the relative energy content of oil, condensate and natural gas liquids as compared to natural gas. Prices have historically often been higher or substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

Net Revenue Interest. The operating interest used to determine the owner’s share of total production.

Normally pressured reservoirs. Reservoirs with a formation-fluid pressure equivalent to 0.465 psi per foot of depth from the surface. For example, if the formation pressure is 4,650 psi at 10,000 feet, then the pressure is considered to be normal.

Over-pressured reservoirs. Reservoirs subject to abnormally high pressure as a result of certain types of subsurface formations.

Petrophysical study. Study of rock and fluid properties based on well log and core analysis.

Present value. When used with respect to oil and natural gas reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date

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indicated, without giving effect to nonproperty-related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed nonproducing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and able to produce to market.

Proved developed reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

PV-10 Value. The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with Securities and Exchange Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

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

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Royalty interest. An interest in an oil and natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

3-D seismic data. Three-dimensional pictures of the subsurface created by collecting and measuring the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

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PART II

Item 6. Selected Financial Data

Our financial information set forth below for each of the five years ended December 31, 2004, has been derived from our audited consolidated financial statements, including restatements described in "Management's Discussion and Analysis of Financial Condition and Results of Operations." The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included in Item 8. Financial Statements and Supplementary Data.

	Year Ended December 31,				
	2000	2001	2002	2003	2004 (Restated)
	(In thousands, except per share data)				
Statement Of Operations Data:					
Oil and natural gas revenues	$ 26,834	$ 26,226	$ 26,802	$ 38,508	$ 52,397
Costs and expenses:					
Oil and natural gas operating expenses	4,941	4,138	4,908	6,724	8,392
Depreciation, depletion and amortization	7,170	6,492	10,574	11,868	15,464
General and administrative	3,143	3,333	4,133	5,639	7,191
Accretion expense related to asset retirement	-	-	-	41	23
Stock option compensation expense (income)	652	(558)	(84)	313	1,064
Total costs and expenses	15,906	13,405	19,531	24,585	32,134
Operating income	10,928	12,821	7,271	13,923	20,263
Market-to-market loss on derivatives, net	-	-	-	-	(625)
Equity in loss of Pinnacle Gas Resources, Inc.	-	-	-	(830)	(1,399)
Interest expense (income), net of amounts capitalized and interest income	579	269	54	(19)	(622)
Other income and expenses, net	1,482	1,777	274	29	506
Income before income taxes	12,989	14,867	7,599	13,103	18,123
Income tax expense (benefit)	1,004	5,336	2,809	5,063	7,009
Income before cumulative effect of change in accounting principle	11,985	9,531	4,790	8,040	11,114
Dividends and accretion of discount on preferred stock	-	-	588	741	350
Income available to common shareholders before cumulative effect of change in accounting principle	11,985	9,531	4,202	7,299	10,764
	-	-	-	(128)	-

Cumulative effect of change in accounting principle										
Net income available to common shareholders	$	11,985	$	9,531	$	4,202	$	7,171	$	10,764
Basic earnings per common share	$	0.85	$	0.68	$	0.30	$	0.50	$	0.54
Diluted earnings per common share	$	0.74	$	0.57	$	0.26	$	0.43	$	0.49
Basic weighted average shares outstanding		14,028		14,059		14,158		14,312		19,958
Diluted weighted average shares outstanding		16,256		16,731		16,148		16,744		21,818
Statements of Cash Flow Data:										
Net cash provided by operating activities	$	15,906	$	22,669	$	18,572	$	33,631	$	32,501
Net cash used in investing activities		(15,211)		(29,942)		(22,747)		(29,673)		(80,294)
Net cash provided by (used in) financing activities		(3,823)		2,292		5,682		(5,379)		50,139
Other Operating Data:										
Capital expenditures	$	19,746	$	38,264	$	23,343	$	31,930	$	83,891
Debt repayments (1)		3,923		5,479		8,745		5,951		13,737

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	As of December 31,				
	2000	**2001**	**2002**	**2003**	**2004 (Restated)**
Balance Sheet Data:					
Working capital (deficit)	$ 6,433	$ (582)	$ (1,442)	$ (11,817)	$ (8,937)
Property and equipment, net	72,129	104,132	120,526	135,273	205,482
Total assets	93,000	117,392	135,388	156,803	234,345
Long-term debt, including current maturities	34,556	38,188	39,495	36,253	62,974
Convertible participating preferred stock	-	-	6,373	7,114	-
Total equity	52,939	63,204	66,816	76,072	121,060

(1) Debt repayments include amounts refinanced.

Forward Looking Statements. The statements contained in all parts of this document, (including any portion attached hereto) 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 oil and gas exploration, acquisition of 3-D seismic data (including number, timing and size of projects), planned evaluation of prospects, probability of prospects having oil and natural gas, 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 hiring, future exploration activity, production rates, potential drilling locations targeting coal seams, the outcome of legal challenges to new coalbed methane drilling permits in Montana, financing for our 2005 exploration and development program, 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,” “believe” and similar expressions are be among the statements that identify forward looking statements. Such statements involve risks and uncertainties, including, but not limited to, those relating to our dependence on our exploratory drilling activities, the volatility of oil and natural gas prices, the need to replace reserves depleted by production, operating risks of oil and natural gas operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, risks relating to our limited operating history, technological changes, our significant capital requirements, the potential impact of government regulations, adverse regulatory determinations, including those related to coalbed methane drilling in Montana, litigation, competition, the uncertainty of reserve information and future net revenue estimates, property acquisition risks, industry partner issues, availability of equipment, weather and other factors detailed herein and in our other filings with the Securities and Exchange Commission. Some of the factors that could cause actual results to differ from those expressed or implied in forward-looking statements are described under “Management’s Discussion and Analysis of Financial Condition and Results of Operations - 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 duty to update any forward looking statement.

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

You should read this discussion together with the consolidated financial statements and other financial information included in this Form 10-K/A. The financial information in this section has been restated, as further discussed in "Item 8. Financial Statements and Supplementary Data - Note 3 - Financial Restatement". The 2004 to 2003 period to period comparison is based upon restated amounts. Our financial statements and the notes thereto, which are found elsewhere in the Form 10-K/A contain detailed information that should be referred to in conjunction with the following discussion.

Restatement

In connection with the preparation of our consolidated financial statements for the year ended December 31, 2005, we reviewed our accounting policy used to account for our derivatives on oil and natural gas prices on our proved producing properties and determined that these instruments should have been accounted for as non-designated derivatives instead of cash flow hedges in accordance with Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." Accordingly, as a result of the changes in accounting for our derivatives for the oil and natural gas hedges we have restated our consolidated financial statements for the year ended December 31, 2004, as presented in this Form 10-K/A. In addition to the financial statements for the year ended December 31, 2004, these changes in accounting affect the four quarterly periods of 2004. See Note 3 and Note 17 to the Company's consolidated financial statements.

Under cash flow hedge accounting, the after-tax change in the fair value of the open derivative positions ("fair value change") is reported as Other Comprehensive Income in the equity section of the balance sheet. Alternatively, if the derivative does not qualify as a cash flow hedge, mark-to-market accounting requires that the fair value change be reported in earnings. For our cash flow commodity hedges, we had accounted for the realized gain or losses on these hedging activities as being recognized in earnings as oil and natural gas revenues when the forecasted transaction occurred. Our derivative instruments had previously been accounted for as cash flow hedges.

The Company has determined that the derivatives entered into in 2004 were not timely designated as cash flow hedges and lacked sufficient documentation to be accounted for as cash flow hedges. As a result, the Company is restating its financial statements for the year ended December 31, 2004 and all the unaudited quarterly periods in 2004. All such derivatives in this restatement are now classified as non-designated derivatives and are marked-to-market, with realized and unrealized gains and losses being reflected as "mark-to-market gains (losses) on derivatives, net" within the other income and expense section of the Statement of Operations.

In the process of restating our financials to account for our derivatives on a mark-to-market basis, we discovered certain computational errors in the fair value of the Company's derivatives that was previously reported in other comprehensive income in 2004. These errors resulted from the information we had relied upon to establish oil and gas prices in connection with establishing the fair value of the derivatives. For all the periods covered by our consolidated financial statements, we used a third-party website source to obtain oil and gas market prices and to calculate the fair value of the derivatives. However, we determined in the course of our evaluation that the information from the third party provider was not entirely reliable and that Houston Ship Channel market prices should have been used in the fair value computation in place of New York Mercantile ("NYMEX") index prices. Nevertheless, in marking these derivatives to market, the gains and losses reflected in the other income and expense have been based upon corrected fair valuations and were not based upon the information from the third party provider.

These restated amounts have previously been disclosed in our Form 10-K/A amendment to Form 10K for the fiscal year ended December 31, 2005, filed with the SEC on April 11, 2006.

Details of these restatements are presented in this Form 10-K/A in Note 3 to the consolidated financial statements. Where appropriate, notes to the consolidated financial statements and certain other disclosures in this Form 10-K/A have been adjusted to conform to these restatements. A summary of the restated periods is comprised as follows:

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	Year Ended December 31, 2004 As Reported	Year Ended December 31, 2004 As Restated
Statement of Operations:		
Oil and natural gas revenues	$ 51,374	$ 52,397
Operating income	19,240	20,263
Mark-to-market loss of derivatives, net	-	(625)
Income before income taxes	17,725	18,123
Income tax Expense	6,871	7,009
Net income	10,854	11,114
Net income available to common shareholders	$ 10,504	$ 10,764
Earnings per common share		
Basic Earnings per common share	$ 0.53	$ 0.54
Diluted earnings per common share	$ 0.48	$ 0.49

	Year Ended December 31, 2004 As Reported	Year Ended December 31, 2004 As Restated
Cash Flow Statement:		
Net income	$ 10,854	$ 11,114
Fair value (gain) of derivative financial instruments	-	(400)
Deferred income taxes	6,678	6,818
Net cash provided by operating activities	32,501	32,501

	Year Ended December 31, 2004 As Reported	Year Ended December 31, 2004 As Restated
Statement of Shareholders' Equity		
Net income	$ 10,854	$ 11,114
Accumulated other comprehensive income	59	-
Comprehensive income	11,099	11,300

	December 31, 2004 As Reported	December 31, 2004 As Restated
Balance Sheet:		
Other current assets	$ 1,614	$ 1,924
Total current assets	21,634	21,944
Other assets	57	57
Total assets	234,035	234,345
Accrued liabilities	7,516	7,624
Total current liabilities	30,772	30,881
Deferred Income Taxes	18,113	18,113

Retained earnings	20,733	20,993
Accumulated other comprehensive income	59	-
Total Liabilities and Shareholders' Equity	234,035	234,345

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Quarterly Financial Statements (Restated) (Unaudited)

	Quarters Ended							
	March 31, 2004		June 30, 2004		September 30, 2004		December 31, 2004	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
Statement of Operations:								
Oil and Natural Gas Revenues	$ 10,873	$ 10,861	$ 11,959	$ 11,935	$ 12,274	$ 13,041	$ 16,268	$ 16,560
Operating Income	3,801	3,789	3,907	3,883	5,274	6,041	6,258	6,550
Mark-to-market gain (loss) of derivatives, net	-	(972)	-	460	-	(1,296)	-	1,183
Income Before Income Taxes	3,536	2,552	3,526	3,962	5,469	4,940	5,194	6,669
Income Tax Expense	1,353	1,008	1,388	1,539	2,079	1,893	2,051	2,569
Net Income	2,183	1,544	2,138	2,423	3,390	3,047	3,143	4,100
Net Income Available to Common Shareholders	1,985	1,346	1,986	2,271	3,390	3,047	3,143	4,100
Earnings per common share:								
Basic earnings per common share	$ 0.12	$ 0.08	$ 0.10	$ 0.12	$ 0.15	$ 0.14	$ 0.16	$ 0.19
Diluted earnings per common share	$ 0.10	$ 0.07	$ 0.09	$ 0.10	$ 0.15	$ 0.13	$ 0.14	$ 0.18

In conjunction with the Restatement of the quarterly information above, the respective Form 10-Qs as previously filed for the quarterly periods ended March 31, 2004, June 30, 2004 and September 30, 2004 should no longer be relied upon.

General Overview

For the year ended December 31, 2004, we achieved record annual drilling success rates, levels of production, natural gas and oil revenues and our proved oil and gas reserves at the end of 2004 also reached a record level.

Due to our drilling success, we produced a record 8.3 Bcfe in 2004 compared to 7.5 Bcfe in 2003. At the end of 2004, we also reached a record estimated proved reserves level of 109.3 Bcfe with 47.3 Bcfe of net additions for the year, replacing 568% of our 2004 production. See "Business and Properties - Natural Gas and Oil Reserve Replacement."

In 2004, we drilled 71 wells (27.3 net), including 38 wells in the onshore Gulf Coast area and 33 wells in the Barnett Shale play, with a success rate of 92% compared to a success rate of 90% in 2003, in which we drilled 39 wells (10.2 net), in the onshore Gulf Coast and Barnett Shale areas combined. Between January 1, 2002 and December 31, 2004, 78% of our wells drilled were exploratory and 22% were developmental. In 2004, 63% of these wells were exploratory and 37% were developmental. This increase in our percentage of developmental wells reflects our increased activity in the Barnett Shale area, which has a relatively higher concentration of development well targets than the onshore Gulf Coast area.

In 2004, our natural gas and oil revenues reached a record level at $51.4 million, and our net income available to common shareholders was $10.5 million, or $0.53 and $0.48 per basic and fully diluted share, respectively. In 2003, our natural gas and oil revenues were $38.5 million, and our net income available to common shareholders was $7.2 million, or $0.50 and $0.43 per basic and fully diluted share, respectively. These increases in natural gas and oil revenues and net income were attributable in part to the record levels of production discussed above and to higher commodity prices.

Our financial results are largely dependent on a number of factors, including commodity prices. Commodity prices are outside of our control and historically have been and are expected to remain volatile. Natural gas prices in particular have remained volatile during the last few years. Commodity prices are affected by changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, natural gas liquids and crude oil prices, and therefore, cannot accurately predict revenues. In 2004, our realized natural gas price was 15% higher and our realized oil price was 42% higher in 2004 than in 2003.

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 fluctuations associated with a portion of our natural gas and oil production and to achieve a more predictable cash flow. The use of these arrangements limits our ability to benefit from potential increases in the prices of natural gas and oil. Our hedging arrangements may apply to only a portion of our production and provide only partial protection against declines in natural gas and oil prices.

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We have continued to reinvest a substantial portion of our operating cash flows into funding our drilling program and increasing the amount of 3-D seismic data available to us. In 2005, we expect capital expenditures to be approximately $85 to $90 million, as compared to $82.6 million in 2004.

At December 31, 2004, our debt-to-total book capitalization ratio was 34.3%, an increase from the 30.4% ratio at the end of 2003. This increase was primarily the result of: (1) an increase of $11 million in the amount borrowed under our revolving credit facility, (2) the issuance of the 10% Senior Subordinated Secured Notes and (3) a $1.6 million net increase related to the 9% Senior Subordinated Notes; partially offset by increases in shareholders' equity from (1) the $23.3 million of net proceeds from the public offering in February 2004 and (2) the $7.5 million preferred stock conversion to common stock in the second quarter 2004. The debt changes are described under "—Liquidity and Capital Resources—Financing Arrangements."

Since our initial public offering, we have grown primarily through the exploration of properties within our project areas although we consider acquisitions from time to time and may in the future complete acquisitions that we find attractive.

2004 Public Offering

In the first quarter of 2004, we completed the public offering of 6,485,000 shares of our common stock at $7.00 per share. The offering included 3,655,500 newly issued shares offered by us and 2,829,500 shares offered by certain existing stockholders. Our net proceeds of approximately $23.3 million from this offering were used: (1) to accelerate our drilling program, (2) to retain larger interests in portions of our drilling prospects that we otherwise would sell down (or for which we would seek joint partners), (3) to fund a portion of our activities in the Barnett Shale area and (4) for general corporate purposes. We did not receive any proceeds from the shares sold by the selling stockholders.

Barnett Shale Area

In mid-2003, we became active in the Barnett Shale play located in Tarrant and Parker counties in Northeast Texas. Our activity accelerated as a result of the acquisition on February 27, 2004 of working interests and acreage in certain oil and gas wells located in the Newark East Field in Denton County, Texas in the Barnett Shale trend for $8.2 million (the "Barnett Shale Acquisition"). This acquisition included non-operated working interests in properties ranging from 12.5% to 45% over 3,800 gross acres, or an average working interest of 39%. The acquisition included 21 existing gross wells (6.7 net) and interests in approximately 1,500 net acres, which we expect will provide another 31 gross drill sites: five of which were drilled in 2004, 21 of which will target proved undeveloped reserves and five of which will be exploratory.

Initially, we financed our Barnett Shale activities with our available cash on hand. Subsequently, we have financed a portion of our 2004 capital expenditure program for the Barnett Shale area with funds from the October 2004 issuance of the 10% Senior Subordinated Secured Notes. We are exploring a number of financing alternatives which may be used to partially fund our 2005 capital expenditure program for the Barnett Shale area. We may not be able to obtain such financing on terms that acceptable to us, or at all.

In the Barnett Shale area, we drilled six gross wells (2.1 net) in 2003 and 33 gross wells (13.7 net) in 2004, all of which were successful. We plan to drill 37 gross wells (24.0 net) in this area in 2005, subject to obtaining additional financing to supplement our Credit Facility, additional Senior Secured Note financing available and achieving expected operating cash flows. At the end of 2004 our net production had risen to approximately 2.8 MMcfe/d with 38 gross wells on line and another 22 gross wells in various stages of testing, completion and awaiting pipeline hookup. At the end of February 2005 our estimated net production was 3.5 MMcfe/d.

In addition to our drilling activity, we have continued to expand our Barnett Shale acreage position, growing our net leasehold acreage from approximately 4,100 to 30,700 to 35,000 acres, at the end of 2003, 2004 and February 2005, respectively. Similarly, we have increased our estimated number of developmental locations from four to 40 to 41 horizontal locations, at the end of 2003, 2004 and February 2005, respectively and we have increased our estimated number of exploratory drilling locations (horizontal) in the Barnett Shale area from 21 to 152 to 179 locations, at the end of 2003, 2004 and February 2005, respectively.

Pinnacle Gas Resources, Inc.

During the second quarter of 2001, we acquired interests in natural gas and oil leases in Wyoming and Montana in areas prospective for coalbed methane and subsequently began to drill wells on those leases. During the second quarter of 2003, we contributed our interests in certain of these leases to a newly formed company, Pinnacle Gas Resources, Inc. ("Pinnacle"). In exchange for this contribution, we received 37.5% of the common stock of Pinnacle and options to purchase additional Pinnacle common stock. We account for our interest in Pinnacle using the equity method. As a result, our contributed operations and reserves are no longer directly reflected in our financial statements. In March 2004, Credit Suisse First Boston Private Equity Entities (the "CSFB Parties")

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contributed additional funds of $11.8 million into Pinnacle to fund its 2004 development program, which increased the CSFB Parties' ownership to 66.7% on a fully diluted basis assuming we and RMG each elect not to exercise our available options.

In March 2005, Pinnacle entered into a purchase and sale agreement to acquire additional undeveloped acreage, which would also significantly increase its development program budget in 2005. CCBM and the other Pinnacle shareholders have the option to participate in the equity contribution into Pinnacle needed to finance this acquisition and its development program in 2005. Should we elect to maintain our proportionate ownership interest in Pinnacle, we estimate that we would be required to contribute $2.5 million. If CCBM opts not to participate, its fully diluted ownership in Pinnacle would be reduced. CCBM currently plans to purchase additional Pinnacle capital stock valued at $2.5 million in March 2005, its share of the first installment of the equity capital needed to fund the acquisition and part of the additional development program. There can be no assurance regarding CCBM's level of participation in future equity contributions, if any.

In addition to our interest in Pinnacle, we have maintained interests in approximately 162,489 gross acres at the end of 2004 in the Castle Rock coalbed methane project area in Montana and the Oyster Ridge project area in Wyoming. During 2004, we opted to exercise our right to cancel one-half of the remaining note payable to RMG, or approximately $300,000, in exchange for assigning one-half of our mineral interest in the Oyster Ridge leases to RMG, leaving CCBM with a 25% working interest, in this project area. See "Business and Properties—Pinnacle Transaction" for a description of this transaction. Our discussion of future drilling and capital expenditures does not reflect operations conducted through Pinnacle.

Derivative Transactions

Our financial results are largely dependent on a number of factors, including commodity prices. Commodity prices are outside of our control and historically have been and are expected to remain volatile. Natural gas prices in particular have remained volatile during the last few years and more recently oil prices have become volatile. Commodity prices are affected by changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, natural gas liquids and crude oil prices, and therefore, cannot accurately predict revenues.

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 fluctuations associated with a portion of our natural gas and oil production and 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 and provide only partial protection against declines in natural gas and oil prices.

Results of Operations

Year Ended December 31, 2004 Compared to the Year Ended December 31, 2003

Oil and natural gas revenues for 2004 increased 36% to $52.4 million from $38.5 million in 2003. Production volumes for natural gas in 2004 increased 36% to 6,462 MMcf from 4,763 MMcf in 2003. Realized average natural gas prices increased 15% to $6.14 per Mcf in 2004 from $5.35 per Mcf in 2003. Production volumes for oil in 2004 decreased 31% to 309 MBbls from 450 MBbls in 2003. The increase in natural gas production was primarily due to the commencement of production from the Beach House #1 and #2, the Peal Ranch wells, the Barnett Shale wells, the Shadyside #1 (which we later sold in February 2005), the new Encinitas wells and the LL&E #1, partially offset by the natural decline in production from the Hankamer #1, Espree #1, Staubach #1, Burkhart #1R, Pauline Huebner A-382 #1, Matthes Huebner #1, Pitchfork Ranch #1 and other wells. The decrease in oil production was due primarily to the natural decline of production at the Staubach #1, Burkhart #1R, Pauline Huebner A-382 #1, Beach House #1, Matthes Huebner #1, Hankamer #1 and Espree #1, partially offset by the commencement of production from the Delta Farms #1 workover, LL&E #1 and other wells.

Average oil prices increased 42% to $41.00 per Bbl in 2004 from $28.90 per Bbl in 2003.

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, 2003 and 2004:

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	December 31, 2003	December 31, 2004	2004 Period Compared to 2003 Period Increase (Decrease)	% Increase (Decrease)
Production volumes-				
Oil and condensate (Mbbls)	450	309	(141)	(31%)
Natural gas (MMcf)	4,763	6,462	1,699	36%
Average sales prices-(1)				
Oil and condensate (per Bbl)	$ 28.90	$ 41.00	$ 12.10	42%
Natural gas (per Mcf)	5.35	6.14	0.79	15%
Operating revenues (In thousands) -				
Oil and condensate	$ 13,014	$ 12,687	$ (327)	(3%)
Natural gas	25,494	39,710	14,216	56%
Total	$ 38,508	$ 52,397	$ 13,889	36%

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(1) Including the impact of hedging in 2003.

Oil and natural gas operating expenses for 2004 increased 25% to $8.4 million from $6.7 million in 2003. Oil and natural gas operating expenses increased primarily due to higher severance taxes of $0.7 million on higher commodity prices, while higher lifting costs of $0.9 million were attributable to the increased number of producing wells and in part due to higher ad valorem taxes. Operating expenses per equivalent unit in 2004 increased to $1.01 per Mcfe from $0.90 per Mcfe in 2003. The per unit cost increased primarily as a result of the higher costs noted above.

Depreciation, depletion and amortization (“DD&A”) expense for 2004 increased 30% to $15.4 million from $11.9 million in 2003. This increase was primarily due to the increased land, seismic and drilling costs added to the proved property cost base.

General and administrative (“G&A”) expense for 2004 increased 28% to $7.2 million from $5.6 million for 2003. The increase in G&A was due primarily to higher incentive compensation of $0.4 million, higher compensation costs of $0.2 million, higher professional fees of $0.7 million in connection with (1) the 2003 annual audit and Section 404 of the Sarbanes-Oxley Act compliance project ($0.5 million), and (2) discontinued refinancing projects ($0.2 million), and due to an increase in the allowance for doubtful accounts of $0.3 million.

We recorded a $1.4 million after tax charge, or $0.06 per fully diluted share, on our minority interest in Pinnacle. Of this charge, $0.3 million relates to a valuation allowance for federal income taxes. It is likely that Pinnacle will continue to record a valuation allowance on the deferred federal tax benefit generated from the operating losses incurred during the early development stages of Pinnacle’s coalbed methane project. Concurrently, we will record valuation allowances relative to our share of Pinnacle’s financial results.

Mark-to-market gain (loss) on derivatives, net was ($0.6) million in 2004 comprised of (1) $1.0 million of realized loss on net settled derivatives and (2) $0.4 million of net unrealized gain on the derivatives. There were no such gains reported in 2003.

Income taxes increased to $7.0 million in 2004 from $5.1 million in 2003 due to the increase in pre-tax income.

Dividends and accretion of discount on preferred stock decreased to $0.4 million in 2004 from $0.7 million in 2003 as a result of the conversion of all of the Series B Preferred Stock into common stock during the second quarter of 2004.

Net Income available to common shareholders before cumulative effect of change in accounting principle for 2004 increased to $10.8 million from $7.3 million in 2003 primarily as a result of the factors described above.

Year Ended December 31, 2003 Compared to the Year Ended December 31, 2002

Oil and natural gas revenues for 2003 increased 44% to $38.5 million from $26.8 million in 2002. Production volumes for natural gas in 2003 decreased 1% to 4,763 MMcf from 4,801 MMcf in 2002. Realized average natural gas prices increased 53% to $5.35 per Mcf in 2003 from $3.50 per Mcf in 2002. Production volumes for oil in 2003 increased 12% to 450 MBbls from 401 MBbls in 2002. The increase in oil production was due primarily to the commencement of production at the Pauline Huebner A-382 #1, Beach House

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#1 Hankamer and Espree #1. Natural gas production was virtually unchanged compared to 2002 or declined less than 1%. Oil and natural gas revenues include the impact of hedging activities as discussed below under "Volatility of Oil and Gas Prices."

Average oil prices increased 16% to $28.90 per bbl in 2003 from $24.94 per bbl in 2002.

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, 2002 and 2003:

	December 31,		2003 Period Compared to 2002 Period	
	2002	2003	Increase (Decrease)	% Increase (Decrease)
Production volumes-				
Oil and condensate (Mbbls)	401	450	49	12%
Natural gas (MMcf)	4,801	4,763	(38)	(1%)
Average sales prices-(1)				
Oil and condensate (per Bbl)	$ 24.94	$ 28.90	$ 3.96	16%
Natural gas (per Mcf)	3.50	5.35	1.85	53%
Operating revenues (In thousands) -				
Oil and condensate	$ 10,001	$ 13,014	$ 3,013	30%
Natural gas	16,801	25,494	8,693	52%
Total	$ 26,802	$ 38,508	$ 11,706	44%

(1) Including the impact of hedging.

Oil and natural gas operating expenses for 2003 increased 37% to $6.7 million from $4.9 million in 2002. Oil and natural gas operating expenses increased primarily due to higher severance taxes of $0.9 million on higher commodity prices, higher lifting costs of $0.9 million attributable to the increased number of producing wells and in part due to higher ad valorem taxes. Operating expenses per equivalent unit in 2003 increased to $0.90 per Mcfe from $0.68 per Mcfe in 2002. The per unit cost increased primarily as a result of the higher costs noted above.

Depreciation, depletion and amortization ("DD&A") expense for 2003 increased 12% to $11.9 million from $10.6 million in 2002. This increase was primarily due to the increased land, seismic and drilling costs added to the proved property cost base.

General and administrative ("G&A") expense for 2003 increased 36% to $5.6 million from $4.1 million for 2002. The increase in G&A was due primarily to higher incentive compensation of $0.6 million, executive severance of $0.3 million, increased legal and professional fees attributable to special projects and rising insurance costs of $0.1 million.

We recorded a $0.8 million aftertax charge, or $0.05 per fully diluted share, on our minority interest in Pinnacle. Of this charge, $0.2 million, or $0.01 per fully diluted share, relates to a valuation allowance for federal income taxes. It is likely that Pinnacle will continue to record a valuation allowance on the deferred federal tax benefit generated from the operating losses incurred during the early development stages of Pinnacle's coalbed methane project. Concurrently, we will record valuation allowances relative to our share of Pinnacle's financial results.

Income taxes increased to $5.1 million in 2003 from $2.8 million in 2002 due to the increase in pre-tax income.

Dividends and accretion of discount on preferred stock increased to $0.7 million in 2003 from $0.6 million in 2002 as a result of the declaration of dividends on preferred stock in 2003.

Net income available to common shareholders before cumulative effect of change in accounting principle for 2003 increased to $7.3 million from $4.2 million in 2002 primarily as a result of the factors described above.

Liquidity and Capital Resources

During 2004, we made capital expenditures in excess of our net cash flows provided by operating activities, using the proceeds generated from our 2004 public offering, as described in "—General Overview—2004 Public Offering," and from our October 2004 sale of the 10% Senior Subordinated Secured Notes (the "Senior Secured Notes") . For future capital expenditures in 2005, we expect

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to use cash on hand and cash generated by operating activities, draws on the Credit Facility and additional sales of Senior Secured Notes to partially fund our planned drilling expenditures and fund leasehold costs and geological and geophysical costs on our exploration projects in 2005. We also continue to consider other financing alternatives to fund our 2005 capital expenditures program, including possible debt or equity financings.

We may not be able to obtain adequate financing on terms that would be acceptable to us. If we cannot obtain adequate financing, we anticipate that we may be required to limit or defer our planned natural gas and oil exploration and development program, thereby adversely affecting the recoverability and ultimate value of our natural gas and oil properties.

Our liquidity position was enhanced by our receipt of approximately $23.3 million in net proceeds from the completion of the 2004 public offering, the increase in availability of funds under the Credit Facility and the proceeds from the October 2004 sale of the Senior Secured Notes. Our other primary sources of liquidity have included funds generated by operations, proceeds from the issuance of various securities, including our common stock, preferred stock and warrants, and borrowings, primarily under revolving credit facilities and through the issuance of Senior Subordinated Notes. We also recently increased our liquidity through the sale of certain oil and gas properties for $9.0 million in the first quarter of 2005.

Cash flows provided by operating activities were $18.6 million, $33.4 million and $32.5 million for 2002, 2003 and 2004, respectively. This increase in cash flows provided by operations in 2003 as compared to 2002 was due primarily to higher commodity prices and higher trade payables in 2003. The decrease in cash flows provided by operations in 2004 as compared to 2003 was primarily due to a smaller increase in trade payables, partially offset by higher operating income, generally due to record production and record commodity prices realized in 2004.

Estimated maturities of long-term debt are $0.1 million in 2005, none in 2006, $18.0 million in 2007 and the remainder in 2008. The following table sets forth estimates of our contractual obligations as of December 31, 2004:

	Payments Due by Year (In thousands)				
	Total	2005	2006 to 2007	2008 to 2009	Thereafter
Long-Term Debt(1)	$ 64,961	$ 90	$ 18,032	$ 46,839	$ -
Operating Leases	3,186	222	954	954	1,056
Total Contractual Cash Obligations	$ 68,147	$ 312	$ 18,986	$ 47,793	$ 1,056

(1) Includes future accretion of discounts.

We have planned capital expenditures in 2005 of approximately $85 to $90 million, of which $70.0 million is expected to be used for drilling activities in our project areas and the balance is expected to be used to fund 3-D seismic surveys, land acquisitions and capitalized interest and overhead costs. We plan to drill approximately 34 gross wells (14.4 net) in the onshore Gulf Coast area and 37 gross wells 24.0 net in our Barnett Shale and nine gross well (7.7 net) in our East Texas areas in 2005. As described above, we expect to seek additional financing to fund a portion of our acquisition, exploration and development program in 2005. If we are not successful in obtaining this financing, our capital expenditures could be reduced by $15 to $20 million in 2005. The actual number of wells drilled and capital expended is dependent upon available financing, cash flow, availability and cost of drilling rigs, land and partner issues and other factors. The planned capital expenditures do not include the additional contributions to

Pinnacle as described under "– General Overview – Pinnacle Gas Resources, Inc."

We have continued to reinvest a substantial portion of our cash flows into increasing our 3-D prospect portfolio, improving our 3-D seismic interpretation technology and funding our drilling program. Oil and gas capital expenditures were $23.3 million, $31.9 million and $82.6 (including the Barnett Shale Acquisition) for 2002, 2003 and 2004, respectively. Our drilling efforts resulted in the successful completion of 17 gross wells (6.0 net) in 2002, 35 gross wells (9.4 net) in 2003, including six gross wells (2.1 net) in the Barnett Shale area, and 65 gross wells (23.6 net) in 2004 including 33 gross wells (13.7 net) in the Barnett Shale area . We also expect to make an additional $2.5 million equity contribution to Pinnacle. See "-Overview-Pinnacle Gas Resources, Inc."

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Since its inception, CCBM has spent $5.0 million for drilling costs through the end of 2004, 50% of which was applied pursuant to an obligation to fund $2.5 million of drilling costs on behalf of RMG. By December 31, 2004, CCBM had satisfied all of its drilling obligations on behalf of RMG.

Through the end of 2004, Pinnacle has reported that it has drilled 241 gross wells since inception and estimates that 97% of these wells have been completed. Pinnacle reportedly added approximately 16.2 Bcfe of net proved reserves through development drilling through December 31, 2004, excluding the 10.6 Bcfe contributed or acquired at inception. Its gross operated production has increased by approximately 170% since its inception (to approximately 13 MMcf/d at December 31, 2004), and its total well count stands at 485 gross operated wells, according to Pinnacle. Because of the nature of coalbed methane wells that require an extended dewatering period before significant natural gas production, Pinnacle has not been able to complete its determination on commerciality of all of these wells.

Off Balance Sheet Arrangements

We currently do not have any off balance sheet arrangements.

Financing Arrangements

Credit Facility

On September 30, 2004, we entered into a Second Amended and Restated Credit Agreement with Hibernia National Bank and Union Bank of California, N.A. (the "Credit Facility"), maturing on September 30, 2007. The Credit Facility amended, restated and extended our prior credit facility with Hibernia National Bank, amended and restated on December 12, 2002 (such prior facility herein referred to as the "Prior Credit Facility"). The Credit Facility provides for (1) a revolving line of credit of up to the lesser of the Facility A Borrowing Base and $75.0 million and (2) a term loan facility of up to the lesser of the Facility B Borrowing Base and $25.0 million. It is secured by substantially all of our assets and is guaranteed by our subsidiary.

The Facility A Borrowing Bases will be determined by the lenders at least semi-annually on each November 1 and May 1. The Facility A Borrowing Base, under the Credit Facility, on September 30, 2004 and December 31, 2004 was $28 million and $30 million, respectively, of which $19.0 and $18.0 million, respectively, were drawn and outstanding. The Facility A Borrowing Base, under the Prior Credit Facility, on December 31, 2003 was $19.0 million, of which $7.0 million was drawn and outstanding. We used proceeds from the public offering in February 2004 to repay the outstanding balance under the Prior Credit Facility.

We and the lenders may each request one unscheduled borrowing base determination subsequent to each scheduled determination. The Facility A Borrowing Base will at all times equal the Facility A Borrowing Base most recently determined by the lenders, less quarterly borrowing base reductions required subsequent to such determination. The lenders will reset the Facility A Borrowing Base amount at each scheduled and each unscheduled borrowing base determination date.

If the outstanding principal balance of the revolving loans under the Credit Facility exceeds the Facility A Borrowing Base at any time (including, without limitation, due to a quarterly borrowing base reduction (as described above)), 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 Facility A 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.

For each revolving loan, the interest rate will be, at our option, (1) the Eurodollar Rate, plus an applicable margin equal to 2.375% if the amount borrowed is greater than or equal to 90% of the Facility A Borrowing Base, 2.0% if the amount borrowed is less than 90%, but greater than or equal to 50% of the Facility A Borrowing Base, or 1.625% if the amount borrowed is less than 50% of the Facility A Borrowing Base; or (2) the Base Rate, plus an applicable margin of 0.375% if the amount borrowed is greater than or equal to 90% of the Facility A Borrowing Base. The interest rate on each term loan will be, at our option, (1) the Eurodollar Rate, plus an applicable margin to be determined by the lenders; or (2) the Base Rate, plus an applicable margin to be determined by the lenders. Interest on Eurodollar Loans is payable on either the last day of each Eurodollar option period or monthly, whichever is earlier. Interest on Base Rate Loans is payable monthly.

We are subject to certain covenants under the terms of the Credit Facility, which were amended at the time of the issuance of the Senior Secured Notes. These covenants, as amended, include, but are not limited to the maintenance of the following financial covenants: (1) a minimum current ratio of 1.0 to 1.0 (including availability under the borrowing base), (2) a minimum quarterly debt services coverage of 1.25 times, (3) a minimum shareholders' equity equal to $100.0 million, plus 100% of all subsequent common and preferred equity contributed by shareholders subsequent to June 30, 2004, plus 50% of all positive earnings occurring subsequent to June 30, 2004, plus, 180 days after issuance of any second-lien subordinated debt with another lender (the "Secured Subordinated Debt"), an amount equal to the difference, if positive, of (A) 50% of the net proceeds from the issuance less (B) 100% of all common and preferred equity contributed by shareholders from September 30, 2004 to the date of the issuance of any Secured Subordinated Debt, and (4) a maximum total recourse debt to EBITDA ratio (as defined in the Credit Facility) of not more than 3.0 to 1.0. The Credit Facility also places restrictions on additional indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, asset pledges and mortgages, change of control, repurchase or redemption for cash of our common stock, speculative commodity transactions and other matters.

In connection with the Senior Secured Notes Purchase Agreement, we amended the Credit Facility including without limitation, to: (1) amend the covenant regarding maintenance of a minimum shareholders' equity, (2) add a new covenant requiring maintenance of a minimum EBITDA to interest expense ratio and (3) add other provisions and a consent which allow for the indebtedness incurred under the Senior Secured Notes.

On November 7, 2004, we determined that, as of September 30, 2004, we were not in compliance with the minimum current ratio covenant in the Credit Facility. We cured the noncompliance on October 29, 2004 with the issuance of the Senior Secured Notes. On November 10, 2004, the lenders under the Credit Facility agreed in a letter to the Company to waive the noncompliance period from September 30, 2004 through October 29, 2004.

At December 31, 2003 and 2004, no letters of credit were issued and outstanding under the Prior Credit Facility and the Credit Facility, respectively.

Rocky Mountain Gas Note

In June 2001, CCBM issued a non-recourse promissory note payable in the amount of $7.5 million to RMG as consideration for certain interests in oil and natural gas leases held by RMG in Wyoming and Montana. The RMG note was payable in 41-monthly principal payments of $0.1 million plus interest at 8% per annum commencing July 31, 2001 with the balance due December 31, 2004. The RMG note was secured solely by CCBM's interests in the oil and natural gas leases in Wyoming and Montana. At December 31, 2003 and 2004, the outstanding principal balance of this note was $0.9 million and $0, respectively. In connection with our investment in Pinnacle, we received a reduction in the principal amount of the RMG note of approximately $1.5 million and relinquished the right to certain revenues related to the properties contributed to Pinnacle. In the second quarter of 2004, we opted to exercise our right to cancel one-half of the remaining note payable to RMG, or approximately $300,000, in exchange for assigning one-half of our mineral interest in the Oyster Ridge leases to RMG.

Capital Leases

In December 2001, we entered into a capital lease agreement secured by certain production equipment in the amount of $0.2 million. The lease is payable in one payment of $11,323 and 35 monthly payments of $7,549 including interest at 8.6% per annum. In October 2002, we entered into a capital lease agreement secured by certain production equipment in the amount of $0.1 million. The lease is payable in 36 monthly payments of $3,462 including interest at 6.4% per annum. In May 2003, we entered into a capital lease agreement secured by certain production equipment in the amount of $0.1 million. The lease is payable in 36 monthly payments of $3,030 including interest at 5.5% per annum. In August 2003, we entered into a capital lease agreement secured by certain production equipment in the amount of $0.1 million. The lease is payable in 36 monthly payments of $2,179 including interest at 6.0% per annum. We have the option to acquire the equipment at the conclusion of the lease for $1 under all of these leases. Depreciation on the capital leases for the years ended December 31, 2003 and 2004 amounted to $48,000 and $46,000, respectively, and accumulated depreciation on the leased equipment at December 31, 2003 and 2004 amounted to $78,000 and $0.1 million, respectively.

Senior Subordinated Notes and Related Securities

In December 1999, we consummated the sale of $22.0 million principal amount of 9% Senior Subordinated Notes due 2007 (the "Subordinated Notes") and $8.0 million of common stock and warrants. We sold $17.6 million, $2.2 million, $0.8 million, $0.8 million and $0.8 million principal amount of Subordinated Notes; 2,909,092, 363,636, 121,212, 121,212 and 121,212 shares of our common stock and 2,208,152, 276,019, 92,006, 92,006 and 92,006 warrants to CB Capital Investors, L.P. (now known as JPMorgan Partners (23A SBIC), L.P.), Mellon Ventures, L.P., Paul B. Loyd, Jr., Steven A. Webster and Douglas A.P. Hamilton, respectively. The Subordinated Notes were sold at a discount of $0.7 million, which is being amortized over the life of the notes. Interest payments are due quarterly commencing on March 31, 2000. As amended and described below, the Subordinated Notes allow us, by annual election and we have historically elected, to increase the amount of the Subordinated Notes by 60% of the interest which would otherwise be payable in cash through December 15, 2006. As a result, our cash obligation on the Subordinated Notes will increase significantly after December 2006. As of December 31, 2003 and 2004, the outstanding balance of the Subordinated Notes had been increased by $5.3 million and $6.8 million, respectively, for such interest paid in kind. Concurrently with the sale of the Subordinated Notes, we sold to the original purchasers 3,636,634 shares of our common stock at a price of $2.20 per share and warrants expiring in December 2007 to purchase up to 2,760,189 shares of our common stock at an exercise price of $2.20 per share. For accounting purposes, the warrants were valued at $0.25 each.

In 2004, Mellon Ventures, L.P., JPMorgan Partners (23A SBIC), Steven A. Webster and Douglas A. P. Hamilton exercised warrants to purchase 276,019, 2,208,152, 92,006 and 92,006 shares of common stock, respectively, on a cashless exercise basis for a total of 205,692, 1,684,949, 70,205 and 70,205 shares of common stock, respectively, and Paul B. Loyd, Jr., exercised warrants to purchase 92,006 shares for a total of 92,006 shares of common stock. As a result, no warrants to purchase shares remain outstanding from the warrants originally issued in December 1999.

On June 7, 2004, an unaffiliated third party (the "Subordinated Notes Purchaser") purchased all the outstanding Subordinated Notes from the original note holders. In exchange for a $0.4 million amendment fee, certain terms and conditions of the Subordinated Notes were amended, to provide for, among other things, (1) a one year extension of the maturity to December 15, 2008, (2) a one year extension, through December 15, 2005, of the paid-in-kind ("PIK") interest option to pay-in-kind 60% of the interest due each period by increasing the principal balance by a like amount (the "PIK option"), (3) an additional one year option to extend the PIK option through December 15, 2006 at an annual interest rate on the deferred amount of 10% and the payment of a one-time fee equal to 0.5% of the principal then outstanding, (4) an increase and extension on the prepayment premium on the Subordinated Notes, (5) a modification of a covenant regarding maximum quarterly leverage that our Total Debt will not exceed 3.5 times EBITDA (as such terms are defined in the securities purchase agreement related to the Subordinated Notes) for the last 12 months at any time and (6) additional flexibility to obtain a separate project financing facility in the future. The amendment fee will be amortized over the remaining life of the Subordinated Notes.

We are subject to certain other covenants under the terms under the Subordinated Notes securities purchase agreement, including but not limited to, (a) maintenance of a specified tangible net worth, (b) maintenance of a ratio of EBITDA (earnings before interest, taxes, depreciation and amortization) to quarterly Debt Service (as defined in the agreement) of not less than 1.00 to 1.00, (c) a limitation of our capital expenditures to an amount equal to our EBITDA for the immediately prior fiscal year (unless approved by our Board of Directors) and (d) a limitation on our Total Debt (as defined in the securities purchase agreement related to the Subordinated Notes) to 3.5 times EBITDA for any twelve month period.

Senior Subordinated Secured Notes

On October 29, 2004, we entered into a Note Purchase Agreement (the "Senior Secured Notes Purchase Agreement") with PCRL Investments L.P. (the "Senior Secured Notes Purchaser"). Pursuant to the Senior Secured Notes Purchase Agreement, we may issue up to $28 million aggregate principal amount of our 10% Senior Subordinated Secured Notes due 2008 (the "Senior Secured Notes") for a purchase price equal to 90% of the principal amount of the Senior Secured Notes then issued. On October 29, 2004, the Senior Secured Notes Purchaser purchased $18 million aggregate principal amount of the Senior Secured Notes for a purchase price of $16.2 million. The debt discount is being amortized to interest expense using the effective interest method over the life of the notes. Subject to the satisfaction of certain conditions, we have an option to issue up to an additional $10 million aggregate principal amount of the Senior Secured Notes to the Senior Secured Notes Purchaser before October 29, 2006.

The Senior Secured Notes are secured by a second lien on substantially all of our current proved producing reserves and non-reserve assets, guaranteed by our subsidiary, and subordinated to our obligations under the Credit Facility. The Senior Secured Notes bear interest at 10% per annum, payable quarterly on the 5th day of March, June, September and December of each year beginning March 5, 2005. The principal on the Senior Secured Notes is due December 15, 2008, and we have the option to prepay the Senior Secured Notes at any time. The Senior Secured

Notes include an option that allows us to pay-in-kind 50% of the interest due until June 5, 2007 by increasing the principal due by a like amount. Subject to certain conditions, we have the option to pay the interest on and principal of (at maturity or upon prepayment) the Senior Secured Notes with our common stock, as long as the Secured Note Purchaser would not hold more than 9.99% of the number of shares of our common stock outstanding immediately after giving effect to such payment. The value of such shares issued as payment on the Senior Secured Notes is determined based on 90% of the volume weighted average trading price during a specified period of days beginning with the date of the payment notice and ending before the payment date. Our issuance costs related to the transaction were $0.5 million.

As contemplated by the Senior Secured Notes Purchase Agreement, we also entered into a registration rights agreement with the Secured Note Purchaser (the “Registration Rights Agreement”). In the event that we choose to issue shares of our common stock as payment of interest on the principal of the Senior Secured Notes, the Registration Rights Agreement provides registration rights with respect to such shares. We are generally required to file a resale shelf registration statement to register the resale of such shares under the Securities Act of 1933 (the “Securities Act”) if such shares are not freely tradable under Rule 144(k) under the Securities Act. We are subject to certain covenants under the terms of the Registration Rights Agreement, including the requirement that the registration

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statement be kept effective for resale of shares subject to certain “blackout periods,” when sales may not be made. In certain circumstances, including those relating to (1) delisting of our common stock, (2) blackout periods in excess of a maximum length of time, (3) certain failures to make timely periodic filings with the Securities and Exchange Commission, or (4) certain delays or failures to deliver stock certificates, we may be required to repurchase common stock issued as payment on the Senior Secured Notes and, in certain of these circumstances, to pay damages based on the market value of our common stock. In certain situations, we are required to indemnify the holders of registration rights under the Registration Rights Agreement, including, without limitation, for liabilities under the Securities Act.

The Senior Secured Notes Purchase Agreement includes certain representations, warranties and covenants by the parties thereto. We are subject to certain covenants under the terms of the Senior Secured Notes Purchase Agreement, including, without limitation, the maintenance of the following financial covenants: (1) a maximum total recourse debt to EBITDA ratio of not more than 3.50 to 1.0, (2) a minimum EBITDA to interest expense ratio of 2.50 to 1.0, and (3) as of April 30, 2005, a minimum tangible net worth of $12.5 million in excess of our tangible net worth as of September 30, 2004. Upon a change of control, any holders of the Senior Secured Notes may require us to repurchase such holders’ Senior Secured Notes at a price equal to the then outstanding principal amount of such Senior Secured Notes, together with all interest accrued on such Senior Secured Notes through the date of repurchase. The Senior Secured Notes Purchase Agreement also places restrictions on additional indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, asset pledges and mortgages, repurchase or redemption for cash of our common stock, speculative commodity transactions and other matters. The Senior Secured Notes Purchaser is an affiliate of the Subordinated Notes Purchaser.

Series B Preferred Stock

In February 2002, we consummated the sale of 60,000 shares of Series B Preferred Stock and 2002 Warrants to purchase 252,632 shares of common stock for an aggregate purchase price of $6.0 million. We sold $4.0 million and $2.0 million of Series B Preferred Stock and 168,422 and 84,210 warrants to Mellon Ventures, Inc. and Steven A. Webster, respectively. The Series B Preferred Stock was convertible into common stock by the investors at a conversion price of $5.70 per share, subject to adjustment for transactions including issuance of common stock or securities convertible into or exercisable for common stock at less than the conversion price, and is initially convertible into 1,052,632 shares of common stock. The approximately $5.8 million net proceeds of this financing were used to fund our ongoing exploration and development program and general corporate purposes. In the first quarter of 2004, Mellon Ventures exercised all 168,422 of its 2002 warrants on a cashless basis and received 36,570 shares which were sold in the 2004 public offering.

Mellon Ventures, Inc. converted all of its Series B Preferred Stock (approximately 49,938 shares) into 876,099 shares of common stock on May 25, 2004. Steven A. Webster converted all of his Series B Preferred Stock (approximately 25,195 shares) into 442,026 shares of common stock on June 30, 2004. As a result, no shares of Series B Preferred Stock remain outstanding.

The 2002 Warrants have a five-year term and originally entitled the holders to purchase up to 252,632 shares of our common stock at a price of $5.94 per share, subject to adjustment, and are exercisable at any time after issuance. As of December 31, 2004, 84,210 of the 2002 Warrants remained outstanding. For accounting purposes, the 2002 Warrants were valued at $0.06 per Warrant.

Each of our series of warrants was exercisable on a cashless basis at the option of the holder.

On March 22, 2005, Steven A. Webster exercised in full his 2002 Warrants to purchase 84,211 shares of our common stock at a price of $5.94 per share. As a result of the cashless exercise of the 2002 Warrants, Mr. Webster received 54,669 shares of common stock upon exercise.

Recently Issued Accounting Pronouncements

On December 16, 2004, the FASB issued SFAS No. 123 (revised 2004), "Share-Based Payment" ("SFAS No. 123(R)"). SFAS No. 123(R) will require companies to measure all employee stock-based compensation awards using a fair value method and record such expense in its consolidated financial statements. In addition, the adoption of SFAS No. 123(R) requires additional accounting and disclosure related to the income tax and cash flow effects resulting from share-based payment arrangements. SFAS No. 123(R) is effective beginning as of the first interim or annual reporting period beginning after June 15, 2005. The Company is in the process of determining the impact of the requirements of SFAS No. 123(R). The Company believes it is likely that the impact of the requirements of SFAS No. 123(R) will significantly impact the Company's future results of operations and continues to evaluate it to determine the degree of significance.

In December 2004, SFAS No. 153, "Exchanges of Nonmonetary Assets - an amendment of APB Opinion No. 29" is effective for fiscal years beginning after June 15, 2005. This Statement addresses the measurement of exchange of nonmonetary assets and eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets in paragraph 21(b) of

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APB Opinion No. 29, “Accounting for Nonmonetary Transactions” and replaces it with an exception for exchanges that do not have commercial substance. The adoption of SFAS No. 153 is expected to have no impact on the Company’s consolidated financial statements.

In October 2004, the SEC released SAB 106, which expresses the staff’s views on the application of SFAS No. 143 by oil and gas producing companies following the full cost accounting method. SAB 106 provides interpretive responses related to computing the full cost ceiling to avoid double-counting the expected future cash outlays associated with asset retirement obligations, required disclosures relating to the interaction of SFAS No. 143 and the full cost rules, and the impact of SFAS No. 143 on the calculation of depreciation, depletion and amortization. The Company is in the process of determining the impact of the requirements of SAB 106.

Critical Accounting Policies and Estimates

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.

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 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 calculation 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, bad debts, derivatives, contingencies and 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 date and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, 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 markets 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 for employees working directly on exploration activities of $1.0 million, $1.4 million and $1.7 million in 2002, 2003 and 2004, 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. We do not amortize investments in unproved properties until proved reserves associated with the projects can be determined or until these investments are impaired. We periodically evaluate, on a property-by-property basis, unevaluated properties 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 2002, 2003 and 2004 was $1.41, $1.55 and $1.86, 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 subject to a “ceiling test” which limits such costs to the estimated present value, discounted at a 10% interest rate, of future net revenues from proved reserves, based on current economic and

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operating conditions (the “Full Cost Ceiling”). If net capitalized costs exceed this limit, the excess is charged to operations through depreciation, depletion and amortization.

In mid-March 2004, during the year-end close of our 2003 financial statements, it was determined that there was a computational error in the ceiling test calculation which overstated the tax basis used in the computation to derive our after-tax present value (discounted at 10%) of future net revenues from proved reserves. We further determined that this tax basis error was also present in each of our previous ceiling test computations dating back to 1997. This error only affected our after-tax computation, used in the ceiling test calculation and the unaudited supplemental oil and gas disclosure, and did not impact our: (1) pre-tax valuation of the present value (discounted at 10%) of future net revenues from proved reserves, (2) our proved reserve volumes, (3) our EBITDA or our future cash flows from operations, (4) our net deferred tax liability, (5) our estimated tax basis in oil and gas properties, or (6) our estimated tax net operating losses.

After discovering this computational error, the ceiling tests for all quarters since 1997 were recomputed and it was determined that no write-down of our oil and gas assets was necessary in any of the years from 1997 to 2003. However, based upon the oil and natural gas prices in effect on March 31, 2003 and September 30, 2003, the unamortized cost of oil and natural gas properties exceeded the cost center ceiling. As permitted by full cost accounting rules, improvements in pricing and/or the addition of proved reserves subsequent to those dates sufficiently increased the present value of our oil and natural gas assets and removed the necessity to record a write-down in these periods. Using the prices in effect and estimated proved reserves existing on March 31, 2003 and September 30, 2003, the after-tax write-down would have been approximately $1.0 million, and $6.3 million, respectively, had we not taken into account these subsequent improvements. These improvements at September 30, 2003 included estimated proved reserves attributable to our Shady Side #1 well, which we have since sold in February 2005. Because of the volatility of oil and gas prices, no assurance can be given that we will not experience a write-down in future periods.

In connection with our year-end 2004 ceiling test computation, a price sensitivity study also indicated that a 20 percent increase in commodity prices at December 31, 2004 would have increased the pre-tax present value of future net revenues (“NPV”) by approximately $56.5 million. Conversely, a 20 percent decrease in commodity prices at December 31, 2004 would have reduced our NPV by approximately $56.5 million. This would have caused our unamortized cost of proved oil and gas properties to exceed the cost pool ceiling, resulting in an after-tax write-down of approximately $2.7 million. The aforementioned price sensitivity and NPV is as of December 31, 2004 and, accordingly, does not include any potential changes in reserves due to first quarter 2005 performance, such as commodity prices, reserve revisions and drilling results.

The Full Cost Ceiling cushion at the end of 2004 of approximately $32.5 million was based upon average realized oil and natural gas prices of $41.18 per Bbl and $5.68 per Mcf, respectively, or a volume weighted average price of $37.63 per BOE. This cushion, however, would have been zero on such date at an estimated volume weighted average price of $31.50 per BOE. A BOE means one barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids, which approximates the relative energy content of oil, condensate and natural gas liquids as compared to natural gas. Prices have historically been higher or substantially higher, more often for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

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 and estimated future development costs 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, which are primarily oil reserves. We had 42.0 Bcfe, 44.9 Bcfe and 72.5 Bcfe of proved undeveloped reserves, representing 66%, 64% and 66% of our total proved reserves at December 31, 2002, 2003 and 2004, respectively. As of December 31, 2002, 2003 and 2004, a portion of these proved undeveloped reserves, or approximately 41.9 Bcfe, 43.9 Bcfe and 45.7 Bcfe, respectively, are attributable to our Camp Hill properties that we acquired in 1994. See "Business and Properties - East Texas Area -- Camp Hill Project" 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 2.25 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 nondepleted 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

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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 earnings by (i) 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), (ii) an estimated $5.9 million in 2003 (due to higher depletion expense) and (iii) an estimated $3.4 million in 2004 (due to higher depletion expense).

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 reserve data included in this document are estimates prepared by Ryder Scott Company, DeGolyer and MacNaughton, 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 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 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 SEC requirements, we based the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate.

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 9.5% for the year ended December 31, 2004.

Derivative Instruments and Hedging Activities

Upon entering into a derivative contract, we must either designate the derivative instruments as a hedge of the variability of cash flow to be received (cash flow hedge) or the derivatives must be accounted for as non-designated derivatives. Changes in the fair value of a cash flow hedge are recorded in other comprehensive income to the extent that the derivative is effective in offsetting changes in the fair value of the hedged item. Any ineffectiveness in the relationship between the cash flow hedge and the hedged item is recognized currently in income. Gains and losses accumulated in other comprehensive income associated with the cash flow hedge are recognized in earnings as oil and natural gas revenues when the forecasted transaction occurs. All of our derivative instruments at December 31, 2002, 2003 and 2004 had been designated as cash flow hedges. However, in connection with the preparation of our consolidated financial statements for the year ended December 31, 2005, we determined that we had not timely designated the instruments as a cash flow hedges and was lacking certain other documentation for the derivatives entered into during 2004. As a result, we are restating in this Form 10-K/A the consolidated financial information for 2004 (and the quarterly financial data for all periods in 2004), accounting for them as non-designated derivatives. Accordingly, these derivatives will be marked-to-market at the end of each period and the realized and unrealized gain or loss will be recorded as market to market gains and losses on derivatives, net within other income on our Statement of Income. See Note 3 of the notes to the consolidated financial statements for further discussion of the financial restatement.

When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value and gains and losses that were accumulated in other comprehensive income will be recognized in earnings immediately. In all other situations in which hedge accounting is discontinued, the derivative will be carried at fair value on the balance sheet with future changes in its fair value recognized in future earnings.

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For 2003 and prior years, we typically used fixed rate swaps and costless collars to hedge our exposure to material changes in the price of natural gas and oil. We formally documented all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking various hedge transactions. This process included linking all derivatives that are designated cash flow hedges to forecasted transactions. We also formally assessed, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions.

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 policy, and reviews volumes, types of instruments and counterparties, on a quarterly basis. These policies are followed by management through the execution of trades 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 authorized 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.

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 "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—Natural gas and oil prices are highly volatile, and lower prices will negatively affect our financial results."

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

Total oil purchased and sold under swaps and collars during 2002, 2003 and 2004 were 131,300 Bbls, 193,600 Bbls and 121,700, respectively. Total natural gas purchased and sold under swaps and collars in 2002, 2003 and 2004 were 2,314,000 MMBtu, 2,739,000 MMBtu and 3,936,000 MMBtu, respectively. The net losses realized by us under such hedging arrangements were $(0.9 million), $(1.8 million) and $(1.0) million for 2002, 2003 and 2004, respectively, and were included in oil and natural gas revenues for 2002 and 2003 and mark-to-market gain (loss) on derivative, net for 2004.

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. For derivatives designated as cash flow hedges, we record the costs and any benefits derived from these price floors as a reduction or increase, as applicable, in natural gas and oil sales revenue. The costs to purchase put options are amortized over the option period. We do not hold or issue derivative instruments for trading purposes.

As of December 31, 2004, unrealized gains on oil and gas derivatives of $0.4 million were included in mark-to-market gain on derivatives, net.

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

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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 be exposed again to price risk. We have some 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 derivative 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 gas derivative transactions are generally settled based upon the average of the reporting settlement prices on the Houston Ship Channel 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. For the month of December 2004, a $0.10 change in the price per Mcf of gas sold would have changed revenue by $71,000. A $0.70 change in the price per barrel of oil would have changed revenue by $16,000.

The table below summarizes our total natural gas production volumes subject to derivative transactions during 2004 and the weighted average Houston Ship Channel reference price for those volumes.

Natural Gas Swaps			**Natural Gas Caps**		
Volumes MMBtu		180,000	Volumes MMBtu		3,756,000
Average price $/MMBtu	$	6.67	Average price $/MMBtu		
			Floor	$	4.50
			Ceiling	$	6.47

The table below summarizes our total crude oil production volumes subject to derivative transactions during 2004 and the weighted average Houston Ship Channel reference price for those volumes.

Crude Oil Swaps			**Crude Oil Caps**		
Volumes Bbls		91,200	Volumes Bbls		30,500
Average price $/Bbls	$	33.72	Average price $/Bbls		
			Floor	$	42.83
			Ceiling	$	51.84

At December 31, 2003 and 2004 we had the following outstanding derivative positions:

	December 31, 2003				
	Contract Volumes		**Average**	**Average**	**Average**
Quarter	**BBls**	**MMbtu**	**Fixed Price**	**Floor Price**	**Ceiling Price**
First Quarter 2004	27,000		$ 30.36		
First Quarter 2004		180,000	6.67		
First Quarter 2004		546,000		$ 4.10	$ 7.00

Second Quarter 2004	18,300		30.38		
Second Quarter 2004		546,000		4.00	5.60
Third Quarter 2004		552,000		4.00	5.60
Fourth Quarter 2004		369,000		4.00	5.80

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	December 31, 2004				
	Contract Volumes		Average	Average	Average
Quarter	BBls	MMbtu	Fixed Price	Floor Price	Ceiling Price
First Quarter 2005	27,000			$ 41.67	$ 50.50
First Quarter 2005		928,000		5.40	8.11
Second Quarter 2005		364,000		5.25	7.15
Second Quarter 2005		91,000	$ 6.03		
Third Quarter 2005		368,000		5.25	7.40
Third Quarter 2005		92,000	6.03		
Fourth Quarter 2005		276,000		5.25	7.92
Fourth Quarter 2005		92,000	6.03		

In addition to the derivative positions above, during the second quarter of 2003, we acquired options to sell 6,000 MMBtu of natural gas per day for the period July 2003 through August 2003 (552,000 MMBtu) at $8.00 per MMBtu for approximately $119,000. We acquired these options to protect our cash position against potential margin calls on certain natural gas derivatives due to large increases in the price of natural gas. These options were classified as derivatives. As of December 31, 2003, these options have expired and a charge of $119,000 has been included in other income and expense for the year ended December 31, 2003.

Since year-end 2004, we entered into costless collar arrangements covering 1,099,000 MMBtu of natural gas for April 2005 through December 2005 production comprised as follows: 455,000 MMbtu in the second quarter 2005 with average floor and ceiling prices of $6.10 and $7.50, respectively, 368,000 MMbtu in the third quarter 2005 with average floor and ceiling prices of $6.15 and $7.69, respectively, and 276,000 MMbtu in the fourth quarter 2005 with average floor and ceiling prices of $6.00 and $8.60, respectively. We also entered into swap arrangements covering 27,100 Bbls of crude oil for February 2005 and June 2005 production at an average fixed price of $50.19.

RISK FACTORS

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 on the success of our drilling efforts, which involve numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. Historically, we have been particularly dependent upon exploratory drilling, which generally involves greater risk than developmental drilling. 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.

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Because we identify the areas desirable for drilling 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. 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. 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 reduce our available cash and other resources, which would result in a significant decline in our production and revenues. 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 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 depend on a number of factors, including:

· the results of our exploration efforts and the acquisition, review and analysis of our 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, license options, farm-outs, other rights to explore 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. 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.

There are uncertainties inherent in estimating natural gas and oil reserves and their estimated values, 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 subjective and inexact process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The reserve data included in this Form 10-K/A represents estimates that depend on a number of factors and is based on assumptions that may vary considerably from actual results, including:

· historical production from the area compared with production from other areas;

· the assumed effects of regulations by governmental agencies;

- assumptions concerning future natural gas and oil prices;
- future operating costs;
- severance and excise taxes;

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- development costs; and
- workover and remedial costs.

For these reasons, estimates of the economically recoverable quantities of natural gas and oil attributable to any particular group of properties, classifications of those reserves based on risk of recovery and estimates of the future net cash flows expected from them prepared by different engineers or by the same engineers but at different times may vary substantially. 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, 2004, approximately 83% 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, 2004 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 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 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 SEC, 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 in 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 depletion dependent on reservoir characteristics. Our proved reserves will decline as reserves are produced unless we conduct successful exploration and development activities or acquire properties containing proved reserves, or both. 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 must find 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 may be unable to complete our desired exploratory activity, and our ability to maintain or expand our asset base of natural gas and oil reserved would be impaired.

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NATURAL GAS AND OIL PRICES ARE HIGHLY VOLATILE, AND LOWER PRICES WILL NEGATIVELY AFFECT OUR FINANCIAL RESULTS.

Prevailing prices of natural gas and oil substantially affect 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. 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;
- 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 on and maintain oil price controls.

Declines in natural gas and oil prices may materially adversely affect our financial condition, liquidity and ability to finance planned capital expenditures and results of operations.

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. 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, particularly given our size, 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

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available technology that is appropriate for our activities, our business, financial condition and results of operations could be materially adversely affected.

WE ARE SUBJECT TO VARIOUS GOVERNMENTAL REGULATIONS AND ENVIRONMENTAL RISKS.

Natural gas and oil operations are subject to various federal, state and local 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. Further, we or our affiliates hold certain mineral leases in the State of Montana that require coalbed methane drilling permits, the issuance of which has been challenged in pending litigation. We may not be able to obtain new permits in an optimal time period or at all. 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 MAY NOT HAVE ENOUGH INSURANCE TO COVER ALL OF THE RISKS WE FACE.

In accordance with customary industry practices, we maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. We do not carry business interruption insurance. We may elect not to carry insurance if our 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. While we intend to obtain and maintain appropriate insurance coverage for these risks, there can be no assurance that our operations will not expose us to liabilities exceeding such insurance coverage or to liabilities not covered by insurance.

WE CANNOT CONTROL THE ACTIVITIES ON PROPERTIES WE DO NOT OPERATE AND ARE UNABLE TO ENSURE THEIR PROPER OPERATION AND PROFITABILITY.

We do not operate all of the properties in which we have an interest. As of December 31, 2004, a majority of the gross wells in which we had an interest were operated by others. We have limited ability to exercise influence over, and control the risks associated with, operations of the properties we do not operate. 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. The success and timing of our drilling and development activities on properties operated by others therefore depend on a number of factors outside of our control, including the operator's

- timing and amount of capital expenditures;
- expertise and financial resources;

· inclusion of other participants in drilling wells; and

· use of technology.

THE MARKETABILITY OF OUR 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 on the proximity of our reserves to, and the availability and capacity of, facilities and third party services, including oil and natural gas gathering systems, pipelines, trucking or terminal facilities and processing facilities. We generally deliver natural gas through gas gathering systems and gas pipelines that we do not own under interruptible or

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short-term transportation agreements. Under those of our transportation agreements that are interruptible, the transportation of our natural 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. The unavailability or lack of capacity of third party services and facilities could result in the shut-in of our producing wells or the delay or discontinuance of development plans for properties, any of which could adversely affect our revenues and financial condition.

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 problems. Any acquisition of property interests may not be economically successful, and economically unsuccessful acquisitions may have a material adverse effect on our financial condition and future results of operations. We have grown primarily through exploratory activities rather than the acquisition of producing properties. Our experience in acquisitions, therefore, has been limited, which could heighten this risk.

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 each of S.P. Johnson IV, our President and Chief Executive Officer, Paul F. Boling, our Chief Financial Officer, Gregory E. Evans, our Vice President of Exploration, Kendall A. Trahan, our Vice President of Land, and J. Bradley Fisher, our Vice President of Operations. 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.

WHEN WE HEDGE THE PRICE RISKS ASSOCIATED WITH OUR PRODUCTION, WE MAY BE REQUIRED TO MAKE CASH PAYMENTS OR PREVENTED FROM BENEFITING TO THE FULLEST EXTENT POSSIBLE 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 hedging 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.

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 existing or new credit facilities may not be available in the future. 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 program and thereby adversely affect the recoverability and ultimate value of our natural gas and oil properties, in turn materially adversely affecting our business, financial condition and results of operations. Our ability to raise additional capital will depend on the results of operations and the status of various capital and industry markets at the time such additional capital is sought. Accordingly, capital may not become available to us from any particular source or at all. Even if additional capital becomes available, it may not be on terms acceptable to us.

OUR 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 proved reserve amounts and the resulting increase in our estimated discounted future net revenue have allowed us to increase our available borrowing amounts. In the future, commodity prices may decline, we may increase our borrowings or our borrowing base may be adjusted downward, thereby reducing our borrowing capacity. Our credit facility is secured by a pledge of substantially all of our producing natural gas and oil properties assets, is guaranteed by our subsidiary and contains covenants that limit additional borrowings, dividends to nonpreferred shareholders, the incurrence of liens, investments, sales or pledges of assets, changes in control, repurchases or redemptions for cash of our common or preferred stock, speculative commodity transactions and other matters. The credit facility also requires that specified financial ratios be maintained. We may not be able to refinance our debt or obtain additional financing, particularly in view of our credit facility's restrictions on our ability to incur additional debt and the fact that substantially all of our assets are currently pledged to secure obligations under the credit facility. The restrictions of our 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 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;

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

We may incur additional debt in order to fund our exploration and development activities. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and reduce our level of indebtedness depends on future performance. General economic conditions, natural gas and oil prices and financial, business and other factors, many of which are beyond our control, affect our operations and our future performance. Our senior subordinated notes and senior subordinated secured notes contain restrictive covenants similar to those under our credit facility.

In addition, under the terms of our credit facility, our borrowing base is subject to redeterminations at least semiannually 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 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 above in "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.

Item 8. Financial Statements and Supplementary Data

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

Item 9A. Controls and Procedures

(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 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 and 15d-15, 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 of the end of the period covered by this report. As described below under Management's Annual Report on Internal Control over Financial Reporting, we identified material weaknesses in the Company's internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)). As a result of these material weaknesses, 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, the Company's disclosure controls and procedures were not effective. The Company has outlined a number of initiatives, as discussed below under paragraph (b) of this Item 9A.

The audit report of Pannell Kerr Forster of Texas, P.C., dated March 15, 2005, which was included in the Form 10-K, expressed an unqualified opinion on our consolidated financial statements, and its assessment of Management's Annual Report on Internal Control over Financial Reporting is included herein under paragraph (d) of this Item 9A.

(b) MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING. Management, including the Company's Chief Executive Officer and Chief Financial Officer, has the responsibility for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). 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 accounting principles generally accepted in the United States of America ("GAAP"). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate or insufficient because of changes in operating conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A control deficiency exists when the design or operation of a control does not allow management or employees, in the ordinary course of performing their assigned functions, to prevent or detect misstatements on a timely basis. A significant deficiency is a control deficiency, or combination of control deficiencies, that adversely affects the Company's ability to initiate, authorize, record, process, or report external financial data reliably in accordance with GAAP, such that there is a more than remote likelihood that a misstatement of the Company's annual or interim financial statements that is more than inconsequential will not be prevented or detected. A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

Management assessed internal control over financial reporting of the Company and its subsidiary as of December 31, 2004. The Company's management conducted its assessment in accordance with the Internal Control -- Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"):

CLOSING CYCLE

Upon completion of the Company's Sarbanes-Oxley Compliance assessment, the Company identified the following control deficiencies present in its closing cycle.

- The accounting system is a manually intensive system, requiring the extensive use of spreadsheets to accumulate data and prepare the underlying support for reconciliations, account analysis and routine journal entries, all of which increases the review time and chance for error.

- The current vacancy on the accounting staff for a financial reporting director, partially remedied by reliance upon independent financial reporting consultants for review of critical accounting areas and disclosures and material non-standard transactions.

As described below, when considered in the aggregate, these deficiencies constituted a material weakness over the effectiveness of detection and monitoring controls over the financial statement close process. 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, 2004. The Company had previously noted conditions related to the sufficiency of review applied to the financial statement closing process in connection with the finalization of its 2003 financial statements.

The manual year-end closing processes were performed substantially by our accounting and finance staff, with some reliance on contract professionals and financial reporting consultants. The combination of our manual, review intensive accounting system and the absence of a financial reporting director placed greater burdens of detailed reviews upon our middle and upper-level accounting professionals which, in turn compromised the level of their qualitative review of the financial statements and disclosures in the time available. These review procedures are an important component of our controls surrounding the closing process. As a result, we believe that the lack of a financial reporting director, the greater demands on the time of our accounting staff and their overall

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workload resulted in inadequate staffing, supervision and financial reporting expertise in our accounting department, which constituted a material weakness in our internal controls as of December 31, 2004.

Accordingly, in connection with its audit of our 2004 financial results, Pannell Kerr Forster of Texas, P.C. ("PKF"), our independent registered public accounting firm, detected a number of errors and/or omissions, none of which were material, individually or in aggregate, but were an indication that the aforementioned material weakness was present at December 31, 2004, increasing the likelihood to more than remote that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected. The most notable of these errors related to stock based compensation expense and related footnote disclosures. Correcting adjustments were recorded by the Company prior to the finalization of its 2004 financial statements. The Company has implemented procedures to prevent these specific errors from occurring in the future. However, the additional initiatives (outline below), are needed to remediate the material weakness in our internal controls, and thus lower the risk level to remote of other potential material errors or omissions.

We plan to take the following initiatives in 2005: (1) increasing the level of our professional accounting staff, including the successful placement of a financial reporting professional (recruiting efforts were begun in the second half of 2004), (2) expanding the use of independent reviews by outside financial reporting experts during the vacancy of our financial reporting position, and (3) completing our transition to a new fully-integrated accounting software system (data conversion began in 2004) to automate processes and improve qualitative reviews. Until these initiatives are fully implemented, we will continue to rely on manual processes and require additional commitment of resources to the closing process to produce our financial records and reports. We have discussed this material weakness and our remediation steps with our Audit Committee.

Subsequent to management's original annual report on internal controls over financial reporting in the Company's 10-K/A filed on May 2, 2005, management determined that other material weaknesses existed as of December 31, 2004, as described in the following two paragraphs:

In connection with the preparation of our consolidated financial statements for the year ended December 31, 2005, we completed a review of our documentation practices underlying our derivative positions in 2004 and determined that we lacked sufficient contemporaneous documentation and did not timely designate our derivative positions at inception as cash flow hedges as required by Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities" to account for these positions as cash flow hedges. Under cash flow hedge accounting, the after-tax change in the fair value of the open derivative positions ("fair value change") is reported as Other Comprehensive Income in the equity section of the balance sheet. Alternatively, if the derivative does not qualify as a cash flow hedge, mark-to-market accounting requires that the fair value change be reported in earnings. This error came to management's attention during the preparation of our Consolidated Financial Statements for the year ended December 31, 2005 which ultimately resulted in a restatement of our financial statements for 2004.

In the process of restating our financials to account for our derivatives on a mark-to-market basis, we discovered certain computational errors in the fair value of the Company's derivatives that was previously reported in other comprehensive income in 2004. These errors resulted from the information we had relied upon to establish oil and gas prices used in connection with determining the fair value of the derivatives. For all the periods covered by our consolidated financial statements, we used a third-party website source to obtain New York Mercantile ("NYMEX") oil and gas prices and then used those prices to determine the fair value of the derivatives. However, we determined in the course of our evaluation that the use of Houston Ship Channel prices was instead required for this purpose which matched the index used within our derivative agreements, furthermore we also determined that the information from the third party provider was not entirely reliable. As a result of the restatement relating to our change in the treatment of our derivatives, we no longer report the change in fair value of our derivatives in other comprehensive income but now record them as a change to earnings. Nevertheless, in marking these derivatives to market, the gains and losses reflected in other income and expense have been based upon corrected amounts that were not based upon the information from the third party provider. These items constituted an additional material weakness in our internal controls as of December 31, 2004. Additional information relating to these items is included in Note 3 to the Company's consolidated financial statements.

PKF has issued its own attestation report on management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004, which is filed herewith.

(c) CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING. There have not been any changes in the Company's internal control over financial reporting during the fiscal quarter ended December 31, 2004 that have materially affected, or are reasonably likely to materially affect, the Company's 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, the Company identified a material weakness in the Company's internal control over financial reporting and has described a number of planned changes to its internal control over financial reporting during 2005 designed to remediate this weakness.

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(d) REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM.

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

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting (Restated) appearing under Item 9A, that Carrizo Oil & Gas, Inc. did not maintain effective internal control over financial reporting as of December 31, 2004, because of the effect of the material weakness identified in management's assessment, based on criteria established in Internal Control--Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. In our report dated May 2, 2005, we expressed an unqualified opinion on management's assessment that the Company did not maintain effective internal control over financial reporting and a qualified opinion on the effectiveness of internal control over financial reporting. As previously reported, a material weakness was identified and included in management's assessment of internal control over financial reporting. Management identified, at that time, the following internal control deficiencies that constitute a material weakness:

- The accounting system is a manually intensive system, requiring the extensive use of spreadsheets to accumulate data and prepare the underlying support for reconciliations, account analysis and routine journal entries, all of which increases the review time and chance for error.

- The current vacancy on the accounting staff for a financial reporting director, partially remedied by reliance upon independent financial reporting consultants for review of critical accounting areas and disclosures and material non-standard transactions.

As described in the following paragraph, the Company subsequently identified an error in its 2004 annual financial statements and 2004 interim financial statements, which caused such financial statements to be restated in April 2006. Management subsequently revised its assessment due to the identification of additional material weaknesses, described in the following paragraph, which resulted in the April 2006 financial statement restatements for 2004. Accordingly, our opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 expressed herein is different from that expressed in our initial report dated May 2, 2005.

Additional material weaknesses have been identified and included in management's assessment regarding the fact that management did not design and maintain adequate controls over the accounting for derivative instruments in accordance with Statement of Financial Accounting Standards No. 133, *"Accounting for Derivative Instruments and Hedge Activities."* Management concluded that

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derivatives entered into during 2004 lacked sufficient documentation to be accounted for as cash flow hedges. Furthermore, these hedges were not properly fair valued during these periods due to the failure to use the appropriate market index. These material weaknesses have caused the restatement of the consolidated financial statements for the year ended December 31, 2004 and for the three, six and nine month periods included in the quarterly reports on Form 10-Q for the periods ended March 31, June 30 and September 30, 2004. These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements as of and for the year ended December 31, 2004 (as restated) and this report does not affect our report on such restated financial statements.

In our opinion, management’s revised assessment that Carrizo Oil & Gas, Inc. did not maintain effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, Carrizo Oil & Gas, Inc. has not maintained effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the Standards of the Public Company Accounting Oversight Board (United States), the Consolidated Balance Sheet and the related Consolidated Statements of Income, Cash Flows, and Stockholders’ Equity of Carrizo Oil & Gas, Inc. as of and for the year ended December 31, 2004. Our report dated March 15, 2005 (April 10, 2006 as to the effects of the restatement discussed in Note 3) expressed an unqualified opinion on those financial statements and included an explanatory paragraph relating to the restatement described in Note 3 to the financial statements.

We do not express an opinion or any level of assurance on management’s statement referring to the effectiveness of the process instituted to remediate the material weaknesses.

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

Houston, Texas
Described in Management’s Report on Internal Control over Financial Reporting (Restated) May 2, 2005 (April 10, 2006 as to the effects of the additional material weaknesses)

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(A)(1) FINANCIAL STATEMENTS

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

(A)(2) FINANCIAL STATEMENT SCHEDULES

All schedules and other statements for which provision is made in the applicable regulations of the Commission have been omitted because they are not required under the relevant instructions or are inapplicable.

(A)(3) EXHIBITS

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 June 6, 1998 (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).

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EXHIBIT NUMBER	DESCRIPTION
3.2 --	Amended and Restated Bylaws of the Company, as amended by Amendment No. 1 (Incorporated herein by reference to Exhibit 3.2 to the Company's Registration Statement on Form 8-A (Registration No. 000-22915), Amendment No. 2 (Incorporated herein by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K dated December 15, 1999) and Amendment No. 3 (Incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated February 20, 2002).
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 --	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)).
+10.8 --	Employment Agreement between the Company and Kendall A. Trahan (Incorporated herein by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).
+10.9 --	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)).
+10.10 --	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)).
10.11 --	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).
10.12 --	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)).
10.13 --	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)).
+10.14 --	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).

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EXHIBIT NUMBER	DESCRIPTION
10.15 --	Securities Purchase Agreement dated December 15, 1999 among the Company, CB Capital Investors, L.P., Mellon Ventures, L.P., Paul B. Loyd Jr., Douglas A. P. Hamilton and Steven A. Webster (Incorporated herein by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K dated December 15, 1999).
10.16 --	First Amendment to Securities Purchase Agreement dated as of June 7, 2004 among Carrizo Oil & Gas, Inc., Steelhead Investments Ltd., Douglas A.P. Hamilton, Paul B. Loyd, Jr., Steven A. Webster and Mellon Ventures, L.P. (incorporated herein by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed on June 10, 2004).
10.17 --	Form of Amended and Restated 9% Senior Subordinated Note due 2008 (incorporated herein by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed on June 10, 2004).
10.18 --	Second Amendment to Securities Purchase Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc. and the Investors named therein (incorporated herein by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed on November 3, 2004).
10.19 --	Shareholders Agreement dated December 15, 1999 among the Company, CB Capital Investors, L.P., Mellon Ventures, L.P., 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 99.2 to the Company's Current Report on Form 8-K dated December 15, 1999).
10.20 --	First Amendment to Shareholders Agreement dated as of December 15, 1999 by and among Carrizo Oil & Gas, Inc, J.P. Morgan Partners (23A SBIC), LLC, Mellon Ventures, L.P., S.P. Johnson IV, Frank A. Wojtek, Steven A. Webster, Douglas A.P. Hamilton, Paul B. Loyd, Jr. and DAPHAM Partnership, L.P. dated April 21, 2004 (incorporated herein by reference to Exhibit 32 to the Schedule 13D/A filed by Paul B. Loyd, Jr. on May 27, 2004).
10.21 --	Second Amendment to Shareholders Agreement dated as of December 15,1999 by and among Carrizo Oil & Gas, Inc., J.P. Morgan Partners (23A SBIC), LLC, Mellon Ventures, L.P., S.P. Johnson IV, Frank A. Wojtek and Steven A. Webster dated June 7, 2004 (incorporated herein by reference to Exhibit 99.4 to the Company's Current Report on Form 8-K filed on June 10, 2004).
10.22 --	Registration Rights Agreement dated December 15, 1999 among the Company, CB Capital Investors, L.P. and Mellon Ventures, L.P. (Incorporated herein by reference to Exhibit 99.4 to the Company's Current Report on Form 8- K dated December 15, 1999).
10.23 --	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).
+10.24 --	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).
10.25 --	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).
10.26 --	Purchase and Sale Agreement by and between Rocky Mountain Gas, Inc. and CCBM, Inc., dated June 29, 2001 (Incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
10.27 --	Securities Purchase Agreement dated February 20, 2002 among the Company, Mellon Ventures, L.P. and Steven A. Webster (Incorporated herein by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K dated February 20, 2002).

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EXHIBIT NUMBER	DESCRIPTION
10.28 --	Warrant Agreement dated February 20, 2002 among the Company, Mellon Ventures, L.P. and Steven A. Webster (including Warrant Certificate) (Incorporated herein by reference to Exhibit 99.4 to the Company's Current Report on Form 8-K dated February 20, 2002).
10.29 --	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).
+10.30 --	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).
10.31 --	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).
10.32 --	Contribution and Subscription Agreement dated June 23, 2003 by and among Pinnacle Gas Resources, Inc., CCBM, Inc., Rocky Mountain Gas, Inc. and the CSFB Parties listed therein (Incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.33 --	Transition Services Agreement dated June 23, 2003 by and between the Company and Pinnacle Gas Resources, Inc. (Incorporated herein by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.34 --	Second Amended and Restated Credit Agreement dated as of September 30, 2004 by and among Carrizo Oil & Gas, Inc., CCBM, Inc., Hibernia National Bank, as Agent, Union Bank of California, N.A., as co-agent, and Hibernia National Bank and Union Bank of California, N.A., as lenders (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 6, 2004).
10.35 --	First Amendment to Second Amended and Restated Credit Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc., CCBM, Inc., Hibernia National Bank and Union Bank of California, N.A. (incorporated herein by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on November 3, 2004).
10.36 --	Commercial Guaranty made and entered into as of September 30, 2004 by CCBM, Inc. in favor of Hibernia National Bank, as agent (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on October 6, 2004).
10.37 --	Amended and Restated Stock Pledge and Security Agreement dated and effective as of September 30, 2004 by Carrizo Oil & Gas, Inc. in favor of Hibernia National Bank, as agent (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on October 6, 2004).
10.38 --	Note Purchase Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc., the Purchasers named therein and PCRL Investments L.P., as collateral agent (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 3, 2004).
10.39 --	Form of 10% Senior Subordinated Secured Note due 2008 (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on November 3, 2004).
10.40 --	Stock Pledge and Security Agreement dated as of October 29, 2004 by Carrizo Oil & Gas, Inc. in favor of PCRL Investments L.P., as collateral agent (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on November 3, 2004).
10.41 --	Commercial Guaranty dated as of October 29, 2004 by CCBM, Inc. in favor of PCRL Investments L.P., guarantying the indebtedness of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on November 3, 2004).

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EXHIBIT NUMBER	DESCRIPTION
10.42 --	Registration Rights Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc. and the Investors named therein (incorporated herein by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on November 3, 2004).
*+10.43 --	Form of Stock Option Award Agreement.
+10.44 --	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).
*10.45 --	Director Compensation.
*10.46 --	Base Salaries and 2004 Annual Bonuses 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 Ernst & Young LLP.
**23.3 --	Consent of Ryder Scott Company Petroleum Engineers.
**23.4 --	Consent of Fairchild & Wells, Inc.
**23.5 --	Consent of DeGolyer and MacNaughton.
**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, 2004.
*99.2 --	Summary of Reserve Report of Fairchild & Wells, Inc. as of December 31, 2004.
*99.3 --	Summary of Reserve Report of DeGolyer and MacNaughton as of December 31, 2004.

* Previously filed.
** Filed herewith.
+ Compensatory plan, contract or arrangement.

CARRIZO OIL & GAS, INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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 sheet of Carrizo Oil & Gas, Inc. as of December 31, 2004 (restated) and the related consolidated statements of operations, shareholders' equity and cash flows for the year ended December 31, 2004 (restated). 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 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 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Carrizo Oil & Gas, Inc. at December 31, 2004 (restated), and the consolidated results of its operations and its cash flows for the year then ended (restated), in conformity with U.S. generally accepted accounting principles.

As referred to in Note 3, management of the Company determined that derivatives entered into during 2004 lacked sufficient documentation to be accounted for as cash flow hedges. As a result, the Company has restated its consolidated financial statements as of and for the year ended December 31, 2004.

/s/PANNELL KERR FORSTER OF TEXAS, P.C.

Houston, Texas
March 15, 2005
(Except for Note 3 for which the date
is April 10, 2006)

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheet of Carrizo Oil & Gas, Inc. as of December 31, 2003, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the two years in the period ended December 31, 2003. 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. The consolidated financial statements of Carrizo Oil & Gas, Inc. as of December 31, 2001 and for the year then ended, were audited by other auditors who have ceased operations and whose report dated March 20, 2002, expressed an unqualified opinion on those statements.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Carrizo Oil & Gas, Inc. at December 31, 2003, and the consolidated results of its operations and its cash flows for each of the two years in the period ended December 31, 2003, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

/s/Ernst & Young LLP

Houston, Texas
March 25, 2004

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CARRIZO OIL & GAS, INC.

CONSOLIDATED BALANCE SHEETS

		As of December 31,		
ASSETS		**2003**		**2004**
				(Restated)
		(In thousands)		
CURRENT ASSETS:				
Cash and cash equivalents	$	3,322	$	5,668
Accounts receivable, trade (net of allowance for doubtful accounts of none and $325 at December 31, 2003 and 2004, respectively)		8,970		12,738
Advances to operators		1,877		1,614
Other current assets		156		1,924
Total current assets		14,325		21,944
PROPERTY AND EQUIPMENT, net-full-cost method of accounting for oil and natural gas properties (including unevaluated costs of properties of $32,978 and $45,067 at December 31, 2003 and 2004, respectively)		135,273		205,482
Investment in Pinnacle Gas Resources, Inc.		6,637		5,229
Deferred financing costs, net		479		1,633
Other assets		89		57
	$	156,803	$	234,345
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES:				
Accounts payable, trade	$	19,515	$	21,359
Accrued liabilities		1,057		7,624
Advances for joint operations		3,430		1,808
Current maturities of long-term debt		1,037		90
Current maturities of seismic obligation payable		1,103		-
Total current liabilities		26,142		30,881
LONG-TERM DEBT		34,113		62,884
ASSET RETIREMENT OBLIGATION		883		1,407
DEFERRED INCOME TAXES		12,479		18,113
COMMITMENTS AND CONTINGENCIES (Note 11)				
CONVERTIBLE PARTICIPATING PREFERRED STOCK (10,000,000 shares of preferred stock authorized, of which 150,000 are shares designated as convertible participating shares, with 71,987 and zero convertible participating shares issued and outstanding at December 31, 2003 and 2004, respectively) (Note 10)		7,114		-

SHAREHOLDERS' EQUITY:				
Warrants (3,262,821 and 334,210 outstanding at December 31, 2003 and 2004, respectively)		780		80
Common stock, par value $.01 (40,000,000 shares authorized with 14,591,348 and 22,161,457 issued and outstanding at December 31, 2003 and 2004, respectively)		146		221
Additional paid in capital		65,103		99,766
Retained earnings		10,229		20,993
Accumulated other comprehensive income (loss)		(186)		-
Total shareholders' equity		76,072		121,060
	$	156,803	$	234,345

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

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CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31, 2002	2003	2004 (Restated)
	(In thousands except for per share amounts)		
OIL AND NATURAL GAS REVENUES	$ 26,802	$ 38,508	$ 52,397
COSTS AND EXPENSES:			
Oil and natural gas operating expenses (exclusive of depletion, depreciation and amortization, shown separately below)	4,908	6,724	8,392
Depreciation, depletion and amortization	10,574	11,868	15,464
General and administrative	4,133	5,639	7,191
Accretion expenses related to asset retirement obligation	-	41	23
Stock option compensation (benefit)	(84)	313	1,064
Total costs and expenses	19,531	24,585	32,134
OPERATING INCOME	7,271	13,923	20,263
OTHER INCOME AND EXPENSES:			
Mark-to-market loss on derivatives, net	-	-	(625)
Equity in loss of Pinnacle Gas Resources, Inc.	-	(830)	(1,399)
Other income and expenses	274	29	506
Interest income	55	58	75
Interest expense	(846)	(617)	(2,553)
Interest expense, related parties	(2,255)	(2,379)	(1,082)
Capitalized interest	3,100	2,919	2,938
INCOME BEFORE INCOME TAXES	7,599	13,103	18,123
INCOME TAXES (Note 7)	2,809	5,063	7,009
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	4,790	8,040	11,114
DIVIDENDS AND ACCRETION ON PREFERRED STOCK	588	741	350
INCOME AVAILABLE TO COMMON SHAREHOLDERS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	4,202	7,299	10,764
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, NET OF INCOME TAXES	-	(128)	-
	$ 4,202	$ 7,171	$ 10,764

NET INCOME AVAILABLE TO COMMON SHAREHOLDERS			
BASIC EARNINGS PER COMMON SHARE BEFORE CUMULATIVE			
EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	$ 0.30	$ 0.51	$ 0.54
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING			
PRINCIPLE, NET OF INCOME TAXES	-	(0.01)	-
BASIC EARNINGS PER COMMON SHARE	$ 0.30	$ 0.50	$ 0.54
DILUTED EARNINGS PER COMMON SHARE BEFORE CUMULATIVE			
EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	$ 0.26	$ 0.44	$ 0.49
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING			
PRINCIPLE, NET OF INCOME TAXES	-	(0.01)	-
DILUTED EARNINGS PER COMMON SHARE	$ 0.26	$ 0.43	$ 0.49
WEIGHTED AVERAGE SHARES OUTSTANDING:			
BASIC	14,158,438	14,311,820	19,958,452
DILUTED	16,148,443	16,744,296	21,818,065

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

	Warrants		Common Stock	
	Number	**Amount** (Dollars in thousands)	**Shares**	**Amount**
BALANCE, January 1, 2002	3,010,189	$ 765	14,064,077	$ 141
Net income	-	-	-	-
Net change in fair value of hedging instruments	-	-	-	-
Comprehensive income				
Warrants issued	252,632	15	-	-
Common stock issued	-	-	113,306	1
Dividends and accretion of discount on preferred stock	-	-	-	-
BALANCE, December 31, 2002	3,262,821	780	14,177,383	142
Net income	-	-	-	-
Net charge in fair value of derivative financial instruments	-	-	-	-
Comprehensive income				
Common stock issued	-	-	413,965	4
Dividends and accretion of discount on preferred stock	-	-	-	-
BALANCE, December 31, 2003	3,262,821	780	14,591,348	146
Net income (Restated)	-	-	-	-
Net change in fair value of derivative financial instruments (Restated)	-	-	-	-
Comprehensive income (Restated)				
Warrants converted	(2,836,605)	(677)	2,067,621	20
Warrants exercised for cash	(92,006)	(23)	92,006	1
Common stock issued, secondary offering, net of offering costs	-	-	3,655,500	37
Stock options exercised for cash	-	-	436,858	4
Preferred stock conversion	-	-	1,318,124	13

Tax benefit of stock options exercised	-		-	-		-
Stock option compensation	-		-	-		-
Dividends and accretion of discount on preferred stock	-		-	-		-
BALANCE, December 31, 2004 (Restated)	334,210	$	80	22,161,457	$	221

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

	Additional Paid in Capital	Comprehensive Income	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (loss)	Shareholders' Equity
			(Dollars in thousands)		
BALANCE, January 1, 2002	$ 62,736		$ (1,144)	$ 706	$ 63,204
Net income	-	$ 4,790	4,790	-	4,790
Net change in fair value of hedging instruments	-	(1,094)	-	(1,094)	(1,094)
Comprehensive income		$ 3,696			
Warrants issued	-		-	-	15
Common stock issued	488		-	-	489
Dividends and accretion of discount on preferred stock	-		(588)	-	(588)
BALANCE, December 31, 2002	63,224		3,058	(388)	66,816
Net income	-	$ 7,912	7,912	-	7,912
Net change in fair value of derivative financial instruments	-	202	-	202	202
Comprehensive income		$ 8,114			
Common stock issued	1,879		-	-	1,883
Dividends and accretion of discount on preferred stock	-		(741)	-	(741)
BALANCE, December 31, 2003	65,103		10,229	(186)	76,072
Net income (Restated)	-	$ 11,114	11,114	-	11,114
Net change in fair value of derivative financial instruments (Restated)	-	186	-	186	186
Comprehensive income (Restated)		$ 11,300			
Warrants converted	657		-	-	-
Warrants exercised for cash	224		-	-	202
Common stock issued, secondary offering, net of offering costs	23,262		-	-	23,299
Stock options exercised for cash	1,650		-	-	1,654

Preferred stock conversion		7,452		-	-		7,465
Tax benefit of stock options exercised		1,045		-	-		1,045
Stock option compensation		373		-	-		373
Dividends and accretion of discount on preferred stock		-		(350)			(350)
BALANCE, December 31, 2004 (Restated)	$	99,766	$	20,993	-	$	121,060

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

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CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Year Ended December 31,		
	2002	**2003**	**2004** (Restated)
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Income before cumulative effect of change in accounting principle	$ 4,790	$ 8,040	$ 11,114
Adjustments to reconcile net income to net cash provided by operating activities -			
Depreciation, depletion and amortization	10,574	11,868	15,464
Fair value (gain) loss on derivative financial instruments	-	-	(400)
Provision for allowance for doubtful accounts	-	-	325
Accretion of discounts on asset retirement obligations and debt	86	161	177
Ineffective derivative instruments	(706)	119	-
Stock option compensation (benefit)	(84)	313	1,064
Equity in loss of Pinnacle Gas Resources, Inc.	-	830	1,399
Deferred income taxes	2,645	4,883	6,818
Other	-	-	296
Changes in assets and liabilities -			
Accounts receivable	530	(762)	(4,094)
Other assets	(59)	335	(1,470)
Accounts payable	643	7,803	(689)
Accrued liabilities	153	41	2,497
Net cash provided by operating activities	18,572	33,631	32,501
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(23,343)	(31,930)	(83,891)
Proceeds from the sale of oil and natural gas properties	355	-	-
Change in capital expenditure accrual	(949)	1,755	4,955
Advances to operators	8	(1,377)	263
Advances for joint operations	1,182	1,879	(1,621)
Net cash used in investing activities	(22,747)	(29,673)	(80,294)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from sale of common stock:			
Secondary offering, net of offering costs	-	-	23,299
Other	14	691	1,856
Net proceeds from sale of preferred stock	5,800	-	-
Net proceeds from debt issuance	8,613	-	16,200
Advances under borrowing base facility	-	-	24,000
Debt repayments	(8,745)	(5,951)	(13,737)
Deferred loan costs	-	-	(1,479)
Loss on ineffective derivatives	-	(119)	-
Net cash provided by (used in) financing activities	5,682	(5,379)	50,139

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		1,507		(1,421)		2,346
CASH AND CASH EQUIVALENTS, beginning of year		3,236		4,743		3,322
CASH AND CASH EQUIVALENTS, end of year	$	4,743	$	3,322	$	5,668
SUPPLEMENTAL CASH FLOW DISCLOSURES:						
Cash paid for interest (net of amounts capitalized)	$	1	$	77	$	697
Cash paid for income taxes	$	-	$	-	$	-

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. (Carrizo, a Texas corporation; together with its subsidiary, affiliates and predecessors, the Company) is an independent energy company formed in 1993 and is engaged in the exploration, development, exploitation and production of oil and natural gas. Its operations are focused along the onshore Gulf Coast of Texas and Louisiana, primarily the Frio, Wilcox and Vicksburg trends and in the Barnett Shale trend in North Texas. The Company, through CCBM, Inc. (a wholly-owned subsidiary) ("CCBM"), acquired interests in certain oil and natural gas leases in Wyoming and Montana in areas prospective for coalbed methane. During 2003, the Company obtained offshore licensees to explore in the U.K. North Sea and acquired interests in the Barnett Shale trend located in Tarrant and Parker counties in North Texas.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The consolidated financial statement 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 subsidiary. All intercompany accounts and transactions have been eliminated in consolidation.

Investment in Unconsolidated Subsidiary

The Company's investment in Pinnacle Gas Resources, Inc. ("Pinnacle") is recorded using the equity method of accounting. Under this method, the investment is recorded at cost initially, and the investment is adjusted for the Company's equity in the subsidiary's profit or loss. The investment is further adjusted for additional contributions to and distributions from the subsidiary.

The Company would also record any loss in fair value of the investment other than a temporary decline.

Reclassifications

Certain reclassifications have been made to prior periods' financial statements to conform to the current presentation.

Critical Accounting Policies and 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 reporting periods. Actual results could differ from these estimates.

Significant 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, bad debts, derivatives, contingencies and 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. Results of drilling, testing and production subsequent to the date of the estimate 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 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

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to these assumptions may affect these significant estimates materially in the near term.

The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of its consolidated financial statements:

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 for employees working directly on exploration activities of $1.0 million, $1.4 million and $1.7 million in 2002, 2003 and 2004, respectively. Maintenance and repairs are expensed as incurred.

Oil and natural gas properties are amortized based on the unit-of-production method using estimates of proved reserve quantities. Investments in unproved properties are not amortized until proved reserves associated with the projects can be determined or until they are impaired. Unevaluated properties are evaluated periodically for impairment on a property-by-property basis. If the results of an assessment indicate that the properties are impaired, the amount of impairment is added to the proved oil and natural gas property costs to be amortized. The amortizable base includes estimated future development costs and, dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for 2002, 2003 and 2004 was $1.41, $1.55 and $1.86, 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 of proved oil and natural gas properties are subject to a “ceiling test” which limits such costs to the estimated present value, discounted at a 10% interest rate, of future net revenues from proved reserves, based on current economic and operating conditions. If net capitalized costs exceed this limit, the excess is charged to operations through depreciation, depletion and amortization. During the year-end close of 2003, a computational error was identified in the ceiling test calculation which overstated the tax basis used in the computation to derive the after-tax present value (discounted at 10%) of future net revenues from proved reserves. This tax basis error was also present in each of the previous ceiling test computations dating back to 1997. This error only affected the after-tax computation, used in the ceiling test calculation and the unaudited supplemental oil and natural gas disclosure and did not impact: (1) the pre-tax valuation of the present value (discounted at 10%) of future net revenues from proved reserves, (2) the proved reserve volumes, (3) our EBITDA or our future cash flows from operations, (4) the net deferred tax liability, (5) the estimated tax basis in oil and natural gas properties, or (6) the estimated tax net operating losses.

After discovering this computational error, the ceiling tests for all quarters since 1997 were recomputed and it was determined that no write-down of oil and natural gas assets was necessary in any of the years from 1997 to 2003. However, based upon the oil and natural gas prices in effect on March 31, 2003 and September 30, 2003, the unamortized cost of oil and natural gas properties exceeded the cost center ceiling. As permitted by full cost accounting rules, improvements in pricing and/or the addition of proved reserves subsequent to those dates sufficiently increased the present value of the oil and natural gas assets and removed the necessity to record a write-down in these periods. Using the prices in effect and estimated proved reserves on March 31, 2003 and September 30, 2003, the after-tax write-down would have been approximately $1.0 million and $6.3 million, respectively, had we not taken into account the subsequent improvements. These improvements at September 30, 2003 included estimated proved reserves attributable to our Shady Side # 1 well. Because of the volatility of oil and natural gas prices, no assurance can be given that we will not experience a write-down in future periods.

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, DeGolyer and MacNaughton 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 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.

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 sales volumes are not significantly different from the Company's share of production.

Financing Costs

Long-term debt financing costs of $0.5 million and $1.6 million are included in other assets as of December 31, 2003 and 2004, respectively, and are being amortized using the effective yield method over the term of the loans (through September 30, 2007 for the credit facility and through December 15, 2008 for both the Senior Subordinated Notes payable and the Senior Subordinated Secured Notes payable).

Supplemental Cash Flow Information

The Statement of Cash Flows for the year ended December 31, 2002 does not reflect the following non-cash transactions: the $2.5 million acquisition of seismic data, the $0.5 million acquisition of oil and natural gas properties through the issuance of common stock, and the $0.6 million reduction of oil and natural gas properties for the amount of insurance recoveries expected to be received related to difficulties encountered in the drilling of a well. The Statement of Cash Flows for the year ended December 31, 2003 does not include the acquisition of $1.2 million of seismic data through the issuance of common stock, and the $0.2 million non-cash cumulative effect recorded in connection with the implementation of Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations." The Statement of Cash Flows for the year ended December 31, 2004 does not include the net exercise of $0.7 million of warrants and the conversion of $7.5 million of preferred stock into common stock and the $0.3 relinquishment of interests in certain leases to RMG in lieu of principal payments on a note payable.

Financial Instruments

The Company's recorded 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 amount of bank debt approximates fair value as this borrowing bears interest at variable interest rates. The fair value of the 9% Senior Subordinated Notes payable and the 10% Senior Subordinated Secured Notes payable at December 31, 2004 was $28.8 million and $18.0 million, respectively. Fair values of these subordinated notes payable were determined based upon interest rates available to the Company at December 31, 2004 with similar terms.

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Stock-Based Compensation

The Company accounts for employee stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations. Under this method, the Company records no compensation expense for stock options granted when the exercise price of those options is equal to or greater than the market price of the Company's common stock on the date of grant. As allowed by SFAS No. 123, "Accounting for Stock Based Compensation," the Company has continued to apply APB No. 25 for the purposes of determining net income.

In December 2002, the Financial Accounting Standards Board (FASB) issued SFAS No. 148, "Accounting for Stock Based Compensation - Transition and Disclosure, an amendment of SFAS No. 123." The Company has adopted the disclosure requirements of SFAS No. 148 and has elected to record employee compensation expense utilizing the intrinsic value method permitted under APB 25. The Company accounts for its employees' stock-based compensation plan under APB Opinion No. 25 and its related interpretations. Accordingly, any deferred compensation expense would be recorded for stock options based on the excess of the market value of the common stock on the date the options were granted over the aggregate exercise price of the options. This deferred compensation would be amortized over the vesting period of each option to the extent that the market value exceeds the exercise price of the option. Had compensation cost been determined consistent with SFAS No. 123 "Accounting for Stock Based Compensation" for all options, the Company's net income and earnings per share would have been as follows:

	For the Year Ended December 31,					
	2002		2003		2004	
	(In thousands except per share amounts)					
Income available to common shareholders before cumulative effect of change in accounting principle as reported	$	4,202	$	7,299	$	10,764
Add: Stock-based employee compensation expense (benefit) recognized, net of tax		-		-		691
Less: Total stock-based employee compensation expense determined under fair value method for all awards, net of tax		(872)		(662)		(578)
Pro forma income available to common shareholders before cumulative effect of change in accounting principle	$	3,330	$	6,637	$	10,877
Income available to common shareholders						

before cumulative effect of change in accounting						
principle per common share, as reported:						
Basic	$	0.30	$	0.51	$	0.54
Diluted		0.26		0.44		0.49
Pro Forma income available to common						
shareholders before cumulative effect of change						
in accounting principle per common share, as if						
the fair value method had been applied to all awards:						
Basic	$	0.24	$	0.46	$	0.54
Diluted		0.21		0.40		0.50

Repriced options are accounted for as compensatory options using variable accounting treatment in accordance with FASB Interpretation No. 44, “Accounting for Certain Transactions involving Stock Based Compensation – on Interpretation of APB No. 25”

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(FIN 44). Under variable plan accounting, compensation expense is adjusted for increases or decreases in the fair market value of the Company's common stock to the extent that the market value exceeds the exercise price of the option. Variable plan accounting is applied to the repriced options until the options are exercised, forfeited, or expire unexercised (See Note 12).

The fair value of each option grant was estimated on the date of grant using the Black-Scholes option pricing model with the following assumptions used for grants in 2002, 2003 and 2004: risk free interest rate of 4.8%, 4.0%, and 4.3%, respectively, expected dividend yield of 0%, expected life of 10 years and expected volatility of 77.7%, 72.2% and 43.2%, respectively.

Derivative Instruments and Hedging Activities

The Company uses derivatives to manage the price risk underlying its oil and gas production.

Upon entering into a derivative contract, the Company must 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. The Company documents all relationships between hedging instruments and hedged items, as well as its risk management objectives and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designed cash flow hedges to forecasted transactions. The Company also assesses whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions. The cash flow hedges are marked-to-market each reporting period and are recorded as either an asset or as a liability on the balance sheet with the corresponding amount recorded as other comprehensive income, net of tax, within equity. Changes in the fair value of a cash flow hedge are recorded in other comprehensive income to the extent that the derivative is effective in offsetting changes in the fair value of the hedged item. Any ineffectiveness in the relationship between the cash flow and the hedged item is recognized currently in income. Gains and losses accumulated in other comprehensive income associated with the cash flow hedge are recognized in earnings as oil and natural gas revenues when the forecasted transaction occurs. However, in connection with the preparation of the Company's financial statements for the year ended December 31, 2005, the Company determined that it had not timely designated its derivative instruments as cash flow hedges and lacked certain documentation for the derivatives entered into during 2004 to qualify for cash flow hedge accounting treatment. Alternatively, the Company must account for its non-designated derivative activities by marking the instruments to market and record the unrealized gains and/or loss to earnings. As a result, the Company is restating in this Form 10-K/A the consolidated financial statements for 2004 and the quarterly financial data for all periods in 2004. See Note 3 of the notes to the consolidated financial statements for further discussion of this financial restatement.

When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value and gains and losses that were accumulated in other comprehensive income will be recognized in earnings immediately. In all other situations in which hedge accounting is discontinued, the derivative will be carried at fair value on the balance sheet with future changes in its fair value recognized in future earnings. See Note 14 with respect to the Company's positions with an affiliate of Enron Corp.

The Company's Board of Directors sets all of the Company's hedging policy, including volumes, types of instruments and counterparties, on a quarterly basis. These policies are implemented by management through the execution of trades 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 authorized 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 hedging activities quarterly.

Income Taxes

Under SFAS No. 109, "Accounting for Income Taxes," deferred income taxes are recognized 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. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts expected to be realized.

Concentration of Credit Risk

Substantially all of the Company's accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the oil and natural gas industry. 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

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require collateral from its customers and the Company has not experienced material credit losses on such receivables. Further, 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. The Company transacts the majority of its derivative contracts with two counterparties.

Major Customers

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

	For the Year Ended December 31,		
	2002	**2003**	**2004**
WMJ Investments Corp.	-	16%	12%
Cokinos Natural Gas Company	12%	15%	17%
Gulfmark Energy, Inc.	-	14%	-
Texon L.P.	-	-	13%
Discovery Producer Services, LLC.	10%	-	-

Earnings Per Share

Supplemental earnings per share information is provided below:

	For the Year Ended December 31, (In thousands except share and per share amounts)								
	Income			**Shares**			**Per-Share Amount**		
	2002	**2003**	**2004**	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**
Basic Earnings per Common Share									
Income available to common shareholders before cumulative effect of change in accounting principle	$ 4,202	$ 7,299	$ 10,764	14,158,438	14,311,820	19,958,452	$ 0.30	$ 0.51	$ 0.54
Dilutive effect of Stock Options, Warrants and Preferred Stock conversions	-	-	-	1,990,005	2,432,476	1,859,613			
Diluted Earnings per Share									
Income available to common									

shareholders plus assumed conversions before cumulative effect of change in accounting principle	$ 4,202	$ 7,299	$ 10,764	16,148,443	16,744,296	21,818,065	$ 0.26	$ 0.44	$ 0.49

	For the Year Ended December 31, (In thousands except share and per share amounts)								
	Income			**Shares**			**Per-Share Amount**		
	2002	**2003**	**2004**	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**
Cumulative effect of change in accounting principle net of income taxes									
Basic Earnings per Common Share									
Net loss available to common shareholders	$ -	$ (128)	$ -	14,158,438	14,311,820	19,958,452	$ 0.00	$ (0.01)	$ 0.00
Dilutive effect of Stock Options, Warrants and Preferred Stock conversions	-	-	-	1,990,005	2,432,476	1,859,613			
Diluted Earnings per Share									
Cumulative effect of change in accounting principle net of income taxes plus assumed conversions	$ -	$ (128)	$ -	16,148,443	16,744,296	21,818,065	$ 0.00	$ (0.01)	$ 0.00

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	For the Year Ended December 31, (In thousands except share and per share amounts)								
	Income			Shares			Per-Share Amount		
	2002	2003	2004	2002	2003	2004	2002	2003	2004
Basic Earnings per Common Share									
Net income available to common shareholders	$ 4,202	$ 7,171	$ 10,764	14,158,438	14,311,820	19,958,452	$ 0.30	$ 0.50	$ 0.54
Dilutive effect of Stock Options, Warrants and Preferred Stock conversions	-	-	-	1,990,005	2,432,476	1,859,613			
Diluted Earnings per Share									
Net income available to common shareholders plus assumed conversions	$ 4,202	$ 7,171	$ 10,764	16,148,443	16,744,296	21,818,065	$ 0.26	$ 0.43	$ 0.49

Basic earnings per common share is based on the weighted average number of shares of common stock outstanding during the periods. Diluted earnings per common share is based on the weighted average number of common shares and all dilutive potential common shares outstanding during the period. The Company had outstanding 172,333, 117,000 and 30,000 stock options at December 31, 2002, 2003 and 2004, respectively, that were antidilutive. The Company had outstanding 252,632 warrants at December 31, 2002 that were antidilutive. These antidilutive stock options and warrants were not included in the calculation because the exercise price of these instruments exceeded the underlying market value of the options and warrants as of the dates presented. The Company had 1,145,515 and 1,262,930 convertible preferred shares at December 31, 2002 and 2003, respectively, that were antidilutive and were not included in the calculation.

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 FASB issued SFAS No. 143, “Accounting for Asset Retirement Obligations.” 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 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. The ARO is recorded at fair value, 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 Company adopted SFAS No. 143 on January 1, 2003, which resulted in an increase to net oil and natural gas properties of $0.4 million and additional liabilities related to asset retirement obligations of $0.6 million. These amounts reflect the ARO of the Company had the provisions of SFAS No. 143 been applied since inception and resulted in a non-cash cumulative effect decrease to earnings of $0.1 million ($0.2 million pretax). 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, rather than its past practice of accruing the expected undiscounted abandonment costs on a unit-of-production basis over the productive life of the associated full cost pool. 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.

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 then amounts accrued with the ARO are recovered as a gain or loss upon settlement.

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The following table is a reconciliation of the asset retirement obligation liability since adoption:

	For the Year Ended December 31, 2003	For the Year Ended December 31, 2004
	(in thousands)	
Asset retirement obligation at beginning of year	$ 597	$ 883
Liabilities incurred	91	425
Liabilities settled	-	(29)
Accretion expense	42	23
Revisions in estimated liabilities	153	105
Asset retirement obligation at end of year	$ 883	$ 1,407

The following table shows the pro forma effect of the implementation on the Company's income available to common shareholders before cumulative effect of change in accounting principle had SFAS No. 143 been adopted by the Company on January 1, 2002.

	For the Year Ended December 31, 2002 (In thousands, except per share data)
Income Available to Common Shareholders	$ 4,202
Effect on Net Income had SFAS No. 143 been applied	(37)
Income Attributable to Common Stock before Cumulative Effect of Change in Accounting Principle	$ 4,165

Basic Net Income per Common Share:		
Net Income	$	0.30
Effect on Net Income had SFAS No. 143 been applied		-
Net Income	$	0.30
Diluted Net Income per Common Share:		
Net Income	$	0.26
Effect on Net Income had SFAS No. 143 been applied		-
Net Income	$	0.26

Recently Issued Accounting Pronouncements

On December 16, 2004, the FASB issued SFAS No. 123 (revised 2004), "Share-Based Payment" ("SFAS No. 123(R)"). SFAS No. 123(R) will require companies to measure all employee stock-based compensation awards using a fair value method and record such expense in their consolidated financial statements. In addition, the adoption of SFAS No. 123(R) requires additional accounting and disclosure related to the income tax and cash flow effects resulting from share-based payment arrangements. SFAS No. 123(R) is effective beginning as of the first interim or annual reporting period beginning after June 15, 2005. The Company believes it is likely that the impact of the requirements of SFAS No. 123(R) will significantly impact the Company's future results of operations and continues to evaluate it to determine the degree of significance.

In December 2004, SFAS No. 153, "Exchanges of Nonmonetary Assets - an Amendment of APB Opinion No. 29" is effective for fiscal years beginning after June 15, 2005. This statement addresses the measurement of exchange of nonmonetary assets and eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets in paragraph 21(b) of

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APB Opinion No. 29, “Accounting for Nonmonetary Transactions” and replaces it with an exception for exchanges that do not have commercial substance. The Company expects the adoption of SFAS No. 153 to have no impact on its consolidated financial statements.

In October 2004, the SEC released SAB 106, which expresses the staff’s views on the application of SFAS No. 143 by oil and gas producing companies following the full cost accounting method. SAB 106 provides interpretive responses related to computing the full cost ceiling to avoid double counting the expected future cash outflows associated with asset retirement obligations, required disclosure relating to the interaction of SFAS No. 143 and the full cost rules, and the impact of SFAS No. 143 on the calculation of depreciation, depletion and amortization. The Company is in the process of determining the impact of the requirements of SAB 106.

3. FINANCIAL RESTATEMENT

In connection with the preparation of the Company’s consolidated financial statements for the year ended December 31, 2005, the Company reviewed its accounting policy used to account for its derivatives on interest rate swaps on the Second Lien Credit Facility and for oil and natural gas prices on its proved producing properties (“Derivatives”) and determined that these the derivatives entered into in 2004 had not been timely designated and lacked sufficient documentation to be accounted for as cash flow hedges and should have been accounted for as non-designated derivatives instead of cash flow hedges in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 133, “Accounting for Derivative Instruments and Hedging Activities.” Accordingly, as a result of the changes in accounting for the Company’s derivatives for interest rate swaps and the oil and natural gas hedges the Company has restated its consolidated financial statements for the year ended December 31, 2004, as presented in this Form 10-K/A. All such derivatives in this restatement, including oil and gas derivatives and interest rate swaps, are now classified as non-designated derivatives and are marked-to-market, with realized and unrealized gains and losses being reflected as “mark-to-market gains (losses) on derivatives, net” within the other income and expense section of the Statement of Operations. In addition to the financial statements for the year ended December 31, 2004, these changes in accounting affect the four quarterly periods of 2004. Restatements of unaudited quarterly statements of operations are also presented in the table below.

Under cash flow hedge accounting, the after-tax change in the fair value of the open derivative positions (“fair value change”) is reported as Other Comprehensive Income in the equity section of the balance sheet. Alternatively, if the derivative does not qualify as a cash flow hedge, mark-to-market accounting requires that the fair value change be reported in earnings. For the Company’s cash flow commodity hedges, the Company had accounted for the realized gains and losses on these hedging activities in earnings within oil and natural gas revenues when the forecasted transaction occurred. The Company’s derivative instruments had previously been accounted for as cash flow hedges.

In the process of restating its financials to account for its derivatives on a mark-to-market basis, the Company discovered certain computational errors in the fair value of the Company’s derivatives that was previously reported in Other Comprehensive Income. These errors resulted from the information the Company had relied upon to establish oil and gas prices in connection with determining the fair value of the derivatives. For all the periods covered by the Company’s consolidated financial statements, the Company used a third-party website source to obtain oil and gas market prices and to calculate the fair value of the derivatives. However, the Company determined in the course of its evaluation that the information from the third party provider was not entirely reliable and that Houston Ship Channel market prices should have been used in the fair value computation in place of New York Mercantile (“NYMEX”) index prices. Nevertheless, in marking these derivatives to market, the gains and losses reflected in the other income and expense have been based upon corrected fair valuations and were not based upon the information from the third party provider.

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A comparison of the previously reported and restated amounts from the Company's financial statements follows:

	For the Year Ended December 31, 2004	
	As Reported	As Restated
Statement of Operations:		
Oil and natural gas revenues	$ 51,374	$ 52,397
Operating income	19,240	20,263
Mark-to-market loss on derivatives, net	-	(625)
Income before income taxes	17,725	18,123
Income tax expense	6,871	7,009
Net income	$ 10,854	$ 11,114
Net income available to common shareholders	10,504	10,764
Earnings per common share:		
Basic earnings per common share	$ 0.53	$ 0.54
Diluted earnings per common share	$ 0.48	$ 0.49

	For the Year Ended December 31, 2004	
	As Reported	As Restated
Cash Flow Statement:		
Net income	$ 10,854	$ 11,114
Fair value (gain) on derivative financial instrument	-	(400)
Deferred income taxes	6,678	6,818
Net cash provided by operating activities	32,501	32,501

	For the Year Ended December 31, 2004	
	As Reported	As Restated
Statement of Shareholders' Equity:		
Net income	$ 10,854	$ 11,114
Accumulated other comprehensive income	59	-

Comprehensive income	11,099	11,300

	As of December 31, 2004	
	As Reported	As Restated
Balance Sheet:		
Other current assets	$ 1,614	$ 1,924
Total current assets	21,634	21,944
Other Assets	57	57
Total Assets	234,035	234,345
Accrued liabilities	7,516	7,624
Total current liabilities	30,772	30,881
Deferred income taxes	18,113	18,113
Retained earnings	20,733	20,993
Accumulated other comprehensive income	59	-
Total Liabilities and Shareholders' Equity	234,035	234,345

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Quarterly Statements of Operations Data (Restated) (Unaudited)

	For the Quarters Ended							
	March 31, 2004		June 30, 2004		September 30, 2004		December 31, 2004	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
Statement of Operations:								
Oil and Natural Gas Revenues	$ 10,873	$ 10,861	$ 11,959	$ 11,935	$ 12,274	$ 13,041	$ 16,268	$ 16,560
Operating Income	3,801	3,789	3,907	3,883	5,274	6,041	6,258	6,550
Mark-to-market gain (loss) on derivatives, net	-	(972)	-	460	-	(1,296)	-	1,183
Income Before Income Taxes	3,536	2,552	3,526	3,962	5,469	4,940	5,194	6,669
Income tax expense	1,353	1,008	1,388	1,539	2,079	1,893	2,051	2,569
Net Income	2,183	1,544	2,138	2,423	3,390	3,047	3,143	4,100
Net Income Available to Common Shareholders	1,985	1,346	1,986	2,271	3,390	3,047	3,143	4,100
Earnings per common share:								
Basic earnings per common share	$ 0.12	$ 0.08	$ 0.10	$ 0.12	$ 0.15	$ 0.14	$ 0.16	$ 0.19
Diluted earnings per common share	$ 0.10	$ 0.07	$ 0.09	$ 0.10	$ 0.15	$ 0.13	$ 0.14	$ 0.18

In conjunction with the restatement of the quarterly information above, the respective Form 10-Qs as previously filed for the quarterly periods ended March 31, 2004, June 30, 2004, and September 30, 2004 should no longer be relied upon.

4. INVESTMENT IN MICHAEL PETROLEUM CORPORATION

In 2000, the Company received a finder's fee valued at $1.5 million from affiliates of Donaldson, Lufkin & Jenrette ("DLJ") in connection with their purchase of a significant minority shareholder interest in Michael Petroleum Corporation ("MPC"). MPC is a privately held exploration and production company which focuses on the natural gas producing Lobo Trend in South Texas. The minority shareholder interest in MPC was purchased by entities affiliated with DLJ. The Company elected to receive the fee in the form of 18,947 shares of common stock, 1.9% of the outstanding common shares of MPC, which, until its sale in 2001, was accounted for as a cost basis investment. Steven A. Webster, who is the Chairman of the Board of the Company, and a Managing Director of Global Energy Partners Ltd., a merchant banking affiliate of DLJ which makes investments in energy companies, joined the Board of Directors of MPC in connection with the transaction.

In 2001, the Company agreed to sell its interest in MPC pursuant to an agreement between MPC and its shareholders for the sale of a majority interest in MPC to Calpine Natural Gas Company. The Company received total cash proceeds of $5.7 million, of which $5.5 million was paid to the Company during the third quarter of 2001, resulting in a financial statement gain of $3.9 million being reflected in the third quarter 2001 financial results. The remaining amounts were paid in 2003.

5. INVESTMENT IN PINNACLE GAS RESOURCES, INC.

The Pinnacle Transaction

On June 23, 2003, pursuant to a Subscription and Contribution Agreement by and among the Company and its wholly-owned subsidiary, CCBM, Inc., Rocky Mountain Gas, Inc. (“RMG”) and the Credit Suisse First Boston Private Equity entities, named therein (the “CSFB Parties”), CCBM and RMG contributed their respective interests, having a estimated fair value of approximately $7.5 million each, in (1) leases in the Clearmont, Kirby, Arvada and Bobcat project areas and (2) oil and natural gas reserves in the Bobcat project area to a newly formed entity, Pinnacle Gas Resources, Inc., a Delaware corporation. In exchange for the contribution of these assets, CCBM and RMG each received 37.5% of the common stock of Pinnacle (“Pinnacle Common Stock”) as of the closing date and options to purchase Pinnacle Common Stock (“Pinnacle Stock Options”). CCBM no longer has a drilling obligation in connection with the oil and natural gas leases contributed to Pinnacle.

Simultaneously with the contribution of these assets, the CSFB Parties contributed approximately $17.6 million of cash to Pinnacle in return for the Redeemable Preferred Stock of Pinnacle (“Pinnacle Preferred Stock”), 25% of the Pinnacle Common Stock as of the closing date and warrants to purchase Pinnacle Common Stock (“Pinnacle Warrants”). The CSFB Parties also agreed to contribute additional cash, under certain circumstances, of up to approximately $11.8 million to Pinnacle to fund future drilling, development and acquisitions. The CSFB Parties currently have greater than 50% of the voting power of the Pinnacle capital stock through their

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ownership of Pinnacle Common Stock and Pinnacle Preferred Stock.

Immediately following the contribution and funding, Pinnacle used approximately $6.2 million of the proceeds from the funding to acquire an approximate 50% working interest in existing leases and acreage prospective for coalbed methane development in the Powder River Basin of Wyoming from Gastar Exploration, Ltd. Pinnacle also agreed to fund up to $14.9 million of future drilling and development costs on these properties on behalf of Gastar prior to December 31, 2005. The drilling and development work will be done under the terms of an earn-in joint venture agreement between Pinnacle and Gastar. The majority of these leases are part of, or adjacent to, the Bobcat project area. All of CCBM and RMG's interests in the Bobcat project area, the only producing coalbed methane property owned by CCBM prior to the transaction, were contributed to Pinnacle.

Prior to and in connection with its contribution of assets to Pinnacle, CCBM paid RMG approximately $1.8 million in cash as part of its outstanding purchase obligation on the coalbed methane property interests CCBM previously acquired from RMG. As of June 30, 2003, approximately $1.1 million of the remaining balance of CCBM's obligation to RMG was scheduled to be paid in monthly installments of approximately $52,805 through November 2004 and a balloon payment on December 31, 2004, all of which were paid. The RMG note was secured solely by CCBM's interests in the remaining oil and natural gas leases in Wyoming and Montana. In connection with the Company's investment in Pinnacle, the Company received a reduction in the principal amount of the RMG note of approximately $1.5 million and relinquished the right to receive certain revenues related to the properties contributed to Pinnacle.

CCBM continues its coalbed methane business activities and, in addition to its interest in Pinnacle, owns direct interests in acreage in coalbed methane properties in the Castle Rock project area in Montana and the Oyster Ridge project area in Wyoming, which were not contributed to Pinnacle. CCBM and RMG will continue to conduct exploration and development activities on these properties as well as pursue other potential acquisitions. Other than indirectly through Pinnacle, CCBM currently has no proved reserves of, and is no longer receiving revenue from, coalbed methane gas.

As of December 31, 2004, on a fully diluted basis, assuming that all parties exercised their Pinnacle Warrants and Pinnacle Stock Options, the CSFB Parties, CCBM and RMG would have ownership interests of approximately 54.6%, 22.7% and 22.7%, respectively. In March 2004, the CSFB Parties contributed additional funds of $11.8 million into Pinnacle to continue funding the 2004 development program which increased their ownership to 66.7% on a fully diluted basis should CCBM and RMG each elect not to exercise their available options.

For accounting purposes, the transaction was treated as a reclassification of a portion of CCBM's investments in the contributed properties to an investment in Pinnacle Gas Resources, Inc. The property contribution made by CCBM to Pinnacle is intended to be treated as a tax-deferred exchange as constituted by property transfers under section 351(a) of the Internal Revenue Code of 1986, as amended.

The reclassification of investments in contributed properties resulting from the transaction with Pinnacle are reflected in accordance with the full cost method of accounting in the Company's December 31, 2003 balance sheet included in this Form 10-K/A.

6. PROPERTY AND EQUIPMENT

At December 31, 2003 and 2004, property and equipment consisted of the following:

	As of December 31,	
	2003	**2004**
	(In thousands)	

Proved oil and natural gas properties	$ 168,329	$ 241,746
Unproved oil and natural gas properties	32,978	45,067
Other equipment	742	846
Total property and equipment	202,049	287,659
Accumulated depreciation, depletion and amortization	(66,776)	(82,177)
Property and equipment, net	$ 135,273	$ 205,482

Oil and natural gas properties not subject to amortization consist of the cost of unevaluated leaseholds, seismic costs associated with specific unevaluated properties, exploratory wells in progress, and secondary recovery projects before the assignment of proved reserves. These unproved costs are reviewed periodically by 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

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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. Of the $45.1 million of unproved property costs at December 31, 2004 being excluded from the amortizable base, $5.1 million, $5.8 million and $24.8 million were incurred in 2002, 2003 and 2004, respectively, and $9.4 million was incurred in prior years. These costs are primarily seismic and lease acquisition costs. The Company expects it will complete its evaluation of the properties representing the majority of these costs within the next two to five years.

7. INCOME TAXES

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

	For the Year Ended December 31,		
	2002	2003	2004
		(In thousands)	
Provision at the statutory tax rate	$ 2,660	$ 4,586	$ 6,343
Preferred dividend on Pinnacle	-	108	405
Increase in valuation allowance			
for equity in loss of Pinnacle	-	189	70
State taxes	149	180	191
Income tax provision	$ 2,809	$ 5,063	$ 7,009

Deferred income tax provisions result from temporary differences in the recognition of income and expenses for financial reporting purposes and for tax purposes. At December 31, 2003 and 2004, the tax effects of these temporary differences resulted principally from the following:

	As of December 31,	
	2003	2004
	(In thousands)	
Deferred income tax assets:		
Net operating loss carryforward	$ 1,763	$ 2,519
Hedge valuation	100	-
Equity in the loss of Pinnacle	189	274
Valuation allowance	(204)	(274)
	1,848	2,519
Deferred income tax liabilities:		
Oil and gas acquisition,		

exploration and development costs deducted for tax purposes in excess of financial statement DD&A	9,544	14,935
Capitalized interest	4,683	5,697
Hedge valuation	-	140
	14,227	20,772
Net deferred income tax liability	$ 12,379	$ 18,253

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The net deferred income tax liability is classified as follows:

	As of December 31, 2003	2004
	(In thousands)	
Other current assets	$ 100	$ -
Accrued liabilities	-	140
Deferred income tax liability	12,479	18,113
Deferred income tax liability, net	$ 12,379	$ 18,253

Realization of deferred tax assets are 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. It is more unlikely than not that Pinnacle will not realize the tax benefit. The Company has net operating loss carryforwards totaling approximately $7.2 million, which begin expiring in 2012 through 2021.

8. LONG-TERM DEBT

At December 31, 2003 and 2004, long-term debt consists of the following:

	As of December 31, 2003	2004
	(In thousands)	
Credit Facility	$ 7,000	$ 18,000
Senior Secured notes(1)	-	16,268
Senior Subordinated notes(1)	-	28,584
Senior Subordinated notes, related parties(1)	26,992	-
Capital lease obligations	295	122
Non-recourse note payable to RMG	863	-
	35,150	62,974
Less: current maturities	(1,037)	(90)

	$ 34,113	$ 62,884

(1) Amounts are presented net of discount of $0.3 and $2.0 million as of December 31, 2003 and 2004, respectively.

Credit Facility

On September 30, 2004, the Company entered into a Second Amended and Restated Credit Agreement with Hibernia National Bank and Union Bank of California, N.A. (the "Credit Facility"), which matures on September 30, 2007. The Credit Facility amended, restated and extended the Company's prior credit facility (such prior facility herein referred to as the "Prior Credit Facility"). The Credit Facility provides for (1) a revolving line of credit of up to the lesser of the Facility A Borrowing Base and $75.0 million and (2) a term loan facility of up to the lesser of the Facility B Borrowing Base and $25.0 million. It is secured by substantially all of the Company's assets and is guaranteed by the Company's wholly-owned subsidiary, CCBM.

The Facility A Borrowing Bases will be redetermined by the lenders at least semi-annually on each November 1 and May 1. The initial Facility A Borrowing Base, under the Credit Facility on September 30, 2004 was $28.0 million and is $30.0 million as of December 31, 2004. The initial Facility B Borrowing Base was $0.00 and is subject to redetermination by the lenders in their sole discretion. The Company and the lenders may each request one unscheduled borrowing base redetermination subsequent to each scheduled redetermination. The Facility A Borrowing Base will at all times equal the Facility A Borrowing Base most recently redetermined by the lenders, less quarterly borrowing base reductions required subsequent to such redetermination. The lenders will

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reset the Facility A Borrowing Base amount at each scheduled and each unscheduled borrowing base redetermination date.

If the outstanding principal balance of the revolving loans under the Credit Facility exceeds the Facility A Borrowing Base at any time (including, without limitation, due to a quarterly borrowing base reduction (as described above)), 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 Facility A 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.

For each revolving loan, the interest rate will be, at the Company's option, (1) the Eurodollar Rate, plus an applicable margin equal to 2.375% if the amount borrowed is greater than or equal to 90% of the Facility A Borrowing Base, 2.0% if the amount borrowed is less than 90%, but greater than or equal to 50% of the Facility A Borrowing Base, or 1.625% if the amount borrowed is less than 50% of the Facility A Borrowing Base; or (2) the Base Rate, plus an applicable margin of 0.375% if the amount borrowed is greater than or equal to 90% of the Facility A Borrowing Base. The interest rate on each term loan will be, at the Company's option, (1) the Eurodollar Rate, plus an applicable margin to be determined by the lenders; or (2) the Base Rate, plus an applicable margin to be determined by the lenders. Interest on Eurodollar Loans is payable on either the last day of each Eurodollar option period or monthly, whichever is earlier. Interest on Base Rate Loans is payable monthly.

The Company is subject to certain covenants under the terms of the Credit Facility, including, but not limited to the maintenance of the following financial covenants: (1) a minimum current ratio of 1.0 to 1.0 (including availability under the borrowing base), (2) a minimum quarterly debt services coverage of 1.25 times, (3) a minimum shareholders equity equal to $100.0 million, plus 100% of all subsequent common and preferred equity contributed by shareholders' subsequent to June 30, 2004, plus 50% of all positive earning occurring subsequent to June 30, 2004, plus, 180 days after issuance of any second-lien subordinated debt with another lender ("the Secured Subordinated Debt"), an amount equal to the difference, if positive, of (A) 50% of the net proceeds from the issuance less (B) 100% of all common and preferred equity contributed by shareholders from September 30, 2004 to the date of the issuance of any Secured Subordinated Debt, and (4) a maximum total recourse debt to EBITDA ratio (as defined in the Credit Facility) of not more than 3.0 to 1.0. The Credit Facility also places restrictions on additional indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, asset pledges and mortgages, change of control, repurchase or redemption for cash of the Company's common stock, speculative commodity transactions and other matters.

In connection with the Senior Secured Notes Purchase Agreement, we amended the Credit Facility including without limitation, to: (1) amend the covenant regarding maintenance of a minimum shareholders' equity, (2) add a new covenant requiring maintenance of a minimum EBITDA to interest expense ratio and (3) add other provisions and a consent which allow for the indebtedness incurred under the Senior Secured Notes.

On November 7, 2004, we determined that, as of September 30, 2004, we were not in compliance with the minimum current ratio covenant in the Credit Facility. We cured the noncompliance on October 29, 2004 with the issuance of the Senior Secured Notes. On November 10, 2004, the lenders under the Credit Facility agreed in a letter to the Company to waive the noncompliance period from September 30, 2004 through October 29, 2004.

At December 31, 2003, amounts outstanding under the Prior Credit Facility totaled $7.0 million with an additional $12.0 million available for future borrowings. At December 31, 2004, amounts outstanding under the Credit Facility totaled $18.0 million, with an additional $12.0 million available for future borrowings. At December 31, 2003, no letters of credit were issued and outstanding under the Prior Credit Facility. At December 31, 2003 and 2004, no letters of credit were issued and outstanding under the prior Credit Facility and the Credit Facility, respectively.

Rocky Mountain Gas, Inc. Note

On June 29, 2001, CCBM, Inc. issued a non-recourse promissory note payable in the amount of $7.5 million to RMG as consideration for certain interests in oil and natural gas leases held by RMG in Wyoming and Montana. The RMG note was payable in 41-monthly principal payments of $0.1 million plus interest at 8% per annum commencing July 31, 2001 with the balance due December 31, 2004, all of which have been paid. The RMG note was secured solely by CCBM's interests in the oil and natural gas leases in Wyoming and Montana. In connection with the Company's investment in Pinnacle Gas Resources, Inc., the Company received a reduction in the principal amount of the RMG note of approximately $1.5 million and relinquished the right to certain revenues related to the properties contributed to Pinnacle. During the second quarter of 2004, CCBM relinquished a portion of its

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interests in certain oil and natural gas leases to RMG and reduced the principal due on the RMG note by $0.3 million.

Capital Leases

In December 2001, the Company entered into a capital lease agreement secured by certain production equipment in the amount of $0.2 million. The lease was payable in one payment of $11,323 and 35 monthly payments of $7,549 including interest at 8.6% per annum. In October 2002, the Company entered into a capital lease agreement secured by certain production equipment in the amount of $0.1 million. The lease is payable in 36 monthly payments of $3,462 including interest at 6.4% per annum. In May 2003, the Company entered into a capital lease agreement secured by certain production equipment in the amount of $0.1 million. The lease is payable in 36 monthly payments of $3,030 including interest at 5.5% per annum. In August 2003, the Company entered into a capital lease agreement secured by certain production equipment in the amount of $0.1 million. The lease is payable in 36 monthly payments of $2,179 including interest at 6.0% per annum. The Company has the option to acquire the equipment at the conclusion of the lease for $1 under all of these leases. Depreciation on the capital leases for the years ended December 31, 2002, 2003 and 2004 amounted to $28,000, $48,000 and $46,000, respectively, and accumulated depreciation on the leased equipment at December 31, 2003 and 2004 amounted to $78,000 and $124,000, respectively.

Senior Subordinated Notes and Related Securities

In December 1999, the Company consummated the sale of $22.0 million principal amount of 9% Senior Subordinated Notes due 2007 (the "Subordinated Notes") and $8.0 million of common stock and warrants. The Company sold $17.6 million, $2.2 million, $0.8 million, $0.8 million and $0.8 million principal amount of Subordinated Notes; 2,909,092, 363,636, 121,212, 121,212 and 121,212 shares of the Company's common stock and 2,208,152, 276,019, 92,006, 92,006 and 92,006 Warrants to CB Capital Investors, L.P. (now known as JPMorgan Partners (23A SBIC), L.P.), Mellon Ventures, L.P., Paul B. Loyd, Jr., Steven A. Webster and Douglas A.P. Hamilton, respectively. The Subordinated Notes were sold at a discount of $0.7 million, which is being amortized over the life of the notes. Interest payments are due quarterly commencing on March 31, 2000. As amended as described below, the Subordinated Notes allow the Company, until December 2005, to increase the amount of the Subordinated Notes for 60% of the interest which would otherwise be payable in cash. As of December 31, 2003 and December 31, 2004, the outstanding balance of the Subordinated Notes had been increased by $5.3 million and $6.8 million respectively, for such interest paid in kind. During 2004, Mellon Ventures, L.P., JPMorgan Partners (23A SBIC), Steven A. Webster and Douglas A. P. Hamilton exercised warrants to purchase 276,019, 2,208,152, 92,006 and 92,006 shares of common stock, respectively, on a cashless exercise basis for a total of 205,692, 1,684,949, 70,205 and 70,205 shares of common stock, respectively, and Paul B. Loyd, Jr., exercised warrants for cash to purchase 92,006 shares for a total of 92,006 shares of common stock. As a result, no warrants to purchase shares of common stock remain outstanding from the warrants originally issued in December 1999.

On June 7, 2004, an unaffiliated third party (the "Subordinated Notes Purchaser") purchased all the outstanding Subordinated Notes from the original note holders. In exchange for a $0.4 million amendment fee, certain terms and conditions of the Subordinated Notes were amended, to provide for, among other things, (1) a one year extension of the maturity to December 15, 2008, (2) a one year extension, through December 15, 2005, of the paid-in-kind ("PIK") interest option to pay-in-kind 60% of the interest due each period by increasing the principal balance by a like amount (the "PIK option"), (3) an additional one year option to extend the PIK option through December 15, 2006 at an annual interest rate on the deferred amount of 10% and the payment of a one-time amendment fee equal to 0.5% of the principal then outstanding and (4) additional flexibility to obtain a separate project financing facility in the future. The amendment fee will be amortized over the remaining life of the Note.

The Company is subject to certain covenants under the terms of the Subordinated Notes securities purchase agreement, including but not limited to, (a) maintenance of a specified tangible net worth, (b) maintenance of a ratio of EBITDA (earnings before interest, taxes, depreciation and amortization) to quarterly Debt Service (as defined in the agreement) of not less than 1.00 to 1.00, (c) a limitation of its capital expenditures to an amount equal to the Company's EBITDA for the immediately prior fiscal year (unless approved by the Company's Board of Directors) and (d) a limitation on our Total Debt (as defined in the securities purchase agreement) to 3.5 times EBITDA for any twelve month period.

Senior Subordinated Secured Notes

On October 29, 2004, the Company entered into a Note Purchase Agreement (the "Senior Secured Notes Purchase Agreement") with PCRL Investments L.P. (the "Senior Secured Notes Purchaser"). Pursuant to the Senior Secured Notes Purchase Agreement, the Company may issue up to $28 million aggregate principal amount of 10% Senior Subordinated Secured Notes due 2008 (the "Senior Secured Notes") for a purchase price equal to 90% of the principal amount of the Senior Secured Notes then issued. On October 29,

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2004, the Senior Secured Notes Purchaser purchased $18 million aggregate principal amount of the Senior Secured Notes for a purchase price of $16.2 million. The debt discount is being amortized to interest expense using the effective interest method over the life of the note. Subject to the satisfaction of certain conditions, the Company has an option to issue up to an additional $10 million aggregate principal amount of the Senior Secured Notes to the Senior Secured Notes Purchaser before October 29, 2006.

The Senior Secured Notes are secured by a second lien on substantially all of the Company's current proved producing reserves and non-reserve assets, guaranteed by the Company's subsidiary, and subordinated to the Company's obligations under the Credit Facility. The Senior Secured Notes bear interest at 10% per annum, payable quarterly on the 5th day of March, June, September and December of each year beginning March 5, 2005. The principal on the Senior Secured Notes is due December 15, 2008, and the Company has the option to prepay the Senior Secured Notes at any time. The Senior Secured Notes include an option that allows the Company to pay-in-kind 50% of the interest due until June 5, 2007 by increasing the principal due by a like amount. Subject to certain conditions, the Company has the option to pay the interest on and principal of (at maturity or upon prepayment) the Senior Secured Notes with the Company's common stock, as long as the Secured Note Purchaser not hold more than 9.99% of the number of shares of the Company's common stock outstanding immediately after giving effect to such payment. The value of such shares issued as payment on the Senior Secured Notes is determined based on 90% of the volume weighted average trading price during a specified period of days beginning with the date of the payment notice and ending before the payment date. Issuance costs related to the transaction were $0.5 million and have been recorded as deferred financing costs amortized to interest expense over the life of the Senior Secured Notes.

As contemplated by the Secured Senior Notes Purchase Agreement, the Company also entered into a registration rights agreement with the Secured Note Purchaser (the "Registration Rights Agreement"). In the event the Company chooses to issue shares of its common stock as payment of interest on the principal of the Senior Secured Notes, the Registration Rights Agreement provides registration rights with respect to such shares. The Company is generally required to file a resale shelf registration statement to register the resale of such shares under the Securities Act of 1933 (the "Securities Act") if such shares are not freely tradable under Rule 144(k) under the Securities Act. The Company is subject to certain covenants under the terms of the Registration Rights Agreement, including the requirement that the registration statement be kept effective for resale of shares subject to certain "blackout periods," when sales may not be made. In certain circumstances, including those relating to (1) delisting of the Company's common stock, (2) blackout periods in excess of a maximum length of time, (3) certain failures to make timely periodic filings with the Securities and Exchange Commission, or (4) certain delays or failures to deliver stock certificates, the Company may be required to repurchase common stock issued as payment on the Senior Secured Notes and, in certain of these circumstances, to pay damages based on the market value of its common stock. In certain situations, the Company is required to indemnify the holders of registration rights under the Registration Rights Agreement, including, without limitation, for liabilities under the Securities Act.

The Senior Secured Notes Purchase Agreement includes certain representations, warranties and covenants by the parties thereto. The Company is subject to certain covenants under the terms of the Senior Secured Notes Purchase Agreement, including, without limitation, the maintenance of the following financial covenants: (1) a maximum total recourse debt to EBITDA ratio of not more than 3.50 to 1.0, (2) a minimum EBITDA to interest expense ratio of 2.50 to 1.0, and (3) as of April 30, 2005, a minimum tangible net worth of $12.5 million in excess of the Company's tangible net worth as of September 30, 2004. Upon a change of control, any holders of the Senior Secured Notes may require the Company to repurchase such holders' Senior Secured Notes at a price equal to then outstanding principal amount of such Senior Secured Notes, together with all interest accrued on such Senior Secured Notes through the date of repurchase. The Senior Secured Notes Purchase Agreement also places restrictions on additional indebtedness, dividends to stockholders, liens, investments, mergers, acquisitions, asset dispositions, asset pledges and mortgages, repurchase or redemption for cash of the Company's common stock, speculative commodity transactions and other matters. The Senior Secured Notes Purchaser is an affiliate of the Subordinated Notes Purchaser.

Estimated maturities of long-term debt are $0.1 million in 2005, none in 2006, $18.0 million in 2007, and the remainder in 2008.

At December 31, 2004, the Company was in compliance with all of its debt covenants.

9. SEISMIC OBLIGATION PAYABLE

In 2002, the Company acquired (or obtained the right to acquire) certain seismic data in its core areas in the Texas and Louisiana Gulf Coast regions. Under the terms of the acquisition agreements, the Company was required to make monthly payments of $0.1 million through March 2004 and an additional payment of $0.8 million in April 2004. All payments have been made.

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10. CONVERTIBLE PARTICIPATING PREFERRED STOCK

In February 2002, the Company consummated the sale of 60,000 shares of Convertible Participating Series B Preferred Stock (the "Series B Preferred Stock") and warrants to purchase 252,632 shares of common stock for an aggregate purchase price of $6.0 million. The Company sold 40,000 and 20,000 shares of Series B Preferred Stock and 168,422 and 84,210 warrants to Mellon Ventures, Inc. and Steven A. Webster, respectively. The Series B Preferred Stock was convertible into common stock by the investors at a conversion price of $5.70 per share, subject to adjustments, and was initially convertible into 1,052,632 shares of common stock. Dividends on the Series B Preferred Stock were payable in either cash at a rate of 8% per annum or, at the Company's option, by payment in kind of additional shares of the same series of preferred stock at a rate of 10% per annum. At December 31, 2003 and through the conversion dates specified below, the outstanding balance of the Series B Preferred Stock has been increased by $1.2 million (11,987 shares) and $1.5 million (15,133 shares), respectively, for dividends paid in kind. The Series B Preferred Stock was redeemable at varying prices in whole or in part at the holders' option after three years or at the Company's option at any time. The Series B Preferred Stock also participated in any dividends declared on the common stock. Holders of the Series B Preferred Stock would have received a liquidation preference upon the liquidation of, or certain mergers or sales of substantially all assets involving, the Company. Such holders also had the option of receiving a change of control repayment price upon certain deemed change of control transactions. Mellon Ventures, Inc., converted all of its Series B Preferred Stock (approximately 49,938 shares) into 876,099 shares of common stock on May 25, 2004. Steven A. Webster converted all of his Series B Preferred Stock (approximately 25,195 shares) into 442,026 shares of common stock on June 30, 2004. As a result, no shares of Series B Preferred Stock remain outstanding at December 31, 2004. The total value of the Series B Preferred Stock upon conversion was $7.5 million and was reclassified to stockholders' equity following the conversion.

The warrants have a five-year term and entitle the holders to purchase up to 252,632 shares of Carrizo's common stock at a price of $5.94 per share, subject to adjustments, and are exercisable at any time after issuance. The warrants may be exercised on a cashless exercise basis. During the year ended December 31, 2004, Mellon Ventures, Inc. exercised all of its 168,422 warrants on a cashless exercise basis for a total of 36,570 shares of common stock.

Net proceeds of the sale of the Series B Preferred Stock were approximately $5.8 million and were used primarily to fund the Company's ongoing exploration and development program and general corporate purposes.

11. 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.

In July 2001, the Company was notified of a prior lease in favor of a predecessor of ExxonMobil purporting to be valid and covering the same property as the Company's Neblett lease in Starr County, Texas. The Neblett lease is part of a unit in N. La Copita Prospect in which the Company owns a non-operating interest. The operator of the lease, GMT, filed a petition for, and was granted, a temporary restraining order against ExxonMobil in the 229th Judicial Court in Starr County, Texas enjoining ExxonMobil from taking possession of the Neblett wells. Pending resolution of the underlying title issue, the temporary restraining order was extended voluntarily by agreement of the parties, conditioned on GMT paying the revenues into escrow and agreeing to provide ExxonMobil with certain discovery materials in this action. ExxonMobil has filed a counterclaim against GMT and all the non-operators, including the Company, to establish the validity of their lease, remove cloud on title, quiet title to the property, and for conversion, trespass and punitive damages. The Company, along with GMT and other partners, reached a final settlement with ExxonMobil on February 11, 2003. Under the terms of the settlement, the Company recovered the balance of its drilling costs (approximately $0.1 million) and certain other costs and retained no further interest in the property. No reserves with respect to these properties were included in the Company’s reported proved reserves as of December 31, 2002.

Rent expense for each of the years ended December 31, 2002, 2003 and 2004 was $0.2 million. Effective December 2004, the Company relocated its offices and entered into a new long-term operating lease agreement that expires December 2011. Under the terms of the lease agreement, the Company received a rent abatement equal to six months of lease payments that is being amortized to expense over the term of the lease. The Company is obligated for remaining lease payments as of December 31, 2004 as follows:

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Year ended December 31,	Amount (In thousands)
2005	$ 222
2006	477
2007	477
2008	477
2009	477
Remainder	1,056
	$ 3,186

12. SHAREHOLDERS' EQUITY

In the first quarter of 2004, the Company completed the public offering of 6,485,000 shares of common stock at $7.00 per share. The offering included 3,655,500 newly issued shares offered by the Company and 2,829,500 shares offered by certain existing selling shareholders. The Company did not receive any proceeds from the shares sold by the selling shareholders. The Company used part of the net proceeds from this offering to accelerate its drilling program and to retain larger interests in portions of its drilling prospects that the Company otherwise would sell down or for which the Company would seek joint partners and for general corporate purposes. Initially, the Company used a portion of the net proceeds to repay the $7 million outstanding principal amount under its revolving credit facility and to complete an $8.2 million Barnett Shale acquisition on February 27, 2004.

The Company issued 413,965 and 7,570,109 shares of common stock during the years ended December 31, 2003 and 2004, respectively. In June of 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the "Incentive Plan"). The shares issued during the year ended December 31, 2003 were the result of the exercise of options granted under the Company's Incentive Plan. The shares issued during the year ended December 31, 2004, consisted of 3,655,500 shares issued through the public offering, 2,159,627 shares issued through the exercise of warrants, 1,318,124 shares issued through the conversion of Series B Preferred Stock and the balance issued through the exercise of options granted under the Company's Incentive Plan.

The following table summarizes information for the options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options Outstanding at 12/31/04	Weighted Average Remaining Contractual Life in Years	Weighted Average Exercise Price	Number of Options Exercisable at 12/31/04	Weighted Average Exercise Price
$1.75-2.25	436,635	5.13	$ 2.21	436,635	$ 2.21
$3.14-4.00	111,629	4.75	$ 3.52	102,517	$ 3.50
$4.01-5.00	524,202	7.20	$ 4.30	374,480	$ 4.24

$5.17-8.00	252,835	7.67	$	7.18	95,611	$	6.43

The Company may grant options ("Incentive Plan Options") to purchase up to 2,350,000 shares under the Incentive Plan and has granted options covering 1,955,168 shares through December 31, 2004. Through December 31, 2004, 739,656 stock options had been exercised. A summary of the status of the Company's stock options at December 31, 2002, 2003 and 2004 is presented in the table below:

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	Shares	2002 Weighted Average Exercise Prices	Range of Exercise Prices
Outstanding at beginning of year	1,636,657	$ 3.49	$ 1.75 - $8.00
Granted (Incentive Plan Options)	54,500	$ 4.31	$ 3.76 - $5.37
Exercised (Incentive Plan Options)	(6,834)	$ 2.12	$ 2.00 - $2.25
Expired (Incentive Plan Options)	(54,000)	$ 6.38	$ 1.75 - $8.00
Outstanding at end of year	1,630,323	$ 3.35	$ 1.75 - $8.00
Exercisable at end of year	1,048,212	$ 3.28	
Weighted average of fair value of			
options granted during the year	$ 3.57		

	Shares	2003 Weighted Average Exercise Prices	Range of Exercise Prices
Outstanding at beginning of year	1,630,323	$ 3.35	$ 1.75 - $8.00
Granted (Incentive Plan Options)	257,500	$ 4.63	$ 4.37 - $5.75
Exercised (Pre-IPO Options)	(85,000)	$ 3.60	$ 3.60
Exercised (Incentive Plan Options)	(161,001)	$ 2.39	$ 2.00 - $4.40
Expired (Incentive Plan Options)	(4,000)	$ 3.33	$ 2.25 - $4.40
Outstanding at end of year	1,637,822	$ 3.63	$ 1.75 - $8.00
Exercisable at end of year	1,261,655	$ 3.44	
Weighted average of fair value of			
options granted during the year	$ 3.65		

	2004 Weighted Average Exercise	Range of Exercise

	Shares		Prices		Prices
Outstanding at beginning of year	1,637,822	$	3.63	$	1.75 - $8.00
Granted (Incentive Plan Options)	131,668	$	8.01	$	6.98 - $9.215
Exercised (Pre-IPO Options)	(88,825)	$	3.60	$	3.60
Exercised (Incentive Plan Options)	(348,033)	$	3.83	$	1.8125 - $8.00
Expired (Incentive Plan Options)	(7,331)	$	5.89	$	4.40 - $8.00
Outstanding at end of year	1,325,301	$	4.09	$	1.75 - $9.215
Exercisable at end of year	1,009,243	$	3.49		
Weighted average of fair value of options granted during the year	$ 4.86				

In March of 2000, the FASB issued FIN No. 44 which was effective July 1, 2000 and clarifies the application of APB No. 25 for certain issues associated with the issuance or subsequent modifications of stock compensation. For certain modifications, including stock option repricings made subsequent to December 15, 1998, the Interpretation requires that variable plan accounting be applied to those modified awards prospectively from July 1, 2000. This requires that the change in the intrinsic value of the modified awards be recognized as compensation expense. On February 17, 2000, Carrizo repriced certain employee and director stock options covering

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348,500 shares of stock with a weighted average exercise price of $9.13 to a new exercise price of $2.25 through the cancellation of existing options and issuance of new options at current market prices. Subsequent to the adoption of the Interpretation, the Company records the effects of any changes in its stock price over the remaining vesting period through February 2010 on the corresponding intrinsic value of the repriced options in its results of operations as compensation expense until the repriced options either are exercised or expire. Stock option compensation expense (benefit) relating to the repriced options for the years ended December 31, 2002, 2003 and 2004 amounted to $(0.1 million), $0.3 million and $1.1 million, respectively.

In December 1999, the Company reduced the exercise price of certain warrants originally issued to affiliates of Enron Corp. in January 1998. 250,000 of these warrants outstanding as of December 31, 2003 and 2004 were exercised in January 2005, for 250,000 shares of the Company's common stock at $4.00 per share.

13. RELATED-PARTY TRANSACTIONS

During the years ended December 31, 2003 and 2004, the Company incurred drilling costs in the amount of and $2.2 million and $1.6 million, respectively, with Grey Wolf Drilling. Mr. Webster is the Chairman of the Board of Carrizo and a member of the Board of Directors of Grey Wolf Drilling. During the year ended December 31, 2003 and 2004, the Company incurred lease operating costs of $0.4 million and $0.4 million, respectively, with Basic Services, Inc. Mr. Webster and Mr. Johnson are members of the Board of Directors of Basic Services, Inc. It is management's opinion that the transactions with both of these entities were performed at prevailing market rates.

At December 31, 2004, the Company had outstanding related-party accounts receivable and payable balances of $0.3 million and $0.7 million, respectively. At December 31, 2003, the Company had outstanding related party accounts payable balances of $0.9 million.

During the year ended 2004, Goodrich Petroleum ("Goodrich") participated in the drilling of one well operated by the Company. During the year ended December 31, 2004, the Company incurred land and drilling expenses of $0.6 million with the Company. Mr. Webster is a member of the Board of Directors of Goodrich. The terms of the operating agreements between the Company and Goodrich are consistent with standard industry practices.

See Notes 5, 8 and 10 for a discussion of the investment in Pinnacle, Subordinated Notes and Series B Preferred Stock with parties that include members of the Company's Board of Directors or their affiliates.

Steven A. Webster, Chairman of the Board of the Company, is also a managing director of Credit Suisse First Boston Private Equity and is therefore a related party to the Pinnacle transaction.

The Company entered into a transition services agreement with Pinnacle pursuant to which the Company provided certain accounting, treasury, tax, insurance and financial reporting functions to Pinnacle for a monthly fee equal to the Company's actual cost to provide such services. No such services were provided during 2004.

14. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITY

The Company's operations involve managing market risks related to changes in commodity prices. Derivative financial instruments, specifically swaps, futures, options and other contracts, are used to reduce and manage those risks. The Company addresses market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. The Company enters into swaps, options, collars and other derivative contracts to hedge the price risks associated with a portion of anticipated future oil and natural gas production. While the use of hedging arrangements 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 hedging transactions with two counterparties and a netting agreement is 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.

As of December 31, 2003 and 2004, the unrealized gain/(loss), net of tax, on oil and gas derivative instruments related to the mark-

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to-market valuation was $0.2 million and $0.4 million, respectively, which are presented as mark-to-market gain(loss) on derivatives, net in the other income and expense section of our restated Statement of Operations.

Total oil purchased and sold under swaps and collars during 2002, 2003 and 2004 were 131,300 Bbls, 193,600 Bbls and 121,700 Bbls, respectively. Total natural gas purchased and sold under swaps and collars in 2002, 2003 and 2004 were 2,314,000 MMBtu, 2,739,000 MMBtu and 3,936,000 MMBtu, respectively. The net losses realized by the Company under such hedging arrangements were $(0.9) million, $(1.8) million and $(1.0) million for 2002, 2003 and 2004, respectively, and are included in other income and expense.

At December 31, 2003 and 2004 the Company had the following outstanding derivative positions:

As of December 31, 2003

Quarter	Contract Volumes BBls	Contract Volumes MMbtu	Average Fixed Price	Average Floor Price	Average Ceiling Price
First Quarter 2004	27,000		$ 30.36		
First Quarter 2004		180,000	6.67		
First Quarter 2004		546,000		$ 4.10	$ 7.00
Second Quarter 2004	18,300		30.38		
Second Quarter 2004		546,000		4.00	5.60
Third Quarter 2004		552,000		4.00	5.60
Fourth Quarter 2004		369,000		4.00	5.80

As of December 31, 2004

Quarter	Contract Volumes BBls	Contract Volumes MMbtu	Average Fixed Price	Average Floor Price	Average Ceiling Price
First Quarter 2005	27,000			$ 41.67	$ 50.50
First Quarter 2005		928,000		5.40	8.11
Second Quarter 2005		364,000		5.25	7.15
Second Quarter 2005		91,000	$ 6.03		
Third Quarter 2005		368,000		5.25	7.40
Third Quarter 2005		92,000	6.03		
		276,000		5.25	7.92

Fourth Quarter 2005		
Fourth Quarter 2005	92,000	6.03

In addition to the hedge positions above, during the second quarter of 2003, the Company acquired options to sell 6,000 MMBtu of natural gas per day for the period July 2003 through August 2003 (552,000 MMBtu) at $8.00 per MMBtu for approximately $119,000. The Company acquired these options to protect its cash position against potential margin calls on certain natural gas derivatives due to large increases in the price of natural gas. These options were classified as derivatives. As of December 31, 2003, these options have expired and a charge of $119,000 has been included in other income and expenses for the year ended December 31, 2003.

In November 2001, the Company had no-cost collars with an affiliate of Enron Corp. which, because of Enron’s financial condition, were no longer considered effective. An allowance was recorded at that time for the full value of the collars (the “Enron Claim”) that was classified as other expense. The Company sold its Enron Claim to a financial institution for $0.5 million that was recorded in the third quarter of 2004 as other income.

15. SUBSEQUENT EVENT

Effective February 1, 2005, the Company sold to a private company its interest in the Patterson Prospect Area in St. Mary Parish, Louisiana, including the Shadyside #1 well and any anticipated follow-up wells, for approximately $9.0 million. The Company’s average daily production from the Shadyside #1 during the fourth quarter 2004 was approximately 970 Mcfe per day. Proceeds from the sale are expected to be used in the 2005 Barnett Shale and Gulf Coast drilling program and for general corporate purposes.

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16. 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."

Costs Incurred

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

	For the Year Ended December 31, 2002	2003	2004
	(In thousands)		
Property acquisition costs			
Unproved	$ 6,402	$ 7,280	$ 21,831
Proved	660	-	8,357
Exploration costs	14,194	23,745	39,181
Development costs	2,351	112	12,697
Asset retirement obligation	-	744	529
Total costs incurred (1)	$ 23,607	$ 31,881	$ 82,595

Excludes capitalized interest on unproved properties of $3.1 million, $2.9 million and $2.9 million for the years ended December 31, 2002, 2003 and 2004, respectively, and includes capitalized overhead of $1.0 million, $1.4 million and $1.7 million for the years ended December 31, 2002, 2003 and 2004, respectively. The table also includes non-cash asset retirement obligations of $0.7 million and $0.5 million for the year ended December 31, 2003 and 2004, 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, 2002, 2003 and 2004, and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company, DeGolyer and MacNaughton and Fairchild & Wells, Inc., independent petroleum engineers. 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:

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	Thousands of Barrels of Oil and Condensate at December 31,		
	2002	2003	2004
Proved developed and undeveloped reserves -			
Beginning of year	6,857	8,381	8,714
Purchase of oil and natural gas properties in place	-	-	5
Discoveries and extensions	369	231	208
Revisions	1,568	553	500
Sales of oil and gas properties in place	(12)	(1)	-
Production	(401)	(450)	(309)
End of year	8,381	8,714	9,118
Proved developed reserves at beginning of year	1,158	1,393	1,395
Proved developed reserves at end of year	1,393	1,395	1,459

	Millions of Cubic Feet of Natural Gas at December 31,		
	2002	2003	2004
Proved developed and undeveloped reserves -			
Beginning of year	17,858	12,922	18,069
Purchase of oil and natural gas properties in place	585	-	13,390
Discoveries and extensions	3,280	10,305	32,002
Revisions	(3,726)	129	(2,378)
Sales of oil and gas properties in place	(274)	(523)	-
Production	(4,801)	(4,764)	(6,462)
End of year	12,922	18,069	54,621
Proved developed reserves at beginning of year	13,754	12,826	17,098
Proved developed reserves at end of year	12,826	17,098	28,066

Carrizo uses the equity method of accounting to record its minority ownership in the operations of Pinnacle, formed in June 2003. Accordingly, the proved reserve tables, above, do not include the Company’s interest ownership, 22.7% on a fully diluted basis, in the proved reserves of Pinnacle at the end of 2004, or an estimated 5.6 Bcfe of proved reserves.

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:

	For the Year Ended December 31, 2002	2003	2004
	(In thousands)		
Future cash inflows	$ 305,087	$ 375,160	$ 685,598
Future oil and natural gas operating expenses	142,597	167,090	244,618
Future development costs	15,259	15,943	55,730
Future income tax expenses	33,232	45,540	108,295
Future net cash flows	113,999	146,587	276,955
10% annual discount for estimating timing of cash flows	49,702	58,961	127,234
Standard measure of discounted future net cash flows	$ 64,297	$ 87,626	$ 149,721

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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 2002, 2003 and 2004 future cash flows were $29.16, $30.29 and $41.18 for oil, respectively and $4.70, $6.19 and $5.68 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 tax basis and availability of 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.

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:

	For The Year Ended December 31,		
	2002	2003	2004
	(In thousands)		
Changes due to current-year operations -			
Sales of oil and natural gas, net of oil and natural gas operating expenses	$ (23,377)	$ (34,177)	$ (42,982)
Extensions and discoveries	20,680	42,530	80,933
Purchases of oil and gas properties	888	-	16,467
Changes due to revisions in standardized variables			
Prices and operating expenses	36,511	8,654	34,516
Income taxes	(12,748)	(9,606)	(31,667)
Estimated future development costs	417	(377)	12,951
Revision of quantities	8,818	5,374	(1,307)
Sales of reserves in place	(191)	(836)	-
Accretion of discount	4,795	8,304	11,485
Production rates, timing and other	(12,880)	3,463	(18,301)
Net change	22,913	23,329	62,095
Beginning of year	41,384	64,297	87,626
End of year	$ 64,297	$ 87,626	$ 149,721

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 an after-tax basis.

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17. SUPPLEMENTAL QUARTERLY FINANCIAL DATA (UNAUDITED)

2004 (Restated - Note 3)	First	Second	Third	Fourth
	(In thousands except per share amounts)			
Revenues	$ 10,861	$ 11,935	$ 13,041	$ 16,560
Costs and expenses, net	9,317	9,512	9,994	12,460
Net income	1,544	2,423	3,047	4,100
Dividends and accretion	198	152	-	-
Net income available to common shareholders	$ 1,346	$ 2,271	$ 3,047	$ 4,100
Basic net income per share (1)	$ 0.08	$ 0.12	$ 0.14	$ 0.19
Diluted net income per share (1)	$ 0.07	$ 0.10	$ 0.13	$ 0.18

	First	Second	Third	Fourth
	(In thousands except per share amounts)			
2003				
Revenues	$ 10,663	$ 8,828	$ 10,123	$ 8,893
Costs and expenses, net	7,693	6,868	8,041	7,866
Net income	2,970	1,960	2,082	1,027
Dividends and accretion	181	181	190	189
Net income available to common shareholders before cumulative effect of change in accounting principle	$ 2,789	$ 1,779	$ 1,892	$ 838
Cumulative effect of change in accounting principle	128	-	-	-
Net income available to common shareholders	$ 2,661	$ 1,779	$ 1,892	$ 838
Basic net income per share (1)	$ 0.19	$ 0.13	$ 0.13	$ 0.06
Diluted net income per share (1)	$ 0.16	$ 0.11	$ 0.11	$ 0.05

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(1) The sum of individual quarterly net income per common share may not agree with year-to-date net income per common share as each period's computation is based on the weighted average number of common shares outstanding during that period.

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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: June 12, 2006

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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 June 6, 1998 (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 --	Amended and Restated Bylaws of the Company, as amended by Amendment No. 1 (Incorporated herein by reference to Exhibit 3.2 to the Company's Registration Statement on Form 8-A (Registration No. 000-22915), Amendment No. 2 (Incorporated herein by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K dated December 15, 1999) and Amendment No. 3 (Incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated February 20, 2002).
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 --	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)).
+10.8 --	Employment Agreement between the Company and Kendall A. Trahan (Incorporated herein by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).
+10.9 --	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)).
+10.10 --	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)).
10.11 --	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).

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EXHIBIT NUMBER	DESCRIPTION
10.12 --	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)).
10.13 --	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)).
+10.14 --	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).
10.15 --	Securities Purchase Agreement dated December 15, 1999 among the Company, CB Capital Investors, L.P., Mellon Ventures, L.P., Paul B. Loyd Jr., Douglas A. P. Hamilton and Steven A. Webster (Incorporated herein by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K dated December 15, 1999).
10.16 --	First Amendment to Securities Purchase Agreement dated as of June 7, 2004 among Carrizo Oil & Gas, Inc., Steelhead Investments Ltd., Douglas A.P. Hamilton, Paul B. Loyd, Jr., Steven A. Webster and Mellon Ventures, L.P. (incorporated herein by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed on June 10, 2004).
10.17 --	Form of Amended and Restated 9% Senior Subordinated Note due 2008 (incorporated herein by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed on June 10, 2004).
10.18 --	Second Amendment to Securities Purchase Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc. and the Investors named therein (incorporated herein by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed on November 3, 2004).
10.19 --	Shareholders Agreement dated December 15, 1999 among the Company, CB Capital Investors, L.P., Mellon Ventures, L.P., 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 99.2 to the Company's Current Report on Form 8-K dated December 15, 1999).
10.20 --	First Amendment to Shareholders Agreement dated as of December 15, 1999 by and among Carrizo Oil & Gas, Inc, J.P. Morgan Partners (23A SBIC), LLC, Mellon Ventures, L.P., S.P. Johnson IV, Frank A. Wojtek, Steven A. Webster, Douglas A.P. Hamilton, Paul B. Loyd, Jr. and DAPHAM Partnership, L.P. dated April 21, 2004 (incorporated herein by reference to Exhibit 32 to the Schedule 13D/A filed by Paul B. Loyd, Jr. on May 27, 2004).
10.21 --	Second Amendment to Shareholders Agreement dated as of December 15,1999 by and among Carrizo Oil & Gas, Inc., J.P. Morgan Partners (23A SBIC), LLC, Mellon Ventures, L.P., S.P. Johnson IV, Frank A. Wojtek and Steven A. Webster dated June 7, 2004 (incorporated herein by reference to Exhibit 99.4 to the Company's Current Report on Form 8-K filed on June 10, 2004).
10.22 --	Registration Rights Agreement dated December 15, 1999 among the Company, CB Capital Investors, L.P. and Mellon Ventures, L.P. (Incorporated herein by reference to Exhibit 99.4 to the Company's Current Report on Form 8- K dated December 15, 1999).
10.23 --	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).
+10.24 --	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).

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EXHIBIT NUMBER	DESCRIPTION
10.25 --	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).
10.26 --	Purchase and Sale Agreement by and between Rocky Mountain Gas, Inc. and CCBM, Inc., dated June 29, 2001 (Incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
10.27 --	Securities Purchase Agreement dated February 20, 2002 among the Company, Mellon Ventures, L.P. and Steven A. Webster (Incorporated herein by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K dated February 20, 2002).
10.28 --	Warrant Agreement dated February 20, 2002 among the Company, Mellon Ventures, L.P. and Steven A. Webster (including Warrant Certificate) (Incorporated herein by reference to Exhibit 99.4 to the Company's Current Report on Form 8-K dated February 20, 2002).
10.29 --	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).
+10.30 --	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).
10.31 --	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).
10.32 --	Contribution and Subscription Agreement dated June 23, 2003 by and among Pinnacle Gas Resources, Inc., CCBM, Inc., Rocky Mountain Gas, Inc. and the CSFB Parties listed therein (Incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.33 --	Transition Services Agreement dated June 23, 2003 by and between the Company and Pinnacle Gas Resources, Inc. (Incorporated herein by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.34 --	Second Amended and Restated Credit Agreement dated as of September 30, 2004 by and among Carrizo Oil & Gas, Inc., CCBM, Inc., Hibernia National Bank, as Agent, Union Bank of California, N.A., as co-agent, and Hibernia National Bank and Union Bank of California, N.A., as lenders (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 6, 2004).
10.35 --	First Amendment to Second Amended and Restated Credit Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc., CCBM, Inc., Hibernia National Bank and Union Bank of California, N.A. (incorporated herein by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on November 3, 2004).
10.36 --	Commercial Guaranty made and entered into as of September 30, 2004 by CCBM, Inc. in favor of Hibernia National Bank, as agent (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on October 6, 2004).
10.37 --	Amended and Restated Stock Pledge and Security Agreement dated and effective as of September 30, 2004 by Carrizo Oil & Gas, Inc. in favor of Hibernia National Bank, as agent (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on October 6, 2004).
10.38 --	Note Purchase Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc., the Purchasers named therein and PCRL Investments L.P., as collateral agent (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 3, 2004).

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EXHIBIT NUMBER	DESCRIPTION
10.39 --	Form of 10% Senior Subordinated Secured Note due 2008 (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on November 3, 2004).
10.40 --	Stock Pledge and Security Agreement dated as of October 29, 2004 by Carrizo Oil & Gas, Inc. in favor of PCRL Investments L.P., as collateral agent (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on November 3, 2004).
10.41 --	Commercial Guaranty dated as of October 29, 2004 by CCBM, Inc. in favor of PCRL Investments L.P., guarantying the indebtedness of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on November 3, 2004).
10.42 --	Registration Rights Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc. and the Investors named therein (incorporated herein by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on November 3, 2004).
*+10.43 --	Form of Stock Option Award Agreement.
+10.44 --	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).
*10.45 --	Director Compensation.
*10.46 --	Base Salaries and 2004 Annual Bonuses 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 Ernst & Young LLP.
**23.3 --	Consent of Ryder Scott Company Petroleum Engineers.
**23.4 --	Consent of Fairchild & Wells, Inc.
**23.5 --	Consent of DeGolyer and MacNaughton.
**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, 2004.
*99.2 --	Summary of Reserve Report of Fairchild & Wells, Inc. as of December 31, 2004.
*99.3 --	Summary of Reserve Report of DeGolyer and MacNaughton as of December 31, 2004.

* Previously filed.
** Filed herewith.
+ Compensatory plan, contract or arrangement.