CARRIZO OIL & GAS INC
Form 10-K/A
April 11, 2006

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

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

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

For the Fiscal Year Ended December 31, 2005

Commission No. 0-22915

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

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

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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ¨ NO x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. YES ¨ NO x

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. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨

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

At June 30, 2005, the aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $354.5 million based on the closing price of such stock on such date of $17.06.

At March 1, 2006, the number of shares outstanding of the registrant's Common Stock was 24,388,170.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 2006 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, 2005.

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Explanatory Note

Carrizo Oil & Gas, Inc. is filing this Amendment No.1 to Form 10-K to amend and restate its original Form 10-K that was filed on April 10, 2005 in order to replace the original Form 10-K, which was an incorrect version of the Form 10-K that was filed due to an error by a third-party Edgar filing service provider, and to include certain other information intended to be contained in the original Form 10-K.

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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. We have obtained licenses to explore in the U.K. North Sea. We recently acquired acreage in shale plays in the Barnett/Woodford in West Texas/New Mexico, Floyd/Neal in Mississippi/Alabama, the western New Albany in Kentucky and the Fayetteville in Arkansas.

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, 2005 on an annualized basis was 14 %. From our inception through December 31, 2005, we participated in the drilling of 438 wells (155.5 net) with an apparent success rate of approximately 70% in our onshore Gulf Coast area and apparent 100% in the Barnett Shale area in North Texas. Exploratory wells accounted for 83 % of the total wells we drilled. Our total proved reserves as of December 31, 2005 were an estimated 150.6 Bcfe with a PV-10 Value of $404.2 million. During 2005, we added a record 50.9 Bcfe to proved reserves and produced a record 9.6 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 10,000 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 177% to over 7,600 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 299 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, Unocal, 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, 2005, we had 145,144 net 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 64,795 net acres in our onshore Gulf Coast area, predominantly all covered by 3-D seismic data, and 80,349 net acres in our Barnett Shale area. We have identified: (1) 174 potential exploratory drilling locations in our onshore Gulf Coast area, comprised of 104 leased exploratory drillsites, ten of which are field extension wells based on initial drilling activities, and 70 seismically defined prospects on which we are pursuing acreage, and (2) over 500 potential exploratory and development horizontal drilling locations on our leased acreage 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 247 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.

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

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reserves in the Barnett Shale, which is now considered one of the most active natural gas plays in North America. The reserve profile 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 primarily horizontal wells in the Barnett Shale area. Typical costs to drill and complete are approximately $2.4 million for horizontal wells. We also drill vertical wells with typical costs of approximately $0.9 million. Our Barnett horizontal wells generally have target depths of 8,500 to 10,500 feet including the lateral section. During 2005, we held an average 60 percent working interest participation in the Barnett wells drilled as we shifted to a primarily Carrizo-operated program and operated a majority of the wells drilled. For wells drilled in 2006, we plan to increase our average working interests to between 70 and 80 percent.

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, 2005, we had acquired approximately 80,000 net acres, drilled 76 gross (37.8 net) wells and increased our total proved reserves in the Barnett Shale area to 82.1 Bcfe. As of March 1, 2006, our current net production in the Barnett Shale area was estimated at 14 MMcfe/d.

As of December 31, 2005, we operated 106 producing oil and gas wells, which accounted for 48% of the onshore Gulf Coast area producing wells and 15% of the Barnett Shale 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. RMG subsequently transferred its interest in Pinnacle to U.S. Energy Corp. 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 U.S. Energy Corp. each elect not to exercise our available options. In 2005, the CSFB Parties contributed $15.0 million to Pinnacle to finance an acquisition of additional undeveloped acreage. CCBM and U.S. Energy Corp. elected not to participate in the equity contribution. In November 2005, the CSFB Parties and a former Pinnacle employee received 30,000 and 2,000 shares of Pinnacle common stock, respectively, after exercising certain warrants and options. Accordingly, CCBM’s ownership in Pinnacle is 32.3% as of December 31, 2005 (15.8% on a fully diluted basis). 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. We understand that Pinnacle is in the process of raising additional capital to expand its operations, which may result in a further dilution of our interest.

In addition to our interest in Pinnacle, CCBM has maintained interests in approximately 159,000 gross acres at the end of 2005 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:

- *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 2006, we are drilling or plan to drill approximately 26 wells (11.7 net) in the onshore Gulf Coast area and 49 wells (35 net) in the Barnett Shale area. We have planned approximately $117.5 million for capital expenditures in 2006, $112.4 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, the U.K. North Sea and shale trends in West Texas/New Mexico, Mississippi/Alabama, Kentucky and Arkansas, 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 in North Texas 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 2005, we added approximately 823 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, 2005, we had accumulated licenses for approximately 10,023 square miles of 3-D seismic data and identified over 674 drilling locations and extension opportunities (comprised of 174 locations in the onshore Gulf Coast area, and approximately 500 locations in the Barnett Shale area) including 604 locations currently under lease or in the process of being leased (comprised of 104 locations in the onshore Gulf Coast area and 500 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 20 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 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.

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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 were completed in the second quarter of 2005. We also entered into a 3-D seismic data acquisition program in 2004 and 2005 to complete seismic shoots over significant acreage positions in our Barnett Shale area, covering an estimated 299 square miles.

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.

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.

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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, 2005, we operated 106 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 and other shale trends in West Texas/New Mexico, Mississippi/Alabama, Kentucky and Arkansas. The table below highlights our main areas of activity:

3-D PROJECT SUMMARY CHART
As of December 31, 2005

	Productive Wells		3-D Seismic Data (Sq. Miles)	Net Options/ Leased Acres	Drilling Capital Expenditures	
	Gross	Net			2005	2006 Plan
Onshore Gulf Coast:						
Wilcox	31	10	2,066	16,175	$ 2.9	$ 2.8
Frio/Vicksburg	98	29	2,166	12,319	11.5	2.7
Southeast Texas	18	6	977	8,387	6.1	11.0
South Louisiana	10	3	1,957	6,979	4.8	11.9
Barnett Shale	67	28	299	80,349	51.4	84.0
East Texas	52	51	503	4,558	4.6	5.1
Rocky Mountain	—	—	473	16,330	—	—
North Sea	—	—	577	123,673	—	—
West Texas/New Mexico Shale	—	—	—	20,018	—	—
Alabama/Mississippi Shale	—	—	—	15,200	—	—
Kentucky Shale	—	—	—	11,522	—	—
Arkansas Shale	—	—	—	360	—	—

Other Areas	1	1	1,005	1,145	0.6	—
Total	277	128	10,023	317,015	$ 81.3	$ 117.5

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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 a total inventory of 104 leased exploratory drillsites, ten of which are field extension wells based on initial drilling success. We are pursuing acreage on an additional 70 seismically defined prospects. We plan to spend approximately $28.4 million on drilling expenditures in 2006, comprised of approximately 26 wells (11.7 net). We also plan to spend $2.2 million to purchase and reprocess 3-D seismic surveys during 2006.

Texas - Wilcox Areas

We have licenses for approximately 2,066 square miles of 3-D seismic data and 16,175 net acres of leasehold in the Wilcox trend in Texas. From January 1, 2002 through December 31, 2005, we drilled and completed 28 wells (9.8 net) on 33 attempts in this area. We incurred capital expenditures of $3.2 million and drilled 4 wells (1.56 net) in the Texas Wilcox area in 2005 and expect to devote approximately $2.8 million to drill 4 wells (1.48 net) in this area in 2006. In the Wilcox area 29 exploratory drillsites have been leased, seven of which are field extension wells based on results of initial drilling. We are pursuing acreage on an additional 28 seismically defined prospects.

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 12,319 net leasehold acres over this trend. Our current focus is primarily in Brooks County, the location of the Encinitas Field.

We have an inventory of 25 leased exploratory drillsites in the Frio/Vicksburg trend, three of which are field extension wells based on success of initial drilling. We are pursing acreage on an additional 13 seismically defined prospects.

From January 1, 2002 through December 31, 2005, we drilled and completed 43 wells (9.65 net) in 48 attempts in this trend. We incurred capital expenditures of $11.5 million and drilled 9 wells (6.0 net) in the Frio/Vicksburg trend area in 2005 and expect to devote approximately $2.7 million to drill 5 wells (1.55 net) in this area in 2006.

Encinitas Field. This field, the site of our first 3-D seismic survey in 1995, has 38 wells currently producing. Since 1996, we have participated in the drilling of 37 wells (7.4 net) in this area, 35 (6.9 net) of which were successfully completed. During 2005, we participated in the drilling of 8 wells, all of which were successfully completed. We expect to drill 3 wells (0.8 net) in 2006, with an additional ten 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 usually 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 977 square miles of 3-D data over our Southeast Texas project area which is focused primarily on the Frio, Yegua, Cook Mountain and Vicksburg formations.

We have 28 leased exploratory drillsites, none of which are dependent on success of the other wells. An additional four prospects have been seismically mapped on which we are currently pursuing acreage.

From January 1, 2002 to December 31, 2005, we participated in the drilling and completion of 15 wells (4.8 net) in 18 attempts in this area. We incurred capital expenditures of $7.0 million and drilled 5 wells (1.58 net) in the Southeast Texas area in 2005 and expect to devote approximately $11.0 million and drill 10 wells (5.2 net) in this area in 2006. 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 2006.

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Liberty

We have identified and leased prospects including the Frio, Yegua, Cook Mountain, and Wilcox formations within the 600 square miles of 3-D seismic data in the Liberty Project Area which now covers significant areas of Liberty, Harris, and Hardin Counties, Texas.

As of December 31, 2005, we had identified 28 leased exploratory drilling locations and an additional four potential locations that we are attempting to lease in the Liberty Project Area. Thirteen of the total 28 prospects were generated from our 2005 seismic survey project. Carrizo's 2006 drilling budget provides for drilling of ten of these exploratory locations. Accordingly, we expect to continue significant drilling activity in the Liberty Project area in 2007.

South Louisiana Area

The South Louisiana area primarily contains objectives in the Middle and Lower Miocene intervals. We have acquired licenses for approximately 1,957 square miles of 3-D data and approximately 6,979 net acres of leasehold. The 3-D seismic data sets are concentrated in one general area including St. Mary, Terrebonne and LaFourche Parishes.

Our South Louisiana inventory consists of 13 leased exploratory drillsites none of which are dependent on the success of the other wells. Carrizo is currently pursuing acreage on an additional 18 seismically defined prospects. From January 1, 2002 to December 31, 2005, we drilled and completed 5 wells (2.2 net) on ten attempts in this area. We incurred capital expenditures of $1.8 million and drilled 1 well (0.33 net) in the South Louisiana area in 2005 and expect to devote approximately $11.9 million to drill 7 wells (3.4 net) in this area in 2006.

LaRose

During 2002, we successfully drilled and completed an offset well to the discovery well in this area. We operate the 2 wells with an estimated 40% working interest. We plan to participate in 1 additional well (0.37 net) in the general area during 2006.

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, 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. Production at year end 2004 was approximately 2,800 Mcfe/d.

In April 2005 we acquired 600 net acres and working interests in 14 existing wells (7.3 net) with an estimated 5.4 MMcfe of proved reserves in the Barnett Shale trend for $2.3 million in cash and 112,697 shares of our common stock.

During 2005, we drilled 37 additional wells (22.1 net) and acquired an additional 49,632 net acres, increasing our acreage at the end of 2005 to over 80,000 net acres (primarily in Tarrant, Parker, Denton, Johnson, Hill and Erath counties). Carrizo was operator on 18 of the gross wells drilled. At year-end, 18 of the gross wells were producing and the remaining 19 wells were awaiting completion and/or pipeline connection.

We are continuing to expand our leasehold acquisition in this trend. Production at the end of 2005 and at March 1, 2006 was approximately 11,000 Mcfe/d and 14,000 Mcfe/d, respectively. Net proved reserves have grown by 259% from 31.7 Bcfe in December 31, 2004 to 82.1 Bcfe at December 31, 2005. We are drilling with three Carrizo operated rigs as of March 1, 2006.

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 503 square miles of 3-D seismic data in the East Texas area and 4,558 net acres under lease.

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We expect to invest $5.1 million to drill 35 to 40 (35 to 40 net) wells in this region in 2006.

Camp Hill Project. We own interests in approximately 800 gross acres in the Camp Hill field in Anderson County, Texas. We currently operate all of these leases. During the year ended December 31, 2005, the project produced an average of 46.7 Bbls/d of 19 API gravity oil. The wells produce from a depth of 500 feet and have utilized and plan to 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, 2005 averaged $27.45 per barrel ($4.57 per Mcfe). The oil produced, although viscous, commands a comparable price to West Texas Intermediate crude (an average premium of $0.15 per Bbl to Koch WTI during the year ended December 31, 2005) due to its suitability as a lube oil feedstock.

As of December 31, 2005, we had 7.1 MMBbls of proved oil reserves in this project, with 740 MBbls of oil reserves currently developed. The proved undeveloped reserves at the Camp Hill Field constitute 25.3% of our proved reserves and account for 26.0% of our present value of net future revenues from proved reserves as of December 31, 2005. We have an average working interest of approximately 92.1% in this field and an approximate net revenue interest of 71.0%.

Prior to 2003, we estimated an ultimate recovery efficiency (i.e. the percentage of the oil in the ground that we would be able to produce economically) after steam drive of 45% of the original oil in place in the Camp Hill field. As of January 1, 2003, we raised our estimate to an ultimate recovery of 55% of the estimated original oil in place based upon our review of recovery efficiencies from prior projects by other companies in both the Camp Hill Field as well as in nearby projects that we considered to have similar geologic and hydrocarbon attributes. We have lowered our estimated recovery efficiency as of December 31, 2005 to 49% of the estimated original oil in place in the field. We believe this revised recovery efficiency is reasonable, particularly in light of the fact that a project that we have operated in the Camp Hill Field since 1993 has a current 48.7% recovery efficiency as of December 31, 2005 and is currently producing at a rate of approximately 0.8% of original oil in place per year, even without steam injection. Our estimated proved reserves for the Camp Hill Field as of year-end 2005 were adversely impacted by this revision in the recovery efficiency estimate; resulting in a reduction of 991,515 net Bbls of oil as of December 31, 2005. We made other negative revisions to our December 31, 2005 Camp Hill reserves totaling 483,418 net Bbls of oil as a result of new well data and additional analysis.

Although in 2005 we accelerated our development activities in the Camp Hill Field, this follows an extended period during which we deferred development in the field. We deferred development (1) to optimize returns by awaiting an economic entry point for developing a cogeneration plant as further explained below, (2) to pursue other opportunities in both our onshore Gulf Coast and later, Barnett Shale areas with higher rates of return and (3) to continue increasing our net acreage position in the field in a competitive environment. Although we at all times believed that we could develop this field on a profitable basis, we nonetheless believed that we were optimizing our economic position by deferring development. We acquired our initial interests in the Camp Hill field in 1993. We performed remedial work on the existing wells and steam generators and began injecting steam in March 1994. From 1994 through 1998 and during the first nine months of 2000, we injected steam in 31 patterns. In the fourth quarter of 2000, we suspended steam injection in response to high fuel gas prices and to pursue a lower steam cost solution through our cogeneration negotiations. Thereafter, we drilled one well in 2001 and seven wells in 2005.

The most important reason for our delay in both resuming steam injection and moving to full development was the potential for significantly improved profitability that would result from the construction of a nearby cogeneration plant. Cogeneration plants typically provided steam at less than half the cost of small steam generators. Steam costs are critical to the economics of the development of the field. Expected steam costs far outweigh the capital costs for the development of the Camp Hill Field. We currently estimate approximately $139 million in steam costs compared to $22 million for drilling and development capital that is needed to fully develop the proved undeveloped reserves in this field. Previously, our management believed that the demand for electricity in the East Texas area would increase in the future such that it would become lucrative for us or a third party to build a cogeneration plant in the area. In this cogeneration plant, a gas turbine would be used to generate electricity, and the waste heat would be used to produce steam. The steam would be captured for injection in the Camp Hill field, while the electricity would be sold into the Texas electric power grid. In 2000, we engaged in discussions with another party regarding the building of a cogeneration facility, but we ultimately did not reach acceptable terms with that party. We subsequently continued to explore the possibility of a cogeneration facility in the Camp Hill field and worked with electricity industry consultants in 2002 and 2005.

During the time we were continuing to assess the relative attractiveness of building a cogeneration plant, and in light of relatively high fuel gas costs at that time, we pursued other exploration projects primarily along the onshore Gulf Coast and in the Barnett Shale, starting in 2003, that we believed offered us potentially higher rates of return. These other projects have been the primary focus of our

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operations over the last several years. Our timing of Camp Hill development has also been impacted by our leasing activities in the field by which we increased our working interest and net revenue interest in our leases in the field so that we would own a greater share of these properties when we later developed them. We believe that we were able to increase our interests on more favorable terms by deferring the full scale development of the field. The addition of working interests in the Camp Hill leases further improved the economics of the development of this field as well as favorably affect the development plan for the steam drive patterns in the field.

In 2005, we continued to invest the majority of our budgeted capital expenditures in our Barnett Shale and onshore Gulf Coast areas where the rates of return are traditionally higher and our leases expire sooner, which gives these projects greater immediacy. We did, however, drill seven gross wells (7.0 net) on four leases in the Camp Hill field in 2005, all of which are apparent successes and currently producing.

In mid-2005, we reengaged an electricity industry consultant with cogeneration experience to further investigate the feasibility of establishing a cogeneration plant in the area. After extensive discussions with the consultant, we concluded that there continues to be overcapacity of electricity in the regional market and that overcapacity is not likely to reverse itself in the near term and that the capital expenditures associated with building a cogeneration plant are not likely to be warranted for a period of several years. As a result, we determined that, rather than awaiting the construction of a cogeneration plant, we would instead further develop our Camp Hill properties with the existing steam generators.

In August 2005, management proposed the acceleration of the Camp Hill development to our board of directors. Accordingly, a development plan was formally approved by the board for increased drilling activity in the Camp Hill field, beginning with an initial 60-well drilling program. In February 2006, our board of directors formally approved a multi-year plan to fully develop the entire Camp Hill field. In furtherance of this plan, we expect to drill between 35 and 40 gross wells (35 to 40 net) in this area at an estimated cost of $3.2 million during 2006. To fully develop the field, we expect to drill approximately 326 wells from 2006 through 2017, at a total cost of approximately $22 million and total operating costs including steam of approximately $175.0 million. The precise timing and amount of our expenditures on additional well drilling and increased steam injection to develop the proved undeveloped reserves in this project will depend on several factors including the relative prices of oil and natural gas.

We have recently taken other steps to accelerate Camp Hill development. To implement our development plan, we have entered into a new fuel gas supply contact; we are upgrading the steam generator burners and burner controls; and we have obtained a 30-well drilling rig contract. This rig was placed in the field in late March 2006. We recommenced steam injection in the Camp Hill field in April 2006.

Other Project Areas in the East Texas Region

We have leased nine additional exploratory prospects in our East Texas region and an additional seven prospects that are currently being pursued. We expect to invest $1.9 million to drill one (0.5 net) well in these areas other than Camp Hill in 2006.

Wyoming/Montana Coalbed Methane Project Area

Rocky Mountain Region

In June 2003, we contributed our Powder River Basin interests, including all leasehold, wells and reserves, in the Arvada, Bobcat, Clearmont and Kirby prospects into the formation of Pinnacle. Our interests in Castle Rock, Montana and Oyster Ridge, Wyoming were retained. While no proved reserves have yet been booked in either area, drilling operations were conducted at both during 2005, with two and four wells respectively drilled in each area. As the end of 2005, we owned direct interests in approximately 159,090 gross acres (including 21,864 acres which have now been optioned via drill-to-earn provisions of a farmout at Oyster Ridge).

At year-end 2005, Pinnacle had completed the acquisition and/or drilling of 624 gross wells, or approximately 336 net. Of those wells, 621 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 December 31, 2005, Pinnacle had drilled 383 wells; of these wells, (1) 283 are producing gas; (2) 47 remain in the completion/hook-up phase; (3) 33 are in the dewatering phase with no early indication as to gas production; (4) 17 are waiting on or being evaluated for workovers or redrill or plugging and abandonment; and (5) three of these wells did encounter coal accumulations.

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As of December 31, 2005, of the 241 wells that Pinnacle had acquired, (1) 81 are producing gas, (2) 108 remain in the completion/hook-up phase; (3) 17 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 were originally awarded seven acreage blocks in 2003, consisting of one "Traditional" and three "Promote" licenses, in the United Kingdom's 21st Round of Licensing. Subsequently, the Company has generated a number of prospects from certain of these blocks and, accordingly, has renewed the promote licenses on certain of these blocks in 2005. As of December 31, 2005, the awarded blocks, to explore for natural gas and oil totaling six blocks and 124,000 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. We expect to drill two prospects in 2006, retaining a 25% carried interest in each. Geological and geophysical costs will be incurred in an attempt to maximize the value of our retained interest. Our estimated project commitments for 2006 are $1.3 million, largely for data processing and prospect generation.

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."

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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, 2005. The reserve data and the present value as of December 31, 2005 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, 2005, 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 12 of Notes to Consolidated Financial Statements.

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
	(Dollars in thousands)		
Oil and condensate (MBbls)	1,343	6,582	7,925
Natural gas (MMcf)	44,681	58,378	103,059
Total proved reserves (MMcfe)	52,739	97,870	150,609
PV-10 Value(1)(2)	$ 216,049	$ 188,181	$ 404,230

(1) The PV-10 Value as of December 31, 2005 is pre-tax and was determined by using the December 31, 2005 sales prices, which averaged $57.17 per Bbl of oil, $8.04 per Mcf of natural gas. Management believes that the presentation of PV-10 Value may be considered a non-GAAP financial measure as defined in Item 10(e) of Regulation S-K. Therefore we have included a reconciliation of the measure to the most directly comparable GAAP financial measure (standardized measure of discounted future net cash flows in footnote (2) below). Management believes that the presentation of PV-10 Value provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company may impact the amount of future income taxes to be paid, the use of the pre-tax measure provides greater comparability when evaluating companies. It is relevant and useful to investors for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. Management also uses this pre-tax measure when assessing the potential return on investment related to its oil and natural gas properties and in evaluating acquisition candidates. The PV-10 Value is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of the estimated oil and natural gas reserves owned by us. PV-10 Value should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

(2) Future income taxes and present value discounted (10%) future income taxes were $195.9 and $104.9 million, respectively. Accordingly, the after-tax PV-10 Value of Total Proved Reserves (or "Standardized Measure of Discounted Future Net Cash Flows") is $299.3 million.

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.”

In accordance with SEC regulations, Ryder Scott Company Petroleum Engineers, Fairchild & Wells, Inc. and DeGolyer and MacNaughton each used year-end oil and natural gas prices in effect at December 31, 2005, adjusted for basis and quality differentials. The prices used in calculating the estimated future net revenue attributable to proved reserves do not necessarily reflect

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market prices for oil and natural gas production subsequent to December 31, 2005. There can be no assurance that all of the proved reserves will be produced and sold within the periods indicated, that the assumed prices will actually be realized for such production or that existing contracts will be honored or judicially enforced. In particular, natural gas prices at December 31, 2005 were at or near their record highs. While crude oil prices have remained approximately the same since year-end, natural gas prices have experienced significant volatility and since that time prices for natural gas have fallen substantially. As of March 15, 2006, the average price of natural gas that we receive for our production had fallen to approximately $7.00 per Mcf. Decreases in the assumed commodity prices result in decreases in estimated future net revenue as well as in estimated reserves.

DeGolyer and MacNaughton determined 55% of our proved reserves for the year ended December 31, 2005, which reserves were located on our Barnett Shale properties. Fairchild & Wells, Inc. determined 28% of our proved reserves for the year ended December 31, 2005, which reserves were located on our properties in the Camp Hill field. Ryder Scott Company Petroleum Engineers determined 17% of our proved reserves for the year ended December 31, 2005, 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 11.2% in 2003, to 17.2% in 2004 and to 19.1% in 2005. Set forth below is our reserve replacement ratio for the year ended December 31, 2005, 2004 and 2003.

	2003	2004	2005
Reserve Replacement Ratio	203%	568%	530%

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. For 2003, the table includes the cash impact of hedging activities.

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	Year Ended December 31, 2003	2004 (Restated)	2005
Production volumes			
Oil (MBbls)	450	309	234
Natural gas (MMcf)	4,763	6,462	8,206
Natural gas equivalent (MMcfe)	7,463	8,319	9,612
Average sales prices			
Oil (per Bbl)	$ 28.90	$ 41.00	$ 56.36
Natural gas (per Mcf)	5.35	6.14	7.90
Natural gas equivalent (per Mcfe)	5.16	6.30	8.13
Average costs (per Mcfe)			
Camp Hill operating expenses	$ 3.45	$ 3.31	$ 4.57
Other operating expenses	0.58	0.59	0.62
Total operating expenses(1)	0.90	1.01	1.09

(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 $2.9 million, $2.9 million and $5.8 million for the years ended December 31, 2003, 2004 and 2005, respectively. We have also included capitalized overhead in our finding cost of $1.4 million, $1.7 million and $2.1 million for the years ended December 31, 2003, 2004 and 2005, respectively. We have also included non-cash asset retirement obligations of $0.7 million, $0.5 million and $1.8 million for the years ended December 31, 2003, 2004 and 2005, respectively.

	Year Ended December 31, 2003	2004	2005
	(In thousands except per Mcfe amounts)		
Acquisition costs:			
Other unproved properties	$ 7,280	$ 21,831	$ 49,089
Proved properties	-	8,357	1,954
Exploration	23,745	39,181	50,303
Development	112	12,697	20,883
Asset retirement obligation	744	529	1,820
Total costs incurred	$ 31,881	$ 82,595	$ 124,049
Total proved reserves added	15,138	47,294	50,929
Average all-sources finding cost (per Mcfe)	$ 2.11	$ 1.75	$ 2.44

For the three year period ended December 31, 2005, our total adjusted costs for development, exploration and acquisition activities was approximately $238.5 million. Total exploration, development and acquisition activities for the three year period ended December 31, 2005 have added approximately 113.4 Bcfe of net proved reserves at an all-sources finding cost of $2.10 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 $0.7 million, $39.8 million and $99.8 million at December 31, 2003, 2004 and 2005, respectively, and includes total additions to proved undeveloped reserves of 2.9, 27.6 and 25.4 Bcfe for the years ended December 31, 2003, 2004 and 2005, respectively. Accordingly, had we included future development costs in our computations, the average all-sources finding costs would have been $2.15, $2.59 and $4.39 per Mcfe for the years ended December 31, 2003, 2004 and 2005, 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 cost may also be calculated differently than the comparable measure of 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,		
	2003	2004	2005
		(In thousands)	
Acquisition costs			
Unproved prospects	$ 7,280	$ 21,831	$ 49,089
Proved properties	-	8,357	1,954
Exploration	23,745	39,181	50,303
Development	112	12,697	20,883
Asset retirement obligation	744	529	1,820
Total costs incurred(1)	$ 31,881	$ 82,595	$ 124,049

(1) Excludes capitalized interest on unproved properties of $2.9 million, $2.9 million and $5.8 million for the years ended December 31, 2003, 2004 and 2005, respectively, and includes capitalized overhead of $1.4 million, $1.7 million and $2.1 million for the years ended December 31, 2003, 2004 and 2005, respectively. The table also includes non-cash asset retirement obligations of $0.7 million and $0.5 million and $1.8 million, respectively, for the years ended December 31, 2003, 2004 and 2005, respectively.

Drilling Activity

The following table sets forth our drilling activity for the years ended December 31, 2003, 2004 and 2005. 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, 2005 has resulted in an apparent commercial success rate of approximately 76%.

Year Ended December 31,		
2003	2004	2005

	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	33	9.2	39	14.9	38	20.6
Nonproductive	5	0.8	6	3.7	4	1.2
Total	38	10.0	45	18.6	42	21.8
Development Wells						
Productive	1	0.2	26	8.7	23	14.0
Nonproductive	-	-	-	-	-	-
Total	1	0.2	26	8.7	23	14.0

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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) and six gross wells (1.1 net) drilled by CCBM during 2004 and 2005, respectively. The wells contributed to Pinnacle are in various stages of development and/or stages of production. The wells contributed to Pinnacle are described in “Wyoming/Montana Coalbed Methane Project Area” above.

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, 2005. 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	60.0	53.1	11.0	4.2	71.0	57.3
Natural gas	46.0	25.4	143.0	35.1	189.0	60.5
Total	106.0	78.5	154.0	39.3	260.0	117.8

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of December 31, 2005. 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	-	-	123,673	123,673	123,673	123,673
Louisiana	3,195	1,060	6,337	5,598	9,532	6,658
Texas	48,633	18,483	217,183	119,231	265,816	137,714
Montana/Wyoming	-	-	137,226	10,863	137,226	10,863
Other	-	-	69,828	31,870	69,828	31,870
Total	51,828	19,543	554,247	291,235	606,075	310,778

The table does not include 2,879 gross and 771 net acres under lease option that we had a right to acquire in Texas and Louisiana, pursuant to various seismic and lease option agreements at December 31, 2005. 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 21,864 gross and 5,466 net acres under lease option in Wyoming that CCBM has the right to earn pursuant to certain drilling obligations and other predetermined terms.

We make certain statements in “Business and Properties-General” above regarding acreage that we are currently pursuing in various project areas. This acreage is not included in the table above. We have no rights in acreage that we are only pursuing because the acreage is not under lease or option and, in many cases, we are not in negotiations with respect to such acreage. Moreover, there can be no assurance that we will ever acquire such acreage.

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

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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;
- 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.

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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.

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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. In light of this increased reliance on competition under the provisions of the Energy Policy Act of 2005, the NGA has been amended to prohibit any forms of market manipulation in connection with the transportation, purchase or sale of natural gas. In addition to the regulations implementing these prohibitions, the FERC has been directed to establish new regulations that are intended to increase natural gas pricing transparency through, among other things, expanded dissemination of information about the availability and prices of gas sold. The Energy Policy Act of 2005 also significantly increases the penalties for violations of the NGA to up to $1 million per day for each violation. There regularly are other legislative proposals pending in the federal and state legislatures which, if enacted, would significantly affect the petroleum industry. 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. 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 second of these reviews was commenced in July 2005, during which the FERC proposed to continue the use of a similar indexing methodology for a further five-year period. 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 noncorporate partnership interests. Following a court remand, the FERC has established a policy that a pipeline structured as a master limited partnership or similar noncorporate entity is entitled to a tax allowance with respect to income for which there is an "actual or potential income tax liability," to be determined on a case by case basis. 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

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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 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

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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 25, 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 further entered an order limiting the issuance of federal drilling permits to 500 per year and placed additional restrictions on certain operations. Various parties appealed these orders to the Ninth Circuit Court of Appeals. On May 31, 2005, the Ninth Circuit entered an order halting the issuance of any new permits pending their review of the parties' various appeals. Oral argument was held in the case on September 15, 2005, and no decision has yet been issued. Although this decision could result in a continued 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 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, 2005 to Chevron Texaco (12%) and Reichman Petroleum (11%); for the year ended December 31, 2004 to Cokinos

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Natural Gas Company (17%), Texon L.P. (13%) and WMJ Investments Corp. (12%); and for the year ended December 31, 2003 to WMJ Investments Corp. (16%), Cokinos Natural Gas Company (15%) and Gulfmark Energy, Inc. (14%). 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, 2005, we had 50 full-time employees, including four landmen, six geoscientists, seven engineers and three technical support staff. 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 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%. In March 2006 we entered into an agreement with Pinnacle and certain other shareholders of Pinnacle allowing us to exercise the Pinnacle stock options on a cashless, net exercise basis. At the end of 2005, we retained our interests in approximately 159,000 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, was Chairman of Global Energy Partners, Ltd., an affiliate of CSFB and is currently Chairman of Avista Capital Holdings, L.P., a private equity firm that makes investments in the energy sector and that has an affiliate that provides consulting services to an affiliate of CSFB.

In March 2004, the CSFB parties contributed additional funds of $11.8 million to continue funding the 2004 development program of Pinnacle.

In 2005, the CSFB Parties contributed $15.0 million to Pinnacle to finance an acquisition of additional undeveloped acreage. CCBM and U.S. Energy Corp. elected not to participate in the equity contribution. In November 2005, the CSFB Parties and a former Pinnacle employee received 30,000 and 2,000 shares of Pinnacle common stock, respectively, after exercising certain warrants and options. Accordingly, CCBM’s ownership in Pinnacle is 32.3% as of December 31, 2005 (15.8% on a fully diluted basis). We understand that Pinnacle is in the process of raising additional capital to expand its operations, which may result in a further dilution of our interest.

As of December 31, 2005, on a fully diluted basis, assuming that all parties exercised their Pinnacle warrants and Pinnacle stock options, the CSFB Parties, CCBM and U.S. Energy Corp. would have ownership interests of approximately 68.4%, 15.8% and 15.8%, respectively.

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

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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 and 2005 Pinnacle's production was approximately 13 MMcfe/d gross (5.6 MMcfe/d net) and 17.8 MMcfe/d gross (6.0 MMcfe/d net). As of December 31, 2004 and 2005, Pinnacle owned interests in approximately 170,000 gross acres (79,000 net) and 418,000 gross acres (272,000 net), respectively, in the Powder River Basin.

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.

Item 1A. 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 upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control, including:

- unexpected or adverse drilling conditions;
- elevated pressure or irregularities in geologic formations;
- equipment failures or accidents;

- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs, crews and equipment.

Because we identify the areas desirable for drilling 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.

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

We may not adhere to our proposed drilling schedule.

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

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

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

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

There are uncertainties inherent in estimating natural gas and oil reserves and their estimated value, including many factors beyond the control of the producer. The reserve data set forth in this Form 10-K/A represents only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner and is based on assumptions that may vary considerably from actual results.

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

As of December 31, 2005, approximately 80.9% 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, 2005 had produced for a relatively short period of time as of that date. Because most of our reserve estimates are calculated using volumetric analysis, those estimates are less reliable than estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure based on seismic analysis. In addition, realization or recognition of our proved undeveloped reserves will depend on our development schedule and plans. Lack of certainty with respect to development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved. Although we have accelerated our development of the Camp Hill Field in East Texas, we have in the past chosen to delay development of our proved undeveloped reserves in the Camp Hill Field in favor of pursuing shorter-term exploration projects with higher potential rates of return, adding to our lease position in this field and further evaluating additional economic enhancements for this field's development.

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

- the actual prices we receive for natural gas and oil;

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

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

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

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

Natural gas and oil prices are highly volatile, and lower prices will negatively affect our financial results.

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

- the level of consumer product demand;
- overall economic conditions;
- weather conditions;
- domestic and foreign governmental relations;
- the price and availability of alternative fuels;
- political conditions;

- the level and price of foreign imports of oil and liquefied natural gas; and

- the ability of the members of the Organization of Petroleum Exporting Countries to agree upon and maintain 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. Such competitors may also be in a better position to secure oilfield services and equipment on a timely basis or on favorable terms. We may not be able to conduct our operations, evaluate and select suitable properties and consummate transactions successfully in this highly competitive environment.

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

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

As of December 31, 2005, we had material weaknesses in our internal control, and our internal control over financial reporting was not effective as of that date. If we fail to maintain an effective system of internal controls, we may not be able to provide timely and accurate financial statements.

As more fully described under Item 9A, Controls and Procedures, our management identified three material weaknesses over the effectiveness of our internal controls. These material weaknesses also resulted in us not being able to file our annual report during the time allowed by the Securities and Exchange Commission. As a result of the material weaknesses, management concluded that, as of December 31, 2005, we did not maintain effective internal control over financial reporting.

The Public Company Accounting Oversight Board has defined a material weakness as 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 statements will not be prevented or detected. Accordingly, a material weakness increases the risk that the financial information we report contains material errors. As more fully described in our annual report on Form 10-K/A for the year ended December 31, 2004, management concluded during 2004 that we did not maintain effective internal control over financial reporting.

We have implemented initiatives to remediate the material weaknesses in our internal controls. The steps we have taken and are taking to address the material weaknesses may not be effective. However, any failure to effectively address a material weakness or other control deficiency or implement required new or improved controls, or difficulties encountered in their implementation, could limit our ability to obtain financing, harm our reputation, disrupt our ability to process key components of our result of operations and financial condition timely and accurately and cause us to fail to meet our reporting obligations under rules of the SEC and Nasdaq and our various debt arrangements. Any failure to remediate the material weaknesses identified in our evaluation of our internal controls could preclude our management from determining our internal control over financial reporting is effective or otherwise from issuing in a timely manner our management report in 2007.

We could face adverse consequences as a result of our late Form 10-K filing.

Our inability to timely file our Form 10-K for the year ended December, 31, 2005, which was related to our restatement, may have an adverse impact on us. In particular, we expect that we will not be eligible to use a registration statement on Form S-3 for a period of 12 months after becoming current with our filings. The inability to use Form S-3 may impair our ability or increase our costs and the complexity of our efforts to raise funds in the public markets.

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

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

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

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

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.

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 a result, we have limited ability to exercise influence over, and control the risks associated with, operations of these properties. The failure of an operator of our wells to adequately perform operations, an operator’s breach of the applicable agreements or an operator’s failure to act in ways that are in our best interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including the operator’s

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

The marketability of our production depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. We generally deliver natural gas through gas gathering systems and gas pipelines that we do not own under interruptible or short-term transportation agreements. Under the interruptible transportation agreements, the transportation of our gas may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system, or for other reasons as dictated by the particular agreements. Our ability to produce and market natural gas on a commercial basis could be harmed by any significant change in the cost or availability of such markets, systems or pipelines.

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

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

Our business may suffer if we lose key personnel.

We depend to a large extent on the services of certain key management personnel, including our executive officers and other key employees, the loss of any of whom could have a material adverse effect on our operations. We have entered into employment agreements with each of S.P. Johnson IV, our President and Chief Executive Officer, Paul F. Boling, our Chief Financial Officer, J. Bradley Fisher, our Vice President of Operations, Gregory E. Evans, our Vice President of Exploration and Jack Bayless, our Vice President of Land. 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;

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- the results of our drilling program;
- hydrocarbon prices; and
- our access to capital.

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

We may continue to enter into derivative transactions to manage the price risks associated with our production. Our derivative transactions may result in our making cash payments or prevent us from benefiting 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 derivative arrangements may apply to only a portion of our production, thereby providing only partial protection against declines in natural gas and oil prices. These arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which production is less than expected, our customers fail to purchase contracted quantities of natural gas and oil or a sudden, unexpected event materially impacts natural gas or oil prices.

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 negatively affecting our business, financial condition and results of operations.

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

Due to current industry demands, well service providers and related equipment and personnel are in short supply. This is causing escalating prices, delays in drilling and other exploration activities, the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries. Such pressures will likely increase the actual cost of services, extend the time to secure such services and add costs for damages due to any accidents sustained from the over use of equipment and inexperienced personnel.

Our credit facilities contain 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 facilities are secured by a pledge of substantially all of our producing natural gas and oil properties and assets, are guaranteed by our subsidiary and contain covenants that limit additional borrowings, dividends, the incurrence of liens, investments, sales or pledges of assets, changes in control, repurchases or redemptions for cash of our common stock, speculative commodity transactions and other matters. The credit facilities also require 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 facilities 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 facilities. The restrictions of our credit facilities 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 facilities that limit our ability to borrow additional funds and dispose of assets may affect our flexibility in planning for, and reacting to, changes in business conditions;
- because our indebtedness is subject to variable interest rates, we are vulnerable to increases in interest rates;
- any additional financing we obtain may be on unfavorable terms;
- we may be required to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for operations and future business opportunities;
- a substantial decrease in our operating cash flow or an increase in our expenses could make it difficult for us to meet debt service requirements and could require us to modify our operations, including by curtailing portions of our drilling program, selling assets, reducing our capital expenditures, refinancing all or a portion of our existing debt or obtaining additional financing; and
- we may become more vulnerable to downturns in our business or the economy.

In addition, under the terms of our credit facilities, our borrowing base is subject to redeterminations at least quarterly 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 upon the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or the fair market value of unproved properties. If net capitalized costs of natural gas and oil properties exceed the ceiling limit, we must charge the amount of the excess to operations through depreciation, depletion and amortization expense. This charge is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities but does reduce our shareholders' equity. The risk that we will be required to write down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are low or volatile. In addition, write-downs would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues, as further discussed in "Risk Factors—Our reserve data and estimated discount future net cash flows are estimates based upon 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. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" for additional information on these matters.

We participate in oil and natural gas leases with third parties.

We may own less than 100% of the working interest in certain leases acquired by us, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for the joint activity obligations of the other working interest owners such as nonpayment of costs and liabilities arising from the actions of the working interest owners. In the event other working interest owners do not pay their share of such costs, we would likely have to pay those costs, which could materially adversely affect our financial condition.

We may incur losses as a result of title deficiencies.

We purchase working and revenue interests in the natural gas and oil leasehold interests upon which we will perform our exploration activities from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. Title insurance covering mineral

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leaseholds is not generally available and, in all instances, we forego the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled. As is customary in our industry, we rely upon the judgment of natural gas and oil lease brokers or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. The work might include obtaining affidavits of heirship or causing an estate to be administered. In cases involving more serious title problems, the amount paid for affected natural gas and oil leases can be generally lost, and the target area can become undrillable.

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

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

Item 1B. Unresolved Staff Comments

None.

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 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.

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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 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.

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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.

Item 3. Legal Proceedings

From time to time, we are 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 our financial position or results of operations.

Item 4. Submission of Matters to a Vote of Security Holders

None.

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Executive Officers of the Registrant

Pursuant to Instruction 3 to Item 401(b) of Regulation S-K and General Instruction G(3) to Form 10-K, the following information is included in Part I of this Form 10-K/A.

The following table sets forth certain information with respect to our executive officers

Name	Age	Position
S.P. Johnson IV	50	President, Chief Executive Officer and Director
Paul F. Boling	52	Chief Financial Officer, Vice President, Secretary and Treasurer
Gregory E. Evans	56	Vice President of Exploration
J. Bradley Fisher	45	Vice President and Chief Operating Officer
Jack L. Bayless	51	Vice President of Land

Set forth below is a description of the backgrounds of each of our executive officers.

S.P. Johnson IV has served as our President and Chief Executive Officer and a director since December 1993. Prior to that, he worked for Shell Oil Company for 15 years. His managerial positions included Operations Superintendent, Manager of Planning and Finance and Manager of Development Engineering. Mr. Johnson is also a director of Basic Energy Services, Inc. (a well servicing contractor). Mr. Johnson is a Registered Petroleum Engineer and has a B.S. in Mechanical Engineering from the University of Colorado.

Paul F. Boling became our Chief Financial Officer, Vice President, Secretary and Treasurer in August 2003. From 2001 to 2003, Mr. Boling was the Global Controller for Resolution Performance Products, LLC, an international epoxy resins manufacturer. From 1990 to 2001, Mr. Boling served in a number of financial and managerial positions with Cabot Oil & Gas Corporation, serving most recently as Vice President, Finance. Mr. Boling is a CPA and holds a B.B.A. from Baylor University.

Gregory E. Evans has served as Vice President of Exploration since March 2005. Prior to joining us, Mr. Evans was Vice President North America Onshore Exploration for Ocean Energy from 2001 to 2003. Prior to that time, he spent 19 years at Burlington Resources where he served as Chief Geophysicist North America during 1999 to 2000, Gulf of Mexico Deep Water Exploration Manager during 1998 to 1999 and Geoscience Manager for the Western Gulf of Mexico Shelf during 1996 to 1998. Between 1982 to 1996, Mr. Evans held various other technical and managerial positions with Burlington Resources, including Division Exploration Manager of both the Rocky Mountain Region as well as the Gulf Coast area. Mr. Evans received a B. S. in Geophysical Engineering from the Colorado School of Mines receiving the Cecil H. Green award for outstanding geophysical student.

J. Bradley Fisher has served as Vice President and Chief Operating Officer since March 2005. Prior to that time, he served as Vice President of Operations since July 2000 and General Manager of Operations from April 1998 to June 2000. Prior to joining us, Mr. Fisher was the Vice President of Engineering and Operations for Tri-Union Development Corp. from August 1997 to April 1998. He spent the prior 14 years with Cody Energy and its predecessor Ultramar Oil & Gas Limited where he held various managerial and technical positions, last serving as Senior Vice President of Engineering and Operations. Mr. Fisher holds a B.S. degree in Petroleum Engineering from Texas A&M University.

Jack L. Bayless has served as Vice President of Land since October of 2005. Prior to joining Carrizo, Mr. Bayless held the position of Land Manager for Union Oil Company of California from January of 2003 through September of 2005 managing both onshore and offshore operating areas including Unocal's deep water Gulf of Mexico efforts. Prior to Unocal, Mr. Bayless held Land Manager positions with Pure Resources from 2001 through 2002 and the Petroleum and Minerals Division of International Paper (IP Petroleum) from 1993 through 2000 as well as senior level positions at Elf Aquitaine from 1985 through 1992 and Gulf Oil Corporation from 1981 through 1984. He has managed land activities in the Gulf Coast, the Gulf of Mexico shelf and deep water, the Rockies, Alaska and the Michigan basin. Mr. Bayless is a Certified Professional Landman with a BBA in Petroleum Land Management from the University of Oklahoma.

PART II

Item 5. Market for Registrant's Common Stock, Related Shareholder Matters and Issuer Purchases of Equity Securities

Our common stock, par value $0.01 per share, trades on the Nasdaq National Market under the symbol CRZO. The following table sets forth the high and low bid prices per share of our common stock on the Nasdaq National Market for the periods indicated. The sales information below reflects interdealer prices, without retail mark-ups, mark-downs or commissions and may not necessarily represent actual transactions.

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	High	Low
2004:		
First Quarter	$ 8.10	$ 6.55
Second Quarter	10.75	7.28
Third Quarter	10.57	7.80
Fourth Quarter	11.57	9.20
2005:		
First Quarter	17.58	9.93
Second Quarter	18.33	13.10
Third Quarter	31.63	16.93
Fourth Quarter	30.60	21.81

The closing market price of our common stock on March 1, 2006 was $23.97 per share. As of March 1, 2006, there were an estimated 100 record owners of our common stock.

We have not paid any dividends on our common stock in the past and do not intend to pay such dividends in the foreseeable future. We currently intend to retain any earnings for the future operation and development of our business, including exploration, development and acquisition activities. Our credit facilities restrict our ability to pay dividends. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Item 6. Selected Financial Data

Our financial information set forth below for each of the five years in the period ended December 31, 2005, 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 such section and our consolidated financial statements and related notes included in Item 8. Financial Statements and Supplementary Data.

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	Year Ended December 31,				
	2001	2002	2003	2004 (Restated)	2005
	(In thousands, except per share data)				
Statement Of Operations Data:					
Oil and natural gas revenues	$ 26,226	$ 26,802	$ 38,508	$ 52,397	$ 78,155
Costs and expenses:					
Oil and natural gas operating expenses	4,138	4,908	6,724	8,392	10,437
Depreciation, depletion and amortization	6,492	10,574	11,868	15,464	21,374
General and administrative	3,333	4,133	5,639	7,191	8,789
Accretion expense related to asset retirement	-	-	41	23	70
Stock option compensation expense (income)	(558)	(84)	313	1,064	2,454
Total costs and expenses	13,405	19,531	24,585	32,134	43,124
Operating income	12,821	7,271	13,923	20,263	35,031
Mark-to-market loss on derivatives, net	-	-	-	(625)	(5,882)
Loss on extinquishment of debt	-	-	-	-	(3,721)
Equity in loss of Pinnacle Gas Resources, Inc.	-	-	(830)	(1,399)	(2,542)
Interest income (expense), net of amounts capitalized and interest income	269	54	(19)	(622)	(4,295)
Other income and expenses, net	1,777	274	29	506	(457)
Income before income taxes	14,867	7,599	13,103	18,123	18,134
Income tax expense	5,336	2,809	5,063	7,009	7,500
Income before cumulative effect of change in accounting principle	9,531	4,790	8,040	11,114	10,634
Dividends and accretion of discount on preferred stock	-	588	741	350	-
Income available to common shareholders before cumulative effect of change in accounting principle	9,531	4,202	7,299	10,764	10,634
Cumulative effect of change in accounting principle	-	-	(128)	-	-
Net income available to common shareholders	$ 9,531	$ 4,202	$ 7,171	$ 10,764	$ 10,634
Basic earnings per common share	$ 0.68	$ 0.30	$ 0.50	$ 0.54	$ 0.45
Diluted earnings per common share	$ 0.57	$ 0.26	$ 0.43	$ 0.49	$ 0.44
Basic weighted average shares outstanding	14,059	14,158	14,312	19,958	23,492
Diluted weighted average shares outstanding	16,731	16,148	16,744	21,818	24,361
Statements of Cash Flow Data:					
Net cash provided by operating activities	$ 22,669	$ 18,572	$ 33,631	$ 32,501	$ 38,839
Net cash used in investing activities	(29,942)	(22,747)	(29,673)	(80,294)	(111,417)
Net cash provided by (used in) financing activities	2,292	5,682	(5,379)	50,139	95,635
Other Operating Data:					
Capital expenditures	$ 38,264	$ 23,343	$ 31,930	$ 83,891	$ 135,156
Debt repayments (1)	5,479	8,745	5,951	13,737	101,021

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	As of December 31,				
	2001	2002	2003	2004 (Restated)	2005
Balance Sheet Data:			(in thousands)		
Working capital (deficit)	$ (582)	$ (1,442)	$ (11,817)	$ (8,937)	$ 10,307
Property and equipment, net	104,132	120,526	135,273	205,482	314,074
Total assets	117,392	135,388	156,803	234,345	383,101
Long-term debt, including current maturities	38,188	39,495	36,253	62,974	149,294
Convertible participating preferred stock	-	6,373	7,114	-	-
Total equity	63,204	66,816	76,072	121,060	155,385

(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 2006 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 in 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.

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”. All period to period comparisons are 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 interest rate swaps on the Second Lien Credit Facility and for 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 interest rate swaps and 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 and the three quarterly periods ended September 30, 2005. See Note 3 and Note 14 to the Company's consolidated financial statements.

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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 and 2005 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 and the first three quarters of 2005. 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 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 and 2005. 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.

Additionally, during the audit of Pinnacle Gas Resources, Inc., an error was discovered that affects amounts that had previously been reported on the Company's quarterly reports on Form 10-Q for the quarterly periods ended March 31, 2005, June 30, 2005 and September 30, 2005. The error arose as a result of the incorrect accounting for certain natural gas derivatives which had historically been accounted for using the cash flow method. Pinnacle's management and its independent registered public accountants have determined that these derivatives are not eligible for cash flow hedge accounting. Accordingly, Pinnacle restated its 2005 quarters using the non-designated derivatives accounting method. The relative change in the fair value of these derivatives due to changing commodity price is reflected as a gain or loss in Pinnacle's earnings each quarter. Because the Company's interest in Pinnacle is accounted for using the equity method, the Company determined that the effect of Pinnacle's restatement of its financial statements required the Company to, in turn, restate its own financial statements.

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:

	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 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		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		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		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

Quarterly Financial Statements (Restated) (Unaudited)

	March 31, 2005		June 30, 2005		September 30, 2005	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated

Balance Sheet:						
Other current assets	$ 1,230	$ 1,681	$ 1,186	$ 877	$ 6,376	$ 7,683
Total Current Assets	19,937	20,388	20,878	20,569	77,094	78,401
Investment in Pinnacle Gas Resources, Inc.	5,007	4,162	4,652	3,962	4,241	2,056
Total Assets	238,397	238,003	271,069	270,070	365,700	364,822
Fair Value of Derivative Financial Instruments	323	1,537	1,275	318	6,033	8,870
Total Current Liabilities	25,166	26,456	34,640	33,759	47,513	51,249
Fair Value of Financial Derivatives, net - Long Term	-	-	-	-	1,670	2,493
Deferred Income Taxes	18,719	18,745	20,726	20,752	20,514	20,540
Retained earnings	23,319	21,474	26,912	26,010	27,490	18,093
Accumulated other comprehensive loss	(210)	-	(833)	-	(4,832)	-
Total Liabilities and Shareholders Equity	238,397	238,003	271,069	270,070	365,700	364,822

	Quarters Ended					
	March 31, 2005		June 30, 2005		September 30, 2005	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
Statement of Operations:						
Oil and Natural Gas Revenues	$ 15,458	$ 15,249	$ 16,321	$ 16,351	$ 17,574	$ 18,442
Operating Income	4,951	4,742	6,935	6,965	6,777	7,645
Other Income and Expenses:						
Equity in loss of Pinnacle Gas Resources, Inc.	(222)	(1,068)	(355)	(200)	(411)	(1,906)
Mark-to-market gain (loss) of Derivatives, net	-	(1,727)	-	1,183	-	(11,638)
Income Before Income Taxes	4,173	1,391	5,847	7,215	1,213	(11,052)
Income Tax Expense (benefit)	1,587	909	2,254	2,679	634	(3,135)
Net Income (Loss)	$ 2,586	$ 482	$ 3,593	$ 4,536	$ 579	$ (7,917)
Net Income (Loss) Available to Common Shareholders	$ 2,586	$ 482	$ 3,593	$ 4,536	$ 579	$ (7,917)
Earnings per common share:						
Basic earnings (Loss) per common share	$ 0.11	$ 0.02	$ 0.15	$ 0.20	$ 0.02	$ (0.33)
Diluted earnings (Loss) per common share	$ 0.11	$ 0.02	$ 0.15	$ 0.19	$ 0.02	$ (0.33)

	Quarters Ended					
	March 31, 2005		June 30, 2005		September 30, 2005	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
Cash Flow Statement:						
Net income (Loss)	$ 2,586	$ 481	$ 3,593	$ 4,536	$ 579	$ (7,917)
Fair value loss (gain) of derivative financial	-	1,936	-	(1,213)	-	10,770

instruments						
Equity in loss of Pinnacle Gas Resources, Inc	222	1,068	355	200	411	1,906
Deferred income taxes (benefit)	1,539	862	2,170	2,595	569	(3,200)
Net cash provided by operating activities	7,379	7,379	6,952	6,952	4,488	4,488

	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, 2005, June 30, 2005 and September 30, 2005 should no longer be relied upon.

General Overview

For the year ended December 31, 2005, we achieved record annual drilling success rates, levels of production, natural gas and oil revenues and at the end of 2005 our proved oil and gas reserves also reached a record level.

Due to our drilling success, we produced a record 9.6 Bcfe in 2005 compared to 8.3 Bcfe in 2004. At the end of 2005, we also reached a record estimated proved reserves level of 150.6 Bcfe with 50.9 Bcfe of net additions for the year, replacing 530% of our 2005 production. See “Business and Properties - Natural Gas and Oil Reserve Replacement.”

In 2005, we drilled 65 wells (35.8 net), including 20 wells in the onshore Gulf Coast area, 37 wells in the Barnett Shale play and 8 wells in the Camp Hill field and other East Texas areas, with an apparent success rate of 94% compared to an apparent success rate of 92% in 2004, in which we drilled 71 wells (27.3 net), in the onshore Gulf Coast and Barnett Shale areas combined. Between January 1, 2003 and December 31, 2005, 71% of our wells drilled were exploratory and 29% were developmental. In 2005, 65% of these wells were exploratory and 35% 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 2005, our natural gas and oil revenues reached a record level at $78.2 million, and our net income available to common shareholders was $10.6 million, or $0.45 and $0.44 per basic and fully diluted share, respectively. In 2004, our natural gas and oil revenues were $52.4 million, and our net income available to common shareholders was $10.8 million, or $0.54 and $0.49 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 2005, our realized natural gas price was 29% higher and our realized oil price was 37% higher than in 2004.

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 derivative arrangements may apply to only a portion of our production and provide only partial protection against declines in natural gas and oil prices.

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 2006, we expect capital expenditures, excluding capitalized interest and overhead, to be approximately $140.0 to $145.0 million, as compared to $127.0 million in 2005.

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In 2006, we plan to drill 26 gross wells (11.7 net) in the onshore Gulf Coast area, 49 gross wells (35.0 net) in our Barnett Shale area and 35 to 40 gross wells (35 to 40 net) in our East Texas area, primarily in our Camp Hill oil field. The actual number of wells drilled will vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our cash flow, success of drilling programs, weather delays and other factors. If we drill the number of wells we have budgeted for 2006, depreciation, depletion and amortization, oil and natural gas operating expenses and production are expected to increase over levels incurred in 2005. Our ability to drill this number of wells is heavily dependent upon the timely access to oilfield services, particularly drilling rigs. The shortage of available rigs in 2005 delayed the drilling of several wells, slowing our growth in production.

At December 31, 2005, our net debt-to-total net capitalization ratio (computed as (1) total debt net of cash (‘net debt’) divided by the sum of (2) net debt plus (3) total book equity) was 44%, an increase from the 32% ratio at the end of 2004. This increase was primarily the result of: (1) our July 2005 debt refinancing and borrowings under our $150.0 million Second Lien Credit Facility which generated net proceeds of $72.1 million after (a) retiring $52.9 million of outstanding obligations under our senior subordinated notes and senior secured subordinated notes and (b) repaying the $18.5 million of outstanding indebtedness under our First Lien Credit Facility, (2) partially offset by the $17.0 million of net proceeds from the private placement of 1.2 million shares of common stock in June 2005. The equity and 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. In 2004 and 2005 we completed asset acquisitions in our Barnett Shale project area described below in “—Barnett Shale Activity.”

2004 Public Offering and 2005 Private Placement of Common Stock

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 selling shareholders. Our net proceeds of approximately $23.4 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 shareholders.

In the second quarter of 2005, we sold 1.2 million shares of our common stock (or approximately 5% of the fully diluted shares outstanding before the offering) to institutional investors at a price of $15.25 per share in a private placement (the “Private Placement”), a 4.7% discount to the close price on the Nasdaq stock market for our common stock the day prior to pricing. The net proceeds from the Private Placement, after the placement agents’ fees but before offering expenses, were approximately $17.0 million. We used the proceeds from the Private Placement to fund a portion of our 2005 capital expenditure program, including our drilling programs in the Barnett Shale and onshore Gulf Coast areas. In connection with the Private Placement, we were required to file a resale shelf registration statement to register the resale of the shares sold under the Securities Act. We filed such registration statement and are required to cause it to become and be kept effective for resale of shares for two years from the date of their original sale. In certain situations, we are required to indemnify the investors in the Private Placement, including without limitation, for certain liabilities under the Securities Act.

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.

In April 2005, we acquired leases and producing wells in the Barnett Shale for approximately $4.1 million which consisted of approximately 600 net acres and working interests in 14 existing gross wells (7.3 net) with an estimated 5.4 MMcfe of proved reserves, based upon our internal estimates. All of the interests in the wells acquired related to wells in which we already had an interest. The consideration paid for this acquisition was $2.3 million in cash and 112,697 shares of our common stock.

Initially, we financed our Barnett Shale activities with our available cash on hand. We 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. In June and July 2005, we completed the Private Placement and entered into the Second Lien Credit Facility (see “2004 Public Offering and 2005 Private Placement Common Stock” above and “Financing Arrangements - Second Lien Credit Facility and Refinancing,” below), a portion of the net proceeds of which were used to partially fund our ongoing capital expenditure program, including our drilling programs in the Barnett Shale and onshore Gulf Coast areas.

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In the Barnett Shale area, we drilled 33 gross wells (13.7 net) in 2004 and 37 gross wells (22.1 net) in 2005, all of which were successful. We plan to drill 49 gross wells (35.0 net) in this area in 2006. We may seek to finance a portion of our remaining 2006 Barnett Shale activities with borrowings under our First Lien Credit Facility. In particular we may need to seek other financing alternatives if the future borrowing base under the First Lien Credit Facility is insufficient in partially funding our drilling program. We may not be able to obtain such financing on terms acceptable to us or at all. At the end of 2005 our net production had risen to approximately 11.0 MMcfe/d with 61 gross wells on line and another 26 gross wells in various stages of testing, completion and awaiting pipeline hookup. As of March 22, 2006, our estimated net production was 15.0 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 30,700 to 80,300 acres, at the end of 2004 and 2005, respectively. Similarly, we have increased our estimated number of developmental locations from 40 to 58 horizontal locations, at the end of 2004 and 2005, respectively, and we have increased our estimated number of exploratory drilling locations (horizontal) in the Barnett Shale area from 152 to 432 locations, at the end of 2004 and 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 (through CCBM, our wholly-owned subsidiary) 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”) 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 U.S. Energy Corp. each elect not to exercise our available options.

In 2005, the CSFB Parties contributed $15.0 million to Pinnacle to finance an acquisition of additional undeveloped acreage. CCBM and U.S. Energy Corp. elected not to participate in the equity contribution. In November 2005, the CSFB Parties and a former Pinnacle employee received 30,000 and 2,000 shares of Pinnacle common stock, respectively, after exercising certain warrants and options. Accordingly, CCBM’s ownership in Pinnacle is 32.3% at December 31, 2005 (15.8% on a fully diluted basis). We understand that Pinnacle is in the process of raising additional capital to expand its operations, which may result in a further dilution of our interest. If Pinnacle engages in any such activities that involve the issuance of additional equity, we could be diluted to an extent where we would no longer use the equity method of accounting to account for our investment in Pinnacle.

As of December 31, 2005, on a fully diluted basis, assuming that all parties exercised their Pinnacle warrants and Pinnacle stock options, the CSFB Parties, CCBM and U.S. Energy Corp. would have ownership interests of approximately 68.4%, 15.8% and 15.8%, respectively.

In addition to our interest in Pinnacle, we have maintained interests in approximately 159,000 gross acres at the end of 2005 in the Castle Rock coalbed methane project area in Montana and the Oyster Ridge project area in Wyoming. 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,

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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, 2005 Compared to the Year Ended December 31, 2004

Oil and natural gas revenues for 2005 increased 49% to $78.2 million from $52.4 million in 2004. Production volumes for natural gas in 2005 increased 27% to 8,206 MMcf from 6,462 MMcf in 2004. Realized average natural gas prices increased 29% to $7.90 per Mcf in 2005 from $6.14 per Mcf in 2004. Production volumes for oil in 2005 decreased 24% to 234 MBbls from 309 MBbls in 2004. The increase in natural gas production was primarily due to the commencement of production from the Galloway #1 and new wells in the Barnett Shale, Encinitas Project and Peters Ranch areas. The gas production volume increases were partially offset by: (1) production declines from the Delta Farms #1 and the Beach House #1 wells, which were shut-in for workovers during the second and third quarters of 2005; (2) the temporary shut-in of a number of wells as a result of the Katrina and Rita hurricanes; and (3) the sale of the Shadyside #1 in the first quarter of 2005. The decrease in oil production volume was principally due to production declines from the aforementioned workovers, the hurricane related shut-ins, and a natural production decline for the Hankamer #1. Oil and natural gas revenues include the impact of hedging activities as discussed below under “Volatility of Oil and Gas Prices.”

Realized average oil prices increased 37% to $56.36 per Bbl in 2005 from $41.00 per Bbl in 2004.

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, 2004 and 2005:

	December 31, 2004	December 31, 2005	2005 Period Compared to 2004 Period: Increase (Decrease)	2005 Period Compared to 2004 Period: % Increase (Decrease)
Production volumes-				
Oil and condensate (Mbbls)	309	234	(75)	(24%)
Natural gas (MMcf)	6,462	8,206	1,744	27%
Average sales prices-(1)				
Oil and condensate (per Bbl)	$ 41.00	$ 56.36	$ 15.36	37%
Natural gas (per Mcf)	6.14	7.90	1.76	29%
Operating revenues (In thousands) -				
Oil and condensate	$ 12,687	$ 13,204	$ 517	4%
Natural gas	39,710	64,951	25,241	64%
Total	$ 52,397	$ 78,155	$ 25,758	49%

Oil and natural gas operating expenses for 2005 increased 24% to $10.4 million from $8.4 million in 2004. Oil and natural gas operating expenses increased primarily due to higher severance taxes of $1.5 million on higher commodity prices, while higher lifting costs of $0.5 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 2005 increased to $1.09 per Mcfe from

$1.01 per Mcfe in 2004. The per unit cost increased primarily as a result of the higher costs noted above.

Depreciation, depletion and amortization (“DD&A”) expense for 2005 increased 38% to $21.4 million from $15.5 million in 2004. This increase was primarily due to (1) an increase in production volumes and (2) an increase in the DD&A rate attributable to the increased land, seismic and drilling costs added to the proved property cost base and to future development costs largely related to the significant increase in Barnett Shale wells.

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General and administrative ("G&A") expense for 2005 increased 22% to $8.8 million from $7.2 million for 2004. The increase in G&A was due primarily to higher salary (due to increased headcount and annual raises) and incentive compensation costs and in part due to $0.3 million of expenses related to an integrated software migration project.

Mark-to-market loss on derivatives, net was $5.9 million in 2005 comprised of (1) $2.3 million of realized loss on net settled derivatives and (2) $3.6 million of net unrealized loss on the derivatives accounted for as non-designated derivatives. Mark-to-market gain (loss) of derivatives, net was ($0.6) million in 2004 comprised of (1) $1.0 million of realized loss on net settled derivates and (2) $0.4 million of net unrealized gain on the derivatives accounted for as fair value hedges.

We recorded a $2.5 million after tax charge, or $0.10 per fully diluted share, on our minority interest in Pinnacle for the ended year December 31, 2005. Of this charge, $0.9 million relates to a valuation allowance for federal income taxes and $1.0 million is for the mark-to-market loss on derivatives. 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.

Interest income was $0.9 million for the year of 2005 compared to $0.1 million in the year of 2004. The increase is due to the significant increase in the average cash and cash equivalent balance outstanding in connection with the July 2005 debt refinancing and borrowings under the $150.0 million Second Lien Credit Facility.

Interest expense and capitalized interest in 2005 were $11.0 million and ($5.8) million, respectively, as compared to interest expense and capitalized interest of $3.6 million and ($2.9) million in 2004. These increases in 2005 are attributable to the aforementioned debt refinancing in July 2005.

Income taxes increased to $7.5 million in 2005 from $7.0 million in 2004 due to the increase in pre-tax income, including the valuation allowance for the equity in loss of Pinnacle Gas Resources, Inc.

Dividends and accretion of discount on preferred stock decreased to zero in 2005 from $0.4 million in 2004 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 for 2005 decreased to $10.6 million from $10.8 million in 2004 primarily as a result of the factors described above.

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. Oil and natural gas revenues in 2003 include the impact of hedging activities as discussed below under "Volatility of Oil and Gas Prices."

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

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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:

	December 31,		2004 Period Compared to 2003 Period	
	2003	2004	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%

(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. There were no such gains reported in 2003.

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.

Liquidity and Capital Resources

During 2005, we made capital expenditures in excess of our net cash flows provided by operating activities, using the proceeds from the Second Lien Credit Facility, $9.0 million from the sale of certain oil and natural gas properties, $2.4 million of proceeds from

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the exercise of warrants and stock options, $17.2 million of net proceeds from the Private Placement and $3.6 million in net proceeds from the issuance of additional Senior Secured Notes. For future capital expenditures in 2006, we expect to use cash on hand, largely generated from the Second Lien Credit Facility, and cash generated by operating activities and available draws on the First Lien Credit Facility to partially fund our planned drilling expenditures and fund leasehold costs and geological and geophysical costs on our exploration projects in 2006. We may need to seek other financing alternatives to fund our 2006 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 the increase in availability of funds under the First Lien Credit Facility before entering into the Second Lien Credit Facility, the $144.6 million net proceeds from the Second Lien Credit Facility, the $17.0 million net proceeds from the Private Placement and the $9.0 million of net proceeds from the property sale in February 2005. 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, under our credit facilities, and through the issuance of senior subordinated notes.

Cash flows provided by operating activities were $33.6 million, $32.5 million and $38.8 million for 2003, 2004 and 2005, respectively. 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. The increase in cash flows provided by operations in 2005 as compared to 2004 was primarily due to higher oil and gas revenues generated from increased production and higher commodity prices.

Estimated maturities of long-term debt are $1.5 million in 2006, $1.5 million in 2007, $1.5 million in each of the years 2006 through 2009 and the remainder in 2010. The following table sets forth estimates of our contractual obligations as of December 31, 2005:

	Payments Due by Year (In thousands)					
	Total	2006	2007	2008	2009 to 2010	Thereafter
Long-Term Debt	$ 149,294	$ 1,535	$ 1,509	$ 1,501	$ 144,750	$ -
Operating Leases	3,125	521	520	521	1,042	521
Drilling Contracts	15,168	9,490	5,678	-	-	-
Seismic Data Commitments	1,333	1,333	-	-	-	-
Total Contractual Cash Obligations	$ 168,920	$ 12,879	$ 7,707	$ 2,022	$ 145,792	$ 521

We have planned capital expenditures in 2006 of approximately $140 to $145 million, of which $117.5 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 26 gross wells (11.7 net) in the onshore Gulf Coast area, 49 gross wells (35 net) in our Barnett Shale and 40 gross wells (39.5 net) in our East Texas, primarily in our Camp Hill oil field, areas in 2006. 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. Capital expenditures do not include operating costs such as the steam costs that will be required for the multi-year development of our Camp Hill project, as discussed below.

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 $31.9 million, $83.9 million (including the Barnett Shale Acquisition) and $123.4 million (reduced by $11.8 million of proceeds from the aforementioned property sale and a seismic participation) for 2003, 2004 and 2005, respectively. Our efforts resulted in the apparent drilling successes comprised of 35 gross wells (9.4 net) in 2003, including six gross wells (2.1 net) in the Barnett Shale area, 65 gross wells (23.6 net) in 2004, including 33 gross wells (13.7 net) in the Barnett Shale area, and 65 gross wells (35.8 net) in 2005 including 37 gross wells (22.1 net) in the Barnett Shale area.

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In September 2005, we entered into an agreement to purchase over an 18 month period a non-exclusive license to certain geophysical data at a cost which will range from $2.0 million to $2.5 million, contingent upon whether we exercise another option to acquire additional data under the agreement.

We have accelerated the development of our Camp Hill project. In August 2005, management proposed the acceleration of the Camp Hill development to our board of directors. Accordingly, a development plan was formally approved by the board for increased drilling activity in the Camp Hill field, beginning with an initial 60-well drilling program. In February 2006, our board of directors formally approved a multi-year plan to fully develop the entire Camp Hill field. In furtherance of this plan, we expect to drill between 35 and 40 gross wells (35 to 40 net) in this area at an estimated cost of $3.2 million during 2006. To fully develop the field, we expect to drill approximately 326 wells from 2006 through 2017, at a total cost of approximately $22 million and total operating costs including steam of approximately $175.0 million. The precise timing and amount of our expenditures on additional well drilling and increased steam injection to develop the proved undeveloped reserves in this project will depend on several factors including the relative prices of oil and natural gas.

Our Board of Directors recently approved a revised development plan for increased drilling activity in two tracts in the Camp Hill field in our East Texas area. During 2005, we have drilled seven gross wells (7.0 net) in this area, all of which are apparent successes. Over the next 18 months, we expect to drill between 55 and 60 gross wells (55 to 60 net), including 35 to 40 gross wells in 2006, in this area at an estimated cost of approximately $4.2 million.

Through the end of 2005, Pinnacle has reported that it has drilled 383 gross wells since inception and estimates that 87.7% of these wells have been completed. Pinnacle reportedly added approximately 20.3 Bcfe of net proved reserves through development drilling through December 31, 2005, excluding the 10.6 Bcfe contributed or acquired at inception. Its gross operated production has increased by approximately 271% since its inception (to approximately 17.8 MMcf/d at December 31, 2005), and its total well count stands at 624 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

First Lien 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 “First Lien Credit Facility”), maturing on September 30, 2007. The First Lien 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 (subject to the limit of the borrowing base, which is currently $22.5 million). It is secured by substantially all of our assets and is guaranteed by our subsidiary. The First Lien Credit Facility was amended on July 21, 2005 in connection with our new Second Lien Credit Facility and refinancing discussed in detail below.

The Facility A Borrowing Base is scheduled to be redetermined by the lenders each quarter. On December 31, 2004 and December 31, 2005 the Facility A Borrowing Base was $30.0 million and $22.5 million, respectively, of which $18.0 and zero, respectively, were drawn and outstanding.

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 borrowing base determination date.

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

Prior to the July 21, 2005 amendment, noted below, we were subject to certain covenants under the terms of the First Lien Credit Facility. 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 $108.8 million, plus 100% of all subsequent common and preferred equity contributed by shareholders subsequent to December 31, 2004, plus 50% of all positive earnings occurring subsequent to December 31, 2004, and (4) a maximum total recourse debt to EBITDA ratio (as defined in the First Lien Credit Facility) of not more than 3.0 to 1.0. These covenants were amended as described below in connection with the July 2005 amendment of the First Lien Credit Facility. The First Lien 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.

On April 27, 2005, we amended the First Lien Credit Facility to, among other things, add a provision restricting loans from us to our subsidiaries or guarantors of the First Lien Credit Facility if the proceeds of such loans will be invested in an entity in which we hold an equity interest.

In connection with entering into the Second Lien Credit Facility, we amended our First Lien Credit Facility on July 21, 2005. Such amendment included without limitation: (1) an adjustment to the maximum total net recourse debt to EBITDA (as defined in the First Lien Credit Facility) ratio, such that the maximum is 3.5 to 1.0 through September 30, 2006, 3.25 to 1.0 through December 31, 2006 and 3.0 to 1.0 thereafter; (2) an adjustment to the covenant regarding maintenance of a minimum shareholders' equity, such that the quarterly minimum is $115.0 million plus 100% of all subsequent common and preferred equity contributed by shareholders subsequent to March 31, 2005, plus 50% of all positive earnings occurring subsequent to March 31, 2005; (3) an adjustment to the covenant regarding maintenance of a minimum EBITDA to interest expense ratio, such that the minimum is 2.75 to 1.0 through September 30, 2006 and 3.0 to 1.0 thereafter; and (4) the addition of other provisions and a consent which permits the indebtedness incurred and the liens granted under the Second Lien Credit Facility.

At December 31, 2004, amounts outstanding under the First Lien Credit Facility totaled $18.0 million with an additional $12.0 million available for future borrowing. At December 31, 2005, there were no amounts outstanding under the First Lien Credit Facility. At December 31, 2004 there were no letters of credit outstanding.

Second Lien Credit Facility and Refinancing

On July 21, 2005, we entered into a second lien credit agreement with Credit Suisse, as administrative agent and collateral agent (the “Agent”) and the lenders party thereto (the “Second Lien Credit Facility”) that matures on July 21, 2010. The Second Lien Credit Facility provides for a term loan facility in an aggregate principal amount of $150.0 million. It is secured by substantially all of our assets and is guaranteed by our subsidiary. The liens securing the Second Lien Credit Facility are second in priority to the liens securing the First Lien Credit Facility, as more fully described in an intercreditor agreement dated July 21, 2005 among us, the Agent, the agent under the First Lien Credit Facility and the lenders.

The net proceeds from the Second Lien Credit Facility, after arrangement and legal fees, were approximately $144.5 million. A portion of the net proceeds were used to: (1) retire the $52.9 million of outstanding obligations under the Subordinated Notes and the Senior Secured Notes and (2) repay, at our election, the $18.5 million outstanding indebtedness under the First Lien Credit Facility. In connection with these transactions, we recorded a $3.7 million pre-tax charge for the early extinguishment of long-term debt in the third quarter of 2005 primarily relating to the write off of unamortized discounts and deferred loan costs.

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The interest rate on each base rate loan will be (1) the greater of the Agent's prime rate and the federal funds effective rate plus 0.5%, plus (2) a margin of 5.0%. The interest rate on each eurodollar loan will be the adjusted LIBOR rate plus a margin of 6.0%. Interest on eurodollar loans is payable on either the last day of each interest period or every three months, whichever is earlier. Interest on base rate loans is payable quarterly.

We are subject to certain covenants under the terms of the Second Lien Credit Facility. These covenants 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 under the First Lien Credit Facility; (2) a minimum quarterly interest coverage ratio of 2.75 to 1.0 through June 30, 2006 and 3.0 to 1.0 thereafter; (3) a minimum quarterly proved reserve coverage ratio of 1.5 to 1.0 through September 30, 2006 and 2.0 to 1.0 thereafter; and (4) a maximum total net recourse debt to EBITDA (as defined in the Second Lien Credit Facility) ratio of not more than 3.5 to 1.0 through June 30, 2006 and 3.25 to 1.0 thereafter. The Second Lien Credit Facility also places restrictions on additional indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of our common stock, speculative commodity transactions, transactions with affiliates and other matters.

The Second Lien Credit Facility is subject to customary events of default. Subject to certain exceptions, if an event of default occurs and is continuing, the Agent may accelerate amounts due under the Second Lien Credit Facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable). If an event of default occurs under the Second Lien Credit Facility as a result of an event of default under the First Lien Credit Facility, the Agent may not accelerate the amounts due under the Second Lien Credit Facility until the earlier of 45 days after the occurrence of the event resulting in the default and acceleration of the loans under the First Lien Credit Facility.

Shelf Registration Statement

In the third quarter of 2005, we filed a registration statement on Form S-3 with the SEC for the proposed offering from time to time of up to $250 million of senior or subordinated debt securities, preferred stock, common stock and warrants to purchase debt securities, preferred stock, common stock or other securities. Due to the delay in our filing of our Annual Report on Form 10-K for the year ended December 31, 2005, we believe that we are not eligible to use a "short form" registration statement on Form S-3 at the present time. Accordingly, unless and until we regain eligibility to use Form S-3, we will not be able to offer and sell securities under our shelf registration statement without first amending it to convert it to a registration statement on Form S-1 and then obtaining a declaration of effectiveness for the registration statement from the SEC. The inability to use Form S-3 may increase the costs and complexity of the registration process. This registration statement has not yet been declared effective by the SEC.

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 zero, 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 2004 and 2005 amounted to $46,000 and $42,000, respectively, and accumulated depreciation on the leased equipment at December 31, 2004 and 2005 amounted to $124,000 and $166,000, respectively.

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Senior Subordinated Notes and Related Securities

We previously issued 9% Senior Subordinated Notes due 2007 (the "Senior Subordinated Notes"). On July 21, 2005, the Senior Subordinated Notes were repaid in full in connection with entering into the Second Lien Credit Facility. See "Financing Arrangements - Second Lien Credit Facility and Refinancing."

In December 1999, we consummated the sale of $22.0 million principal amount of 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 was amortized over the life of the notes. Interest payments were due quarterly commencing on March 31, 2000. As amended and described below, the Subordinated Notes allowed 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 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 shares of our common stock.

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 was amortized over the remaining life of the Subordinated Notes using the effective interest method.

We were 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 Secured Subordinated Notes

We previously issued 10% Senior Secured Subordinated Notes due 2008 (the "Senior Secured Notes"). On July 21, 2005, the Senior Secured Notes were repaid in full in connection with entering into the Second Lien Credit Facility. See "Financing Arrangements - Second Lien Credit Facility and Refinancing." 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 could issue up to $28 million aggregate principal amount of our 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 and May 31, 2005, the Senior Secured Notes

Purchaser purchased $18.0 million and $4.0 million aggregate principal amount of the Senior Secured Notes for a purchase price of $16.2 million and $3.6 million, respectively. The debt discounts were amortized to interest expense using the effective interest method over the life of the notes.

The Senior Secured Notes were 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 bore 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 was due December 15, 2008, and we had the option to prepay the Senior Secured Notes at any time. The Senior Secured Notes included an option that allowed us to pay-in-kind 50% of the interest due until

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June 5, 2007 by increasing the principal due by a like amount. As of the July 21, 2005 retirement date, the outstanding balance of the Senior Secured Notes had been increased by $0.5 million for such interest paid in kind. Subject to certain conditions, we had 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 was 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 transactions were $0.5 million and were amortized over the life of the Senior Secured Notes using the effective interest method. The Senior Secured Notes Purchaser is an affiliate of the Subordinated Notes Purchaser.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing oil and natural gas prices. If the price of oil and natural gas increases (decreases), there could be a corresponding increase (decrease) in the operating cost that we are required to bear for operations, as well as an increase (decrease) in revenues. Inflation has had a minimal effect on us.

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) was effective beginning as of the first interim or annual reporting period beginning after June 15, 2005. On April 14, 2005, the SEC recently adopted a new rule that defers the effective date of SFAS No. 123(R) and allows companies to implement the provisions of SFAS No. 123(R) at the beginning of their next fiscal year. We will adopt the provisions of SFAS No. 123(R) during the first quarter of 2006 using the modified prospective method for transition. We believe it is likely that the impact of the requirements of SFAS No. 123(R) will significantly impact our future results of operations and continue to evaluate it to determine the degree of significance.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections, a replacement of Accounting Principals Board (APB) Opinion No. 20 and FASB Statement No. 3. This statement changes the requirements for the accounting and for reporting of a change in accounting principal. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. This statement shall be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The adoption of SFAS No. 154 was implemented for our restatement of financial statements for the year ended December 31, 2004, including all quarterly periods for 2004, and the first three quarters in 2005 due to the change in accounting for our derivatives.

Summary of Critical Accounting Policies

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

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. The use of these estimates significantly affects our natural gas and oil properties through depletion and the full cost ceiling test, as discussed in more detail below.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of undeveloped properties, future income taxes and related assets/liabilities, 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 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.

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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 $1.4 million, $1.7 million and $2.1 million in 2003, 2004 and 2005 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 2003, 2004 and 2005 was $1.55, $1.86 and $2.22 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 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 connection with our year-end 2005 ceiling test computation, a price sensitivity study also indicated that a 20 percent increase in commodity prices at December 31, 2005 would have increased the pre-tax present value of future net revenues (“NPV”) by approximately $67.0 million. Conversely, a 20 percent decrease in commodity prices at December 31, 2005 would have reduced our NPV by approximately $68.0 million. The aforementioned price sensitivity and NPV is as of December 31, 2005 and, accordingly, does not include any potential changes in reserves due to first quarter 2006 performance, such as commodity prices, reserve revisions and drilling results.

The Full Cost Ceiling cushion at the end of 2005 of approximately $103 million was based upon average realized oil and natural gas prices of $57.17 per Bbl and $8.04 per Mcf, respectively, or a volume weighted average price of $50.63 per BOE. This cushion, however, would have been zero on such date at an estimated volume weighted average price of $34.25 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.

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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 44.9 Bcfe, 72.5 Bcfe, and 97.9 Bcfe of proved undeveloped reserves, representing 64%, 66% and 65% of our total proved reserves at December 31, 2003, 2004 and 2005, respectively. As of December 31, 2003, 2004 and 2005, a portion of these proved undeveloped reserves, or approximately, 43.9 Bcfe, 45.7 Bcfe and 38.1 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 10 years. Accordingly, the combination of a relatively low ratio of future development costs and a relatively long depletable life on our Camp Hill properties has resulted in a relatively low overall historical depletion rate and DD&A expense. This has resulted in a capitalized cost basis associated with producing properties being depleted over a longer period than the associated production and revenue stream, causing the build-up of 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 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), and (iv) an estimated $6.9 million in 2005 (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 proved reserve data as of December 31, 2005 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.

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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 5.9% for the year ended December 31, 2005.

As of December 31, 2005, approximately 81% 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, 2005 had produced for a relatively short period of time as of that date. Because most of our reserve estimates are calculated using volumetric analysis, those estimates are less reliable than estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure based on seismic analysis. In addition, realization or recognition of our proved undeveloped reserves will depend on our development schedule and plans. Lack of certainty with respect to development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved. We have from time to time chosen to delay development of our proved undeveloped reserves in the Camp Hill Field in East Texas in favor of pursuing shorter-term exploration projects with higher potential rates of return, adding to our lease position in this field and further evaluating additional economic enhancements for this field’s development. The average life of the Camp Hill proved undeveloped reserves is approximately 15 years, with 50% of these reserves being booked over 8 years ago. Although we have recently accelerated the pace of the development of the Camp Hill project, there can be no assurance that the aforementioned discontinuance will not occur.

Derivative Instruments

Upon entering into a derivative contract, the Company 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. We typically use fixed rate swaps and costless collars to manage our risk of exposure to material changes in the price of natural gas and oil. 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 the Company’s derivative instruments at December 31, 2003 and 2004 had been designated as cash flow hedges. However, in connection with the preparation of the Company’s consolidated financial statements for the year ended December 31, 2005, the Company determined that it had not timely designated the instruments as a cash flow hedges and was lacking certain other documentation for the derivatives entered into during the periods of 2004 and 2005. As a result, the Company is restating in this Form 10-K/A the consolidated financial information for 2004 (and the quarterly financial data for all periods in 2004 and the first three quarters in 2005), 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 the Company’s 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.

For a discussion of the impact of changes in the prices of oil and gas on our hedging transactions, see "Volatility of Oil and Natural Gas Prices" below. Our Board of Directors sets all of our risk management policies, and reviews 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.

During the third quarter of 2005, we entered into interest rate swap agreements with respect to amounts outstanding under the Second Lien Credit Facility. These arrangements are designed to manage our exposure to interest rate fluctuations during the period beginning January 1, 2006 through June 30, 2007 by effectively exchanging existing obligations to pay interest based on floating rates for obligations to pay interest based on fixed LIBO rates. 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 the Company's Statement of Income.

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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 2003, 2004 and 2005 were 193,600 Bbls, 121,700 Bbls and 108,500 Bbls, respectively. Total natural gas purchased and sold under swaps and collars in 2003, 2004 and 2005 were 2,739,000 MMBtu, 3,936,000 MMBtu and 3,892,000 MMBtu, respectively. The net losses realized by us under such derivative arrangements were $(1.8 million), $(1.0 million) and $(2.3 million) for 2003, 2004 and 2005, respectively, and were included in oil and gas revenue for 2003 and mark-to-market gain (loss) on derivative, net for 2004 and 2005.

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 and 2005, unrealized gains and (losses) on oil and gas derivatives of $0.4 million and $(4.3) million, respectively, were included in mark-to-market gain (losses) 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 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 hedging transaction. Moreover, our derivative arrangements generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our hedges will vary from time to time.

Our gas derivative transactions are generally settled based upon the average of the reporting settlement prices on the Houston Ship Channel index for

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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 2005, a $0.10 change in the price per Mcf of gas sold would have changed revenue by $0.8 million. A $0.70 change in the price per barrel of oil would have changed revenue by $146,000.

At December 31, 2004 and 2005 we had the following outstanding derivative positions:

	December 31, 2004 Contract Volumes				
Quarter	BBls	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		
Fourth Quarter 2005		276,000		5.25	7.92
Fourth Quarter 2005		92,000	6.03		

	December 31, 2005 Contract Volumes				
Quarter	BBls	MMbtu	Average Fixed Price	Average Floor Price	Average Ceiling Price
First Quarter 2006		1,082,000		$ 8.51	$ 11.06
First Quarter 2006	18,000			55.00	68.25
Second Quarter 2006		910,000		7.40	10.70
Second Quarter 2006	18,200			57.00	68.30
Third Quarter 2006		644,000		7.06	10.04
Third Quarter 2006	9,200			57.00	69.05
Fourth Quarter 2006		368,000		7.25	8.75
Fourth Quarter 2006	9,200			57.00	69.65
First Quarter 2007		360,000		7.50	9.45
Second Quarter 2007		273,000		6.68	8.08
Third Quarter 2007		276,000		6.80	8.20
Fourth Quarter 2007		276,000		6.92	8.32
First Quarter 2008		182,000		7.25	8.65

The table below summarizes our total natural gas production volumes subject to derivative transactions during 2005.

Natural Gas Swaps		Natural Gas Caps	
Volumes MMBtu	275,000	Volumes MMBtu	3,617,000
Average price $/MMBtu	$ 6.03	Average price $/MMBtu	
		Floor	$ 5.96
		Ceiling	8.12

The table below summarizes our total crude oil production volumes subject to derivative transactions during 2005.

Crude Oil Swaps		**Crude Oil Caps**	
Volumes Bbls	27,100	Volumes Bbls	81,400
Average price $/Bbls	$ 50.19	Average price $/Bbls	
		Floor	$ 48.82
		Ceiling	$ 60.58

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Since year-end 2005, we entered into costless collar arrangements covering 27,600 Bbls of crude oil for July 2006 through December 2006 production comprised as follows: 18,400 Bbls in the third quarter 2006 with average floor and ceiling prices of $60.00 and $70.80, respectively, 9,200 Bbls in the fourth quarter 2006 with average floor and ceiling prices of $60.00 and $72.20, respectively. We also entered into swap arrangements covering 244,000 MMBtu of natural gas for April 2006 and July 2006 production at an average fixed price of $7.00.

Item 7A. Qualitative and Quantitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for oil and spot prices applicable to natural gas. The effects of such pricing volatility have been discussed above, and such volatility is expected to continue. A 10% fluctuation in the price received for oil and gas production would have an approximate $7.8 million impact on our annual revenues and operating income.

To mitigate some of this risk, we engage periodically in certain limited hedging activities, including price swaps, costless collars and, occasionally, put options, in order to establish some price floor protection. Costs and any benefits derived from these price floors are accordingly recorded as a reduction or increase, as applicable, in oil and gas sales revenue and were not significant for any year presented. The costs to purchase put options are amortized over the option period. We do not hold or issue derivative instruments for trading purposes. Income and (losses) realized by us related to these instruments were $(1.8) million, $(1.0) million and $(2.3) million or $(0.46), $(0.21) and $(0.50) per MMBtu for the years ended December 31, 2003, 2004, and 2005, respectively.

Interest Rate Risk. Our exposure to changes in interest rates results from our floating rate debt. The result of a 10% fluctuation in short-term interest rates would have impacted 2005 cash flow by approximately $0.2 million.

Financial Instruments & Debt Maturities. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and bank borrowings, including borrowings under our Second Lien Credit Facility. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank and vendor borrowings approximate the carrying amounts as of December 31, 2005 and 2004, and were determined based upon interest rates currently available to us for borrowings with similar terms. Maturities of the debt are $1.5 million in 2006, $1.5 million in 2007, $1.5 million in 2008 and $1.5 million in 2009 and the balance, or $143.3 million, in 2010.

Item 8. Financial Statements and Supplementary Data

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

Item 9. Changes In and Disagreements With Accountants on Accounting and Financial Disclosure

None.

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

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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, that it believes will remediate these material weaknesses in 2006. As a result of such material weaknesses, the Company was not able to file its Annual Report on Form 10-K for the year ended December 31, 2005 with the Securities and Exchange Commission in the time required.

The audit report of Pannell Kerr Forster of Texas, P.C., dated March 31, 2006, which is included in the Form 10-K/A, 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, 2005. 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"):

Upon completion of the Company's Sarbanes-Oxley compliance assessment, management identified the following material weaknesses.

Hedging

We completed a review of our documentation practices underlying our derivative positions in 2004 and 2005 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 as well as the first three quarterly periods in 2005.

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 and 2005. 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 a material weakness in our internal controls as of December 31, 2005. Additional information relating to these items is included in Note 3 to the Company's consolidated financial statements.

Year-end Close Process and Other Controls

In the fourth quarter of 2005, we hired a manager of financial reporting, filling the prior vacancy described in our Annual Report on Form 10-K for the year ended December 31, 2004. This manager of financial reporting subsequently left the Company late in the fourth quarter of 2005, creating a new vacancy. Our manager of accounting left the Company in November 2005. In February 2006, our controller and our director of financial planning and analysis also both left the company. We attempted to fill these vacancies, but were not able to do so as quickly as we would have liked. We subsequently hired a new controller and manager of accounting in March 2006, near the end of our year-end closing process. We have also hired a new manager of financial reporting, who is expected to join the Company in April 2006.

The accounting and financial staff vacancies described above occurred during the year-end close process. While these vacancies were partially remedied by reliance upon independent financial reporting consultants for review of critical accounting areas and disclosures and material nonstandard transactions, these absences, combined with our complex manual, review intensive accounting system, placed greater burdens of detailed reviews on our remaining middle and upper-level accounting professionals, which in turn compromised the level of their qualitative review of the elements of the year end close, financial statements and disclosures. These review procedures are an important component of our controls surrounding the closing process and in financial reporting. As a result, we believe that these vacancies resulted in inadequate staffing, supervision and financial reporting expertise in our accounting and financial areas, which constituted a material weakness in our internal control over financial reporting as of December 31, 2005. These deficiencies ultimately affect the accuracy of our financial statement reporting and disclosures.

Accordingly, in connection with the audit of our 2005 financial results, Pannell Kerr Forster of Texas, P.C. ("PKF"), our independent registered public accounting firm, detected a number of errors and/or omissions that were an indication that the aforementioned material weaknesses were present at December 31, 2005, 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 included (1) our accounting for our derivatives as cash flow hedges rather than on a mark-to-market basis, (2) corrections for certain computational errors in the fair value of the Company's derivatives previously reported in other comprehensive income in 2004 and 2005, (3) errors related to our capital expenditures accrual, (4) errors in the evaluation of our unproved property pool and (5) errors related to the evaluation of our asset retirement obligation. These errors came to management's attention in connection with the preparation of our consolidated financial statements for the year ended December 31, 2005. The controls in place related to items (3), (4) and (5) ("Other Controls") were not properly designed and/or operating to provide reasonable assurance that amounts would be properly recorded in the Company's consolidated financial statements. The failure of the Other Controls constituted a third material weakness in our internal controls as of December 31, 2005. Management has determined that the restatement of our consolidated financial statements discussed in Note 3 to our consolidated financial statements included in Item 8 of this report was an additional effect of the year-end close process material weakness. All correcting adjustments were recorded by the Company prior to the finalization of its 2005 financial statements. The Company has implemented procedures to prevent these specific errors from occurring in the future. However, the additional initiatives (outlined below) are needed to remediate the material weaknesses in our internal controls, and thus lower the risk level to remote of other potential material errors or omissions.

As a result of these three material weaknesses, our management has concluded that our internal control over financial reporting was not effective as of December 31, 2005. We made a similar conclusion as of December 31, 2004.

Remediation Steps

While there can be no assurance in this regard, we expect that the following initiatives will eliminate the material weaknesses relating to our year-end close process and Other Controls in 2006: (1) increasing the level of our professional accounting staff, including the successful placement of a new manager of financial reporting, new controller, new manager of accounting and new director of financial planning and analysis (except for the last position, the new professionals have either already started work or will begin in April 2006), and (2) completing our transition to a new fully-integrated accounting software system (phase one was completed in the fourth quarter of 2005) to automate processes and improve qualitative reviews. Until the 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 engaged a consultant to assist us in evaluating our risk management program to provide guidance, and where needed, assistance so that we may continue to account for our derivative activities as cash flow hedges in accordance with the requirements of SFAS No. 133 on a prospective basis. As of the date of this report, we have not yet completed the initiatives described above. While we have hired three new accounting professionals, we have not yet hired a new director of financial planning and analysis. Also, our project team has made significant progress towards completing the transition to a new fully-integrated accounting software system described in the second initiative. We have discussed these material weaknesses and our remediation steps with our Audit Committee.

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PKF has issued its own attestation report on management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2005, which is filed herewith.

(c) *Changes in Internal Control Over Financial Reporting*. Except as described above there have not been any changes in the Company's internal control over financial reporting during the fiscal quarter ended December 31, 2005 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 material weaknesses 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 2006 designed to remediate these weaknesses.

(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 appearing under Item 9A, that Carrizo Oil & Gas, Inc. did not maintain effective internal control over financial reporting as of December 31, 2005, because of the effect of the material weaknesses 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). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. 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. Material weaknesses have been identified and are included in management's assessment of internal control over financial reporting. Management has identified and included within their assessment the following internal control deficiencies that are considered material weaknesses in the design and operating effectiveness of internal controls over financial reporting:

· Vacancies in accounting staff for a financial reporting manager, controller, manager of accounting and director of financial planning and analysis during the year end close process were partially remedied by the reliance upon independent financial accounting and reporting consultants for the review of critical accounting areas and disclosures and material non-standard transactions.

· Management concluded that derivatives entered into during 2004 and 2005 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.

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- Controls in place relating to the capital expenditures accrual, evaluation of unproved property, and evaluation of the asset retirement obligation were not properly designed and/or operating effectively to provide reasonable assurance that amounts would be properly recorded and disclosed in the consolidated financial statements.

These material weaknesses manifested themselves through several accounting adjustments certain of which impacted the consolidated financial statements and disclosures for the years ended December 31, 2004 and 2005 as well as each quarterly period during 2004 and the first three quarterly periods of 2005 resulting in restatements to the financial statements previously filed with the Securities and Exchange Commission. Turnover in key accounting positions during the fourth quarter and during the year-end 2005 financial close process was a notable contributing factor in the failure of certain key control activities to operate effectively. Furthermore, due to reasons described above, the Company was not able to file its Annual Report on Form 10-K for the year ended December 31, 2005 with the Securities and Exchange Commission in the time required.

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, 2005, of the Company and this report does not affect our report dated April 10, 2006 on such financial statements.

In our opinion, management's assessment that Carrizo Oil & Gas, Inc. did not maintain effective internal control over financial reporting as of December 31, 2005 is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework* issued by COSO. Also, in our opinion, because of the effect of the material weaknesses 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, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by COSO.

We do not express an opinion or any other form of assurance on management's statement referring to the effectiveness of the processes instituted to remediate the material weaknesses.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the years ended December 31, 2004 and 2005 and our report dated April 10, 2006 expressed an unqualified opinion on those consolidated financial statements.

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

Houston, Texas
April 10, 2006

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

The information required by this item is incorporated by reference to information under the caption "Proposal 1-Election of Directors" and to the information under the caption "Section 16(a) Reporting Delinquencies" in our definitive Proxy Statement (the "2006 Proxy Statement") for our 2006 annual meeting of shareholders. The 2006 Proxy Statement will be filed with the Securities and Exchange Commission (the "Commission") not later than 120 days subsequent to December 31, 2005.

Pursuant to Item 401(b) of Regulation S-K, the information required by this item with respect to our executive officers is set forth in Part I of this report.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2006 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2005.

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

Information required by this item is incorporated herein by reference to the 2006 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2005.

Item 13. Certain Relationships and Related Transactions

The information required by this item is incorporated herein by reference to the 2006 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2005.

Item 14. Principal Accountant Fees and Services

The information required by this item is incorporated by reference to the 2006 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2005.

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 INDEX

Exhibit Number		Description
†2.1	–	Combination Agreement by and among the Company, Carrizo Production, Inc., Encinitas Partners Ltd., La Rosa Partners Ltd., Carrizo Partners Ltd., Paul B. Loyd, Jr., Steven A. Webster, S.P. Johnson IV, Douglas A.P. Hamilton and Frank A. Wojtek dated as of September 6, 1997 (incorporated herein by reference to Exhibit 2.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).
†3.1	–	Amended and Restated Articles of Incorporation of the Company (incorporated herein by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 1998).
†3.2	–	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).

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†10.6	–	Amendment No. 4 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Appendix B to the Company's Proxy Statement dated April 26, 2004).
†10.7	–	Amendment No. 5 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 16, 2005).
†10.8	–	Amendment No. 6 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on August 19, 2005).
†10.9	–	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)).
†10.10	–	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)).
†10.11	–	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)).
†10.12	–	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).
†10.13	–	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).
†10.14	–	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	–	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).
†10.16	–	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).
†10.17	–	Form of Amendment to Executive Officer Employment Agreement (incorporated herein by reference to Exhibit 99.7 to the Company's Current Report on Form 8-K dated February 20, 2002).
†10.18	–	Form of Amendment to Director Indemnification Agreement (incorporated herein by reference to Exhibit 99.8 to the Company's Current Report on Form 8-K dated February 20, 2002).
†10.19	–	Amendment to the Employment Agreement between the Company and S.P. Johnson IV (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 27, 2006).
†10.20	–	Amendment to the Employment Agreement between the Company and Paul F. Boling (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on January 27, 2006).
†10.21	–	Amendment to the Employment Agreement between the Company and Gregory E. Evans (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8- K filed on January 27, 2006).
†10.22	–	Amendment to the Employment Agreement between the Company and J. Bradley Fisher (incorporated herein by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on January 27, 2006).

†10.23	–	Employment Agreement between the Company and Jack Bayless (incorporated herein by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on January 27, 2006).
†10.24	–	Form of Stock Option Award Agreement (incorporated herein by reference to Exhibit 10.43 to the Company's Annual Report on Form 10-K for the year ended December 31,2004).
†10.25	–	Form of Director Restricted Stock Award Agreement under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 19, 2005).
†10.26	–	Form of Director Restricted Stock Award Agreement under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on April 19, 2005).
†10.27	–	Form of Employee Restricted Stock Award Agreement under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on April 19, 2005).
†10.28	–	Form of Employee Restricted Stock Award under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on January 27, 2006).
†10.29	–	Employee Restricted Stock Award under the Incentive Plan of Carrizo Oil & Gas, Inc. granted to Jack Bayless effective January 23, 2006 (incorporated herein by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed on January 27, 2006).
†10.30	–	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)).
†10.31	–	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)).

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†10.32	–	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).
†10.33	–	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).
†10.34	–	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).
10.35	–	Amendment to Contribution and Subscription Agreement dated as of August 9, 2005 among Pinnacle Gas Resources, Inc., CCBM, Inc., U.S. Energy Corp., Crested Corp. and the CSFB Parties referred to therein.
†10.36	–	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).
†10.37	–	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).
†10.38	–	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).
†10.39	–	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).
†10.40	–	Second Amendment dated of as April 27, 2005 to the 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 10.1 to the Company's Current Report on Form 8-K filed on May 3, 2005).
†10.41	–	Third Amendment dated as of July 21, 2005 to the 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 10.4 to the Company's Current Report on Form 8-K filed on July 22, 2005).
†10.42	–	Second Lien Agreement dated as of July 21, 2005 among Carrizo Oil & Gas, Inc., CCBM, Inc., and the lenders named therein and Credit Suisse, as collateral agent and administrative agent (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on July 22, 2005).
†10.43	–	Stock Pledge and Security Agreement dated as of July 21, 2005 by Carrizo Oil & Gas, Inc. in favor of Credit Suisse, as collateral agent (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on July 22, 2005).

†10.44	–	Commercial Guaranty dated as of July 21, 2005 by CCBM, Inc. in favor of Credit Suisse (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on July 22, 2005).
10.45	–	Director Compensation.
10.46	–	Base Salaries and 2005 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.

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99.1	–	Summary of Reserve Report of Ryder Scott Company Petroleum Engineers as of December 31, 2005.
99.2	–	Summary of Reserve Report of Fairchild & Wells, Inc. as of December 31, 2005.
99.3	–	Summary of Reserve Report of DeGolyer and MacNaughton as of December 31, 2005.

† Incorporated by reference as indicated.

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CARRIZO OIL & GAS, INC.
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Financial Index

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Carrizo Oil & Gas, Inc. as of December 31, 2004 (Restated) and 2005 and the related consolidated statements of operations, shareholders' equity and cash flows for the years ended December 31, 2004 (Restated) and 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Carrizo Oil & Gas, Inc. at December 31, 2004 (Restated) and 2005 and the consolidated results of its operations and its cash flows for the years ended December 31, 2004 (Restated) and 2005, in conformity with U.S. generally accepted accounting principles.

As referred to in Note 3, management of the Company determined that the derivatives entered into during 2004 and 2005 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.

PANNELL KERR FORSTER OF TEXAS, P.C.

Houston, Texas
April 10, 2006

Financial Index

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated statements of operations, shareholders' equity, and cash flows of Carrizo Oil & Gas, Inc. for the year 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 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 results of operations and cash flows of Carrizo Oil & Gas, Inc. for the year 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.

Ernst & Young LLP

Houston, Texas
March 25, 2004

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CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2004 (Restated)	December 31, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 5,668	$ 28,725
Accounts receivable, trade (net of allowance for doubtful accounts of $325 and $253 at December 31, 2004 and 2005, respectively)	12,738	24,898
Advances to operators	1,614	3,049
Other current assets	1,924	3,512
Total current assets	21,944	60,184
PROPERTY AND EQUIPMENT, net-full-cost method of accounting for oil and natural gas properties (including unevaluated costs of properties of $45,067 and $71,581 at December 31, 2004 and 2005, respectively)	205,482	314,074
INVESTMENT IN PINNACLE GAS RESOURCES, INC.	5,229	2,687
DEFERRED FINANCING COSTS	1,633	5,858
OTHER ASSETS	57	298
	$ 234,345	$ 383,101
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$ 21,359	$ 17,571
Accrued liabilities	7,624	23,321
Advances for joint operations	1,808	5,887
Current maturities of long-term debt	90	1,535
Fair value of derivative financial instruments	-	1,563
Total current liabilities	30,881	49,877
LONG-TERM DEBT, NET OF CURRENT MATURITIES	62,884	147,759
ASSET RETIREMENT OBLIGATION	1,407	3,235
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	-	2,295
DEFERRED INCOME TAXES	18,113	24,550
COMMITMENTS AND CONTINGENCIES	-	-
SHAREHOLDERS' EQUITY:		
Warrants (334,210 and none outstanding at December 31,2004 and 2005, respectively)	80	-
Common stock, par value $.01 (40,000,000 shares authorized with 22,161,457 and		

24,251,430 issued and outstanding at December 31, 2004 and 2005, respectively)		221		243
Additional paid in capital		99,766		124,586
Retained earnings		20,993		31,627
Unearned compensation - restricted stock		-		(1,071)
Total shareholders' equity		121,060		155,385
	$	234,345	$	383,101

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

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CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands except for per share amounts)

	For the Year Ended December 31, 2003	2004 (Restated)	2005
OIL AND NATURAL GAS REVENUES	$ 38,508	$ 52,397	$ 78,155
COSTS AND EXPENSES:			
Oil and natural gas operating expenses (exclusive of depletion, depreciation and amortization, shown separately below)	6,724	8,392	10,437
Depreciation, depletion and amortization	11,868	15,464	21,374
General and administrative	5,639	7,191	8,789
Accretion expenses related to asset retirement obligation	41	23	70
Stock option compensation	313	1,064	2,454
Total costs and expenses	24,585	32,134	43,124
OPERATING INCOME	13,923	20,263	35,031
OTHER INCOME AND EXPENSES:			
Mark-to-market loss on derivatives, net	-	(625)	(5,882)
Loss on extinguishment of debt	-	-	(3,721)
Equity in loss of Pinnacle Gas Resources, Inc.	(830)	(1,399)	(2,542)
Other income and expenses	29	506	(457)
Interest income	58	75	904
Interest expense	(617)	(2,553)	(11,044)
Interest expense, related parties	(2,379)	(1,082)	-
Capitalized interest	2,919	2,938	5,845
INCOME BEFORE INCOME TAXES	13,103	18,123	18,134
INCOME TAX EXPENSE (Note 6)	5,063	7,009	7,500
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	8,040	11,114	10,634
DIVIDENDS AND ACCRETION ON PREFERRED STOCK	741	350	-
INCOME AVAILABLE TO COMMON SHAREHOLDERS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	7,299	10,764	10,634
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, NET OF INCOME TAXES	(128)	-	-
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 7,171	$ 10,764	$ 10,634

BASIC EARNINGS PER COMMON SHARE BEFORE CUMULATIVE						
EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	$	0.51	$	0.54	$	0.45
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING						
PRINCIPLE, NET OF INCOME TAXES		(0.01)		-		-
BASIC EARNINGS PER COMMON SHARE	$	0.50	$	0.54	$	0.45
DILUTED EARNINGS PER COMMON SHARE BEFORE CUMULATIVE						
EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	$	0.44	$	0.49	$	0.44
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING						
PRINCIPLE, NET OF INCOME TAXES		(0.01)		-		-
DILUTED EARNINGS PER COMMON SHARE	$	0.43	$	0.49	$	0.44
WEIGHTED AVERAGE SHARES OUTSTANDING:						
BASIC		14,311,820		19,958,452		23,491,976
DILUTED		16,744,296		21,818,065		24,361,453

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
(dollars in thousands)

	Warrants		Common Stock	
	Number	**Amount**	**Shares**	**Amount**
BALANCE, January 1, 2003	3,262,821	$ 780	14,177,383	$ 142
Net income	-	-	-	-
Net charge in fair value of derivative financial instruments	-	-	-	-
Comprehensive income				
Common stock issued, net of offering cost	-	-	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
Net income	-	-	-	-
Net change in fair value of derivative financial instruments	-	-	-	-
Comprehensive income				
Warrants converted	(250,000)	(75)	250,000	3
Warrants exercised for cash	(84,210)	(5)	54,669	1
Common stock issued, net of offering cost	-		1,200,000	12

Common stock issued for property	-		-	127,068		1
Stock options exercised for cash	-		-	370,651		4
Tax benefit of stock options exercised	-		-	-		-
Stock option compensation	-		-	-		-
Restricted stock awards, net of forfeitures	-		-	87,585		1
Amortization of unearned compensation restricted stock	-		-	-		-
BALANCE, December 31, 2005	-	$	-	24,251,430	$	243

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
(dollars in thousands)

	Additional Paid in Capital	Comprehensive Income	Retained Earnings	Accumulated Other Comprehensive Income (loss)	Unearned Compensation	Shareholders' Equity
BALANCE, January 1, 2003	$ 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, net of offering cost	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
Net income		10,634	-	-	10,634
Warrants converted	997	-	-	-	925
Warrants exercised for cash	79	-	-	-	75
Common stock issued, net of offering cost	17,001	-	-	-	17,013
Common stock issued for property	1,953	-	-	-	1,954
Stock options exercised for cash	1,375	-	-	-	1,379
Tax benefit of stock options exercised	1,486	-	-	-	1,486
Stock option compensation	530	-	-	-	530
Restricted stock awards, net of forfeitures	1,399	-	-	(1,412)	(12)
Amortization of unearned compensation restricted stock	-	-	-	341	341
BALANCE, December 31, 2005	$ 124,586	$ 31,627	$ -	$ (1,071)	$ 155,385

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CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Year Ended December 31, 2003	2004 (Restated)	2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Income before cumulative effect of change in accounting principle	$ 8,040	$ 11,114	$ 10,634
Adjustments to reconcile net income to net cash provided by operating activities -			
Depreciation, depletion and amortization	11,868	15,464	21,374
Fair value loss (gain) of derivative financial instruments	-	(400)	3,610
Provision for allowance for doubtful accounts	-	325	(72)
Accretion of discounts on asset retirement obligations and debt	161	177	358
Loss on extinguishment of debt	-	-	3,365
Ineffective derivative instruments	119	-	-
Stock based compensation	313	1,064	2,453
Equity in loss of Pinnacle Gas Resources, Inc.	830	1,399	2,542
Deferred income taxes	4,883	6,818	7,236
Other	-	296	869
Changes in assets and liabilities -			
Accounts receivable	(762)	(4,094)	(12,087)
Other assets	335	(1,470)	(954)
Accounts payable	7,803	(689)	(1,890)
Accrued liabilities	41	2,497	1,401
Net cash provided by operating activities	33,631	32,501	38,839
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(31,930)	(83,891)	(135,156)
Change in capital expenditure accrual	1,755	4,955	12,274
Proceeds from the sale of oil and natural gas properties	-	-	9,037
Advances to operators	(1,377)	263	(1,435)
Advances for joint operations	1,879	(1,621)	4,078
Other	-	-	(215)
Net cash used in investing activities	(29,673)	(80,294)	(111,417)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from the sale of common stock:			
Secondary offering, net of offering costs	-	23,299	-
Private placement, net of offering costs			17,013
Warrants exercised			1,000
Stock option exercises and other	691	1,856	1,379
Net proceeds from debt issuance	-	16,200	153,600
Advances under borrowing base facility	-	24,000	30,024
Debt repayments	(5,951)	(13,737)	(101,021)
Deferred loan costs	-	(1,479)	(6,360)
Loss on ineffective derivatives	(119)	-	-
Net cash provided by (used in) financing activities	(5,379)	50,139	95,635

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		(1,421)		2,346		23,057
CASH AND CASH EQUIVALENTS, beginning of year		4,743		3,322		5,668
CASH AND CASH EQUIVALENTS, end of year	$	3,322	$	5,668	$	28,725
SUPPLEMENTAL CASH FLOW DISCLOSURES:						
Cash paid for interest (net of amounts capitalized)	$	77	$	697	$	4,253
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. During 2005 the Company acquired acreage in shale plays in West Texas/New Mexico, Mississippi/Alabama, Kentucky and Arkansas.

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.

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 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.

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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 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 $1.4 million, $1.7 million and $2.1 million in 2003, 2004 and 2005, 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 2003, 2004 and 2005 was $1.55, $1.86 and $2.22, 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.

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 were used in the 2005 Barnett Shale and Gulf Coast drilling program and for general corporate purposes.

In April 2005, the Company acquired assets in the Barnett Shale for approximately $4.1 million. This acquisition consisted of approximately 600 net acres and working interests in 14 existing gross wells (7.3 net) with an estimated 5.4 Bcfe of proved reserves, based upon the Company's internal estimates. All of the interests in the wells acquired related to wells in which the Company already had an interest. The consideration paid for this acquisition was approximately $2.3 million in cash and 112,697 shares of the Company's common stock.

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.

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

Loss on Early Extinguishment of Long-Term Debt

On July 21, 2005, the Company entered into the Second Lien Credit Facility (see Note 7) and used a portion of the net proceeds from that facility to redeem the balances outstanding under the Senior Subordinated Notes ($29.6 million), and the Senior Subordinated Secured Notes ($22.5 million). In connection with the repayment of this indebtedness, the Company recorded a loss of $3.7 million on the early extinguishment of debt in its 2005 third quarter primarily attributable to the write-off of deferred loan costs and unamortized debt discount which totaled $3.4 million of the total loss incurred.

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

Net long-term debt financing costs, of $1.6 million and $5.9 million are included in other assets as of December 31, 2004 and 2005, respectively, and are being amortized using the effective yield method over the term of the loans (through September 2007 for the First Lien Credit Facility and through July 2010 for the Second Lien Credit Facility (the First Lien Facility and the Second Lien Facility together the “Credit Facilities”).

Supplemental Cash Flow Information

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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 million relinquishment of interests in certain leases to RMG in lieu of principal payments on a note payable. The Statement of Cash Flows for the year ended December 31, 2005 does not include interest paid-in-kind of $1.3 million, the net exercise of 80,000 warrants for common stock and the acquisition of $2.0 million of oil and gas properties in exchange for the Company's common stock.

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 amounts of the Credit Facilities approximate fair value as these borrowings bear interest at variable interest rates.

Stock-Based Compensation

In June of 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the "Incentive Plan"). In October 1995, the FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation," which requires the Company to record stock-based compensation at fair value.

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 Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees. 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:

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	For the Year Ended December 31,		
	2003	2004	2005
	(In thousands except per share amounts)		
Income available to common shareholders before cumulative effect of change in accounting principle, as reported	$ 7,299	$ 10,764	$ 10,634
Add: Stock-based employee compensation expense (benefit) recognized, net of tax	-	691	1,595
Less: Total stock-based employee compensation expense determined under fair value method for all awards, net of tax	(662)	(578)	(555)
Pro forma income available to common shareholders before cumulative effect of change in accounting principle	$ 6,637	$ 10,877	$ 11,674
Income available to common shareholders before cumulative effect of change in accounting principle per common share, as reported:			
Basic	$ 0.51	$ 0.54	$ 0.45
Diluted	0.44	0.49	0.44
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	$ 0.46	$ 0.54	$ 0.50
Diluted	0.40	0.50	0.48

The Company typically uses fixed rate swaps and costless collars to manage the risk of its exposure to material changes in the price of oil and natural gas and variable interest rates on long-term debt. Repriced options are accounted for as compensatory options using variable plan accounting treatment in accordance with FASB Interpretation No. 44, “Accounting for Certain Transactions involving Stock Based Compensation – An Interpretation of APB No. 25” (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 10).

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 2003, 2004 and 2005: risk free interest rate of 4.0%, 4.3% and 4.3%, respectively, expected dividend yield of 0%, expected life of 10 years and expected volatility of 72.2%, 43.2% and 46.1% respectively.

The Company records deferred compensation based on the closing price of the Company’s stock on the issuance date for restricted stock. The deferred compensation is amortized to stock based compensation expense ratably over the vesting period of the restricted stock (one to three years). Deferred compensation amounted to $1.1 million as of December 31, 2005.

Derivative Instruments

The Company uses derivatives to manage price and interest rate risk underlying its oil and gas production and the variable interest rate on its Second Lien Credit Facility.

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 designated 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 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. 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 the periods of 2004 and 2005 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 and the first three quarters in 2005. 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 12 with respect to the Company's positions with an affiliate of Enron Corp.

During the third quarter of 2005, we entered into interest rate swap agreements with respect to amounts outstanding under the Second Lien Credit Facility. These arrangements are designed to manage our exposure to interest rate fluctuations during the period beginning January 1, 2006 through June 30, 2007 by effectively exchanging existing obligations to pay interest based on floating rates for obligations to pay interest based on fixed LIBO rates. 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 (expense) on the Company's Statement of Operations.

The Company's Board of Directors sets all of the Company's risk management policies, 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 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.

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 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. The Company maintains its cash with major U.S. banks. From time to time, cash amounts may exceed the FDIC insured limit of $100,000. The terms of these deposits are on demand to minimize risk. Historically, the Company has not incurred losses related to these deposits.

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Major Customers

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

	For the Year Ended December 31,		
	2003	2004	2005
WMJ Investments Corp.	16%	12%	-
Cokinos Natural Gas Company	15%	17%	-
Reichman Petroleum	14%	-	11%
Texon L.P.	-	13%	-
Chevron/Texaco	-	-	12%

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		
	2003	2004	2005	2003	2004	2005	2003	2004	2005
Basic Earnings per Common Share									
Income available to common shareholders before cumulative effect of change in accounting principle	$ 7,299	$ 10,764	$ 10,634	14,311,820	19,958,452	23,491,976	$ 0.51	$ 0.54	$ 0.45
Dilutive effect of Stock Options, Restricted Stock, Warrants and Preferred Stock conversions	-	-	-	2,432,476	1,859,613	869,477			
Diluted Earnings per Share									
Income available to common shareholders plus assumed conversions before cumulative effect of change in accounting	$ 7,299	$ 10,764	$ 10,634	16,744,296	21,818,065	24,361,453	$ 0.44	$ 0.49	$ 0.44

principle									
Basic Earnings per Common Share									
Cumulative effect of change in accounting principle, net of income taxes	$ (128)	$ -	$ -	14,311,820	19,958,452	23,491,976	$ (0.01)	$ 0.00	$ 0.00
Dilutive effect of Stock Options, Restricted Stock, Warrants and Preferred Stock conversions	-	-	-	2,432,476	1,859,613	869,477			
Diluted Earnings per Share									
Cumulative effect of change in accounting principle net of income taxes plus assumed conversions	$ (128)	$ -	$ -	16,744,296	21,818,065	24,361,453	$ (0.01)	$ 0.00	$ 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		
	2003	2004	2005	2003	2004	2005	2003	2004	2005
Basic Earnings per Common Share									
Net income available to common shareholders	$ 7,171	$ 10,764	$ 10,634	14,311,820	19,958,452	23,491,976	$ 0.50	$ 0.54	$ 0.45
Dilutive effect of Stock Options, Restricted Stock, Warrants and Preferred Stock conversions	-	-	-	2,432,476	1,859,613	869,477			
Diluted Earnings per Share									
Net income available to common shareholders plus assumed conversions	$ 7,171	$ 10,764	$ 10,634	16,744,296	21,818,065	24,361,453	$ 0.43	$ 0.49	$ 0.44

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 periods. The Company had outstanding 117,000, 30,000 and 2,500 stock options at December 31, 2003, 2004 and 2005, respectively, that were antidilutive. The Company had 1,262,930 convertible preferred shares at December 31, 2003, 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 than amounts accrued as ARO are recovered as a gain or loss upon settlement.

The following table is a reconciliation of the asset retirement obligation liability for 2004 and 2005:

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	For the Year Ended December 31, 2004	2005
	(in thousands)	
Asset retirement obligation at beginning of year	$ 883	$ 1,407
Liabilities incurred	425	593
Liabilities settled	(29)	(62)
Accretion expense	23	70
Revisions to previous estimates	105	1,227
Asset retirement obligation at end of year	$ 1,407	$ 3,235

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) was effective beginning as of the first interim or annual reporting period beginning after June 15, 2005. On April 14, 2005, the SEC adopted a new rule that defers the effective date of SFAS No. 123(R) and allows companies to implement the provisions of SFAS No. 123(R) at the beginning of their next fiscal year. The Company adopted the provisions of SFAS No. 123(R) during the first quarter of 2006 using the modified prospective method for transition. 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 May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections, a replacement of Accounting Principals Board (APB) Opinion No. 20 and FASB Statement No. 3. This statement changes the requirements for the accounting and for reporting of a change in accounting principal. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. This statement shall be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The adoption of SFAS No. 154 was implemented for our restatement of financial statements for the year ended December 31, 2004 and the first three quarters in 2005 due to the change in accounting for our derivatives.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. The statement requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). A majority of those instruments were previously classified as equity. Some of the provisions of this statement are consistent with the current definition of liabilities in FASB Concepts Statement No. 6, Elements of Financial Statements. The remaining provisions of this statement are consistent with the Board's proposal to revise that definition to encompass certain obligations that a reporting entity can or must settle by issuing its own equity shares, depending on the nature of the relationship established between the holder and the issuer. This statement is effective for financial instruments entered into or modified after May 31, 2003. The company has adopted the provisions of SFAS No. 150.

3. FINANCIAL 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 interest rate swaps on the Second Lien Credit Facility and for oil and natural gas prices on our proved producing properties ("Derivatives") and determined that these the derivatives entered into in 2004 and 2005 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 our derivatives for interest rate swaps and 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. 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 and the three quarterly periods ended September 30, 2005. These restatements 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 our cash flow commodity hedges, we 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. Our derivative instruments had previously been accounted for as cash flow hedges.

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 and 2005. These errors resulted from the information we 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 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.

Additionally, during the audit of Pinnacle Gas Resources, Inc., an error was discovered that affects amounts that had previously been reported on the Company's quarterly reports on Form 10-Q for the quarterly periods ended March 31, 2005, June 30, 2005 and September 30, 2005. The error arose as a result of the incorrect accounting for certain natural gas derivatives which had historically been accounted for using the cash flow method. Pinnacle's management have determined that these derivatives are not eligible for cash flow hedge accounting. Accordingly, Pinnacle restated its 2005 quarters using the non-designated derivatives accounting method. The relative change in the fair value of these derivatives due to changing commodity price is reflected as a gain or loss in Pinnacle's earnings each quarter. Because the Company's interest in Pinnacle is accounted for using the equity method, the Company determined that the effect of Pinnacle's restatement of its financial statements required the Company to, in turn, restate its own financial statements.

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

	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 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		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

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	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

	December 31, 2004	
	As Reported	As Restated
Balance Sheet:		
Other current assets	$ 1,614	$ 1,924
Total current assets	21,634	21,944
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

Quarterly Financial Statements (Restated) (Unaudited)

	March 31, 2005		June 30, 2005		September 30, 2005	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
Balance Sheet:						
Other current assets	$ 1,230	$ 1,681	$ 1,186	$ 877	$ 6,376	$ 7,683
Total Current Assets	19,937	20,388	20,878	20,569	77,094	78,401
Investment in Pinnacle Gas Resources, Inc.	5,007	4,162	4,652	3,962	4,241	2,056
Total Assets	238,397	238,003	271,069	270,070	365,700	364,822
Fair Value of Derivative Financial Instruments	323	1,537	1,275	318	6,033	8,870
Total Current Liabilities	25,166	26,456	34,640	33,759	47,513	51,249
Fair Value of Financial Derivatives, net - Long-Term	-	-	-	-	1,670	2,493
Deferred Income Taxes	18,719	18,745	20,726	20,752	20,514	20,540
Retained earnings	23,319	21,474	26,912	26,010	27,490	18,093
Accumulated other comprehensive loss	(210)	-	(833)	-	(4,832)	-
Total Liabilities and Stockholders' Equity	238,397	238,003	271,069	270,070	365,700	364,822

Quarters Ended

	March 31, 2005		June 30, 2005		September 30, 2005	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
Statement of Operations:						
Oil and Natural Gas Revenues	$ 15,458	$ 15,249	$ 16,321	$ 16,351	$ 17,574	$ 18,442
Operating Income	4,951	4,742	6,935	6,965	6,777	7,645
Other Income and Expenses:						
Equity in loss of Pinnacle Gas Resources, Inc.	(222)	(1,068)	(355)	(200)	(411)	(1,906)
Mark-to-market gain (loss) of derivatives, net	-	(1,727)	-	1,183	-	(11,638)
Income Before Income Taxes	4,173	1,391	5,847	7,215	1,213	(11,052)
Income Tax Expense (Benefit)	1,587	909	2,254	2,679	634	(3,135)
Net Income (Loss)	2,586	482	3,593	4,536	579	(7,917)
Net Income (Loss) Available to Common Shareholders	2,586	482	3,593	4,536	579	(7,917)
Earnings per common share:						
Basic earnings (Loss) per common share	$ 0.11	$ 0.02	$ 0.15	$ 0.20	$ 0.02	$ (0.33)
Diluted earnings (Loss) per common share	$ 0.11	$ 0.02	$ 0.15	$ 0.19	$ 0.02	$ (0.33)

	Quarters Ended					
	March 31, 2005		June 30, 2005		September 30, 2005	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
Cash Flow Statement:						
Net income (Loss)	$ 2,586	$ 481	$ 3,593	$ 4,536	$ 579	$ (7,917)
Fair value of derivative loss (gain) financial instruments	-	1,936	-	(1,213)	-	10,770
Equity in loss of Pinnacle Gas Resources, Inc	222	1,068	355	200	411	1,906
Deferred income taxes (benefit)	1,539	862	2,170	2,595	569	(3,200)
Net cash provided by operating activities	7,379	7,379	6,952	6,952	4,488	4,488

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	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, 2005, June 30, 2005, and September 30, 2005 should no longer be relied upon.

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4. 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"). The Company accounts for its interest in Pinnacle using the equity method. 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 ownership of Pinnacle Common Stock and Pinnacle Preferred Stock and their nominees constitute a majority of Pinnacle's Board of Directors.

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 these amounts have been 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.

In March 2004, the CSFB Parties contributed additional funds of $11.8 million into Pinnacle to continue funding the 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 2005, the CSFB Parties contributed $15.0 million to Pinnacle to finance an acquisition of additional undeveloped acreage. CCBM and U.S. Energy elected not to participate in the equity contribution. In November 2005, the CSFB Parties and a former Pinnacle employee received 30,000 and 2,000 shares of Pinnacle common stock, respectively, after exercising certain warrants and options. Accordingly, CCBM’s interest in Pinnacle is 32.3% (15.8% on a fully diluted basis).

As of December 31, 2005, on a fully diluted basis, assuming that all parties exercised their Pinnacle warrants and Pinnacle stock options, the CSFB Parties, CCBM and U.S. Energy Corp. would have ownership interests of approximately 68.4%, 15.8% and 15.8%, respectively.

For accounting purposes, the Pinnacle contribution in 2003 was treated as a reclassification of a portion of CCBM's investments in the contributed properties. 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.

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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 balance sheets at December 31, 2004 and 2005.

5. PROPERTY AND EQUIPMENT

At December 31, 2004 and 2005, property and equipment consisted of the following:

	December 31, 2004	December 31, 2005
	(In thousands)	
Proved oil and natural gas properties	$ 241,746	$ 345,081
Unproved oil and natural gas properties	45,067	71,581
Other equipment	846	891
Total property and equipment	287,659	417,553
Accumulated depreciation, depletion and amortization	(82,177)	(103,479)
Property and equipment, net	$ 205,482	$ 314,074

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 include drilling results by the Company and other operators, the terms of oil and natural gas leases not held by production, production response to secondary recovery activities and available funds for exploration and development. The Company expects it will complete its evaluation of the properties representing the majority of these costs within the next two to five years.

6. 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, 2003	2004 (Restated)	2005
		(In thousands)	
Provision at the statutory tax rate	$ 4,586	$ 6,343	$ 6,347
Preferred dividend on Pinnacle	108	405	626
Increase in valuation allowance for equity in loss of Pinnacle	189	70	264
State taxes	180	191	263
Income tax expense	$ 5,063	$ 7,009	$ 7,500

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, 2004 and 2005, the tax effects of these temporary differences resulted principally from the following:

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	December 31, 2004 (Restated)	December 31, 2005
	(In thousands)	
Deferred income tax assets:		
Net operating loss carryforward	$ 2,519	$ 8,464
Fair value of derivative instruments	-	1,350
Equity in the loss of Pinnacle	274	538
Valuation allowance	(274)	(538)
	2,519	9,814
Deferred income tax liabilities:		
Oil and gas acquisition, exploration and development costs deducted for tax purposes in excess of financial statement DD&A	14,935	25,848
Capitalized interest	5,697	7,742
Fair value of derivative instruments	140	227
	20,772	33,817
Net deferred income tax liability	$ 18,253	$ 24,003

The net deferred income tax liability is classified as follows:

	As of December 31, 2004 (Restated)	As of December 31, 2005
	(In thousands)	
Other current assets	$ -	$ (547)
Accrued liabilities	140	-
Deferred income tax liability	18,113	24,550
Deferred income tax liability, net	$ 18,253	$ 24,003

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 $15.7 million, which begin expiring in 2012 through 2022.

7. LONG-TERM DEBT

At December 31, 2004 and 2005, long-term debt consisted of the following:

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	December 31, 2004	December 31, 2005
	(In thousands)	
First Lien Credit Facility	$ 18,000	$ -
Second Lien Credit Facility	-	149,250
Senior Secured Notes*	16,268	-
Senior Subordinated Notes*	28,584	-
Capital lease obligations	122	27
Other	-	17
	62,974	149,294
Less: current maturities	(90)	(1,535)
	$ 62,884	$ 147,759

* Amounts are presented net of discount of $2.0 million at December 31, 2004.

First Lien 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 “First Lien Credit Facility”), which matures on September 30, 2007. The First Lien 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 (subject to the limit of the borrowing base which is currently $22.5 million). It is secured by substantially all of the Company’s assets and is guaranteed by the Company’s wholly-owned subsidiary. The First Lien Credit Facility was amended on June 21, 2005 in connection with entering into the Second Lien Credit Facility.

Prior to the July 21, 2005 amendment of the First Lien Credit Facility, the Facility A Borrowing Bases was scheduled to be redetermined by the lenders at least semi-annually on each November 1 and May 1. After the amendment, the Facility A Borrowing Base is scheduled to be redetermined by the lenders each quarter. 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. Before the July 21, 2005 amendment of the First Lien Credit Facility, the Borrowing Base reductions were $4.0 million per quarter. The lenders will 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 First Lien Credit Facility exceeds the Facility A Borrowing Base at any time (including, without limitation, due to a quarterly borrowing base reduction), 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 reduction. 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.

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The Company is subject to the following covenants under the terms of the First Lien Credit Facility. These covenants, as amended, include 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 service coverage of 2.75 times through September 30, 2006 and 3 times thereafter, (3) a maximum total net recourse debt to EBITDA (as defined in the First Lien Credit Facility, as amended) ratio, such that the maximum is 3.5 to 1.0 through September 30, 2006, 3.25 to 1.0 through December 31, 2006 and 3.0 to 1.0 thereafter; (4) a covenant regarding maintenance of a minimum shareholders' equity, such that the quarterly minimum is $115.0 million plus 100% of all subsequent common and preferred equity contributed by shareholders subsequent to March 31, 2005, plus 50% of all positive earnings occurring subsequent to March 31, 2005; and (5) a covenant regarding maintenance of a minimum EBITDA to interest expense ratio, such that the minimum is 2.75 to 1.0 through September 30, 2006 and 3.0 to 1.0 thereafter. The First Lien 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.

On April 27, 2005, the Company amended the First Lien Credit Facility to, among other things, add a provision restricting loans from the Company to its subsidiaries or guarantors of the First Lien Credit Facility if the proceeds of such loans will be invested in an entity in which the Company holds an equity interest.

The Facility A Borrowing Base, under the First Lien Credit Facility, as of December 31, 2004 and December 31, 2005 was $30.0 million and $22.5 million, respectively.

At December 31, 2005, two letters of credit totaling $5.6 million were outstanding under the First Lien Credit Facility. There were no letters of credit outstanding at December 31, 2004.

Second Lien Credit Facility

On July 21, 2005, the Company entered into a second lien credit agreement with Credit Suisse, as administrative agent and collateral agent (the "Agent") and the lenders party thereto (the "Second Lien Credit Facility") that matures on July 21, 2010. The Second Lien Credit Facility provides for a term loan facility in an aggregate principal amount of $150.0 million. It is secured by substantially all of the Company's assets and is guaranteed by the Company's subsidiary. The liens securing the Second Lien Credit Facility are second in priority to the liens securing the First Lien Credit Facility, as more fully described in the intercreditor agreement among the Company, the Agent, the agent under the First Lien Credit Facility and the lenders.

A portion of the proceeds from the Second Lien Credit Facility were used to (1) repay $52.9 million of subordinated notes and cancel all outstanding indebtedness under the Subordinated Notes and the Senior Secured Notes; (2) repay, at the Company's election, $18.5 million existing indebtedness under the First Lien Credit Facility; and (3) to pay associated transaction costs. The remaining proceeds are expected to be used to partially fund the Company's ongoing capital expenditures program and for other general corporate purposes.

The interest rate on each base rate loan will be (1) the greater of the Agent's prime rate and the federal funds effective rate plus 0.5%, plus (2) a margin of 5.0%. The interest rate on each eurodollar loan will be the adjusted LIBOR rate plus a margin of 6.0%. Interest on eurodollar loans is payable on either the last day of each period or every three months, whichever is earlier. Interest on base rate loans is payable quarterly.

The Company is subject to certain covenants under the terms of the Second Lien Credit Facility. These covenants 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 under the First Lien Credit Facility; (2) a minimum quarterly interest coverage ratio of 2.75 to 1.0 through June 30, 2006 and 3.0 to 1.0 thereafter; (3) a minimum quarterly proved reserve coverage ratio of 1.5 to 1.0 through September 30, 2006 and 2.0 to 1.0 thereafter; and (4) a maximum total net recourse debt to EBITDA (as defined in the Second Lien Credit Facility) ratio of not more than 3.5 to 1.0 through June 30, 2006 and 3.25 to 1.0 thereafter. The Second Lien Credit Facility also places restrictions on additional indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of the Company’s common stock, speculative commodity transactions, transactions with affiliates and other matters.

The Second Lien Credit Facility is subject to customary events of default. Subject to certain exceptions, if an event of default occurs and is continuing, the Agent may accelerate amounts due under the Second Lien Credit Facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable). If an event of default occurs under the Second Lien Credit Facility as a result of an event of default under the First Lien Credit Facility, the Agent may not accelerate the amounts due under the Second Lien Credit Facility until the earlier of 45 days after the occurrence of the event resulting in the default and acceleration of the loans under the First Lien Credit Facility.

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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 these amounts 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 its 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 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, 2003, 2004 and 2005 amounted to $48,000, $46,000 and $42,000 respectively, and accumulated depreciation on the leased equipment at December 31, 2004 and 2005 amounted to $124,000 and $166,000, 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 was amortized over the life of the notes. Interest payments were due quarterly commencing on March 31, 2000. As amended as described below, the Subordinated Notes allowed 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, 2004 and the July 21, 2005 repayment date, the outstanding balance of the Subordinated Notes had been increased by $6.8 million and $7.6 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 was amortized over the remaining life of the Subordinated Notes using the effective interest method.

The Company was 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 the Company’s Total Debt (as defined in the securities purchase agreement) to 3.5 times EBITDA for any twelve month period.

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As discussed earlier in this note, the Subordinated Notes were repaid in full in connection with entering into the Second Lien Credit Facility in July 2005.

Senior Secured Subordinated 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 could 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, 2004 and May 31, 2005, the Senior Secured Notes Purchaser purchased $18.0 million and $4.0 million aggregate principal amount of the Senior Secured Notes for a purchase price of $16.2 million and $3.6 million, respectively. The debt discounts were amortized to interest expense using the effective interest method.

The Senior Secured Notes were 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 bore 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 was due December 15, 2008, and the Company had the option to prepay the Senior Secured Notes at any time. The Senior Secured Notes included an option that allowed the Company to pay-in-kind 50% of the interest due until June 5, 2007 by increasing the principal due by a like amount. At the July 21, 2005 repayment date, the outstanding balance of the Senior Secured Notes had been increased by $0.5 million for such interest paid-in-kind. Subject to certain conditions, the Company had 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 was 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 transactions were $0.5 million and were amortized over the life of the Senior Secured Notes using the effective interest method.

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 chose to issue shares of its common stock as payment of interest on the principal of the Senior Secured Notes, the Registration Rights Agreement provided registration rights with respect to such shares. The Company was 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 was 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 could 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 would have been 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 was 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 included certain representations, warranties and covenants by the parties thereto. The Company was 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 could have required 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 placed 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.

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As discussed earlier in this note, the Senior Secured Notes were repaid in full in connection with entering into the Second Lien Credit Facility in July 2005.

Estimated maturities of long-term debt are $1.5 million in each of the years 2006 through 2009 and the remainder of $143.2 million in 2010.

At December 31, 2005, the Company was in compliance with all of its debt covenants.

8. 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 was 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 were outstanding at December 31, 2004 and 2005. 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 had a five-year term and entitled 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 were exercisable at any time after issuance. The warrants were exercisable on a cashless exercise basis. During 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 and during 2005, Mr. Webster exercised all of his 84,210 warrants on a cashless basis, receiving a total of 54,669 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.

9. 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 September 2005, the Company entered into an agreement to purchase over an 18 month period a non-exclusive license to certain geophysical data at a cost of $2.0 million. The license provides the Company the rights to selection of geophysical data located in Texas and Louisiana and all selections must be completed on or before March 31, 2007.

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Rent expense for the years ended December 31, 2003, 2004 and 2005 was $0.2 million, $0.2 million and $0.5 million, respectively. Effective December 2004, the Company relocated its offices and entered into a new long-term operating lease agreements that expire 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.

Minimum rentals and scheduled seismic data purchases for each of the five years subsequent to December 31, 2005 are as follows:

	Amount (In thousands)
2006	$ 1,854
2007	520
2008	521
2009	521
2010	521
Thereafter	521
	$ 4,458

10. 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 generating net proceeds of approximately $23.4 million. The offering included 3,655,500 newly issued shares offered by the Company and 2,829,500 shares offered by certain 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.

On June 13, 2005, the Company sold 1.2 million shares of the Company's common stock to institutional investors (the "Investors") at a price of $15.25 per share in a private placement (the "Private Placement"), a 4.7% discount to the closing price on the NASDAQ stock market for the Company's common stock the day prior to closing. The number of shares sold was approximately 5% of the fully diluted shares outstanding before the offering. The net proceeds of the Private Placement, after deducting placement agents' fees but before paying offering expenses, were approximately $17.2 million. The Company used the proceeds from the Private Placement to fund a portion of its capital expenditure program for 2005, including the drilling programs in the Barnett Shale and onshore Gulf Coast areas.

In connection with the Private Placement, the Company was required to file a resale shelf registration statement to register the resale of the shares sold under the Securities Act. The Company filed such registration statement and is required to cause it to become and be kept effective for resale of shares for two years from the date of their original sale. In certain situations, the Company is required to indemnify the investors in the Private Placement, including without limitation, for certain liabilities under the Securities Act.

In June 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the “Incentive Plan”), which authorizes the granting of incentive stock options (Incentive Plan Options) and restricted stock awards to selected employees. The plan also authorizes the grant of restricted stock awards to directors. The Company may grant options to purchase up to 2,350,000 shares under the Incentive Plan and has granted options covering 2,084,002 shares through December 31, 2005, net of forfeitures. Through that date, 898,634 options had been exercised. During 2005, a total of 87,585 restricted stock awards (net of forfeitures) were granted which are subject to pro rata vesting over a three-year period. These awards had a grant date fair value totaling $1.4 million that were recorded as deferred compensation and which are being amortized as compensation expense over the respective vesting periods of the awards. Such amortization totaled $0.3 million during the year ended December 31, 2005.

The Company issued 7,570,109 and 2,089,973 shares of common stock during the years ended December 31, 2004 and 2005, respectively. The shares issued during the year ended December 31, 2004 consisted of 3,655,500 shares issued through the 2004 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 436,858 shares issued through the exercise of options granted under the Company’s Incentive Plan. The shares issued during the year ended December 31, 2005 consisted of 1,200,000 shares issued in the Private Placement, 127,068 shares issued in connection with the acquisition of certain oil and gas properties, 304,669 shares issued through the exercise of warrants, 87,585 shares issued as restricted stock awards granted under the Incentive Plan and 370,651 shares issued through the exercise of options granted under the Incentive Plan.

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The following table summarizes information for the options outstanding at December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options Outstanding at 12/31/05	Weighted Average Remaining Contractual Life in Years	Weighted Average Exercise Price	Number of Options Exercisable at 12/31/05	Weighted Average Exercise Price
$1.81-2.25	323,834	3.02	$ 2.23	323,834	$ 2.23
$3.14-4.78	401,168	6.44	4.22	341,168	4.18
$5.17-7.40	103,700	6.39	6.46	65,900	6.35
$8.00-12.42	89,668	8.67	9.51	23,445	8.55
$14.81-27.25	106,834	9.35	16.23	-	-

A summary of the status of the Company's stock options at December 31, 2003, 2004 and 2005 is presented in the table below:

2003	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
Forfeited (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			
Outstanding at beginning of year	1,637,822	$ 3.63	$ 1.75 - $8.00
Granted (Incentive Plan Options)	131,668	$ 8.01	$ 6.98 - $9.22
Exercised (Pre-IPO Options)	(88,825)	$ 3.60	$ 3.60
Exercised (Incentive Plan Options)	(348,033)	$ 3.83	$ 1.81 - $8.00
Forfeited (Incentive Plan Options)	(7,331)	$ 5.89	$ 4.40 - $8.00

Outstanding at end of year	1,325,301	$	4.09	$	1.75 - $9.22
Exercisable at end of year	1,009,243	$	3.49		
Weighted average of fair value of options granted during the year	$ 4.86				
2005					
Outstanding at beginning of year	1,325,301	$	4.09	$	1.75 - $ 9.22
Granted (Incentive Plan Options)	128,834	$	15.58	$	12.42 - $27.25
Exercised (Pre - IPO Plan Options)	(42,295)	$	3.60	$	3.60
Exercised (Incentive Plan Options)	(338,803)	$	3.85	$	2.00 - $ 9.22
Forfeited (Incentive Plan Options)	(47,833)	$	5.10	$	3.76 - $ 9.22
Outstanding at end of year	1,025,204	$	5.53	$	1.75 - $27.25
Exercisable at end of year	754,347	$	3.67		
Weighted average of fair value of options granted during the year	$ 9.76				

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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, FIN No. 44 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 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, 2003, 2004 and 2005 amounted to $0.3 million, $1.1 million and $2.1 million, respectively.

In January 2005, all the remaining 250,000 warrants that were originally issued to affiliates of Enron Corp. were exercised for 250,000 shares of the Company's common stock . The net cash proceeds from exercise of the warrant was $1.0 million.

11. RELATED-PARTY TRANSACTIONS

During the years ended December 31, 2004 and 2005, the Company incurred drilling costs in the amount of and $1.6 million and $0 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, 2004 and 2005, the Company incurred lease operating costs of $0.4 million and $0.4 million, respectively, with Basic Energy Services, Inc. Mr. Webster and Mr. Johnson are members of the Board of Directors of Basic Energy Services, Inc. During the year ended December 31, 2005, the Company incurred lease operating costs of $0.2 million with Brigham Exploration. Mr. Webster is a member of the Board of Directors of Brigham Exploration. It is management's opinion that the transactions with these entitities were performed at prevailing market rates.

At December 31, 2005, the Company had outstanding related-party payable balances of $0.1 million. At December 31, 2004, the Company had outstanding related party accounts receivable and payable balances of $0.3 million and $0.7 million, respectively.

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 4, 7 and 8 for a discussion of the investment in Pinnacle, the transactions involving the 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 Chairman of Avista Capital Holdings, L.P. and is therefore a related party to the Pinnacle transaction.

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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 and 2005.

12. DERIVATIVE FINANCIAL INSTRUMENTS

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

As of December 31, 2004 and 2005, the unrealized gain (loss) on oil and gas derivative instruments related to the mark-to-market valuation, was a $0.4 million benefit and a ($3.6) million charge, respectively, which are presented as mark-to-market gain (loss) on derivatives, net in the other income and expense section of our Statement of Operations.

Total oil purchased and sold under swaps and collars during 2003, 2004 and 2005 were 193,600 Bbls, 121,700 Bbls and 108,500 Bbls, respectively. Total natural gas purchased and sold under swaps and collars in 2003, 2004 and 2005 were 2,739,000 MMBtu, 3,936,000 MMBtu and 3,892,000 MMBtu, respectively. The net losses realized by the Company under such arrangements were $(1.8) million, $(1.0) million and $(2.3) million for 2003, 2004 and 2005, respectively, and are included in other income (expense).

At December 31, 2004 and 2005 the Company had the following outstanding derivative positions:

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		
		276,000		5.25	7.92

Fourth Quarter 2005		
Fourth Quarter 2005	92,000	6.03

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December 31, 2005

Quarter	Contract Volumes BBls	Contract Volumes MMbtu	Average Fixed Price	Average Floor Price	Average Ceiling Price
First Quarter 2006		1,082,000		$ 8.51	$ 11.06
First Quarter 2006	18,000			55.00	68.25
Second Quarter 2006		910,000		7.40	10.70
Second Quarter 2006	18,200			57.00	68.30
Third Quarter 2006		644,000		7.06	10.04
Third Quarter 2006	9,200			57.00	69.05
Fourth Quarter 2006		368,000		7.25	8.75
Fourth Quarter 2006	9,200			57.00	69.65
First Quarter 2007		360,000		7.50	9.45
Second Quarter 2007		273,000		6.68	8.08
Third Quarter 2007		276,000		6.80	8.20
Fourth Quarter 2007		276,000		6.92	8.32
First Quarter 2008		182,000		7.25	8.65

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.

During the third quarter of 2005, the Company entered into interest rate swap agreements with respect to amounts outstanding under the Second Lien Credit Facility. These arrangements are designed to manage the Company's exposure to interest rate fluctuations during the period beginning January 1, 2006 through June 30, 2007 by effectively exchanging existing obligations to pay interest based on floating rates for obligations to pay interest based on fixed LIBO rates. At December 31, 2005, the unrealized gain related to the marked-to-market value of these swap arrangements totaled $0.6 million. This derivative will be marked-to-market at the end of each reporting period and the realized and unrealized gain or loss will be reported as marked-to-market gains or losses on derivatives, net in other income and expense on the Statement of Operations.

The Company's outstanding positions under these interest rate swap agreements at December 31, 2005 are as follows (dollars in thousands):

Quarter	Notional Amount	Fixed LIBO Rate

First Quarter 2006	$	149,250	4.39%
Second Quarter 2006		148,875	4.39%
Third Quarter 2006		148,500	4.39%
Fourth Quarter 2006		148,125	4.39%
First Quarter 2007		147,750	4.51%
Second Quarter 2007		147,375	4.51%

13. 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:

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	For the Year Ended December 31, 2003	2004	2005
	(In thousands)		
Property acquisition costs			
Unproved	$ 7,280	$ 21,831	$ 49,089
Proved	-	8,357	1,954
Exploration costs	23,745	39,181	50,303
Development costs	112	12,697	20,883
Asset retirement obligation	744	529	1,820
Total costs incurred (1)	$ 31,881	$ 82,595	$ 124,049

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(1) Excludes capitalized interest on unproved properties of $2.9 million, $2.9 million and $5.8 million for the years ended December 31, 2003, 2004 and 2005, respectively, and includes capitalized overhead of $1.4 million, $1.7 million and $2.1 million for the years ended December 31, 2003, 2004 and 2005, respectively. The table also includes non-cash asset retirement obligations of $0.7 million, $0.5 million and $1.8 million for the years ended December 31, 2003, 2004 and 2005, 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, 2003, 2004 and 2005, 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:

	Thousands of Barrels of Oil and Condensate at December 31, 2003	2004	2005
Proved developed and undeveloped reserves -			
Beginning of year	8,381	8,714	9,118
Purchase of oil and natural gas properties in place	-	5	5
Discoveries and extensions	231	208	253
Revisions	553	500	(1,211)
Sales of oil and gas properties in place	(1)	-	(6)
Production	(450)	(309)	(234)

End of year	8,714	9,118	7,925
Proved developed reserves at beginning of year	1,393	1,395	1,459
Proved developed reserves at end of year	1,395	1,459	1,343

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	Millions of Cubic Feet of Natural Gas at December 31,		
	2003	2004	2005
Proved developed and undeveloped reserves -			
Beginning of year	12,922	18,069	54,621
Purchase of oil and natural gas properties in place	-	13,390	4,634
Discoveries and extensions	10,305	32,002	57,513
Revisions	129	(2,378)	(5,102)
Sales of oil and gas properties in place	(523)	-	(402)
Production	(4,764)	(6,462)	(8,206)
End of year	18,069	54,621	103,058
Proved developed reserves at beginning of year	12,826	17,098	28,066
Proved developed reserves at end of year	17,098	28,066	44,681

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, 15.8% on a fully diluted basis, in the proved reserves of Pinnacle at the end of 2005, or an estimated 4.2 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:

	Year Ended December 31,		
	2003	2004	2005
		(In thousands)	
Future cash inflows	$ 375,160	$ 685,598	$ 1,269,551
Future oil and natural gas operating expenses	167,090	244,618	377,304
Future development costs	15,943	55,730	162,594
Future income tax expenses	45,540	108,295	195,920
Future net cash flows	146,587	276,955	533,733
10% annual discount for estimating timing of cash flows	58,961	127,234	234,392
Standard measure of discounted future net cash flows	$ 87,626	$ 149,721	$ 299,341

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 2003, 2004 and 2005 future cash flows were $30.29, $41.18 and $57.17 for oil, respectively and $6.19, $5.68 and $8.04 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:

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	Year Ended December 31, 2003	2004	2005
		(In thousands)	
Changes due to current-year operations - Sales of oil and natural gas, net of oil and natural gas operating expenses	$ (34,177)	$ (42,982)	$ (65,445)
Extensions and discoveries	42,530	80,933	130,721
Purchases of oil and gas properties	-	16,467	6,549
Changes due to revisions in standardized variables			
Prices and operating expenses	8,654	34,516	105,819
Income taxes	(9,606)	(31,667)	(45,999)
Estimated future development costs	(377)	12,951	347
Revision of quantities	5,374	(1,307)	(38,326)
Sales of reserves in place	(836)	-	(1,042)
Accretion of discount	8,304	11,485	20,861
Production rates, timing and other	3,463	(18,301)	36,135
Net change	23,329	62,095	149,620
Beginning of year	64,297	87,626	149,721
End of year	$ 87,626	$ 149,721	$ 299,341

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, extentions 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.

14. SUPPLEMENTAL QUARTERLY FINANCIAL DATA (UNAUDITED) (RESTATED)

2005	Restated First	Restated Second	Restated Third	Fourth
	(In thousands except per share amounts)			
Revenues	$ 15,249	$ 16,351	$ 18,442	$ 28,113
Costs and expenses, net	14,767	11,815	26,359	14,580
Net income (Loss)	$ 482	$ 4,536	$ (7,917)	$ 13,533
Basic net income (Loss) per share	$ 0.02	$ 0.20	$ (0.33)	$ 0.56
Diluted net income (Loss) per share	$ 0.02	$ 0.19	$ (0.33)	$ 0.54

2004	Restated First	Restated Second	Restated Third	Restated 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 (Loss)	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	$ 0.08	$ 0.12	$ 0.14	$ 0.19

Diluted net income per share	$	0.07	$	0.10	$	0.13	$	0.18

Due to the restatements, as described in Note 3 of Notes to the Consolidated Financial Statements, the Company's previously filed quarterly financial statements on Form 10-Q for the periods ended March 31, 2004, June 30, 2004, September 30, 2004, March 31, 2005, June 30, 2005 and September 30, 2005 should no longer be relied upon.

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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: April 11, 2006.

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

Name	Capacity	Date
/s/ S. P. JOHNSON IV S. P. Johnson IV	President, Chief Executive Officer and Director (Principal Executive Officer)	April 11, 2006
/s/ PAUL F. BOLING Paul F. Boling	Chief Financial Officer, Vice President, Secretary and Treasurer (Principal Financial Officer and Principal Accounting Officer)	April 11, 2006
/s/ STEVEN A. WEBSTER Steven A. Webster	Chairman of the Board	April 11, 2006
/s/ THOMAS L. CARTER, JR. Thomas L. Carter, Jr.	Director	April 11, 2006
/s/ PAUL B. LOYD, JR. Paul B. Loyd, Jr.	Director	April 11, 2006
/s/ F. GARDNER PARKER F. Gardner Parker	Director	April 11, 2006
/s/ ROGER A. RAMSEY Roger A. Ramsey	Director	April 11, 2006
/s/ FRANK A. WOJTEK Frank A. Wojtek	Director	April 11, 2006