CARRIZO OIL & GAS INC
Form 10-Q
August 09, 2006

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended **June 30, 2006**

[ ] TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ________ to _________

Commission File Number 000-29187-87

CARRIZO OIL & GAS, INC.
(Exact name of registrant as specified in its charter)

Texas	**76-0415919**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
1000 Louisiana Street, Suite 1500, Houston, TX	**77002**
(Address of principal executive offices)	(Zip Code)

(713) 328-1000
(Registrant's telephone number)

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 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 Exchange Act).

YES [ ] NO [X]

The number of shares outstanding of the registrant's common stock, par value $0.01 per share, as of August 1, 2006, the latest practicable date, was 25,914,729.

CARRIZO OIL & GAS, INC.

FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2006
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CARRIZO OIL & GAS, INC.

CONSOLIDATED BALANCE SHEETS
(Unaudited)

ASSETS	**December 31, 2005** (In thousands except share amounts)	**June 30, 2006**
CURRENT ASSETS:		
Cash and cash equivalents	$ 28,725	$ 13,792
Accounts receivable, trade (net of allowance for doubtful accounts of $253 at December 31, 2005 and June 30, 2006)	24,898	18,994
Advances to operators	3,049	3,426
Fair value of derivative financial instruments	-	3,026
Other current assets	3,512	687
Total current assets	60,184	39,925
PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil and natural gas properties (including unevaluated costs of properties of $71,581 and $85,370 at December 31, 2005 and June 30, 2006, respectively)	314,074	368,655
INVESTMENT IN PINNACLE GAS RESOURCES, INC.	2,687	2,771
DEFERRED FINANCING COSTS	5,858	5,308
OTHER ASSETS	298	340
	$ 383,101	$ 416,999
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$ 17,571	$ 17,325
Accrued liabilities	23,321	21,632
Advances for joint operations	5,887	7,338
Current maturities of long-term debt	1,535	1,510
Fair value of derivative financial instruments	1,563	-
Other current liabilities	-	1,059
Total current liabilities	49,877	48,864
LONG-TERM DEBT, NET OF CURRENT MATURITIES	147,759	167,005
ASSET RETIREMENT OBLIGATION	3,235	3,717
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	2,295	667
DEFERRED INCOME TAXES	24,550	27,889
COMMITMENTS AND CONTINGENCIES	-	-

SHAREHOLDERS' EQUITY:				
Common stock, par value $0.01 (40,000,000 shares authorized with 24,251,430 and				
24,543,229 issued and outstanding at December 31, 2005 and				
June 30, 2006, respectively)		243		245
Additional paid-in capital		124,586		133,308
Retained earnings		31,627		40,849
Unearned compensation - restricted stock		(1,071)		(5,545)
Total shareholders' equity		155,385		168,857
	$	383,101	$	416,999

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

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CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005 (Restated)	2006	2005 (Restated)	2006
	(In thousands except per share amounts)			
OIL AND NATURAL GAS REVENUES	$ 16,351	$ 16,477	$ 31,600	$ 38,394
COSTS AND EXPENSES:				
Oil and natural gas operating expenses (exclusive of depreciation, depletion and amortization shown separately below)	2,593	3,630	4,829	7,087
Depreciation, depletion and amortization	5,011	6,598	9,689	14,036
General and administrative (inclusive of stock-based compensation expense of $55 and $630 for the three months ended June 30, 2005 and 2006, respectively, and $1,030 and $1,189 for the six months ended June 30, 2005 and 2006, respectively)	1,764	3,143	5,340	7,351
Accretion expense related to asset retirement obligations	18	79	35	158
Total costs and expenses	9,386	13,450	19,893	28,632
OPERATING INCOME	6,965	3,027	11,707	9,762
OTHER INCOME AND EXPENSES:				
Net gain (loss) on derivatives, net	1,183	3,030	(544)	8,403
Equity in income (loss) of Pinnacle Gas Resources, Inc.	(200)	-	(1,268)	35
Other income and expenses, net	(227)	169	(219)	173
Loss on early extinguishment of debt	-	(282)	-	(282)
Interest income	31	279	75	644
Interest expense	(1,774)	(4,594)	(3,370)	(8,869)
Capitalized interest	1,237	2,416	2,225	4,494

INCOME BEFORE INCOME TAXES		7,215		4,045		8,606		14,360
INCOME TAXES		(2,679)		(1,474)		(3,588)		(5,138)
NET INCOME	$	4,536	$	2,571	$	5,018	$	9,222
BASIC EARNINGS PER COMMON SHARE	$	0.20	$	0.11	$	0.22	$	0.38
DILUTED EARNINGS PER COMMON SHARE	$	0.19	$	0.10	$	0.21	$	0.37
WEIGHTED AVERAGE SHARES OUTSTANDING:								
BASIC		23,186,292		24,214,334		22,845,775		24,190,699
DILUTED		23,919,850		24,970,557		23,658,179		24,908,060

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

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CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the Six Months Ended June 30, 2005 (Restated)	2006
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 5,018	$ 9,222
Adjustment to reconcile net income to net		
cash provided by operating activities-		
Depreciation, depletion and amortization	9,689	14,036
Fair value loss (gain) of derivative financial instruments	724	(5,569)
Accretion of discounts on asset retirement obligations and debt	294	158
Stock-based compensation	1,030	1,189
Equity in loss (income) of Pinnacle Gas Resources, Inc.	1,268	(35)
Deferred income taxes	3,455	4,945
Other	201	179
Changes in operating assets and liabilities		
Accounts receivable	(83)	5,903
Other assets	814	1,791
Accounts payable	(7,078)	(1,282)
Other liabilities	(1,001)	1,133
Net cash provided by operating activities	14,331	31,670
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(53,360)	(91,843)
Change in capital expenditure accrual	7,904	1,610
Proceeds from the sale of properties	9,000	23,594
Advances to operators	785	(377)
Advances for joint operations	2,084	1,451
Other	-	(295)
Net cash used in investing activities	(33,587)	(65,860)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from common stock activity:		
2005 private placement, net of offering costs	17,169	-
Warrants exercised	1,000	-
Stock options exercised	1,108	565
Net proceeds from debt issuance	30,124	35,000
Debt repayments	(29,552)	(15,779)
Deferred loan costs	(220)	(417)
Other	-	(112)
Net cash provided by financing activities	19,629	19,257

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		373		(14,933)
CASH AND CASH EQUIVALENTS, beginning of period		5,668		28,725
CASH AND CASH EQUIVALENTS, end of period	$	6,041	$	13,792
SUPPLEMENTAL CASH FLOW DISCLOSURES:				
Cash paid for interest (net of amounts capitalized)	$	1,064	$	3,628

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
(Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

The consolidated financial statements included herein have been prepared by Carrizo Oil & Gas, Inc. (the "Company"), and are unaudited. The financial statements reflect the accounts of the Company and its subsidiaries after elimination of all significant intercompany transactions and balances. The financial statements reflect necessary adjustments, all of which were of a recurring nature, and are in the opinion of management necessary for a fair presentation. Certain information and footnote disclosures normally included in financial statements prepared in accordance with U.S. generally accepted accounting principles have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC"). The Company believes that the disclosures presented are adequate to allow the information presented not to be misleading. The results for the three and six-month periods ended June 30, 2005 have been restated as a result of changes in the accounting and valuation of derivatives for interest rate swaps and oil and natural gas hedges, as further discussed in the Company's Annual Report on Form 10-K/A for the year ended December 31, 2005 (the "2005 Form 10-K/A"). The financial statements included herein should be read in conjunction with the audited financial statements and notes thereto included in the 2005 Form 10-K/A.

Reclassifications

Certain reclassifications have been made to the prior period's 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 periods reported. Actual results could differ from these estimates.

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

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

Oil and Natural Gas Properties

Investments in oil and natural gas properties are accounted for using the full-cost method of accounting. All costs directly associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Such costs include lease acquisitions, seismic surveys, and drilling and completion equipment. The Company proportionally consolidates its interests in oil and natural gas properties. The Company capitalized compensation costs for employees working directly on exploration activities of $1.1 million and $1.7 million for the six months ended June 30, 2005 and 2006, 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

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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, where significant, dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for the quarter ended June 30, 2005 and 2006 was $2.14 and $2.70, 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.

In March 2006, we sold our average 20 percent working interest in 13 non-operated wells in the Barnett Shale area for approximately $5.2 million. The proceeds were used to fund a portion of our drilling program and for general corporate purposes. In May 2006, we sold 1,800 undeveloped acres in the Barnett Shale area for approximately $17.8 million. Proceeds of approximately $12.0 million were reinvested in the acquisition of similar properties and the remaining $5.8 million will be used to fund a portion of our drilling program and for general corporate purposes.

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. For the three and six month periods ended June 30, 2005 and 2006, the Company did not have any charges associated with its ceiling test analysis.

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

Supplemental Cash Flow Information

The Statement of Cash Flows for the six months ended June 30, 2005 does not include interest paid-in-kind of $1.3 million, the net exercise of $80,000 of warrants and the acquisition of $2.0 million of oil and gas properties in exchange for the Company’s common stock. The Company paid no taxes for the six months ended June 30, 2005 and 2006.

Stock-Based Compensation

In June of 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the “Incentive Plan”), which authorizes the granting of incentive stock options and restricted stock awards to directors, employees and independent contractors. For the three and six-month periods ended June 30, 2005, the Company recognized $55,000 and $1.0 million, respectively, for stock-based compensation. The 2005 quarter period expenses are comprised of approximately $40,000 associated with restricted stock and $15,000 associated with the repricing of certain stock options. The 2005 six-month period is comprised of approximately $40,000 associated with restricted stock and $1.0 million associated with the repricing of certain stock options. For the three and six-month periods ended June 30, 2006, the Company recognized $0.6 million and $1.2 million, respectively, for stock-based compensation expenses. The 2006 quarter period expenses are comprised of $0.1 million associated with stock options and $0.5 million associated with restricted stock. The 2006 six-month period expenses are comprised of $0.3 million associated with stock options and $0.9 million associated with restricted stock.

Stock Options. Prior to January 1, 2006, the Company accounted for stock-based compensation utilizing the intrinsic value method as permitted under Accounting Principles Board (“APB”) Opinion No. 25, “Accounting for Stock Issued to Employees.” APB Opinion No. 25 recognized compensation expense only when the market price on the grant date exceeded the option exercise price. In February 2000, the Company repriced certain employee and director stock options. The Company accounted for these repriced stock options in accordance with Financial Accounting Standards Board ("FASB") Interpretation No. 44 "Accounting for Certain Transactions involving Stock Based Compensation - An Interpretation of APB No. 25" ("FIN 44") which prescribes the variable plan accounting treatment for repriced stock options. 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 until the options are exercised, forfeited, or expire unexercised. Under these accounting guidelines, the Company recognized $15,000 and $1.0 million of stock-based compensation expense for the three and six-month periods ended June 30, 2005.

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

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years. The Company implemented SFAS No. 123(R) using the modified prospective transition method. The Company recognizes compensation expense for all unvested options outstanding as of January 1, 2006, options issued after January 1, 2006, and those options that are subsequently modified, repurchased or cancelled. The compensation expense is based on the grant-date fair value of the options and expensed over the vesting period. The Company did not restate prior periods to reflect the impact of adopting the new standard. As part of the adoption of SFAS No. 123(R), the Company stopped recording stock-based compensation expense associated with the February 2000 repriced options mentioned above and the liability associated with the repriced options totaling $2.6 million was reclassified to shareholders' equity during the first quarter of 2006.

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

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

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

For the three and six-month periods ended June 30, 2006, the Company recognized $0.1 million and $0.3 million, respectively, in stock option compensation expense and computed $0.6 million associated with nonvested awards that will be expensed in the future over a weighted-average period of 1.5 years.

The table below summarizes stock option activity for the six month period ended June 30, 2006:

	Shares	Average Exercise Prices	Remaining Life (In years)	Intrinsic Value (In millions)
Outstanding at December 31, 2005	1,025,204	$ 5.53		
Granted	-	-		
Exercised	(93,800)	6.02		
Forfeited	(30,001)	12.29		
Outstanding at June 30, 2006	901,403	$ 5.26	5.6	$ 23.4
Exercisable at June 30, 2006	812,093	$ 4.38	5.3	$ 21.8

The total intrinsic value (current market price less the option strike price) of options exercised during the six month period ended June 30, 2006 was $2.3 million and the Company received $0.6 million in cash in connection with these exercises.

The following table sets forth pro forma information for the three and six-month periods ended June 30, 2005 as if compensation cost had been consistent with the requirements of SFAS No. 123, "Accounting for Stock-based Compensation":

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	For the Three Months Ended June 30, 2005	For the Six Months Ended June 30, 2005
	(Restated) (In thousands except per share amounts)	
Net income as reported	$ 4,536	$ 5,018
Add: Stock-based employee compensation expense recognized, net of tax	10	644
Less: Total stock-based employee compensation expense determined under fair value method for all awards, net of related tax effects	(122)	(245)
Pro forma net income	$ 4,424	$ 5,417
Net income per common share, as reported:		
Basic	$ 0.20	$ 0.22
Diluted	0.19	0.21
Pro forma net income per common share, as if the fair value method had been applied to all awards		
Basic	$ 0.19	$ 0.24

Diluted	0.18	0.23

During the second quarter of 2005, the Company granted options with a weighted average grant date fair value of $8.14 based on the following assumptions:

Risk-free interest rate	4.3%
Dividend yield	-
Volatility	46%
Term (in years)	5.8

<u>*Restricted Stock*</u>. In addition to stock options, the Company issues restricted stock and records deferred compensation based on the closing price of the Company's stock on the issuance date. The deferred compensation is amortized to stock-based compensation expense ratably over the vesting period of the restricted shares (generally one to three years). The unamortized deferred compensation obligation amounted to $5.5 million as of June 30, 2006. The Company recorded compensation expense related to restricted stock of approximately $40,000 for the three and six-month periods ended June 30, 2005, and $0.5 million and $0.9 million, respectively, for the three and six-month periods ended June 30, 2006. The table below summarizes restricted stock activity for the six months ended June 30, 2006:

	Shares	**Weighted-Average Price**
Unvested restricted stock at December 31, 2005	87,585	$ 15.98
Granted	220,443	26.79
Vested	(19,145)	13.93
Forfeited	(21,650)	23.10
Unvested restricted stock at June 30, 2006	267,233	$ 24.44

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.

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Upon entering into a derivative contract, the Company either designates the derivative instrument as a hedge of the variability of cash flow to be received (cash flow hedge) or the derivative must be accounted for as a non-designated derivative. All of the Company's derivative instruments at December 31, 2005 and June 30, 2006 were treated as non-designated derivatives and the unrealized gain/ (loss) related to the mark-to-market valuation was included in the Company's earnings.

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

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

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 Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2005	**2006**	**2005**	**2006**
Chevron/Texaco	14%	12%	15%	13%
Reichman Petroleum	-	12%	-	12%
Liberty Gathering	11%	-	-	-

Earnings Per Share

Supplemental earnings per share information is provided below:

	For the Three Months Ended June 30, (In thousands except share and per share amounts)					
	Income		**Shares**		**Per-Share Amount**	
	2005 (Restated)	**2006**	**2005** (Restated)	**2006**	**2005** (Restated)	**2006**
Basic Earnings per Common Share:						
Net income available to common shareholders	$ 4,536	$ 2,571	23,186,292	24,214,334	$ 0.20	$ 0.11
Dilutive effect of Stock Options and Warrants	-	-	733,558	756,223		

Diluted Earnings per Common Share:										
Net income available to common shareholders	$	4,536	$	2,571	23,919,850	24,970,557	$	0.19	$	0.10

	For the Six Months Ended June 30, (In thousands except share and per share amounts)									
	Income				Shares		Per-Share Amount			
	2005 (Restated)		2006		2005 (Restated)	2006	2005 (Restated)		2006	
Basic Earnings per Common Share:										
Net income available to common shareholders	$	5,018	$	9,222	22,845,775	24,190,699	$	0.22	$	0.38
Dilutive effect of Stock Options and Warrants		-		-	812,404	717,361				
Diluted Earnings per Common Share:										
Net income available to common shareholders	$	5,018	$	9,222	23,658,179	24,908,060	$	0.21	$	0.37

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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 53,334 and 2,500 stock options during the three months ended June 30, 2005 and 2006, respectively, which were antidilutive and were not included in the calculation because the exercise price of these instruments exceeded the underlying market value of the options.

2. LONG-TERM DEBT:

Long-term debt consisted of the following at December 31, 2005 and June 30, 2006:

	December 31, 2005	June 30, 2006
	(In thousands)	
First Lien Credit Facility	$ -	$ -
Second Lien Credit Facility	149,250	148,500
Senior Secured Revolving Credit Facility	-	20,000
Capital lease obligations	27	2
Other	17	13
	149,294	168,515
Current maturities	(1,535)	(1,510)
	$ 147,759	$ 167,005

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 was to mature on September 30, 2007. The First Lien Credit Facility provided 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 was $22.5 million as of March 31, 2006). It was secured by substantially all of the Company’s assets and was guaranteed by the Company’s wholly-owned subsidiary, CCBM, Inc. During the second quarter of 2006, the Company borrowed and repaid $7.0 million under this facility. On May 25, 2006, the Company terminated this agreement upon entering into the Senior Secured Revolving Credit Facility as described below.

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 subsidiaries. The liens securing the Second Lien Credit Facility were second in priority to the liens securing the First Lien Credit Facility prior to its termination in May 2006, as discussed above, and are second in priority to the liens securing the Senior Secured Revolving Credit Facility.

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. On June 30, 2006, the interest rate was approximately 11.50%, excluding the impact of interest rate swaps.

Senior Secured Revolving Credit Facility

On May 25, 2006, the Company entered into a Senior Secured Revolving Credit Facility ("Senior Credit Facility") with JPMorgan Chase Bank, National Association, as administrative agent that matures May 25, 2010. The Senior Credit Facility provides for a revolving credit facility up to the lesser of the borrowing base and $200.0 million. It is secured by substantially all of the Company's assets and is guaranteed by the Company's subsidiary. The liens securing the Senior Credit Facility are first in priority to the liens securing the Second Lien Credit Facility.

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During the second quarter of 2006, the Company borrowed $20.0 million, net under the Senior Credit Facility and used the borrowings to repay $7.0 million of borrowings under the First Lien Credit Facility, to pay associated transaction costs, to fund a portion of the Company's capital expenditure program and for general corporate purposes.

The borrowing base will be determined by the lenders at least semi-annually on each May 1 and November 1, beginning November 1, 2006. The initial borrowing base was $40.0 million. The Company may request one unscheduled borrowing base determination subsequent to each scheduled determination, and the lenders may request unscheduled determinations at any time. A one-time redetermination effective August 1, 2006 increased the borrowing base to $50.0 million. In addition, in the event the outstanding principal balance of indebtedness under the Second Lien Credit Facility exceeds $150.0 million, the borrowing base under the Senior Credit Facility will be reduced $1.00 for every $4.00 of such additional indebtedness under the Second Lien Credit Facility.

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

The annual interest rate on each base rate borrowing will be (1) the greatest of the Agent's Prime Rate, the Base CD Rate plus 1.0% and the Federal Funds Effective Rate plus 0.5%, plus (2) a margin between 0.25% and 1.75% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar loan will be the adjusted LIBOR Rate plus a margin between 1.5% to 3.0% (depending on the current level of borrowing base usage). At June 30, 2006, the weighted average interest rate was 6.86%.

The Company is subject to certain covenants under the terms of the Senior Credit Facility which include, but are not limited to, the maintenance of the following financial ratios: (1) a minimum current ratio of 1.0 to 1.0 and (2) a maximum total net debt to Consolidated EBITDAX (as defined in the Senior Credit Facility) of 3.50 to 1.0 through June 30, 2006 and 3.25 to 1.0 thereafter. The Senior Credit Facility also places restrictions on 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 Senior Credit Facility is subject to customary events of default, the occurrence and continuation of which could result in the acceleration by the agent or the lenders of amounts due under the facility.

3. INVESTMENT IN PINNACLE GAS RESOURCES, INC.:

The Pinnacle Transaction

During the second quarter of 2003, the Company and its wholly-owned subsidiary CCBM, Inc. ("CCBM") and Rocky Mountain Gas, Inc. ("RMG") each contributed their interests in certain natural gas and oil leases in Wyoming and Montana in areas prospective for coalbed methane to a newly formed entity, Pinnacle Gas Resources, Inc. In exchange for the contribution of these assets, CCBM and RMG each received 37.5% of the common stock of Pinnacle and options to purchase additional Pinnacle common stock, or, on a fully diluted basis, CCBM and RMG each received an ownership interest in Pinnacle of 26.9%. U.S. Energy Corp. and Crested Corp (collectively, "U.S. Energy") later succeeded to RMG's interest in Pinnacle. 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, affiliates and related parties of CSFB Private Equity (the "CSFB Parties") 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 at an exercise price of $100.00 per share, subject to adjustments.

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 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. At 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 would have had ownership interests of approximately 68.4%, 15.8% and 15.8%, respectively.

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In April 2006, prior to and in connection with a private placement by Pinnacle of 7,400,000 shares of its common stock, Pinnacle issued 25 new shares of its common stock to each of its stockholders in exchange for each existing share in a stock split; Pinnacle redeemed the preferred stock held by the CSFB Parties at 110% of par value; the CSFB Parties exercised all of their warrants on a "cashless" net exercise basis; and CCBM and U.S. Energy exercised their respective options on a "cashless" net exercise basis. On April 11, 2006, after the stock split, the redemption of the preferred stock, the warrant and option exercises and the private placement, CCBM owned 2,459,102 shares of Pinnacle's common stock, and its ownership of Pinnacle was 9.5% on a fully diluted basis. On such date, U.S. Energy and the CSFB Parties owned 2,459,102 and 7,306,782 shares of Pinnacle's common stock, respectively, and their ownership of Pinnacle was 9.5% and 28.3% on a fully diluted basis, respectively. At June 30, 2006, CCBM owned 2,459,102 shares of Pinnacle's common stock, and its ownership of Pinnacle was 9.5% on a fully diluted basis.

Prior to the April 2006 Pinnacle private placement, the Company accounted for its interest in Pinnacle using the equity method. Beginning in the second quarter of 2006, the Company used the cost method to account for the Pinnacle investment.

4. INCOME TAXES:

The Company provides deferred income taxes at the rate of 35%, which also approximates its statutory rate that amounted to $2.7 million and $1.5 million for the three-month periods ended June 30, 2005 and 2006, respectively, and $3.6 million and $5.1 million for the six-month periods ended June 30, 2005 and 2006, respectively.

5. 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 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 January 2006, the Company exercised an option to purchase over an 18-month period a non-exclusive license to certain geophysical data at a cost of approximately $1.5 million.

6. SHAREHOLDERS' EQUITY:

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

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 "2005 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 2005 Private Placement, after deducting placement agents' fees but before paying offering expenses, were approximately $17.2 million. The Company used the proceeds from the 2005 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, and for other corporate purposes.

The Company issued 2,005,117 and 314,243 shares of common stock during the six months ended June 30, 2005 and 2006, respectively. The shares issued during the six months ended June 30, 2005 consisted of 1,200,000 shares issued in the 2005 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, 69,075 shares issued as restricted stock awards to employees and the balance through the exercise of options granted under the Company's Incentive Plan. The shares issued during the six months ended June 30, 2006 consisted of 220,443 shares issued as restricted stock awards to employees and 93,800 shares issued through the exercise of options granted under the Company's Incentive Plan. Forfeited shares of previously issued restricted stock totaled 21,650 for the six months ended June 30, 2006, and the Company purchased and retired 794 shares to satisfy tax withholding obligations in connection with the vesting of the restricted stock.

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7. DERIVATIVE 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 hedge the 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 or expiration or exchanged for physical delivery contracts. The Company enters into the majority of its derivative transactions with two counterparties and a netting agreement is in place with those counterparties. The Company does not obtain collateral to support the agreements but monitors the financial viability of counterparties and believes its credit risk is minimal on these transactions. In the event of nonperformance, the Company would be exposed to price risk. The Company has some risk of accounting loss since the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the derivative financial instruments.

For the quarters ended June 30, 2005 and 2006, the unrealized mark-to-market gain on oil and natural gas derivative instruments was $1.2 million and $1.3 million, respectively. For the six months ended June 30, 2005 and 2006, the unrealized mark-to-market gain (loss) on oil and natural gas derivatives was ($0.7) million and $4.6 million, respectively. The gains and losses are reported as unrealized mark-to-market gain (loss) on derivatives, net in other income and expenses on the Consolidated Statements of Income.

At June 30, 2006 the Company had the following outstanding derivative positions:

	Contract Volumes				
Quarter	BBls	MMbtu	Average Fixed Price	Average Floor Price	Average Ceiling Price
Third Quarter 2006		1,043,000	$ 7.22	$ 7.06	$ 10.04
Third Quarter 2006	27,600			59.00	70.22
Fourth Quarter 2006		705,000	7.64	7.51	9.06
Fourth Quarter 2006	18,400			58.50	70.93
First Quarter 2007		630,000		7.95	9.81
Second Quarter 2007		728,000		7.31	8.87
		552,000		7.53	9.10

Third Quarter 2007			
Fourth Quarter 2007	276,000	6.92	8.32
First Quarter 2008	182,000	7.25	8.65

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 LIBOR rates. These agreements are treated as derivatives rather than fair value hedges and are marked-to-market at each balance sheet date. For the three months and six months ended June 30, 2006, the unrealized gain related to the mark-to-market value of these swap arrangements totaled $0.3 million and $1.0 million, respectively. These derivatives will be marked-to-market at the end of each reporting period and the realized and unrealized gain or loss will be reported as mark-to-market gain or loss on derivatives, net in other income and expenses on the Statement of Income.

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The Company's outstanding positions under interest rate swap agreements at June 30, 2006 are as follows (dollars in thousands):

Quarter	Notional Amount	Fixed LIBOR Rate
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%

8. RELATED PARTY TRANSACTIONS:

Due to the limited capital available in the first half of 2006 to fund all of the Company's ongoing lease acquisition efforts in the Barnett Shale and other shale plays, the Company elected to enter into several lease option agreements with a number of third parties and with Steven A. Webster, the Company's chairman (collectively, the "counterparties"). The terms and conditions of the leasing arrangement (agreement terms are described below) with Mr. Webster are consistent with the leasing arrangements the Company has entered into with the other third parties. These leasing arrangements provide the Company the option to purchase leases from the counterparties, over an option period, generally 90 days, for the counterparties' original cost of the leases plus an option fee. Strategically, these leasing arrangements have allowed the Company to temporarily control important acreage positions during periods that the Company has lacked sufficient capital to directly acquire such oil and gas leases.

Since May 2006, the Company has acquired certain oil and gas leases through the aforementioned lease option arrangement with Mr. Webster. The acquisitions were made pursuant to a land option agreement between Mr. Webster and the Company dated January 25, 2006. The terms and conditions of this leasing arrangement with Mr. Webster are consistent with leasing arrangements the Company has entered into with the other third parties. Under the option agreement, Mr. Webster agreed to acquire oil and gas leases in areas where the Company is actively leasing or that it deems prospective. On or before the 90th day from the date that Mr. Webster acquires any lease in these areas, the Company has the option to acquire these leases from Mr. Webster for 110% of Mr. Webster's purchase price or, on the 90th day, pay a non-refundable 10% option extension fee to add a second 90-day option period. On or before the end of this second 90-day option period, the Company has the option to pay Mr. Webster 110% of his original purchase price to acquire the lease. If, at the end of the second option period, the Company has not exercised its purchase option, Mr. Webster will retain ownership of the oil and gas leases. In addition to the cash payments described above, the Company will assign a one-half of one percent of 8/8ths overriding royalty interest (proportionally reduced to the actual net interest in any given lease acquired) on any lease it acquires from Mr. Webster in the first 90-day option period and a one percent of 8/8ths overriding royalty interest (also proportionally reduced) on any lease acquired from Mr. Webster in the second 90-day option period. As of June 30, 2006, Mr. Webster has acquired oil and gas leases for approximately $4.2 million, the Company has purchased approximately $2.6 million in leases from Mr. Webster and the Company has made option extension payments of approximately $48,000 to Mr. Webster. In the third quarter of

2006, the Company plans to acquire additional leases from Mr. Webster and the other third parties pursuant to the option agreements and longer term, the Company may continue to use these arrangements as a strategic alternative when available funding may be limited.

9. SUBSEQUENT EVENTS:

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

On August 1, 2006, the borrowing base of the Senior Credit Facility was increased to $50.0 million.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's discussion and analysis of certain significant factors that have affected certain aspects of the Company's financial position and results of operations during the periods included in the accompanying unaudited financial statements. You should read this in conjunction with the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited financial statements included in our Annual Report on Form 10-K/A for the year ended December 31, 2005 and the unaudited financial statements included elsewhere herein.

General Overview

We began operations in September 1993 and initially focused on the acquisition of producing properties. As a result of the increasing availability of economic onshore 3-D seismic surveys, we began obtaining 3-D seismic data and optioning to lease substantial acreage in 1995 and began drilling our 3-D based prospects in 1996. In 2005, we drilled 65 gross wells (35.8 net), including 20 gross wells in the onshore Gulf Coast area, 37 gross wells in the Barnett Shale area, and eight wells in the Camp Hill field and other East Texas areas, with an apparent success rate of 94%. During the six months ended June 30, 2006, we were successful drilling 40 of 43 (26.9 net) wells with an apparent success rate of 93% that was comprised of: (1) seven of ten gross (1.7 net) wells in the onshore Gulf Coast area, (2) 27 of 27 gross (19.3 net) wells in the Barnett Shale area and (3) six of six gross (5.9 net) wells in the East Texas area. We also drilled four gross (3.8 net) service wells in the East Texas area. As of June 30, 2006, we have completed 26 of these wells and 14 are in the process of being completed. 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 25 to 30 gross wells (25 to 30 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 and in the first half of 2006 delayed the drilling of several wells, slowing our growth in production.

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.

Recent Developments

In March 2006, we sold our average 20 percent working interest in 13 non-operated wells in the Barnett Shale area for approximately $5.2 million. We used the proceeds to fund a portion of our drilling program and for general corporate purposes.

In May 2006, we completed the sale of 1,800 undeveloped acres in the Barnett Shale for approximately $17.8 million. Proceeds of approximately $12.0 million were reinvested in the acquisition of similar properties and the remaining $5.8 million was used to fund a portion of our drilling program and for general corporate purposes.
Our second quarter 2006 production declined from first quarter 2006 production. During the second quarter 2006, we experienced mechanical problems with the Galloway #1 and Delta Farms #1. Anticipated production was delayed for six new wells in the Barnett Shale due to delays in pipeline infrastructure, and production from the third-party operated Galloway #2 was setback due to drilling delays. We have responded to these delays in the Barnett Shale by building a gathering system to accelerate the connection of four new wells. Natural declines in wells also contributed

to the decrease in production.

On May 25, 2006, the Company entered into a Senior Secured Revolving Credit Facility ("Senior Credit Facility") with JPMorgan Chase Bank, National Association, as administrative agent, that matures on May 25, 2010. The Senior Credit Facility provides for a revolving credit facility up to the lesser of the borrowing base and $200.0 million. During the second quarter of 2006, the Company borrowed $20.0 million, net, under the Facility and used the proceeds to repay $7.0 million of borrowings under the First Lien Credit Facility, to pay associated transaction costs, to fund a portion of the Company's 2006 capital expenditures program and for general corporate purposes. In August 2006, the borrowing base of the facility was increased to $50.0 million and the outstanding balance of $20.0 million was repaid.

In July 2006, the Company sold 1.35 million shares of the Company's common stock to institutional investors at a price of $26.00 per share in a private placement (the "2006 Private Placement"). The number of shares sold was approximately 5.4% of our fully diluted shares outstanding before the offering. The net proceeds, after deducting placement agents' fees but before paying offering expenses, of approximately $33.7 million are expected to fund a portion of the Company's 2006 capital expenditures program and be used for general corporate purposes.

In connection with the 2006 Private Placement, we entered into Subscription and Registration Rights Agreements (the "Subscription and Registration Rights Agreements") with the investors in the 2006 Private Placement. The Subscription and Registration Rights Agreements provide registration rights with respect to the shares purchased in the 2006 Private Placement. We are generally required to file a resale shelf registration statement to register the resale of such shares under the Securities Act within 30 days of the closing of the 2006 Private Placement and to have the registration statement declared effective by the SEC within 120 days after it is filed. We are generally subject to specified penalties in the event the registration statement is not timely filed or declared effective or if we do not maintain the effectiveness of the registration statement. We are subject to certain covenants under the terms of the Subscription and Registration Rights Agreement, including the requirement that the registration statement be kept effective for resale of shares for two years. In certain situations, we are required to indemnify the Investors, including without limitation, for certain liabilities under the Securities Act.

Pinnacle Gas Resources, Inc.

During the second quarter of 2003, we (through our wholly-owned subsidiary CCBM, Inc.) 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 entity, Pinnacle Gas Resources, Inc. In exchange for the contribution of these assets, we and RMG 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 and RMG each received an ownership interest in Pinnacle of 26.9%. U.S. Energy Corp. and Crested Corp (collectively, "U.S. Energy") later succeeded to RMG's interest in Pinnacle. We no longer have a drilling obligation in connection with the oil and natural gas leases contributed to Pinnacle.

Simultaneously with the contribution of these assets, affiliates and related parties of CSFB Private Equity (the "CSFB Parties") 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 at an exercise price of $100.00 per share, subject to adjustments.

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 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. At 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 would have had ownership interests of approximately 68.4%, 15.8% and 15.8%, respectively.

In April 2006, prior to and in connection with a private placement by Pinnacle of 7,400,000 shares of its common stock, Pinnacle issued 25 new shares of its common stock to each of its stockholders in exchange for each existing share in a stock split; Pinnacle redeemed the preferred stock held by the CSFB Parties at 110% of par value; the CSFB Parties exercised all of their warrants on a "cashless" net exercise basis; and we and U.S. Energy exercised our respective options on a "cashless" net exercise basis. On April 11, 2006, after the stock split, the redemption of the preferred stock, the warrant and option exercises and the private placement, we owned 2,459,102 shares of Pinnacle's common stock, and our ownership of Pinnacle was 9.5% on a fully diluted basis. On such date, U.S. Energy and the CSFB Parties owned 2,459,102 and 7,306,782 shares of Pinnacle's common stock, respectively, and their ownership of Pinnacle was 9.5% and 28.3% on a fully diluted basis, respectively. At June 30, 2006, CCBM owned 2,459,102 shares of Pinnacle's common stock, and its ownership of Pinnacle was 9.5% on a fully diluted basis.

Derivative Transactions

Our financial results are largely dependent on a number of factors, including commodity prices, which historically have been and are expected to remain volatile. Natural gas prices have been particularly 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 or crude oil prices, and therefore, cannot accurately predict revenues.

Because natural gas and oil prices are unstable, we periodically enter into price-risk-management transactions such as swaps, collars, futures and options to reduce our exposure to downward 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 also limits our ability to benefit from

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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

Three Months Ended June 30, 2006,
Compared to the Three Months Ended June 30, 2005

Oil and natural gas revenues for the three months ended June 30, 2006 increased 1% to $16.5 million from $16.4 million for the same period in 2005. Production volumes for natural gas increased from 2.0 Bcf for the three months ended June 30, 2005 to 2.2 Bcf in the same period of 2006. Average natural gas prices excluding the impact of the gain (loss) from our cash settled derivatives of $1.2 million and $(30,000) for the quarters ended June 30, 2006 and 2005, respectively, decreased 4% to $6.29 per Mcf in the second quarter of 2006 from $6.56 per Mcf in the same period in 2005. Average oil prices for the quarter ended June 30, 2006 increased 21% to $66.99 from $55.32 per barrel in the same period in 2005. The increase in natural gas production volume was principally due to the commencement of production from the Galloway #1 and new wells in the Barnett Shale area. These volume increases were partially offset by or adversely affected by production and drilling delays, mechanical failures with the Galloway #1 and the Delta Farms #1 during the second quarter of 2006 and normal production declines.

The following table summarizes production volumes, average sales prices and operating revenues (excluding the impact of derivatives) for the three months ended June 30, 2005 and 2006:

	June 30,		2006 Period Compared to 2005 Period	
	2005 (Restated)	2006	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	60	43	(17)	(28%)
Natural gas (MMcf)	1,983	2,165	182	9%
Average sales prices				
Oil and condensate (per Bbl)	$ 55.32	$ 66.99	$ 11.67	21%
Natural gas (per Mcf)	6.56	6.29	(0.27)	(4%)
Operating revenues (In thousands)				
Oil and condensate	$ 3,337	$ 2,857	$ (480)	(14%)
Natural gas	13,014	13,620	606	5%
Total Operating Revenues	$ 16,351	$ 16,477	$ 126	1%

Oil and natural gas operating expenses for the three months ended June 30, 2006 increased 40% to $3.6 million from $2.6 million for the same period in 2005 primarily as a result of higher lifting costs of $1.3 million primarily attributable to the increased number of producing wells added after the second quarter of 2005, expenses related to workovers, higher market costs of oilfield services and increased ad valorem taxes.

Depreciation, depletion and amortization (DD&A) expense for the three months ended June 30, 2006 increased 32% to $6.6 million ($2.72 per Mcfe) from $5.0 million ($2.14 per Mcfe) for the same period in 2005. 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 increased future development costs largely related to the significant increase in the number of Barnett Shale wells.

General and administrative expense for the three months ended June 30, 2006 increased by $1.4 million to $3.1 million from $1.8 million for the same period in 2005 primarily as a result of (1) higher salary and incentive compensation costs of $0.4 million, attributable to an increased headcount and an overall increase in salaries and incentive bonuses, (2) higher contract service costs of $0.4 million largely due to costs to cover certain key accounting staff vacancies and to support the continued phase-in of our integrated software system and (3) higher stock-based compensation expense of $0.6 million associated with the issuance of restricted stock beginning in May of 2005 and expense associated with the adoption of SFAS No. 123(R) effective January 1, 2006.

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The net gain on derivatives of $3.0 million in the second quarter of 2006 was comprised of (1) $1.4 million of realized gain on net settled derivatives and (2) $1.6 million of net unrealized mark-to-market gain on the derivatives accounted for as nondesignated derivatives. The mark-to-market gain on derivatives of $1.2 million in the second quarter of 2005 was comprised of (1) $30,000 of realized loss on net settled derivatives and (2) $1.2 million of net unrealized mark-to-market gain on the derivatives accounted for as nondesignated derivatives.

In April 2006, our ownership interest in Pinnacle was reduced below 20 percent; consequently, we converted from accounting for our investment in Pinnacle using the equity method to the cost method.

Loss on the early extinguishment of debt was $0.3 million in connection with the Company's refinancing of its First Lien Credit Facility in May 2006. After the refinancing, the Company's borrowing base was increased to $40.0 million from $22.5 million.

Interest expense and capitalized interest for the three months ended June 30, 2006 were $4.6 million and ($2.4) million, respectively, as compared to $1.8 million and ($1.2) million for the same period in 2005. The increases in 2006 are attributable to borrowings under the Second Lien Credit Facility in July 2005, and the borrowings under the Senior Credit Facility in 2006.

Income taxes decreased to $1.5 million for the three months ended June 30, 2006 from $2.7 million for the same period in 2005 as a result of lower taxable income.

Six Months Ended June 30, 2006,
Compared to the Six Months Ended June 30, 2005

Oil and natural gas revenues for the six months ended June 30, 2006 increased 21% to $38.4 million from $31.6 million for the same period in 2005. Production volumes for natural gas increased from 3.9 Bcf for the six months ended June 30, 2005 to 4.5 Bcf in the same period of 2006. Average natural gas prices excluding the impact of the gain from our cash settled derivatives of $2.5 million and $0.2 million for the six months ended June 30, 2006 and 2005, respectively, increased 9% to $6.92 per Mcf in the first half of 2006 from $6.33 per Mcf in the same period in 2005. Average oil prices for the six months ended June 30, 2006 increased 20% to $63.72 from $52.89 per barrel in the same period in 2005. The increase in natural gas production volumes was principally due to the commencement of production from the Galloway #1, Mass #1 and new wells in the Barnett Shale area. These volume increases were partially offset or adversely affected by: (1) production declines from the Beach House #1 and other normal production declines, (2) an after-payout working interest reduction on the LL&E #1 Deepening and (3) mechanical failures with the Galloway #1 and the Delta Farms #1 during the second quarter of 2006.

The following table summarizes production volumes, average sales prices and operating revenues (excluding the impact of derivatives) for the six months ended June 30, 2005 and 2006:

	June 30,		2006 Period Compared to 2005 Period	
	2005 (Restated)	2006	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	125	110	(15)	(12%)

Natural gas (MMcf)	3,949	4,533	584	15%
Average sales prices				
Oil and condensate (per Bbl)	$ 52.89	$ 63.72	$ 10.83	20%
Natural gas (per Mcf)	6.33	6.92	0.59	9%
Operating revenues (In thousands)				
Oil and condensate	$ 6,617	$ 7,018	$ 401	6%
Natural gas	24,983	31,376	6,393	26%
Total Operating Revenues	$ 31,600	$ 38,394	$ 6,794	21%

Oil and natural gas operating expenses for the six months ended June 30, 2006 increased 47% to $7.1 million from $4.8 million for the same period in 2005 due principally to higher lifting costs of $2.4 million primarily attributable to the increased number of producing wells added after the first half of 2005, expenses related to workovers, higher market costs of oilfield services and higher ad valorem

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taxes. Operating expenses per equivalent unit increased to $1.36 per Mcfe in the first half of 2006 compared to $1.03 per Mcfe in the same period in 2005.

Depreciation, depletion and amortization (DD&A) expense for the six months ended June 30, 2006 increased 45% to $14.0 million ($2.70 per Mcfe) from $9.7 million ($2.06 per Mcfe) for the same period in 2005. 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 increased future development costs largely related to the significant increase in the number of Barnett Shale wells.

General and administrative expense for the six months ended June 30, 2006 increased by $2.0 million to $7.3 million from $5.3 million for the same period in 2005 primarily as a result of (1) higher salary and incentive compensation costs of $0.7 million, attributable to an increased headcount and an overall increase in salaries and incentive bonuses, (2) higher contract service costs of $0.8 million largely due to costs to cover accounting staff vacancies and to support the continued phase-in of our integrated software system, (3) higher auditing fees of $0.2 million largely attributable to the financial restatement for mark-to-market accounting on derivatives and (4) higher stock compensation expense of $0.2 million associated with the issuance of restricted stock beginning in May of 2005 and expenses associated with the adoption of SFAS No. 123(R) effective January 1, 2006.

The net gain on derivatives of $8.4 million in the first half of 2006 was comprised of (1) $2.8 million of realized gain on net settled derivatives and (2) $5.6 million of net unrealized mark-to-market gain on the derivatives accounted for as nondesignated derivatives. The mark-to-market loss on derivatives of $0.5 million in the first half of 2005 was comprised of (1) $0.2 million of realized gain on net settled derivatives and (2) $0.7 million of net unrealized mark-to-market loss on the derivatives accounted for as nondesignated derivatives.

We recorded a $35,000 benefit on our equity interest in Pinnacle for the six months ended June 30, 2006. The increase in earnings was primarily due to the non-cash gains related to Pinnacle's hedging activity. In April 2006, our ownership interest in Pinnacle was reduced below 20 percent; consequently, we converted from accounting for our investment in Pinnacle using the equity method to the cost method.

Loss on the early extinguishment of debt was $0.3 million in connection with the Company's refinancing of its First Lien Credit Facility in May 2006. After the refinancing, the Company's borrowing base was increased to $40.0 million from $22.5 million.

Interest expense and capitalized interest for the six months ended June 30, 2006 were $8.9 million and ($4.5) million, respectively, as compared to $3.4 million and ($2.2) million for the same period in 2005. The increases in 2006 are attributable to the borrowings under the Second Lien Credit Facilit in July 2005, and borrowings under the Senior Credit Facility in 2006.

Income taxes increased to $5.1 million for the six months ended June 30, 2006 from $3.6 million for the same period in 2005 as a result of higher taxable income.

Liquidity and Capital Resources

During the six months ended June 30, 2006, capital expenditures, net of $23.6 million in proceeds from property sales, exceeded our net cash flows provided by operating activities. For future capital expenditures in 2006, we expect to use cash on hand, proceeds from the 2006 Private Placement, cash generated by operating activities and available draws on the Senior 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 fully fund our 2006 capital expenditures program, including possible debt or equity financings.

We may not be able to obtain financing as may be needed in the future 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 oil and natural gas exploration and development program, thereby adversely affecting the recoverability and ultimate value of our oil and natural gas properties.

Our 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 (including our public offering in 2004 and our private placement in 2005 of our common stock), and borrowings under our credit facilities. Our liquidity position has been enhanced by the availability of funds under the Senior Credit Facility, the borrowing base of which was increased to $50.0 million effective August 1, 2006. In addition, we received proceeds of $33.7 million from the 2006 Private Placement.

Cash flows provided by operating activities were $14.3 million and $31.7 million for the six months ended June 30, 2005 and 2006, respectively. The increase was primarily due to increased production and higher commodity prices.

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We have planned capital expenditures in 2006 of approximately $140.0 million to $145.0 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 and land acquisitions. In 2006, we plan to drill approximately 26 gross wells (11.7 net) in the onshore Gulf Coast area and 49 gross wells (35.0 net) in our Barnett Shale area and 25 to 30 gross wells (25 to 30 net) in our East Texas areas, primarily in our Camp Hill oil field. The actual number of wells drilled and capital expended is dependent upon our available financing, cash flow, availability and cost of drilling rigs, land and partner issues and other factors.

We have continued to reinvest a substantial portion of our cash flows into our leasehold acreage and 3-D prospect portfolio, improving our 3-D seismic interpretation technology and funding our drilling program. Capital expenditures were $53.4 million (excluding $9.0 million of proceeds from an asset sale) and $91.8 million (excluding $23.6 million of proceeds from asset sales) for the six months ended June 30, 2005 and 2006, respectively.

Our drilling efforts in the Gulf Coast region resulted in apparent successes in drilling seven gross wells (1.7 net) during the six months ended June 30, 2006. In our Barnett Shale area, we had apparent successes in drilling 27 gross wells (19.3 net) during the first six months of 2006, and in our East Texas area, we had apparent successes in drilling six gross wells (5.9 net) during that period. We also drilled four gross (3.8 net) service wells. Of the 40 apparently successful wells, 26 have been completed and the remaining wells were in various stages of completion at June 30, 2006.

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 25 and 30 gross wells (25 to 30 net) in this area at an estimated cost of $2.4 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 $22.0 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.

In our Camp Hill field in the East Texas area, we drilled seven gross wells (7.0 net) during 2005, all of which are apparent successes. During 2006 and the first half of 2007, we expect to drill between 55 and 60 gross wells (55 to 60 net) in this area at an estimated cost of approximately $4.2 million.

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”), which was to mature on September 30, 2007. The First Lien Credit Facility provided 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 was $22.5 million as of March 31, 2006). It was secured by substantially all of our assets and was guaranteed by our subsidiary, CCBM, Inc. The First Lien Credit Facility was amended on July 21, 2005 in connection with the Second Lien Credit Facility and refinancing discussed in our 2005 Annual Report on Form 10-K/A. On May 25, 2006, we terminated this agreement upon entering into the Senior Credit Facility as described below.

Second Lien Credit Facility

On July 21, 2005, we entered into a second lien credit agreement with Credit Suisse, as administrative agent and collateral agent (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 subsidiaries. The liens securing the Second Lien Credit Facility were second in priority to the liens securing the First Lien Credit Facility prior to its termination in May 2006, as discussed above, and are second in priority to the liens securing the Senior Credit Facility.

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 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.

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 Senior 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 Senior Credit Facility.

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 ratios: (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.

Senior Secured Revolving Credit Facility

On May 25, 2006, we entered into a Senior Secured Revolving Credit Facility (“Senior Credit Facility”) with JPMorgan Chase Bank, National Association, as administrative agent that matures May 25, 2010. The Senior Credit Facility provides for a revolving credit facility up to the lesser of the borrowing base and $200.0 million. It is secured by substantially all of our assets and is guaranteed by our subsidiaries. The liens securing the Senior Credit Facility are first in priority to the liens securing the Second Lien Credit Facility.

The borrowing base will be determined by the lenders at least semi-annually on each May 1 and November 1, beginning November 1, 2006. The initial borrowing base was $40.0 million. We may request one unscheduled borrowing base determination subsequent to each scheduled determination, and the lenders may request unscheduled determinations at any time. A one-time redetermination effective August 1, 2006 increased the borrowing base to $50.0 million. In addition, in the event the outstanding principal balance of indebtedness under the Second Lien Credit Facility exceeds $150.0 million, the borrowing base under the Senior Credit Facility will be reduced $1.00 for every $4.00 of such additional indebtedness under the Second Lien Credit Facility.

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

The annual interest rate on each base rate borrowing will be (1) the greatest of the Agent’s Prime Rate, the Base CD Rate plus 1.0% and the Federal Funds Effective Rate plus 0.5%, plus (2) a margin between 0.25% and 1.75% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar Loan will be the adjusted LIBOR Rate plus a margin between 1.5% to 3.0% (depending on the current level of borrowing base usage).

Following completion of the 2006 Private Placement, we repaid all amounts outstanding under the Senior Credit Facility. Effective August 1, 2006, $50.0 million was available for borrowing under the Senior Credit Facility, and we had no borrowings outstanding as of such date. The Company is subject to certain covenants under the terms of the Senior Credit Facility which include, but are not limited to, the maintenance of the following financial ratios: (1) a minimum current ratio of 1.0 to 1.0; and (2) a maximum total net debt to Consolidated EBITDAX (as defined in the Senior Credit Facility) of 3.50 to 1.0 through June 30, 2006 and 3.25 to 1.0 thereafter. The Senior Credit Facility also places restrictions on 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 Senior Credit Facility is subject to customary events of default, the occurrence and continuation of which could result in the acceleration of amounts due under the facility by the agent or the lenders.

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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 $250.0 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. The Company has withdrawn the registration statement with the SEC.

Lease Option Arrangements

Due to the limited capital available in the first half of 2006 to fund all of the Company's ongoing lease acquisition efforts in the Barnett Shale and other shale plays, the Company elected to enter into several lease option agreements with a number of third parties and with Steven A. Webster, the Company's chairman (collectively, the "counterparties"). The terms and conditions of the leasing arrangement (agreement terms are described below) with Mr. Webster are consistent with the leasing arrangements the Company has entered into with the other third parties. These leasing arrangements provide the Company the option to purchase leases from the counterparties, over an option period, generally 90 days, for the counterparties' original cost of the leases plus an option fee. Strategically, these leasing arrangements have allowed the Company to temporarily control important acreage positions during periods that the Company has lacked sufficient capital to directly acquire such oil and gas leases.

Since May 2006, the Company has acquired certain oil and gas leases through the aforementioned lease option arrangement with Mr. Webster. The acquisitions were made pursuant to a land option agreement between Mr. Webster and the Company dated January 25, 2006. The terms and conditions of this leasing arrangement with Mr. Webster are consistent with leasing arrangements the Company has entered into with the other third parties. Under the option agreement, Mr. Webster agreed to acquire oil and gas leases in areas where the Company is actively leasing or that it deems prospective. On or before the 90th day from the date that Mr. Webster acquires any lease in these areas, the Company has the option to acquire these leases from Mr. Webster for 110% of Mr. Webster's purchase price or, on the 90th day, pay a non-refundable 10% option extension fee to add a second 90-day option period. On or before the end of this second 90-day option period, the Company has the option to pay Mr. Webster 110% of his original purchase price to acquire the lease. If, at the end of the second option period, the Company has not exercised its purchase option, Mr. Webster will retain ownership of the oil and gas leases. In addition to the cash payments described above, the Company will assign a one-half of one percent of 8/8ths overriding royalty interest (proportionally reduced to the actual net interest in any given lease acquired) on any lease it acquires from Mr. Webster in the first 90-day option period and a one percent of 8/8ths overriding royalty interest (also proportionally reduced) on any lease acquired from Mr. Webster in the second 90-day option period. As of June 30, 2006, Mr. Webster has acquired oil and gas leases for approximately $4.2 million, the Company has purchased approximately $2.6 million in leases from Mr. Webster and the Company has made option extension payments of approximately $48,000 to Mr. Webster. In the third quarter of 2006, the Company plans to acquire additional leases from Mr. Webster and the other third parties pursuant to the option agreements and longer term, the Company may continue to use these arrangements as a strategic alternative when available funding may be limited.

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 Adopted 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) requires 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 annual reporting period after June 15, 2005. We adopted the provisions of SFAS No. 123(R) during the first quarter of 2006 using the modified prospective method for transition and have recognized approximately $0.3 million in compensation expense in the first half of 2006.

Critical Accounting Policies

The following summarizes several of our critical accounting policies:

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.

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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, stock-based compensation, 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.

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 $1.1 million and $1.8 million for the six months ended June 30, 2005 and 2006, respectively. We expense maintenance and repairs as they are incurred.

We amortize natural gas and oil properties based on the unit-of-production method using estimates of proved reserve quantities. 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 the three months ended June 30, 2005 and 2006 was $2.14 and $2.70, 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 June 30, 2006 ceiling test computation, a price sensitivity study also indicated that a 10% increase in commodity prices at June 30, 2006 would have increased the ceiling test cushion by approximately $35 million. Conversely, a 10% decrease in commodity prices at June 30, 2006 would have reduced the ceiling test cushion by approximately $35 million. The aforementioned price sensitivity and NPV is as of June 30, 2006 and, accordingly, does not include any potential changes in reserves due to third quarter 2006 performance, such as commodity prices, reserve revisions and drilling results.

The Full Cost Ceiling cushion at the end of June 2006 of approximately $53 million was based upon average realized oil and natural gas prices of $68.85 per Bbl and $6.01 per Mcf, respectively, or a volume weighted average price of $46.31 per BOE. This cushion, however, would have been zero on such date at an estimated volume weighted average price of $39.31 per BOE. A BOE means one barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids, which approximates the relative energy content of oil, condensate and natural gas liquids as compared to natural gas. Prices have historically been higher or substantially higher, more often for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

Under the full cost method of accounting, the depletion rate is the current period production as a percentage of the total proved reserves. Total proved reserves include both proved developed and proved undeveloped reserves. The depletion rate is applied to the net book value plus 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 97.9 Bcfe and 91.1 Bcfe of proved undeveloped reserves at December 31, 2005 and June 30, 2006, respectively, representing 65% and 61% of our total proved reserves. As of December 31, 2005 and June 30, 2006, a large portion of these proved undeveloped reserves, or approximately 38.1 Bcfe and 38.0 Bcfe, respectively, are attributable to our Camp Hill properties that we acquired in 1994. 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 (1) an estimated $11.2 million in 2002 (comprised of after-tax charges for a $7.1 million full cost ceiling impairment and a $4.1 million depletion expense increase), (2) an estimated $5.9 million in 2003 (due to higher depletion expense), (3) an estimated $3.4 million in 2004 (due to higher depletion expense) and (4) 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. We estimated the reserve data for all other dates using current market conditions. Reserve engineering is a subjective process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact manner. The process relies on judgment and the interpretation of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions regarding drilling and operating expense, capital expenditures, taxes and availability of funds. The SEC mandates some of these assumptions such as oil and natural gas prices and the present value discount rate.

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

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

Our rate of recording depreciation, depletion and amortization expense for proved properties depends 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 10% for the three months ended June 30, 2006.

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. 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 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

We use derivatives to manage price and interest rate risk underlying our oil and gas production and the variable interest rate on the Second Lien Credit Facility. Given our limited internal resources, we have elected to account for all new derivative contracts as non-designated derivatives that will be marked-to-market. For a discussion of the impact of changes in the prices of oil and gas on our hedging transactions, see “Volatility of Oil and Natural Gas Prices” below.

We have initiated a program designed to manage our exposure to interest rate fluctuations by entering into financial derivative instruments. The primary objective of this program is to reduce the overall cost of borrowing. We have entered into interest rate swap agreements with respect to amounts borrowed under the Second Lien Credit Facility, which effectively exchange existing obligations to pay interest based on floating rates for obligations to pay interest based on fixed LIBOR rates.

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

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 LIBOR rates. These derivatives will be marked-to-market at the end of each period and the realized and unrealized gain or loss will be reported as mark-to-market gain (loss) on derivatives, net within other income and expenses on our Statement of Income.

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.

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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.

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."

Total oil purchased and sold under swaps and collars during the three months ended June 30, 2005 and 2006 was 38,800 Bbls and 18,200 Bbls, respectively. Total natural gas purchased and sold under swaps and collars during the three months ended June 30, 2005 and 2006 was 1,032,000 MMBtu and 1,275,000 MMBtu, respectively. Total oil hedged under swaps and collars during the six months ended June 30, 2005 and 2006 were 71,700 Bbls and 36,200 Bbls, respectively. Total natural gas hedged under swaps and collars during the six months ended June 30, 2005 and 2006 were 1,960,000 MMBtu and 2,357,000 MMBtu, respectively. The net gain/(loss) realized by us under such hedging arrangements was $(30,000) and $1.2 million for the three months ended June 30, 2005 and 2006, respectively, and was $0.2 million and $2.5 million for the six months ended June 30, 2005 and 2006, respectively. These gains/(losses) are included in mark-to-market gain (loss) on derivatives, net.

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

For the quarter ended June 30, 2005 and 2006, the unrealized gain on oil and natural gas derivatives was $1.2 million and $1.3 million, respectively. For the six months ended June 30, 2005 and 2006, the unrealized mark-to-market gain (loss) on derivatives, net was ($0.7) million and $4.6 million, respectively. The gains (losses) are reported as mark-to-market gain (loss) 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 derivatives 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 commodity 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 derivatives arrangements generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our hedges will vary from time to time.

Our natural gas derivative transactions are generally settled based upon the average of the reporting settlement prices on the Houston Ship Channel index for the last three trading days of a particular contract month. Our oil derivative transactions are generally settled based on the average reporting settlement prices on the West Texas Intermediate index for each trading day of a particular calendar month. For the second quarter of 2006, a 10% change in the price per Mcf of gas sold would have changed revenue by $1.4 million. A 10% change in the price per barrel of oil would have changed revenue by $0.3 million.

The table below summarizes our total natural gas production volumes subject to derivative transactions during the six months ended June 30, 2006:

Natural Gas Collars		
Volumes (MMBtu)		2,357,000
Average price ($/MMBtu)		
Fixed	$	7.30
Floor	$	8.00
Ceiling	$	9.21

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The table below summarizes our total crude oil production volumes subject to derivative transactions for the six months ended June 30, 2006:

	Crude Oil Collars
Volumes (Bbls)	36,200
Average price ($/Bbls)	
Floor	$ 56.01
Ceiling	$ 68.28

At June 30, 2006 we had the following outstanding derivative positions:

	Contract Volumes				
Quarter	BBls	MMbtu	Average Fixed Price	Average Floor Price	Average Ceiling Price
Third Quarter 2006		1,043,000	$ 7.22	$ 7.06	$ 10.04
Third Quarter 2006	27,600			59.00	70.22
Fourth Quarter 2006		705,000	7.64	7.51	9.06
Fourth Quarter 2006	18,400			58.50	70.93
First Quarter 2007		630,000		7.95	9.81
Second Quarter 2007		728,000		7.31	8.87
Third Quarter 2007		552,000		7.53	9.10
Fourth Quarter 2007		276,000		6.92	8.32
First Quarter 2008		182,000		7.25	8.65

Forward Looking Statements

The statements contained in all parts of this document, including, but not limited to, those relating to our schedule, targets, estimates or results of future drilling, including the number, timing and results of wells, budgeted wells, increases in wells, the timing and risk involved in drilling follow-up wells, expected working or net revenue interests, planned expenditures, prospects budgeted and other future capital expenditures, risk profile of oil and natural 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 the Company's business strategy, future exploration activity, production rates, exploration and development expenditures, the Company's initiatives designed to eliminate material weaknesses in the Company's internal control over financial reporting and the results of these initiatives and 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," "estimate," "expect," "may," "project," "believe" and similar expression intended to be among the statements that identify forward looking statements. Such statements involve risks and uncertainties, including, but not limited to, those relating to the Company's dependence on its 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, the Company's dependence on its key personnel, factors that affect the Company's ability to manage its growth and achieve its business strategy, risks relating to limited operating history, technological changes, significant capital requirements of the Company, the potential impact of government regulations, litigation, competition, the uncertainty of reserve information and future net revenue estimates, property acquisition risks, availability of equipment, weather, availability of financing, the actual results of the initiatives designed to eliminate a material weakness in the Company's internal control over financial reporting, completion of the implementation of the Company's new accounting software system and the results of audits and assessments and other factors detailed in the Company's Annual Report on Form 10-K/A for the year ended December 31, 2005 and other filings with the Securities and Exchange Commission. 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 the Company undertakes no obligation to update or revise any forward-looking statement.

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ITEM 3- QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

For information regarding our exposure to certain market risks, see “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A of our Annual Report on Form 10-K/A for the year ended December 31, 2005, except for the Company’s hedging activity subsequent to December 31, 2005, which is described above in “Volatility of Oil and Natural Gas Prices.” There have been no material changes to the disclosure regarding our exposure to certain market risks made in the Annual Report on Form 10-K/A. For additional information regarding our long-term debt, see Note 2 of the Notes to Unaudited Consolidated Financial Statements in Item 1 of Part I of this Quarterly Report on Form 10-Q.

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ITEM 4- CONTROLS AND PROCEDURES

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 in more detail in our Form 10-K/A filed on April 11, 2006 , 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)) in connection with the work related to Management’s Annual Report on Internal Control over Financial Reporting. As a result of these material weaknesses, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2005, the Company’s disclosure controls and procedures were not effective. Additionally, 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. Because the control deficiencies leading to such material weaknesses were still present as of June 30, 2006, our Chief Executive Officer and Chief Financial Officer have concluded that as of the end of the period covered by this report, the Company’s disclosure controls and procedures were not effective. The Company has outlined a number of initiatives, as discussed below, that it believes will remediate these material weaknesses in 2006.

Hedging

For a description of a material weakness related to the accounting for our derivatives and related matters, see Item 9A in our Annual Report on Form 10-K/A for the year ended December 31, 2005.

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 operations accounting in March 2006, near the end of our year-end closing process. During the second quarter of 2006, we hired a new manager of financial reporting, a manager of financial planning and analysis and a manager of general accounting.

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 statements, 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 our 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

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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 determined that the restatement of our consolidated financial statements discussed in Note 3 to our consolidated financial statements included in Item 8 of our Annual Report on Form 10-K/A for the year ended December 31, 2005 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 concluded in our Annual Report on Form 10-K/A for the year ended December 31, 2005 that our internal control over financial reporting was not effective as of December 31, 2005.

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 operations accounting, new manager of general accounting and new director of financial planning and analysis (including the placement in the first quarter of 2006 of a new manager of financial reporting, new controller and new manager of operations accounting and the placement in the second quarter of 2006 of a manager of financial planning and analysis and a manager of general accounting), 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 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. Given our limited internal resources, we have elected to account for all new derivative contracts as non-designated derivatives. 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.

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 June 30, 2006 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. As described above, 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. Some of these changes were effected in the first and second quarters of 2006, including some changes in staffing and changes in hedge accounting. This Item 4 should be read in conjunction with Item 9A included in our Annual Report on Form 10-K/A for the year ended December 31, 2005.

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PART II. OTHER INFORMATION

Item 1 - Legal Proceedings

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.

Item 1A - Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K/A for the year ended December 31, 2005, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K/A are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results. Other than the addition of the risk factor set forth below, there have been no material changes from the risk factors described in the Annual Report on Form 10-K/A.

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

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

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

Item 2 - Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

Period	(a) Total Number of Shares Purchased[1]	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Appropriate Dollar Value) of Shares that May Yet Be Purchased Under the Plan or Programs
April 2006	-	-	-	-
May 2006	794	$ 27.48	-	-
June 2006	-	-	-	-

Total	794	$	27.48	-	-

(1) The 794 shares related to the surrender of shares of common stock to satisfy tax withholding obligations in connection with the vesting of restricted stock issued to employees under our long-term incentive plan.

Item 3 - Defaults Upon Senior Securities

None

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

At the Annual Meeting of Carrizo Oil & Gas, Inc., held on May 23, 2006, there were represented by person or by proxy 21,712,788 shares out of 24,401,563 entitled to vote as of the record date, constituting a quorum.

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The matters submitted to a vote of shareholders were:

(1) the reelection of Mr. S.P. Johnson IV; Mr. Steven A. Webster; Mr. Thomas L. Carter, Jr.; Mr. Paul B. Loyd, Jr.; Mr. F. Gardner Parker; Mr. Roger A. Ramsey and Mr. Frank A. Wojtek as directors,

(2) an amendment to the Incentive Plan to increase by 450,000 shares the number of shares of common stock available for issuance under the Incentive Plan and the approval of the performance goals set forth in the Incentive Plan in order to allow certain grants and awards made to our executive officers to qualify as performance-based compensation deductible under Section 162(m) of the Internal Revenue Code, and

(3) the approval of the appointment of Pannell Kerr Forster of Texas, P.C. as the Company's Independent Registered Public Accounting Firm for the fiscal year ending December 31, 2006.

With respect to the election of directors, the following number of votes were cast for the nominees: 20,896,730 for Mr. Johnson and 816,058 withheld; 13,169,896 for Mr. Webster and 8,542,892 withheld; 20,329,848 for Mr. Carter and 1,382,940 withheld; 20,736,041 for Mr. Loyd and 976,747 withheld; 21,147,564 for Mr. Parker and 565,224 withheld; 21,232,770 for Mr. Ramsey and 480,018 withheld; 20,713,351 for Mr. Wojtek and 999,437 withheld. There were no abstentions in the election of directors.

With respect to the amendment to the Incentive Plan, 16,731,027 votes were cast for the amendment, 538,578 votes were against and 74,891 votes abstained. With respect to the approval of the appointment of Pannell Kerr Forster of Texas, P.C. as the Company's Independent Registered Public Accounting Firm, 21,688,605 votes were cast for the appointment, 16,017 votes were cast against, and 8,166 votes abstained.

Item 5 - Other Information

None

Item 6 - Exhibits

Exhibits required by Item 601 of Regulation S-K are as follows:

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, 1997).
†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	—

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

†10.2 — First Lien Stock Pledge and Security Agreement dated as of May 25, 2006, by Carrizo Oil & Gas, Inc., in favor of JPMorgan Chase Bank, National Association, as Administrative Agent (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on May 30, 2006).

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

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

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10.5—Form of Subscription and Registration Rights Agreement among the Company and the Subscribers named therein.

10.6—Placement Agent Agreement dated July 25, 2006 between the Company and Johnson Rice & Company L.L.C.

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.

† Incorporated herein by reference as indicated.

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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 duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

Carrizo Oil & Gas, Inc.
(Registrant)

Date: August 9, 2006	By: /s/S. P. Johnson, IV President and Chief Executive Officer (Principal Executive Officer)
Date: August 9, 2006	By: /s/Paul F. Boling Chief Financial Officer (Principal Financial and Accounting Officer)