CARRIZO OIL & GAS INC
Form 10-Q
November 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 **September 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 (State or other jurisdiction of incorporation or organization)	**76-0415919** (IRS Employer Identification No.)
1000 Louisiana Street, Suite 1500, Houston, TX (Address of principal executive offices)	**77002** (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 October 31, 2006, the latest practicable date, was 25,940,361.

CARRIZO OIL & GAS, INC.

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

CONSOLIDATED BALANCE SHEETS

ASSETS		**December 31, 2005**		**September 30, 2006**
				(Unaudited)
		(In thousands except share amounts)		
CURRENT ASSETS:				
Cash and cash equivalents	$	28,725	$	1,406
Accounts receivable, trade (net of allowance for doubtful accounts of $253 at December 31, 2005 and September 30, 2006)		24,898		28,664
Advances to operators		3,049		4,503
Fair value of derivative financial instruments		-		4,821
Other current assets		3,512		773
Total current assets		60,184		40,167
PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil and natural gas properties (including unevaluated costs of properties of $71,581 and $95,748 at December 31, 2005 and September 30, 2006, respectively)		314,074		405,676
INVESTMENT IN PINNACLE GAS RESOURCES, INC.		2,687		2,771
DEFERRED FINANCING COSTS		5,858		5,072
OTHER ASSETS		298		357
	$	383,101	$	454,043
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES:				
Accounts payable, trade	$	17,571	$	17,881
Accrued liabilities		23,321		22,201
Advances for joint operations		5,887		3,992
Current maturities of long-term debt		1,535		1,508
Fair value of derivative financial instruments		1,563		-
Other current liabilities		-		1,688
Total current liabilities		49,877		47,270
LONG-TERM DEBT, NET OF CURRENT MATURITIES		147,759		164,628
ASSET RETIREMENT OBLIGATION		3,235		3,983
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS		2,295		297
DEFERRED INCOME TAXES		24,550		29,820
COMMITMENTS AND CONTINGENCIES		-		-
SHAREHOLDERS' EQUITY:				

Common stock, par value $0.01 (40,000,000 shares authorized with 24,251,430 and				
25,937,961 issued and outstanding at December 31, 2005 and				
September 30, 2006, respectively)		243		259
Additional paid-in capital		124,586		168,047
Retained earnings		31,627		45,599
Unearned compensation - restricted stock		(1,071)		(5,860)
Total shareholders' equity		155,385		208,045
	$	383,101	$	454,043

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 September 30,		For the Nine Months Ended September 30,	
	2005 (Restated)	**2006**	**2005** (Restated)	**2006**
	(In thousands except per share amounts)			
OIL AND NATURAL GAS REVENUES	$ 18,442	$ 20,333	$ 50,042	$ 58,727
COSTS AND EXPENSES:				
Oil and natural gas operating expenses (exclusive of depreciation, depletion and amortization shown separately below)	2,240	3,893	7,069	10,980
Depreciation, depletion and amortization	4,701	7,594	14,390	21,630
General and administrative (inclusive of stock-based compensation expense of $1,915 and $810 for the three months ended September 30, 2005 and 2006, respectively, and $2,945 and $1,999 for the nine months ended September 30, 2005 and 2006, respectively)	3,838	3,118	9,177	10,469
Accretion expense related to asset retirement obligations	18	79	54	237
Total costs and expenses	10,797	14,684	30,690	43,316
OPERATING INCOME	7,645	5,649	19,352	15,411
OTHER INCOME AND EXPENSES:				
Net gain (loss) on derivatives (Note 7)	(11,638)	3,684	(12,182)	12,087
Equity in income (loss) of Pinnacle Gas Resources, Inc.	(1,906)	-	(3,174)	35
Other income and expenses, net	(73)	29	(292)	202
Loss on early extinguishment of debt	(3,721)	(12)	(3,721)	(294)

Interest income	445	199	520	843
Interest expense	(3,475)	(4,883)	(6,845)	(13,752)
Capitalized interest	1,671	2,740	3,896	7,234
INCOME (LOSS) BEFORE INCOME TAXES	(11,052)	7,406	(2,446)	21,766
INCOME TAX (EXPENSE) BENEFIT (Note 4)	3,135	(2,655)	(453)	(7,793)
NET INCOME (LOSS)	$ (7,917)	$ 4,751	$ (2,899)	$ 13,973
BASIC EARNINGS (LOSS) PER COMMON SHARE	$ (0.33)	$ 0.19	$ (0.12)	$ 0.57
DILUTED EARNINGS (LOSS) PER COMMON SHARE	$ (0.33)	$ 0.18	$ (0.12)	$ 0.55
WEIGHTED AVERAGE SHARES OUTSTANDING:				
BASIC	24,198,152	25,254,054	23,302,734	24,549,045
DILUTED	24,198,152	25,987,388	23,302,734	25,271,731

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 Nine Months Ended September 30,	
	2005 (Restated)	**2006**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (2,899)	$ 13,973
Adjustment to reconcile net income (loss) to net		
cash provided by operating activities-		
Depreciation, depletion and amortization	14,390	21,630
Fair value loss (gain) of derivative financial instruments	11,493	(7,734)
Accretion of discounts on asset retirement obligations and debt	340	237
Stock-based compensation	2,945	1,999
Loss on extinguishment of debt	3,365	294
Equity in loss (income) of Pinnacle Gas Resources, Inc.	3,174	(35)
Deferred income taxes	257	7,503
Other	510	1,129
Changes in operating assets and liabilities		
Accounts receivable	(7,422)	(3,766)
Other assets	(2,846)	1,705
Accounts payable	(6,677)	(778)
Other liabilities	2,189	1,087
Net cash provided by operating activities	18,819	37,244
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(92,273)	(146,196)
Change in capital expenditure accrual	7,502	1,376
Proceeds from the sale of properties	9,000	33,604
Advances to operators	1,087	(1,454)
Advances for joint operations	3,977	(1,894)
Other	-	(342)
Net cash used in investing activities	(70,707)	(114,906)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from common stock issuances:		
Private placements, net of offering costs	17,169	33,593
Warrants exercised	1,000	-
Stock options exercised	1,302	585
Net proceeds from debt issuance and borrowings	183,624	53,000
Debt repayments	(100,624)	(36,159)
Deferred loan costs	(6,214)	(523)
Other	-	(153)
Net cash provided by financing activities	96,257	50,343

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		44,369		(27,319)
CASH AND CASH EQUIVALENTS, beginning of period		5,668		28,725
CASH AND CASH EQUIVALENTS, end of period	$	50,037	$	1,406
SUPPLEMENTAL CASH FLOW DISCLOSURES:				
Cash paid for interest (net of amounts capitalized)	$	-	$	5,381

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 nine-month periods ended September 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 disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates.

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

The significant estimates are based on current assumptions that may be materially effected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates, the market value of the Company's common stock and corresponding volatility and the Company's ability to generate future taxable income. Future changes in these assumptions may materially affect these significant estimates 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 $1.6 million and $2.2 million for the nine months ended September 30, 2005 and 2006, respectively. Maintenance and repairs are expensed as incurred.

Depreciation, depletion and amortization ("DD&A") of proved oil and natural gas properties is based on the unit-of-production method using estimates of proved reserve quantities. Investments in unproved properties are not subject to DD&A until proved reserves associated with the projects can be determined or until they are impaired. Unevaluated properties are evaluated periodically for impairment on a property-by-property basis. If the results of an assessment indicate that the properties have been impaired, the amount of such impairment is determined and added to the proved oil and natural gas property costs subject to DD&A. The depletable base includes estimated future development costs and, where significant, dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for the quarters ended September 30, 2005 and 2006 was $2.15 and $2.59, 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.

Net capitalized costs are limited to a "ceiling-test" based on the estimated future net revenues, discounted at 10% per annum, from proved oil and natural gas reserves, based on current economic and operating conditions ("Full Cost Ceiling"). If net capitalized costs exceed this limit, the excess is charged to earnings through DD&A. For the three and nine month periods ended September 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 nine months ended September 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. In addition, the nine-month period ended September 30, 2006 does not include the acquisition of $55,000 of oil and gas properties in exchange for the Company's common stock. The Company paid no income taxes for the nine months ended September 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 nine-month periods ended September 30, 2005, the Company recognized $1.9 million and $2.9 million, respectively, for stock-based compensation. The 2005 quarter period expenses were comprised of approximately $0.1 million associated with restricted stock and $1.8 million associated with the repricing of certain stock options. The 2005 nine-month period was comprised of approximately $0.1 million associated with restricted stock and $2.8 million associated with the repricing of certain stock options. For the three and nine-month periods ended September 30, 2006, the Company recognized $0.8 million and $2.0 million, respectively, for stock-based compensation expenses. The 2006 quarter period expenses were comprised of $0.1 million associated with stock options and $0.7 million associated with restricted stock. The 2006 nine-month period expenses were comprised of $0.4 million associated with stock options and $1.6 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 $1.8 million and $2.8 million of stock-based compensation expense for the three and nine-month periods ended September 30, 2005, respectively.

Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 123 (revised 2004), "Share-Based Payment" ("SFAS No. 123(R)"), which requires companies to measure all stock-based compensation awards using the fair value method and record such expense in the financial statements over the vesting period of the options, which is generally three years. The Company implemented SFAS No. 123(R) using the modified prospective transition method. The Company recognizes compensation expense for all unvested options outstanding as of January 1, 2006, options issued after January 1, 2006, and those options that are subsequently modified, repurchased or cancelled. The compensation expense is based on the grant-date fair value of

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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 nine-month periods ended September 30, 2006, the Company recognized $0.1 million and $0.4 million, respectively, in stock option compensation expense and computed $0.5 million associated with nonvested awards that will be expensed in the future over a weighted-average period of 1.3 years.

The table below summarizes stock option activity for the nine-month period ended September 30, 2006:

	Shares	**Weighted-Average Exercise Prices**	**Weighted-Average Remaining Life (In years)**	**Aggregate Intrinsic Value (In millions)**
Outstanding at December 31, 2005	1,025,204	$ 5.53		
Granted	-	-		
Exercised	(99,800)	5.87		
Forfeited	(30,001)	12.29		
Outstanding at September 30, 2006	895,403	$ 5.27	5.4	$ 18.5
Exercisable at September 30, 2006	822,613	$ 4.53	5.1	$ 17.6

The total intrinsic value (current market price less the option strike price) of options exercised during the nine-month period ended September 30, 2006 was $2.5 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 nine-month periods ended September 30, 2005 as if stock-based 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 September 30, 2005	For the Nine Months Ended September 30, 2005
	(Restated) (In thousands except per share amounts)	
Net loss as reported	$ (7,917)	$ (2,899)
Add: Stock-based employee compensation expense recognized, net of tax	1,157	1,801
Less: Total stock-based employee compensation expense determined under fair value method for all awards, net tax	(402)	(245)
Pro forma net loss	$ (7,162)	$ (1,343)
Net loss per common share, as reported:		
Basic	$ (0.33)	$ (0.12)
Diluted	(0.33)	(0.12)
Pro forma net loss per common share, as if the fair value method had been applied to all awards		
Basic	$ (0.30)	$ (0.06)
Diluted	(0.30)	(0.06)

During the third quarter of 2005, the Company granted options with a weighted average grant-date fair value of $10.22 per option based on the following assumptions:

Risk-free interest rate	4.3%
Dividend yield	-
Volatility	46%

Term (in years) 5.8

Restricted Stock. 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 $5.9 million as of September 30, 2006. The Company recorded compensation expense related to restricted stock of approximately $0.1 million for both the three and nine-month periods ended September 30, 2005, and $0.7 million and $1.6 million, respectively, for the three and nine-month periods ended September 30, 2006. The table below summarizes restricted stock activity for the nine months ended September 30, 2006:

	Shares	Weighted-Average Price
Unvested restricted stock at December 31, 2005	87,585	$ 15.98
Granted	261,643	26.88
Vested	(34,645)	16.22
Forfeited	(23,292)	23.22
Unvested restricted stock at September 30, 2006	291,291	$ 25.14

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Derivative Instruments

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

Upon entering into a derivative contract, the Company 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 September 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 September 30,		**For the Nine Months Ended September 30,**	
	2005	**2006**	**2005**	**2006**
Chevron/Texaco	14%	11%	15%	12%
Reichman Petroleum	12%	-	-	11%
Liberty Gathering	10%	-	-	-
Energy Transfer	-	10%	-	-
Partner Energy Services	-	10%	-	-

Earnings Per Share

Supplemental earnings per share information is provided below:

For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**	
2005	**2006**	**2005**	**2006**
(Restated)		(Restated)	
(In thousands except share and per share amounts)			

Net income (loss)	$ (7,917)	$ 4,751	$ (2,899)	$ 13,973
Average common shares outstanding				
Weighted average shares outstanding	24,198,152	25,254,054	23,302,734	24,549,045
Stock options and warrants	-	733,334	-	722,686
Diluted weighted average shares outstanding	24,198,152	25,987,388	23,302,734	25,271,731
Earnings (loss) per share				
Basic	$ (0.33)	$ 0.19	$ (0.12)	$ 0.57
Diluted	$ (0.33)	$ 0.18	$ (0.12)	$ 0.55

Basic earnings (loss) per common share is based on the weighted average number of shares of common stock outstanding during the periods. Diluted earnings (loss) per common share is based on the weighted average number of common shares and all dilutive

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potential common shares outstanding during the periods. The Company had outstanding 804,850 and 2,500 stock options during the three months ended September 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 September 30, 2006:

	December 31, 2005 (In thousands)	September 30, 2006
First Lien Credit Facility	$ -	$ -
Second Lien Credit Facility	149,250	148,125
Senior Secured Revolving Credit Facility	-	18,000
Capital lease obligations	27	-
Other	17	11
	149,294	166,136
Current maturities	(1,535)	(1,508)
	$ 147,759	$ 164,628

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 September 30, 2006, the interest rate was approximately 11.4%, 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 subsidiaries. The liens securing the Senior Credit Facility are first in priority to the liens securing the Second Lien Credit Facility.

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As of September 30, 2006 the Company had outstanding borrowings of $18.0 million, under the Senior Credit Facility and had used a portion of 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 September 30, 2006, the weighted average interest rate was 6.9%.

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. On September 22, 2006, U.S. Energy sold all of its 2,459,102 shares of Pinnacle's common stock to the CSFB Parties. At September 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 provided deferred federal income taxes at the rate of 35% (which also approximates its statutory rate) that amounted to a tax benefit of $3.1 million and tax expense of $2.6 million for the three-month periods ended September 30, 2005 and 2006, respectively, and $0.5 million and $7.5 million of tax expense for the nine-month periods ended September 30, 2005 and 2006, respectively. The rate for the three-month and nine-month periods in 2005 varied from the statutory rate of 35% primarily as a result of the preferred dividend and valuation ad valorem on Pinnacle.

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 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 its 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 net proceeds were principally used to fund a portion of the Company's 2005 capital expenditure program.

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

The Company issued 2,060,658 and 1,686,531 net shares of common stock during the nine months ended September 30, 2005 and 2006, respectively. Shares issued during the nine months ended September 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, 80,065 shares issued as restricted stock awards to employees and the balance through the exercise of

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options granted under the Company's Incentive Plan. Shares issued during the nine months ended September 30, 2006 consisted of 1,350,000 shares issued in the July 2006 Private Placement, 236,351 shares issued (net of 23,292 shares forfeited) as restricted stock awards to employees, 99,800 shares issued through the exercise of options granted under the Company's Incentive Plan and 2,000 shares issued in exchange for oil and gas properties in the Barnett Shale. Also during 2006, the Company purchased and retired 1,620 shares to satisfy tax withholding obligations in connection with the vesting of the restricted stock.

7. DERIVATIVE INSTRUMENTS:

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. The Company also uses interest rate swap agreements to manage the Company's exposure to interest rate fluctuations on the Second Lien Credit Facility.

The Company accounts for its oil and natural gas derivatives and interest rate swap agreements as non-designated hedges. These derivatives are marked-to-market at each balance sheet date and the unrealized gains (losses) are reported in the net gain (loss) on derivatives in Other Income and Expenses in the Consolidated Statement of Income. In addition, the company records the realized gains (losses) associated with the cash settlements of these derivative instruments in the net gain (loss) on derivatives in Other Income and Expense in the Consolidated Statement of Income. For the quarters and nine months ended September 30, 2006 and 2005, the Company recorded the following related to its derivatives:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2005	2006	2005	2006
	(In millions)			
Realized gain (loss):				
Natural gas and oil derivatives	$ (0.9)	$ 1.1	$ (0.7)	$ 3.6
Interest rate swaps	-	0.4	-	0.7
	(0.9)	1.5	(0.7)	4.3
Unrealized gain (loss):				
Natural gas and oil derivatives	$ (11.0)	$ 2.9	$ (11.7)	$ 7.5
Interest rate swaps	0.2	(0.7)	0.2	0.3
	(10.8)	2.2	(11.5)	7.8
Net Gain (Loss) on Derivatives	$ (11.7)	$ 3.7	$ (12.2)	$ 12.1

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

Quarter	Contract Volumes BBls	Contract Volumes MMbtu	Average Fixed Price	Average Floor Price	Average Ceiling Price
	-	1,042,000	$ 7.28	$ 7.54	$ 9.08

Fourth Quarter 2006					
Fourth Quarter 2006	18,400	-	-	58.50	70.93
First Quarter 2007	-	900,000	7.05	7.95	9.81
Second Quarter 2007	-	1,001,000	7.05	7.31	8.87
Third Quarter 2007	-	828,000	7.05	7.53	9.10
Fourth Quarter 2007	-	552,000	7.05	6.92	8.32
First Quarter 2008	-	182,000	-	7.25	8.65

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The Company’s outstanding positions under interest rate swap agreements at September 30, 2006 were as follows (dollars in thousands):

Quarter	Notional Amount	Fixed LIBOR Rate
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 September 30, 2006, Mr. Webster has acquired oil and gas leases for approximately $4.2 million, the Company paid approximately $4.4 million for leases from Mr. Webster and the Company has made option extension payments of approximately $48,000 to Mr. Webster. There are currently no outstanding lease options under our arrangement with Mr. Webster. The Company may continue to use these arrangements as a strategic alternative.

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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

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 nine months ended September 30, 2006, we were successful drilling 56 of 59 (37.2 net) wells with an apparent success rate of 95% that was comprised of: (1) 13 of 16 gross (4.3 net) wells in the onshore Gulf Coast area, (2) 37 of 37 gross (27.0 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 September 30, 2006, we have completed 42 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 nine months 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 the nine months ended September 30, 2006, we received a total of $33.6 million in proceeds from asset sales, including $26.6 million from the sale of approximately 2,250 acres in the Barnett Shale area and $5.2 million from the sale of our working interest in 13 non-operated wells in the Barnett Shale area.

Our second quarter 2006 production declined from first quarter 2006 production in part due to mechanical problems with the Galloway #1 and Delta Farms #1, production delays in the Barnett Shale, and drilling delays with the third-party operated Galloway #2. During the third quarter, production increased to record levels as the Galloway #1 was put back on line and Delta Farms #1 was replaced with the Delta Farms #3; a gathering system was built to accelerate the connection of four new wells in the Barnett Shale; and the Galloway #2 started production.

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 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. We have made draws under the Senior Credit 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 from $40.0 million to $50.0 million and, as of September 30, 2006, $18 million was outstanding.

In July 2006, we sold 1.35 million shares of our common stock to institutional investors at a price of $26.00 per share in a private placement (the “2006 Private Placement”). The 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 were principally used to fund a portion of the Company’s 2006 capital expenditures program.

In connection with the 2006 Private Placement, we entered into Subscription and Registration Rights Agreements (the “Subscription and Registration Rights Agreements”) with the investors in the 2006 Private Placement. The Subscription and Registration Rights Agreements provide registration rights with respect to the shares purchased in the 2006 Private Placement. We 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

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the 2006 Private Placement and to have the registration statement declared effective by the SEC within 120 days after it is filed. We filed a resale shelf registration statement in connection with the 2006 Private Placement with the SEC on August 21, 2006, but it has not yet been declared effective by the SEC. 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.

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. On September 22, 2006, U.S. Energy sold all of its 2,459,102 shares of Pinnacle’s common stock to the CSFB Parties. At September 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. For further discussion, see Note 3 in the Notes to Unaudited Consolidated Financial Statements.

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 inherently unpredictable, 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 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 September 30, 2006,
Compared to the Three Months Ended September 30, 2005

Oil and natural gas revenues for the three months ended September 30, 2006 increased 10% to $20.3 million from $18.4 million for the same period in 2005. Production volumes for natural gas for the third quarter of 2006 increased to 2.4 Bcf from 1.9 Bcf for the same period in 2005. Average natural gas prices excluding the impact of the gain (loss) from our cash settled derivatives of $1.2 million and $(0.8) million for the quarters ended September 30, 2006 and

2005, respectively, decreased 21% to $6.39 per Mcf in the third quarter of 2006 from $8.08 per Mcf in the same period in 2005. Average oil prices for the quarter ended September 30, 2006 increased 6% to $68.46 from $64.42 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 Gas Unit 1 Well #2, new wells in the Barnett Shale area and increased production from workovers. These volume increases were partially offset by or adversely affected by production interruption due to mechanical failures with the LL&E #1 Deeping, Hamill Gas Unit #2 and Louisiana Delta Farms #1 during the third quarter of 2006 and normal production declines.

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

	For the Three Months Ended September 30,		2006 Period Compared to 2005 Period	
	2005 (Restated)	2006	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	53	69	16	30%
Natural gas (MMcf)	1,858	2,443	585	31%
Average sales prices				
Oil and condensate (per Bbl)	$ 64.42	$ 68.46	$ 4.04	6%
Natural gas (per Mcf)	8.08	6.39	(1.69)	(21)%
Operating revenues (In thousands)				
Oil and condensate	$ 3,438	$ 4,716	$ 1,278	37%
Natural gas	15,004	15,617	613	4%
Total Operating Revenues	$ 18,442	$ 20,333	$ 1,891	10%

Oil and natural gas operating expenses for the three months ended September 30, 2006 increased 74% to $3.9 million from $2.2 million for the same period in 2005 primarily as a result of higher lifting costs of $1.6 million primarily attributable to increased production, the increased number of producing wells and the rising costs of oilfield services.

Depreciation, depletion and amortization (DD&A) expense for the three months ended September 30, 2006 increased 62% to $7.6 million ($2.66 per Mcfe) from $4.7 million ($2.16 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 September 30, 2006 decreased by $0.7 million to $3.1 million from $3.8 million for the corresponding period in 2005 primarily as a result of lower stock-based compensation expense of $1.1 million due to the change in accounting for stock options effective January 1, 2006 as prescribed in SFAS No. 123(R). This decrease was partially offset by (1) higher salary costs of $0.2 million, attributable to an increased headcount and an overall increase in salaries and (2) higher contract service costs of $0.3 million largely due to costs to cover certain key accounting staff vacancies and to support the continued phase-in of our integrated software system.

The net gain on derivatives of $3.7 million in the third quarter of 2006 was comprised of (1) $1.5 million of realized gain on net settled derivatives and (2) $2.2 million of net unrealized mark-to-market gain on derivatives. The mark-to-market loss on derivatives of $11.7 million in the third quarter of 2005 was comprised of (1) $0.9 million of realized loss on net settled derivatives and (2) $10.8 million of net unrealized mark-to-market loss on 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.

During the third quarter of 2005, we refinanced our senior subordinated notes due 2007 and senior secured notes due 2008 ("Senior Notes") with a new Second Lien Credit Facility and, accordingly, incurred a $3.7 million loss in connection with the early retirement of our Senior Notes. The loss consisted of unamortized discount and deferred loan costs written-off on the repayment of the notes.

Interest expense and capitalized interest for the three months ended September 30, 2006 were $4.9 million and ($2.7) million, respectively, as compared to $3.5 million and ($1.7) million for the same period in 2005. The increases in 2006 are attributable to the borrowings under the Senior Credit Facility in 2006.

Income tax expense increased to $2.7 million for the three months ended September 30, 2006 from a $3.1 million tax benefit for the same period in 2005 as a result of higher taxable income.

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Nine Months Ended September 30, 2006,
Compared to the Nine Months Ended September 30, 2005

Oil and natural gas revenues for the nine months ended September 30, 2006 increased 17% to $58.7 million from $50.0 million for the same period in 2005. Production volumes for natural gas for the nine months ended September 30, 2006 increased to 7.0 Bcf from 5.8 Bcf for the same period in 2005. Average natural gas prices excluding the impact of the gain (loss) from our cash settled derivatives of $3.7 million and $(0.6) million for the nine months ended September 30, 2006 and 2005, respectively, decreased 2% to $6.74 per Mcf in the nine months of 2006 from $6.89 per Mcf in the same period in 2005. Average oil prices for the nine months ended September 30, 2006 increased 16% to $65.54 from $56.34 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 Gas Unit 1 Well #1 and #2 wells, Maas #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) production interruption in the second quarter of 2006 due to mechanical failures with the Galloway Gas Unit 1 #1 and the Delta Farms #1.

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

	For the Nine Months Ended September 30,		2006 Period Compared to 2005 Period	
	2005 (Restated)	2006	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	178	179	1	0%
Natural gas (MMcf)	5,807	6,976	1,169	20%
Average sales prices				
Oil and condensate (per Bbl)	$ 56.34	$ 65.54	$ 9.20	16%
Natural gas (per Mcf)	6.89	6.74	(0.15)	(2%)
Operating revenues (In thousands)				
Oil and condensate	$ 10,055	$ 11,734	$ 1,679	17%
Natural gas	39,987	46,993	7,006	18%
Total Operating Revenues	$ 50,042	$ 58,727	$ 8,685	17%

Oil and natural gas operating expenses for the nine months ended September 30, 2006 increased 55% to $11.0 million from $7.1 million for the same period in 2005 due principally to higher lifting costs of $4.0 million primarily attributable to (1) increased production, (2) the increased number of producing wells, (3) expenses related to workovers, and (4) the rising costs of oilfield services. Operating expenses per equivalent unit increased to $1.35 per Mcfe in the first nine months of 2006 compared to $1.03 per Mcfe in the same period in 2005.

Depreciation, depletion and amortization (DD&A) expense for the nine months ended September 30, 2006 increased 50% to $21.6 million ($2.69 per Mcfe) from $14.4 million ($2.09 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 nine months ended September 30, 2006 increased by $1.3 million to $10.5 million from $9.2 million for the same period in 2005 primarily as a result of (1) higher net salary and incentive compensation costs of $0.9 million, attributable to an increased headcount and an overall increase in salaries and incentive bonuses and (2) higher contract service costs of $1.1 million largely due to costs to cover accounting staff vacancies and to support the continued phase-in of our integrated software system, partially offset by lower stock compensation expense of $0.9 million due to the change in accounting for stock options effective January 1, 2006 as prescribed in SFAS No. 123(R) and the issuance of restricted stock beginning in May of 2005.

The net gain on derivatives of $12.1 million in the first nine months of 2006 was comprised of (1) $4.3 million of realized gain on net settled derivatives and (2) $7.8 million of net unrealized mark-to-market gain on the derivatives accounted for as nondesignated

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derivatives. The mark-to-market loss on derivatives of $12.2 million in the first nine months of 2005 was comprised of (1) $0.7 million of realized loss on net settled derivatives and (2) $11.5 million of net unrealized mark-to-market loss on the derivatives. For further details, see Note 7 of the Notes to Unaudited Consolidated Financial Statements.

We recorded a $35,000 benefit on our equity interest in Pinnacle for the nine months ended September 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 for the nine months ended September 30, 2006 due to the Company's refinancing of its First Lien Credit Facility in May 2006. The loss for the nine months ended September 30, 2005 relates to the early retirement of the senior subordinated notes due 2007 and senior secured subordinated notes due in 2008 in connection with the Company's debt refinancing and issuance of a new Second Lien Credit Facility in July 2005.

Interest expense and capitalized interest for the nine months ended September 30, 2006 were $13.8 million and ($7.2) million, respectively, as compared to $6.8 million and ($3.9) million for the same period in 2005. The increases in 2006 are attributable to the borrowings under the Second Lien Credit Facility in July 2005 and borrowings under the Senior Credit Facility in 2006.

Income tax expenses increased to $7.8 million for the nine months ended September 30, 2006 compared to a tax benefit of $0.5 million for the same period in 2005 as a result of higher taxable income.

Liquidity and Capital Resources

During the nine months ended September 30, 2006, capital expenditures, net of $33.6 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, 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 needed in the future on terms that would be acceptable to us. If we cannot obtain adequate financing, 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 placements in 2005 and 2006 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 $18.8 million and $37.2 million for the nine months ended September 30, 2005 and 2006, respectively. The increase was primarily due to increased production.

We have planned capital expenditures in 2006 of approximately $140.0 million to $145.0 million, net of asset sales, 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 $92.3 million and $146.2 million for the nine months ended September 30, 2005 and 2006, respectively.

Our drilling efforts in the Gulf Coast region resulted in apparent successes in drilling 13 gross wells (4.3 net) during the nine months ended September 30, 2006. In our Barnett Shale area, we had apparent successes in drilling 37 gross wells (27.0 net) during the first nine months of 2006, and in our East Texas area, we had apparent successes in drilling six gross wells (5.9 net) during that period.

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We also drilled four gross (3.8 net) service wells. Of the 56 apparently successful wells, 42 have been completed and the remaining wells were in various stages of completion at September 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

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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.

As of September 30, 2006, the Company had $18.0 million of borrowings and outstanding under the Senior 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).

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.

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.

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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 September 30, 2006, Mr. Webster has acquired oil and gas leases for approximately $4.2 million, the Company has purchased approximately $4.4 million in leases from Mr. Webster and the Company has made option extension payments of approximately $48,000 to Mr. Webster. There are currently no outstanding lease options under our arrangement with Mr. Webster. The Company may continue to use these arrangements as a strategic alternative.

Effects of Inflation and Changes in Price

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

Recently Issued Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes--an Interpretation of FASB Statement 109 ("FIN 48"), which clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is "more-likely-than-not" of being sustained if the position were to be challenged by a taxing authority. The assessment of the tax position is based solely on the technical merits of the position, without regard to the likelihood that the tax position may be challenged. If an uncertain tax position meets the "more-likely-than-not" threshold, the largest amount of tax benefit that is greater than 50 percent likely of being recognized upon ultimate settlement with the taxing authority, is recorded. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We are currently evaluating the impact of adopting FIN 48 on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, "*Fair Value Measurements*." SFAS No. 157 defines fair value, establishes a framework for measuring fair value under Generally Accepted Accounting Principles and requires enhanced disclosures about fair value measurements. It does not require any new fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We are currently assessing whether we will early adopt SFAS No. 157 as of the first quarter of fiscal 2007 as permitted, and are currently evaluating the impact adoption may have on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 158 *"Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."* This Statement amends Statement 87, FASB Statement No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, Statement 106, and FASB Statement No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits*, and other related accounting literature. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in the funded status in the year in which the changes occur through comprehensive income. This statement also requires employers to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. Employers with publicly traded equity securities are required to initially recognize the funded status of a defined benefit postretirement plan and to provide the required disclosures as of

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the end of the fiscal year ending after December 15, 2006. We currently have no defined benefit or other post retirement plans subject to this standard.

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 $0.4 million in additional compensation expense in the first nine months 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.

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

The significant estimates are based on current assumptions that may be materially 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 $1.6 million and $2.2 million for the nine months ended September 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 September 30, 2005 and 2006 was $2.15 and $2.59, 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.

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

In connection with our September 30, 2006 Full Cost Ceiling test computation, a price sensitivity study also indicated that a 10% increase or decrease in commodity prices at September 30, 2006 would have increased or decreased the Full Cost Ceiling test cushion by approximately $29 million. The aforementioned price sensitivity and NPV is as of September 30, 2006 and, accordingly, does not include any potential changes in reserve values due to fourth quarter 2006 performance, such as commodity prices, reserve revisions and drilling results.

The Full Cost Ceiling cushion at the end of September 2006 of approximately $4 million was based upon average realized oil and natural gas prices of $57.82 per Bbl and $4.04 per Mcf, respectively, or a volume weighted average price of $34.80 per BOE. This cushion, however, would have been zero on such date at an estimated volume weighted average price of $34.31 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 of our oil and natural gas properties, excluding unevaluated costs, 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 79.3 Bcfe of proved undeveloped reserves at December 31, 2005 and September 30, 2006, respectively, representing 65% and 53% of our total proved reserves. This decline in proved undeveloped reserves is largely attributable to the decrease in the gas price to $4.04 Mcf at September 30, 2006 from $8.04 at December 31, 2005. As of December 31, 2005 and September 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.

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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 using a discount rate of 10%.

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 September 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 added to our reserves 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 our derivative contracts as non-designated derivatives that will be marked-to-market. For a discussion of the impact of changes in the prices of oil and gas on our hedging transactions, see “Volatility of Oil and Natural Gas Prices” below.

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 recorded as mark-to-market gain (loss) on derivatives, net within other income and expenses on our Statement of Income.

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.

Income Taxes

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

Contingencies

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

Volatility of Oil and Natural Gas Prices

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

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 September 30, 2005 and 2006 was 27,600 each period. Total natural gas purchased and sold under swaps and collars during the three months ended September 30, 2005 and 2006 was 966,000 MMBtu and 1,163,000 MMBtu, respectively. Total oil hedged under swaps and collars during the nine months ended September 30, 2005 and 2006 were 99,300 Bbls and 63,800 Bbls, respectively. Total natural gas hedged under swaps and collars during the nine months ended September 30, 2005 and 2006 were 2,926,000 MMBtu and 3,520,000 MMBtu, respectively. The net gain/(loss) realized by us under such hedging arrangements was $(0.9) million and $1.1 million for the three months ended September 30, 2005 and 2006, respectively, and was $(0.7) million and $3.6 million for the nine months ended September 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 September 30, 2005 and 2006, the unrealized gain (loss) on oil and natural gas derivatives was $(11.0) million and $2.9 million, respectively. For the nine months ended September 30, 2005 and 2006, the unrealized mark-to-market gain (loss) on derivatives, net was ($11.7) million and $7.5 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.

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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 third quarter of 2006, a 10% change in the price per Mcf of gas sold would have changed revenue by $1.6 million. A 10% change in the price per barrel of oil would have changed revenue by $0.5 million.

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

Natural Gas	
Volumes (MMBtu)	3,520,000
Average price ($/MMBtu)	
Fixed	$ 7.24
Floor	$ 7.77
Ceiling	$ 10.68

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

Crude Oil	
Volumes (Bbls)	63,800
Average price ($/Bbls)	
Floor	$ 57.30
Ceiling	$ 69.12

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

	Contract Volumes				
Quarter	**BBls**	**MMbtu**	**Average Fixed Price**	**Average Floor Price**	**Average Ceiling Price**
Fourth Quarter 2006		1,042,000	$ 7.28	$ 7.54	$ 9.08
Fourth Quarter 2006	18,400			58.50	70.93
First Quarter 2007		900,000	7.05	7.95	9.81
Second Quarter 2007		1,001,000	7.05	7.31	8.87
Third Quarter 2007		828,000	7.05	7.53	9.10

Fourth Quarter 2007	552,000	7.05	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,

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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 September 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. During the third quarter of 2006, we continued to build our accounting staff with the addition of two senior accountants.

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 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.

Management identified each of the three material weaknesses referred to above in March of 2006 in connection with the preparation of the Company's financial statements and the work related to management's annual report on internal control over financial reporting. The material weakness in the Company's 2005 year-end close process resulted from accounting and financial staff vacancies beginning in the fourth quarter of 2005. Other similar vacancies existed during the 2004 year-end close process, which resulted in a material weakness as of December 31, 2004. The second material weakness, relating to the Company's hedging practices, was identified in March 2006 by management of the Company in connection with the preparation of the Company's annual financial statements and the work related to management's annual report on internal control over financial reporting. The underlying hedge accounting issues were identified and brought to management's attention by PKF and led management to identify a material weakness and therefore conclude that such material weakness was present as of December 31, 2005 and December 31, 2004. Management's identification of this material weakness ultimately led to the restatement of the Company's 2004 financial statements and the Company's quarterly financial statements for the first nine months of 2005. Management determined that this financial restatement was an additional effect of the year-end close process material weakness. Management also determined that the cumulative impact of the deficiencies associated with hedging practices was not material prior to 2004. The third material weakness related to various errors and omissions made during the 2005 year-end close process that were identified by PKF in March 2006 and led management to identify these errors as a material weakness and therefore conclude that such material weakness was present as of December 31, 2005. The material weakness began in the fourth quarter of 2005 and was related to the Company's accounting and financial staff vacancies.

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 manager of financial planning and analysis and other senior level positions, 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 currently 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 September 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 nine months 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 and in Part II, Item 1A - Risk Factors in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006 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.

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

The following table presents information regarding the Company's purchases of its common stock on a monthly basis during the third quarter of 2006:

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
July 2006	-	-	-	-
August 2006	826	$ 28.51	-	-
September 2006	-	-	-	-
Total	826	$ 28.51	-	-

(1) The 826 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

None.

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)).

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†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—Form of Employee Restricted Stock Award Agreement.

10.2—Form of Employee Stock Option Award Agreement.

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

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