FORM 10-Q

Pinnacle Gas Resources, Inc. - PINN

Filed: November 14, 2007 (period: September 30, 2007)

Quarterly report which provides a continuing view of a company's financial position

Part I.

PART II.

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

Form 10-Q

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

For the quarterly period ended September 30, 2007

or

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

For the transition period from to

Commission file number: 001-33457

Pinnacle Gas Resources, Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**30-0182582** (I.R.S. Employer Identification No.)
1 E. Alger Street **Sheridan, WY** (Address of principal executive offices)	**82801** (Zip code)

(307) 673-9710
(Registrant's telephone number, including area code)

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 ☒ 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 Act. (Check one):

Large Accelerated Filer ☐ Accelerated Filer ☐ 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 ☒

29,025,751 shares of the registrant's Common Stock were outstanding as of November 13, 2007.

PINNACLE GAS RESOURCES, INC.
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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

We are including the following discussion to inform you of some of the risks and uncertainties that can affect our company and to take advantage of the "safe harbor" protection for forward-looking statements that applicable federal securities law affords. Various statements in this prospectus, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements. These include statements relating to such matters as:

- projections and estimates concerning the timing and success of specific projects;
- our financial position or operating results;
- our business strategy;
- our budgets;
- the amount, nature and timing of capital expenditures;
- the drilling of wells;
- the development of recently acquired natural gas and oil properties;
- the timing and amount of future production of natural gas and oil;
- our operating costs and other expenses;
- our estimated future net revenues from natural gas and oil reserves and the present value thereof;
- our cash flow and anticipated liquidity; and
- our other plans and objectives for future operations.

When we use the words "believe," "intend," "expect," "may," "should," "anticipate," "could," "estimate," "plan," "predict," "project," their negatives, or other similar expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The forward-looking statements in this quarterly report on Form 10-Q speak only as of the date of this report. We disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- our ability to implement our business strategy;
- the extent of our success in discovering, developing and producing reserves, including the risks inherent in exploration and development drilling, well completion and other development activities;
- fluctuations in the commodity prices for natural gas and crude oil;
- engineering, mechanical or technological difficulties with operational equipment, in well completions and workovers, and in drilling new wells;
- the effects of government regulation and permitting and other legal requirements;

- labor problems;
- environmental-related problems;
- the uncertainty inherent in estimating future natural gas and oil production or reserves;
- production variances from expectations;
- the substantial capital expenditures required for construction of pipelines and the drilling of wells and the related need to fund such capital requirements through commercial banks and/or public securities markets;
- disruptions of, capacity constraints in or other limitations on our or others' pipeline systems;
- our ability to effectively market our production;
- land issues and the costs associated with perfecting title for natural gas rights in some of our properties;
- our ability to develop and replace reserves;
- ourdependence upon key personnel;
- the lack of liquidity of our equity securities;
- operating hazards attendant to the natural gas and oil business, including down-hole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells;
- climatic conditions or natural disasters;
- acts of terrorism;
- the availability and cost of materials and equipment;
- delays in anticipated start-up dates;
- our ability to find and retain skilled personnel;
- the availability of capital;
- competition from, and the strength and financial resources of, our competitors;
- general economic conditions; and
- regional price differentials.

When you consider these forward-looking statements, you should keep in mind these factors and the other factors discussed under "Risk Factors."

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PINNACLE GAS RESOURCES, INC.
Balance Sheets

	September 30, 2007 (unaudited)	December 31, 2006
	(in thousands, except share and per share data)	
Assets		
Current assets		
Cash and cash equivalents	$ 12,147	$ 4,762
Receivables		
Accrued gas sales	1,148	2,364
Joint interest receivables, net of $100 allowance for doubtful accounts	6,656	9,237
Derivative instruments	1,719	2,856
Inventory of material for drilling and completion	314	271
Prepaid expenses	277	394
Total current assets	22,261	19,884
Property and equipment, at cost, net of accumulated depreciation	2,359	2,107
Oil and gas properties, using full cost accounting, net of accumulated depletion and impairment		
Proved	36,022	39,988
Unproved	85,348	85,094
Inventory of material for drilling and completion	827	944
Deposits	20	520
Restricted certificates of deposit	1,752	1,795
Total assets	$ 148,589	$ 150,332
Liabilities and Stockholders' Equity		
Current liabilities		
Long term debt-current portion	$ 23	$ 21
Trade accounts payable	8,602	17,567
Revenue distribution payable	5,740	7,301
Drilling prepayments from joint interest owners	142	289
Accrued liabilities	1,946	2,375
Total current liabilities	16,453	27,553
Asset retirement obligations	2,655	2,321
Derivative instruments	92	—
Production taxes, non-current	925	843
Long term debt-net of current portion	769	786
Total liabilities	20,894	31,503
Contingencies		
Series A Redeemable Preferred stock, $0.01 par value; 25,000,000 authorized, 0 shares issued and outstanding at September 30, 2007 and December 31, 2006, respectively	—	—
Stockholders' equity		
Common stock, $0.01 par value; 100,000,000 authorized and 29,025,751 and 25,131,301 shares issued and outstanding at September 30, 2007 and December 31, 2006, respectively	289	251
Additional paid-in capital	149,555	119,354
Accumulated deficit	(22,149)	(776)
Total stockholders' equity	127,695	118,829
Total liabilities and stockholders' equity	$ 148,589	$ 150,332

See Notes to Financial Statements (unaudited)

PINNACLE GAS RESOURCES, INC.
Statements of Operations
(unaudited)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in thousands, except share and per share data)			
Revenues				
Gas sales	$ 2,722	$ 2,912	$ 9,812	$ 9,511
Earn-in joint venture	—	—	—	379
Total revenues	2,722	2,912	9,812	9,890
Cost of revenues and expenses				
Lease operating expenses	1,322	777	3,458	1,934
Production taxes	278	332	1,037	1,085
Marketing and transportation	911	537	2,594	1,397
General and administrative, net	1,488	1,421	3,816	3,907
Depreciation, depletion, amortization and accretion	1,704	2,015	4,800	5,060
Impairment of oil and gas properties	70	—	18,225	—
Total cost of revenues and expenses	5,773	5,082	33,930	13,383
Operating loss	(3,051)	(2,170)	(24,118)	(3,493)
Other income(expense)				
Gain on derivatives	1,604	2,809	2,069	5,863
Interest income	234	191	532	504
Other income	88	154	312	322
Unrealized derivative loss	—	—	—	(26)
Interest expense	(26)	(70)	(168)	(129)
Total other income	1,900	3,084	2,745	6,534
Net (loss)/income before income taxes	(1,151)	914	(21,373)	3,041
Income taxes	—	—	—	—
Net (loss)/income	(1,151)	914	(21,373)	3,041
Preferred dividends	—	—	—	(20,964)
Net (loss)/income attributable to common stockholders	$ (1,151)	$ 914	$ (21,373)	$ (17,923)
Basic net (loss)/income per share	$ (0.04)	$ 0.04	$ (0.80)	$ (1.00)
Diluted net (loss)/income per share	$ (0.04)	$ 0.04	$ (0.80)	$ (1.00)
Weighted average shares outstanding — basic	29,014,299	25,139,699	26,695,765	17,980,800
Weighted average shares outstanding — diluted	29,014,299	25,546,199	26,695,765	17,980,800

See Notes to Financial Statements (unaudited)

PINNACLE GAS RESOURCES, INC.
Statements of Cash Flows
(unaudited)

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Cash flows from operating activities		
Net (loss)/income	$ (21,373)	$ 3,041
Adjustments to reconcile net (loss)/income to net cash (used in)/provided by operating activities		
Impairment of oil and gas properties	18,225	—
Depreciation, depletion, amortization and accretion	4,800	5,060
Gain on derivatives	(2,069)	(5,837)
Allowance for doubtful accounts	—	100
Stock-based compensation	619	242
Changes in assets and liabilities		
Decrease (increase) in receivables	3,797	(372)
Increase in inventory of material for drilling and completion	(43)	(146)
Decrease (increase) in prepaid expenses	117	(46)
(Decrease) increase in accounts payable and accrued liabilities	(12,764)	2,775
Decrease in revenue distribution payable	(1,561)	(1,426)
(Decrease) increase in drilling prepayments	(147)	351
Net cash (used in)/provided by operating activities	(10,399)	3,742
Cash flows from investing activities		
Capital expenditures — exploration and production	(14,940)	(47,475)
Capital expenditures — property and equipment	(840)	(735)
Decrease (increase) in restricted certificates of deposit	43	(1,607)
Decrease (increase) in inventory held for exploration and development	117	(3,091)
Decrease (increase) in deposits	500	(520)
Realized gain on derivatives	3,299	151
Proceeds from the sale of assets held for sale	—	394
Net cash used in investing activities	(11,821)	(52,883)
Cash flows from financing activities		
Proceeds from the issuance of common stock	33,750	141,187
Issuance costs related to common stock	(4,130)	(11,417)
Dividends paid on preferred stock	—	(1,397)
Redemption of preferred stock	—	(52,175)
Repurchase and cancellation of common shares	—	(16,304)
Principal payments on note payable and capital leases	(15)	(111)
Net cash provided by financing activities	29,605	59,783
Net increase in cash and cash equivalents	7,385	10,642
Cash and cash equivalents at beginning of year	4,762	2,672
Cash and cash equivalents at end of period	$ 12,147	$ 13,314
Noncash investing and financing activities		
Capital expenditures included in trade accounts payable	$ 3,452	$ 3,838
Asset retirement obligation included in oil and gas properties	182	869
Dividend paid in kind with the issuance of additional preferred stock	—	1,213
Derivative liability related to preferred stock	—	232
Cashless exercise of warrants and options	—	15,428
Inventory used in oil and gas properties	—	2,708
Supplemental cash flow information		
Cash payments for interest, net of amount capitalized	$ 168	$ 129

See Notes to Financial Statements (unaudited)

PINNACLE GAS RESOURCES, INC.
Statements of Redeemable Preferred Stock and Stockholders' Equity

	Redeemable Preferred Stock		Stockholders' Equity					
			Common Stock		Additional Paid-In	Accumulated	
	Shares	Amount	Shares	Amount	Capital	Deficit	Total
			(in thousands except share amounts)				
Balance at December 31, 2006	—	$ —	25,131,301	$ 251	$ 119,354	$ (776)	$ 118,829
Issuance of restricted shares	—	—	155,500	—	243	—	243
Forfeiture of restricted shares	—	—	(11,050)	—	—	—	—
Sale of common stock for cash, net of offering costs of $4,130	—	—	3,750,000	38	29,582	—	29,620
Stock-based compensation	—	—	—	—	376	—	376
Net loss	—	—	—	—	—	(21,373)	(21,373)
Balance at September 30, 2007 (unaudited)	—	$ —	29,025,751	$ 289	$ 149,555	$ (22,149)	$ 127,695

See Notes to Financial Statements (unaudited)

Notes to Financial Statements
Unaudited

Note 1 — Organization and Nature of Operations

Pinnacle Gas Resources, Inc., (the "Company") was formed as a Delaware corporation in June 2003 through a contribution of cash by funds affiliated with DLJ Merchant Banking and oil and gas reserves and leasehold interests by subsidiaries of Carrizo Oil & Gas, Inc. and U.S. Energy Corporation.

Pinnacle's primary business is the exploration for, and the acquisition, development and production of, coalbed methane natural gas in the United States. The Company is also engaged in gas property operations and the construction of low pressure gas collection systems which provide transportation for the Company's coalbed methane production.

Note 2 — Basis of Presentation

The accompanying unaudited financial statements include the Company's proportionate share of assets, liabilities, income and expenses from the properties in which the Company has a participating interest. The Company has no subsidiaries or affiliates with which intercompany transactions are recorded.

The accompanying financial statements are unaudited, and in the opinion of management, reflect all adjustments that are necessary for a fair presentation of the financial position and results of operations for the periods presented. All such adjustments are of a normal and recurring nature. The following notes describe only the material changes in accounting policies, account details, or financial statement notes during the first nine months of 2007. The results for the quarterly period ended September 30, 2007 are not necessarily indicative of the results expected for the entire year. These financial statements should be read in conjunction with the audited financial statements and the summary of significant accounting policies for prior years contained in the Company's Registration Statement on Form S-1/A which was filed April 27, 2007 and declared effective May 10, 2007.

Use of Estimates

The preparation of the Company's financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates. Significant estimates with regard to the Company's financial statements include the estimated carrying value of unproved properties, the estimate of proved oil and gas reserve volumes and the related present value of estimated future net cash flows and the ceiling test applied to capitalized oil and gas properties, the estimate of the timing and cost of the Company's future drilling activity, the estimated cost and timing related to asset retirement obligations, the estimated fair value of derivative assets and liabilities, the realizability of deferred tax assets, the estimates of expenses and timing of exercise of stock options, accrual of operating costs, capital expenditures and revenue, and estimates for litigation.

Oil and Gas Properties

The Company utilizes the full cost method of accounting for oil and gas producing activities. Under this method, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, costs of surrendered and abandoned leaseholds, delay lease rentals and the fair value of estimated future costs of site restoration, dismantlement and abandonment activities are capitalized within a cost center. The Company's oil and gas properties are all located within the United States, which constitutes a single cost center. The Company has not capitalized any overhead costs. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of gas properties and the gain significantly alters the relationship between capitalized costs and proved gas reserves of the cost center. Expenditures for maintenance and repairs are charged to lease operating expense in the period incurred.

Depreciation, depletion and amortization of oil and gas properties ("DD&A") is computed on the unit-of-production method based on proved reserves. Amortizable costs include estimates of future development costs of proved undeveloped reserves and asset retirement obligations. The Company invests in unevaluated oil and gas properties for the purpose of exploration for proved reserves. The costs of such assets, including exploration costs on properties where a determination of whether proved oil and gas reserves will be established is still under evaluation, and any capitalized interest are included in unproved oil and gas properties at the lower of cost or estimated fair market value and are not subject to amortization. On a quarterly basis, such costs are evaluated for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Abandonment of unproved properties is accounted for as an adjustment to capitalized costs related to proved oil and gas properties, with no losses recognized. The Company recorded an impairment of unevaluated properties of $0 and $740,000 during the three and nine months ended September 30, 2007, respectively. Substantially all of the remaining unproved property costs are expected to be developed and included in the amortization base over the next three to five years. Salvage value is taken into account in determining depletion rates and is based on the Company's estimate of the value of equipment and supplies at the time the well is abandoned. As of September 30, 2007 and December 31, 2006, the estimated salvage value was $6,237,000 and $5,736,000, respectively.

Under full cost method of accounting rules, capitalized costs less accumulated depletion and related deferred income taxes may not exceed a "ceiling" value which is the sum of (1) the present value discounted at 10% of estimated future net revenue using current prices and costs, including the effects of derivative instruments designated as cash flow hedges but excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, less any related income tax effects; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of costs or estimated fair value of unproved properties; less (4) the income tax effects related to differences in the book to tax basis of oil and gas properties. This is referred to as the "full cost ceiling limitation." If capitalized costs exceed the limit, the excess must be charged to expense. The expense may not be reversed in future periods. At the end of each quarter, the Company calculates the full cost ceiling limitation. At September 30, 2007, the capitalized cost of oil and gas properties exceeded the full cost ceiling limitation by approximately $37.5 million, based upon a natural gas price of $0.35 per Mcf in effect at that date. Based on subsequent price increases to approximately $4.10 per Mcf at the measurement date of November 12, 2007, the capitalized cost of the Company's oil and gas properties exceeded the full cost ceiling limitation by approximately $70,000 and the Company recorded an impairment of that amount in addition to the approximately $18.2 million recorded at June 30, 2007. The impairment of the Company's oil and gas properties resulted from low commodity prices at September 30, 2007. A decline in gas prices or an increase in operating costs subsequent to the measurement date or reductions in economically recoverable reserve quantities could result in the recognition of additional impairments of the Company's oil and gas properties in future periods.

Per Share Information

Basic earnings (loss) per share is computed by dividing net income (loss) from continuing operations attributable to common stock by the weighted average number of shares of common stock outstanding during each period. Diluted earnings per share is computed by adjusting the average number of shares of common stock outstanding for the dilutive effect, if any, of common stock equivalents such as stock options and warrants. Diluted net loss per share was the same as basic loss per share for the three months ended September 30, 2007 and nine months ended September 30, 2006 and 2007 because potential common stock equivalents were anti-dilutive.

Certain options to purchase shares of Pinnacle's common stock were excluded from the dilution calculations because the shares were antidilutive. During the three and nine months ended September 30, 2007, 907,000 options were excluded because they were antidilutive. During the three months ended September 30, 2006, 342,500 options were excluded because the exercise price was the same as the stock price. During the nine months ended September 30, 2006, 1,050,000 option were excluded because they were antidilutive.

All per share information for common stock has been retroactively restated for all periods to reflect the 25-for-1 stock split which took place on March 31, 2006.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes, in accordance with Statement of Financial Accounting Standard (SFAS) No. 109, "Accounting for Income Taxes." Deferred tax assets and liabilities are recognized for the expected future tax consequences of temporary differences between the financial statements and tax bases of assets and liabilities. If appropriate, deferred tax assets are reduced by a valuation allowance which reflects expectations of the extent to which such assets will be realized. As of September 30, 2007 and December 31, 2006, the Company had recorded a full valuation allowance for its net deferred tax asset.

On January 1, 2007, the Company adopted Financial Accounting Standards Board ("FASB") Interpretation No. 48, "Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109" ("FIN 48"). FIN 48 prescribes a measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return. Additionally, FIN 48 provides guidance regarding uncertain tax positions relating to derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. At September 30, 2007, the Company had no material uncertain tax positions.

Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements. Accordingly, SFAS No. 157 does not require any new fair value measurements. However, for some entities, the application of SFAS No. 157 will change current practice. The provisions of SFAS No. 157 are effective as of January 1, 2008. The Company is currently evaluating the impact of adopting SFAS No. 157 on its financial statements.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." SFAS No. 159 permits entities to choose to measure eligible financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The Statement will be effective as of January 1, 2008 for the Company. SFAS No. 159 offers various options in electing to apply the provisions of this Statement, and at this time the Company has not made any decisions in its application to its financial position or results of operations.

Note 3— Asset Retirement Obligations

The Company follows the provisions of SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143"). SFAS No. 143 generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of a long-lived asset. SFAS No. 143 requires the Company to recognize an estimated liability for costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation with a corresponding increase to the carrying value of the related long-lived asset is recorded at the time a well is completed or acquired. The increased carrying value is depleted using the units-of-production method, and the discounted liability is increased through accretion over the remaining economic life of the respective oil and gas properties.

The estimated liability is based on historical gas industry experience in abandoning wells, including estimated economic lives, external estimates as to the cost to abandon the wells in the future and federal and state regulatory requirements. The Company's liability is discounted using the Company's best estimate of its credit-adjusted risk free rate. Revisions to the liability could occur due to changes in estimated abandonment costs or changes in well economic lives or if federal or state regulators enact new requirements regarding the abandonment of wells.

The following is a summary of the Company's asset retirement obligation activity for the three and nine months ended September 30, 2007 and 2006 (in thousands):

	Three Months Ended September 30,	Nine Months Ended September 30,	Three Months Ended September 30,	Nine Months Ended September 30,
	2007		2006	
	(unaudited)		(unaudited)	
Beginning balance asset retirement obligations	$ 2,533	$ 2,321	$ 1,965	$ 1,277
Additional obligation added during the period	69	182	252	870
Obligations settled during the period	—	—	—	—
Revisions in estimates	—	—	—	—
Accretion expense	53	152	45	115
Ending balance of asset retirement obligations	$ 2,655	$ 2,655	$ 2,262	$ 2,262

Note 4— Restricted Assets (certificates of deposit) and Deposits

*Certificates of deposit.*The Company holds a certificate of deposit ("CD"), which expires in July 2008, totaling $148,000. The CD is collateral on bonding required by the State of Wyoming, the State of Montana and the Federal Bureau of Land Management. Because the Company intends to renew the CD in order to maintain its bonding requirements, the Company has included the CD in other non-current assets as of September 30, 2007. Additionally, the Company holds another CD for $604,000 which was issued in February 2006 and expires in February 2008. This CD collateralizes a letter of credit in favor of Powder River Energy Corporation, a local rural electric association, in order to secure power lines to the Kirby and Deer Creek areas. The Company has included this amount in non-current assets as of September 30, 2007 because the Company also intends to renew the CD in order to maintain a power supply on a long-term basis. In April 2006, the Company issued a $1,000,000 letter of credit that expires in April 2008 in favor of Bitter Creek Pipelines, LLC to secure the construction of a high pressure pipeline and related compression facilities to the Company's Deer Creek and Kirby areas. The Company has included this amount in non-current assets as of September 30, 2007 because the Company anticipates it will be required to renew the letter of credit because construction of the pipeline and compression facility is not expected to be completed until the second quarter of 2009.

Deposits. The Company has included approximately $20,000 related to royalty payments in deposits. These amounts are included in deposits in the accompanying balance sheet at September 30, 2007.

Note 5 — Derivatives

The Company accounts for derivative instruments or hedging activities under the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires the Company to record derivative instruments at their fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income (loss) and are recognized in the statement of operations when the hedged item affects earnings. Ineffective portions of changes in the fair value of cash flow hedges, if any, are recognized in earnings. Changes in the fair value of derivatives that do not qualify for hedge treatment are recognized in earnings.

The Company periodically hedges a portion of its oil and gas production through swap and collar agreements. The purpose of the hedges is to provide a measure of stability to the Company's cash flows in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk. Management of the Company decided not to use hedge accounting for these agreements. Therefore, in accordance with the provisions of SFAS No. 133, the changes in fair market value are recognized in earnings.

As of September 30, 2007 and 2006, the Company had natural gas hedges in place as follows:

Product and Type of Hedging Contract	MMbtu Per Day		Fixed Price Range CIG Index Price	Time Period
September 30, 2007 (unaudited)				
Natural Gas—Collar	1,000	$	5.00-$5.20	10/04-9/07
Natural Gas—Collar	1,000	$	6.50-$10.50	9/06-12/07
Natural Gas—Collar	3,000	$	7.00-$9.05	1/07-12/07
Natural Gas—Collar	3,000	$	6.50-$8.20	1/08-12/08
September 30, 2006 (unaudited)				
Natural Gas—Collar	1,000	$	5.00-$5.20	10/04-9/07
Natural Gas—Collar	1,750	$	6.70-$7.90	1/06-12/06
Natural Gas—Collar	1,000	$	6.50-$10.50	9/06-12/07
Natural Gas—Collar	3,000	$	7.00-$9.05	1/07-12/07

The Company realized hedging gains of $1,623,000 and $266,000 during the three months ended September 30, 2007 and 2006, respectively. As a result of the change in the fair value of the commodity derivatives, the Company had an unrealized loss of $19,000 for the three months ended September 30, 2007 and an unrealized gain of $2,543,000 for the three months ended September 30, 2006. The aggregate of these contracts resulted in a gain on derivatives of $1,604,000 and $2,809,000 for the three months ended September 30, 2007 and 2006, respectively. For the nine months ended September 30, 2007, the Company realized a hedging gain of $3,299,000 as compared to a hedging gain of $151,000 for the nine months ended September 30, 2006. The Company had an unrealized loss of $1,230,000 for the nine months ended September 30, 2007 and an unrealized gain of $5,712,000 for the nine months ended September 30, 2006. The aggregate of these contracts resulted in a gain on derivatives of $2,069,000 and $5,863,000 for the nine months ended September 30, 2007 and 2006, respectively. Unrealized and realized gains and losses are included in gains or losses on derivatives in the accompanying statements of operations. Because the Company's derivative contracts were not accounted for as cash flow hedges, the Company classifies the realized gains and losses in investing activities in the accompanying statements of cash flows.

The Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance.

Note 6 — Stock Based Compensation

Options under Employee Option Plans

The Company has adopted a stock incentive plan containing both incentive and non-statutory stock options. All options allow for the purchase of common stock at prices not less than the fair market value of such stock at the date of grant. If the option holder owns more than 10% of the total combined voting power of all classes of the Company's stock, the exercise price cannot be less than 110% of the fair market value of such stock at the date of grant.

Options granted under the plan become vested as directed by the Company's Board of Directors and generally expire seven or ten years after the date of grant, unless the option holder owns more than 10% of the total combined voting power of all classes of the Company's stock, in which case the non-statutory stock options must be exercised within five years of the date of grant. At September 30, 2007, there were options to purchase 907,000 shares granted under the plan.

The options granted since formation in June 2003 vest as follows:

Year 1	20%
Year 2	30%
Year 3	50%
	100%

Stock-Based Compensation

At September 30, 2007, the Company had unvested options to purchase 525,500 shares with a weighted average grant date fair value of $1.1 million. During the three and nine months ended September 30, 2007, the Company granted options to purchase 0 and 120,000 shares of common stock, respectively, and recognized compensation expense of approximately $139,000 and $376,000, respectively. The Company will recognize compensation expense relating to nonvested options granted after January 1, 2006 of approximately $1.1 million ratably over the next three years.

The following table summarizes stock option activity for the nine months ended September 30, 2007:

	Number of Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Life	Aggregate Intrinsic value
Outstanding, December 31, 2006	1,035,000	$ 6.68		
Granted	120,000	10.03		
Canceled or forfeited	(248,000)	8.11		
Outstanding, September 30, 2007	907,000	$ 6.73	4.84	$ 178,000
Exercisable, September 30, 2007	381,500	$ 5.41	4.05	$ 152,700
Weighted average fair value of options granted during the period		$ 10.03		

The following table summarizes information about stock options outstanding at September 30, 2007:

	Options Outstanding		Options Exercisable		
Exercise Prices	Number of shares Outstanding	Weighted Average Remaining Contractual Life	Number Exercisable	Weighted Average Exercise Price	Fair Value Determination
$4.00	137,500	3.0 years	137,500	$ 4.00	Black-Scholes (minimum value)
$4.80	346,000	4.5 years	167,500	$ 4.80	Black-Scholes (minimum value)
$5.20	112,500	5.3 years	22,500	$ 5.20	Black-Scholes
$8.40	45,000	6.7 years	—	$ 8.40	Black-Scholes
$11.00	266,000	5.7 years	54,000	$ 11.00	Black-Scholes
	907,000		381,500		

Restricted Stock

The Company has a stock incentive plan whereby grants of restricted stock have been awarded to members of the Board of Directors and certain employees. Restrictions and vesting periods for the awards are determined at the discretion of the Board of Directors and are set forth in the award agreements.

Effective February 12, 2007, the Company granted and issued an aggregate of 12,000 shares of restricted common stock to its non-employee directors and 25,000 shares of restricted common stock to certain employees pursuant to the Company's stock incentive plan. In addition, on March 26, 2007, the Company granted an additional 10,000 shares of restricted common stock to an employee pursuant to the stock incentive plan. The 12,000 restricted shares issued to the non-employee directors will be fully vested on February 12, 2008. The other restricted shares issued to employees will vest according to the option vesting schedule set forth above. Effective July 1, 2007, the Company granted and issued an aggregate of 54,000 shares of restricted common stock to certain employees. These shares will vest equally over three years. In addition, on July 20, 2007, the Company entered into employment agreements with certain of its executive officers. In conjunction with the employment agreements, these executive officers were granted 50,000 shares of restricted common stock. These shares will vest 33.34%, 33.33% and 33.33% on the third, fourth and fifth anniversary of the grant date. Effective August 22, 2007, the Company granted and issued 4,500 shares of restricted common stock to a new board member. These shares will vest equally over three years. The Company recognized an expense of approximately $116,000 and $243,000 for the quarter and nine months ended September 30, 2007, respectively, based on the fair value of the vested shares during the period.

A summary of the status and activity of the restricted stock for the nine months ended September 30, 2007 is presented below.

	Shares		Weighted-Average Grant-Date Fair Value
Non-vested at December 31, 2006	27,270	$	11.00
Granted	155,500		8.41
Forfeited	(11,050)		10.69
Vested	(9,090)		11.00
Non-vested at September 30, 2007	162,630	$	8.54

As of September 30, 2007, the Company had approximately $1,389,000 of unrecognized share-based compensation expense related to non-vested stock awards, which is expected to be amortized over the remaining vesting periods of three to five years.

Note 7 — Long-Term Debt

Credit Facility

Effective February 12, 2007, the Company entered into a new $100 million credit facility (the “Credit Agreement”) with The Royal Bank of Scotland (“RBS”), with an initial commitment of $27 million which permits borrowings up to the borrowing base as designated by the administrative agent. As of September 30, 2007, the borrowing base under the Credit Agreement was $22 million although the borrowing availability is less than the initial borrowing base due to covenant limitations. As of September 30, 2007, the borrowing availability was $16.7 million. The borrowing base is determined on a semi-annual basis and at such other times as may be requested by the borrower or administrative agent. Borrowing under the Credit Agreement bears interest either: (i) at a domestic bank rate plus an applicable margin between 0.25% and 1.25% per annum based on utilization or (ii) on a sliding scale from the one, two, three, or six month LIBOR rate plus 1.25% to 2.25% per annum based on utilization. The Credit Agreement matures February 12, 2011 and replaced the Company’s previous credit facility. The Credit Agreement with RBS is collateralized by substantially all of the Company’s producing assets. At September 30, 2007, the Company had no debt outstanding under the Credit Agreement. The Company used a portion of the net proceeds from its initial public offering in May 2007 to pay down all of the outstanding indebtedness under the Credit Agreement.

The Credit Agreement contains covenants that, among other things, restrict the Company’s ability, subject to certain exceptions, to do the following:

- incur liens;
- incur debt;
- make investments in other persons;
- declare dividends or redeem or repurchase stock;
- engage in mergers, acquisitions, consolidations and asset sales or amend the Company’s organizational documents;
- enter into certain hedging arrangements;
- amend material contracts; and
- enter into related party transactions.

With regard to hedging arrangements, the Credit Agreement provides that acceptable commodity hedging arrangements cannot be greater than 80 to 85%, depending on the measurement date, of the Company's monthly production from its hydrocarbon properties that are used in the borrowing base determination and that the fixed or floor price of the Company's hedging arrangements must be equal to or greater than the gas price used by the lenders in determining the borrowing base.

The Credit Agreement also requires that the Company satisfy certain affirmative covenants, meet certain financial tests, maintain certain financial ratios and make certain customary indemnifications to lenders and the administrative agent. The financial covenants include requirements to maintain: (i) earnings before income taxes, depreciation, depletion, amortization and accretions ("EBITDA") to cash interest expense of not less than 3.00 to 1.00, (ii) current ratio of not less than 1.00 to 1.00, (iii) total debt to annualized EBITDA of not more than 3.0 to 1.0, (iv) quarterly total senior debt to annualized EBITDA equal to or less than 3.0 to 1.0 until June 30, 2007 and 2.00 to 1.0 thereafter, and (v) total proved PV-10 value of reserves to total debt of at least 1.50 to 1.00. The Credit Agreement contains customary events of default, including, without limitation, payment defaults, covenant defaults, certain events of bankruptcy and insolvency, defaults in the payment of other material debt, judgment defaults, breaches of representations and warranties, loss of material permits and licenses and a change in control. In addition, the Credit Agreement required us to cure specified title defects within certain time periods. Except for the title defect covenant the compliance with which was waived, the Company was in compliance with the covenants under the Credit Agreement as of September 30, 2007.

Office Building Loan

On November 15, 2005, the Company entered into a mortgage loan secured by its office building in Sheridan, Wyoming in the aggregate principal amount of $829,000. The promissory note provides for monthly payments of principal and interest in the initial amount of $6,400, and unpaid principal bears interest at 6.875% during the first three years, at a variable base rate thereafter and at 18% upon a default. The variable base rate is based on the lender's base rate. The maturity date of this mortgage is November 15, 2015, at which time a principal and interest payment of $615,400 will become due. As of September 30, 2007, the Company had $792,000 outstanding in principal on this mortgage.

Note 8 — Equity

Common Stock. In April 2006, the Company completed a private placement of 12,835,230 shares of common stock at a price of $11.00 per share. The Company received net proceeds of approximately $129.9 million, before offering costs, which were used as follows: (i) approximately $53.6 million to redeem all of the outstanding shares of Series A Redeemable Preferred Stock, including the payment of all accrued and unpaid dividends and a redemption premium, (ii) approximately $27.0 million for the acquisition of the Green River Basin assets, (iii) approximately $16.3 million to repurchase an aggregate of 1,593,783 shares of common stock at a price of $10.23 per share from certain stockholders, and (iv) approximately $33.0 million to fund the Company's development drilling program, additional out of pocket offering costs and for general corporate purposes.

In May 2007, the Company completed an initial public offering of an aggregate of 3,750,000 shares of common stock at a price per share of $9.00, or $8.37 net of underwriters' discounts and commissions. In June 2007, the underwriters partially exercised their over-allotment option to purchase 258,614 shares of the Company's common stock from certain selling stockholders. The Company received net proceeds of approximately $31.4 million from its initial public offering, before out of pocket offering costs of approximately $1.1 million, which were used to pay down the $7.0 million outstanding under the Credit Agreement and will be used to fund the Company's drilling program and for general corporate purposes.

*Preferred Stock.*As of September 30, 2007, there were no shares of preferred stock issued and outstanding. In April 2006, following the initial closing of the Company's private placement discussed above, the Company redeemed all of the outstanding shares of Series A Redeemable Preferred Stock with a portion of the proceeds from the private placement including the payment of accrued and unpaid dividends of $1.4 million. The difference between the redemption price and the carrying value of the Series A Redeemable Preferred Stock resulted in a $19.6 million redemption premium that was recorded as a dividend expense in the accompanying statements of operations for the nine months ended September 30, 2006.

*Warrants.*As of December 31, 2005, there were Series A warrants outstanding to purchase an aggregate 10,530,725 shares of common stock with an exercise price of $4.00 per share. However, immediately prior to the initial closing of the private placement, all outstanding warrants and 1,168,204 escalating options were exchanged in a cashless transaction into an aggregate of 8,062,584 shares of common stock. As of September 30, 2007, there were no outstanding warrants to purchase shares of the Company's common stock.

Note 9 — Contingencies

From time to time, the Company may be involved in litigation that arises in the ordinary course of business operations. As of the date of this report, the Company is not a party to any litigation that it believes could reasonably be expected to have a material adverse effect on its financial position, results of operations or cash flows.

The Company is currently a defendant in two lawsuits whereby the plaintiff, among other things, is seeking to permanently enjoin the State of Montana and its administrative bodies from issuing licenses or permits to drill on, or from authorizing the removal of ground water from under, the plaintiff's property. Based on the information available to date, the Company believes the claims are without merit and intends to defend the cases vigorously. Additionally, the Company's oil and gas operations are subject to various Federal, state and local laws and regulations. The Company could incur significant expense to comply with the new or existing laws and non-compliance could have a material adverse effect on the Company's operations.

Note 10 — Subsequent Events

On October 15, 2007, the Company entered into an agreement and plan of merger with Quest Resources Corporation. The merger agreement provides for Quest's acquisition of all the issued and outstanding shares of the Company's common stock, par value $0.01 per share, for aggregate consideration of approximately 19.1 million shares of Quest's common stock,. For further information, please see the Company's Current Report on Form 8-K filed on October 16, 2007.

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

The discussion and analysis that follows should be read together with the accompanying financial statements and notes related thereto that are included elsewhere in this quarterly report on Form 10-Q. It includes forward-looking statements that may reflect our estimates, beliefs, plans and expected performance. The forward-looking statements are based upon events, risks and uncertainties that may be outside our control. Our actual results could differ significantly from those discussed in these forward-looking statements. Factors that could cause or contribute to these differences include, but are not limited to, market prices for natural gas and oil, regulatory changes, estimates of proved reserves, economic conditions, competitive conditions, development success rates, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this quarterly report on Form 10-Q, including in "Risk Factors" and "Cautionary Statement Concerning Forward-Looking Statements," all of which are difficult to predict. As a result of these assumptions, risks and uncertainties, the forward-looking matters discussed may not occur.

Overview

We are an independent energy company engaged in the acquisition, exploration and development of domestic onshore natural gas reserves. We were formed in June 2003 as a Delaware corporation by funds affiliated with DLJ Merchant Banking III, Inc., which we refer to collectively as DLJ Merchant Banking, and subsidiaries of Carrizo Oil & Gas, Inc., or Carrizo, and U.S. Energy Corporation, or U.S. Energy. We primarily focus our efforts on the development of CBM properties located in the Powder River Basin in northeastern Wyoming and southern Montana. In addition, in April 2006, we acquired properties located in the Green River Basin in southern Wyoming. As of September 30, 2007, we owned natural gas and oil leasehold interests in approximately 507,000 gross (336,000 net) acres, approximately 94% of which are undeveloped. As of February 28, 2007, we had estimated net proved reserves of approximately 25.9 Bcf based on the CIG index price of $6.28, with a pre-tax PV-10 value of $54.8 million. We drilled 67 gross (43 net) wells and completed 82 gross (51 net) wells during the nine months ended September 30, 2007, and we operated 100% of those wells. We incurred capital expenditures of $14.9 million during the nine months ended September 30, 2007 related to drilling, completion and infrastructure costs on our undeveloped acreage in our Kirby, Deer Creek, Cabin Creek and Green River Basin areas.

Recent Developments

In May 2007, we completed an initial public offering of an aggregate of 3,750,000 shares of our common stock at a price per share of $9.00, or $8.37 net of the underwriter's discounts and commissions, and received approximately $30.0 million of net proceeds after offering expenses. In June 2007, the underwriters partially exercised their overallotment option to purchase 258,614 shares of our common stock from certain selling stockholders. We used a portion of the net proceeds from our initial public offering to pay down all of the outstanding indebtedness under our credit facility. Please see "Liquidity and Capital Resources — Credit Facility" for further information regarding our credit facility.

On October 15, 2007, we entered into an agreement and plan of merger with Quest Resources Corporation. The merger agreement provides for Quest's acquisition of all the issued and outstanding shares of our common stock, par value $0.01 per share, for aggregate consideration of approximately 19.1 million shares of Quest's common stock. For further information, please see our Current Report on Form 8-K filed on October 16, 2007.

Critical Accounting Policies

The most subjective and complex judgments used in the preparation of our financial statements are:

- Reserve evaluation and determination.
- Estimates of the timing and cost of our future drilling activity.
- Estimates of the fair valuation of hedges in place.
- Estimates of timing and cost of asset retirement obligations.

- Estimates of the expense and timing of exercise of stock options.
- Accruals of operating costs, capital expenditures and revenue.

Oil and Gas Properties

We use the full cost method of accounting for oil and gas producing activities. Under this method, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, costs of surrendered and abandoned leaseholds, delay lease rentals and the fair value of estimated future costs of site restoration, dismantlement and abandonment activities, are capitalized within a cost center. Our oil and gas properties are all located within the United States, which constitutes a single cost center. We have not capitalized any overhead costs. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of gas properties and the gain significantly alters the relationship between capitalized costs and proved gas reserves of the cost center. Expenditures for maintenance and repairs are charged to lease operating expense in the period incurred.

Depreciation, depletion and amortization of oil and gas properties is computed on the unit-of-production method based on proved reserves. Amortizable costs include estimates of future development costs of proved undeveloped reserves and asset retirement obligations. We invest in unevaluated oil and gas properties for the purpose of exploration for proved reserves. The costs of such assets, including exploration costs on properties where a determination of whether proved oil and gas reserves will be established is still under evaluation, and any capitalized interest, are included in unproved oil and gas properties at the lower of cost or estimated fair market value and are not subject to amortization. On a quarterly basis, such costs are evaluated for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.We recorded an impairment of unevaluated properties of $0 and $740,000, respectively, during the three and nine months ended September 30, 2007. Abandonment of unproved properties are accounted for as an adjustment to capitalized costs related to proved oil and gas properties, with no losses recognized.

Substantially all remaining unproved property costs are expected to be developed and included in the amortization base ratably over the next three to five years. Salvage value is taken into account in determining depletion rates and is based on our estimate of the value of equipment and supplies at the time the well is abandoned. As of September 30, 2007 and December 31, 2006, the estimated salvage value was $6,237,000 and $5,736,000, respectively.

Under full cost method of accounting rules, capitalized costs less accumulated depletion and related deferred income taxes may not exceed a “ceiling” value which is the sum of (1) the present value discounted at 10% of estimated future net revenue using current prices and costs, including the effects of derivative instruments designated as cash flow hedges but excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, less any related income tax effects; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of costs or estimated fair value of unproved properties; less (4) the income tax effects related to differences in the book to tax basis of oil and gas properties. This is referred to as the “full cost ceiling limitation.” If capitalized costs exceed the limit, the excess must be charged to expense. The expense may not be reversed in future periods. At the end of each quarter, we calculate the full cost ceiling limitation. At September 30, 2007, the capitalized cost of our oil and gas properties exceeded the full cost ceiling limitation by approximately $37.5 million, based upon a natural gas price of $0.35 per Mcf in effect at that date. Based on subsequent price increases to approximately $4.10 per Mcf at the measurement date of November 12, 2007, the capitalized cost of our oil and gas properties exceeded the full cost ceiling limitation by approximately $70,000 and we recorded an impairment of that amount in addition to the approximately $18.2 million recorded at June 30, 2007. The impairment of our oil and gas properties resulted from low commodity prices at September 30, 2007. A decline in gas prices or an increase in operating costs subsequent to the measurement date or reductions in economically recoverable reserve quantities could result in the recognition of additional impairments of our oil and gas properties in future periods.

Gas Sales

We use the sales method for recording natural gas sales. Sales of gas applicable to our interest in producing natural gas and oil leases are recorded as revenues when the gas is metered and title transferred pursuant to the gas sales contracts covering our interest in gas reserves. During such times as our sales of gas exceed our pro rata ownership in a well, such sales are recorded as revenues unless total sales from the well have exceeded our share of estimated total gas reserves underlying the property at which time such excess is recorded as a gas imbalance liability. At September 30, 2007 and December 31, 2006, there was no such liability recorded. Although there was no such liability recorded for prior periods, gas reserves are an estimate and are updated on an annual and interim basis. Gas pricing, expenses and production may impact future gas reserves remaining which, in turn, could impact the recording of liabilities in the future. Gas sales accrual at September 30, 2007 and December 31, 2006 were based on the actual volume statements from our purchasers and distribution process. If accruals were to change by 10% at September 30, 2007 and at December 31, 2006, the impact would have been a $371,000 and $319,000 change, respectively.

Asset Retirement Obligations

We follow the provisions of Statement of Financial Accounting Standards (SFAS) No. 143, “Accounting for the Asset Retirement Obligations.” SFAS No. 143 generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires us to recognize an estimated liability for costs associated with the abandonment of our oil and gas properties.

A liability for the fair value of an asset retirement obligation with a corresponding increase to the carrying value of the related long-lived asset is recorded at the time a well is completed or acquired. The increased carrying value is depleted using the units-of-production method, and the discounted liability is increased through accretion over the remaining life of the respective oil and gas properties.

The estimated liability is based on historical gas industry experience in abandoning wells, including estimated economic lives, external estimates as to the cost to abandon the wells in the future and federal and state regulatory requirements. Our liability is discounted using our best estimate of our credit-adjusted risk-free rate. Revisions to the liability could occur due to changes in estimated abandonment costs, changes in well economic lives or if federal or state regulators enact new requirements regarding the abandonment of wells. For example, a 10% change in our estimated retirement costs would have a $247,000 effect on our asset retirement obligation liability at September 30, 2007.

The following is a summary of our asset retirement obligation activity for the three and nine months ended September 30, 2007 and 2006 (in thousands):

	Three Months Ended September 30,	Nine Months Ended September 30,	Three Months Ended September 30,	Nine Months Ended September 30,
	2007		2006	
	(unaudited)		(unaudited)	
Beginning balance asset retirement obligations	$ 2,533	$ 2,321	$ 1,965	$ 1,277
Additional obligation added during the period	69	182	252	870
Obligations settled during the period	—	—	—	—
Revisions in estimates	—	—	—	—
Accretion expense	53	152	45	115
Ending balance of asset retirement obligations	$ 2,655	$ 2,655	$ 2,262	$ 2,262

Inventory

We acquired inventory of oil and gas equipment, primarily tubulars, in 2007 and 2006, to take advantage of quantity pricing and to secure a readily available supply. Inventory is valued at the lower of average cost or market. Inventory is used in the development of gas properties and to the extent it is estimated that it will be billed to other working interest owners during the next year, it is included in current assets. Otherwise, it is recorded in other assets. The price of steel is a primary factor in valuing our inventory. Under the valuation method of lower of average cost or market, a 10% reduction in the price of steel would cause a $74,000 reduction in our inventory valuation as of September 30, 2007. The market price of steel is evaluated each quarter using prices quoted by authorized vendors in the area.

Property and Equipment

Property and equipment is comprised primarily of a building, computer hardware and software, vehicles and equipment, and is recorded at cost. Renewals and betterments that substantially extend the useful lives of the assets are capitalized. Maintenance and repairs are expensed when incurred. Depreciation and amortization are provided using the straight-line method over the estimated useful lives of the assets, ranging as follows: buildings—30 years, computer hardware and software—3 to 5 years, machinery, equipment and vehicles—5 years, and office furniture and equipment—3 to 5 years.

Long-Lived Assets

Long-lived assets to be held and used in our business are reviewed for impairment whenever events or changes in circumstances indicate that the related carrying amount may not be recoverable. When the carrying amounts of long-lived assets exceed the fair value, which is generally based on discounted expected future cash flows, we record an impairment. No impairments were recorded during the year ended December 31, 2006 or the nine months ended September 30, 2007.

General and Administrative Expenses

General and administrative expenses are reported net of amounts allocated and billed to working interest owners of gas properties operated by us. The administrative expenses billed to working interest owners may change in accordance with the terms of the joint operating agreements. Administrative expenses are charged to working interest owners based on productive well counts. A 10% change in well counts for the three and nine months ended September 30, 2007 would have increased or decreased our expenses billed to working interest owners by approximately $45,000 and $117,000, respectively. As we operate and drill additional wells in the future, additional administrative expenses will be charged to the working interest owners when the wells become productive.

Income Taxes

We use the asset and liability method of accounting for income taxes, in accordance with SFAS No. 109, “Accounting for Income Taxes.” Deferred tax assets and liabilities are recognized for the expected future tax consequences of temporary differences between the financial statement and tax bases of assets and liabilities. If appropriate, deferred tax assets are reduced by a valuation allowance which reflects expectations of the extent to which such assets will be realized. As of September 30, 2007 and December 31, 2006, we had recorded a full valuation allowance for our net deferred tax asset.

On January 1, 2007, we adopted the Financial Accounting Standards Board Interpretation No. 48, “Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109.” FIN 48 prescribes a measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return. Additionally, FIN 48 provides guidance regarding uncertain tax positions relating to derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. At September 30, 2007, we had no material uncertain tax positions.

Derivatives

We use derivative instruments to manage our exposure to fluctuating natural gas prices through the use of natural gas swap and option contracts. We account for derivative instruments or hedging activities under the provisions of SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities.” SFAS No. 133 requires us to record derivative instruments at their fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income (loss) and are recognized in the statement of operations when the hedged item affects earnings. Ineffective portions of changes in the fair value of cash flow hedges, if any, are recognized in earnings. Changes in the fair value of derivatives that do not qualify for hedge treatment are recognized in earnings. Please see note 5 included in the accompanying unaudited Notes to Financial Statements for additional discussions of derivatives.

We periodically hedge a portion of our oil and gas production through swap and collar agreements. The purpose of the hedges is to provide a measure of stability to our cash flows in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk. Our management decided not to use hedge accounting for these agreements. Therefore, in accordance with the provisions of SFAS No. 133, the changes in fair market value are recognized in earnings.

Stock-Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123(R), “Share-Based Payments,” which requires companies to recognize compensation expense for share-based payments based on the estimated fair value of the awards.

SFAS No. 123(R) also requires that the benefits of tax deductions in excess of compensation cost recognized for stock awards and options (“excess tax benefits”) be presented as financing cash inflows in the Statement of Cash Flows. Prior to January 1, 2006, we accounted for share-based payments under the recognition and measurement provisions of APB Opinion

No. 25, “Accounting for Stock Issued to Employees,” and related interpretations, as permitted by SFAS No. 123, “Accounting for Stock-Based Compensation.” In accordance with APB No. 25, no compensation cost was required to be recognized for options granted that had an exercise price equal to or greater than the market value of the underlying common stock on the date of the grant.

Accounts Receivable

Our revenue producing activities are conducted primarily in Wyoming. We grant credit to qualified customers, which potentially subjects us to credit risk resulting from, among other factors, adverse changes in the industry in which we operate and the financial condition of our customers. We continuously monitor collections and payments from our customers and, if necessary, record an allowance for doubtful accounts based upon historical experience and any specific customer collection issues identified. We recorded an allowance of $100,000 at September 30, 2007 and December 31, 2006.

Transportation Costs

We account for transportation costs under Emerging Issues Task Force Issues 00-10, “Accounting for Shipping and Handling Fees and Costs,” whereby amounts paid for transportation are classified as operating expenses.

Per Share Information

Basic earnings (loss) per share is computed by dividing net income (loss) from continuing operations attributable to common stock by the weighted average number of shares of common stock outstanding during each period. Diluted earnings per share is computed by adjusting the average number of shares of common stock outstanding for the dilutive effect, if any, of common stock equivalents such as stock options and warrants. Diluted net loss per share was the same as basic loss per share for the three months ended September 30, 2007 and nine months ended September 30, 2006 and 2007 because potential common stock equivalents were anti-dilutive. Certain options to purchase shares of Pinnacle’s common stock were excluded from the dilution calculations because the shares were antidilutive. During the three and nine months ended September 30, 2007, 907,000 options were excluded because they were antidilutive. During the three months ended September 30, 2006, 342,500 options were excluded because the exercise price was the same as the stock price. During the nine months ended September 30, 2006, 1,050,000 options were excluded because they were antidilutive.

New Accounting Pronouncements

For information regarding new accounting pronouncements, please see note 2 included in the accompanying unaudited Notes to Financial Statements.

Trends Affecting Our Business

We have experienced increasing costs since our inception in 2003 due to increased demand for oilfield products and services. The cyclical nature of the natural gas industry causes fluctuations in demand for goods and services from oilfield companies, suppliers and others associated with the industry, which in turn affects the prices for those goods and services. Typically, as prices for natural gas increase, so do all the costs associated with natural gas production. Recently, we have seen increases in the cost of tubulars, drilling rigs and cement in particular. We expect that increased demand for the goods and services we use in our business will continue to put pressure on prices in the near to medium term.

Historically, natural gas prices have been extremely volatile, and we expect that volatility to continue. For example, during the three months ended September 30, 2007, the NYMEX natural gas index price ranged from a high of $7.01 per MMBtu to a low of $5.43 per MMBtu, while the CIG natural gas index price ranged from a high of $4.50 per MMBtu to a low of $0.27 per MMBtu. During the nine months ended September 30, 2007, the NYMEX natural gas index price ranged from a high of $8.19 per MMBtu to a low of $5.43 per MMBtu, while the CIG natural gas index price ranged from a high of $7.11 per MMBtu to a low of $0.27 per MMBtu. During the year ended December 31, 2006, the NYMEX natural gas index price ranged from a high of $11.23 per MMBtu to a low of $4.20 per MMBtu, while the CIG natural gas index price ranged from a high of $7.90 per MMBtu to a low of $1.30 per MMBtu. Changes in natural gas pricing have impacted our revenue streams, production taxes, prices used in reserve calculations, borrowing base calculations and the valuation of potential property acquisitions. During the three and nine months ended September 30, 2007, estimated future gas prices had an impact on both our revenues and the costs attributable to our future operations. We expect that changing natural gas prices will continue to impact our operations and financial results in the future.

Transportation of natural gas and access to throughput capacity have a direct impact on natural gas prices in the Rocky Mountain region, where our operations are concentrated. As drilling activity increases throughout the Rocky Mountain region, additional production may come on line, which could cause bottlenecks or capacity constraints. Generally speaking, a surplus of natural gas production relative to available transportation capacity has a negative impact on prices. Conversely, as capacity increases, and bottlenecks are eliminated, prices generally increase. Although there is currently adequate transportation capacity out of the Powder River Basin, a surplus of natural gas arriving at key marketing hubs from the Powder River Basin and elsewhere relative to available takeaway capacity from these hubs has caused Rocky Mountain gas to trade at a discount to the NYMEX natural gas index price. Two major projects that are expected to be completed in 2008 will increase takeaway capacity from these hubs, and we expect that they will therefore help reduce the differential between gas produced in the Rocky Mountain region and the NYMEX natural gas index price.

Results of Operations

Three Months Ended September 30, 2007 Compared To Three Months Ended September 30, 2006

Net loss attributable to stockholders for the three months ended September 30, 2007 was $1.2 million, or $0.04 per diluted share, on total revenues of $2.7 million. Net loss attributable to stockholders for the three months ended September 30, 2007 included a $0.02 million unrealized loss associated with the change in the fair valuation of our natural gas hedges in place in accordance with the provisions of SFAS No. 133. Absent such a change in the valuation, we would have shown a net loss attributable to stockholders of $1.2 million on total revenues of $2.7 million. This compares to net income attributable to stockholders of $0.9 million for the three months ended September 30, 2006 on total revenues of $2.9 million. Adjusted for an unrealized gain in the fair valuation of our natural gas hedges in place of $2.5 million, our results for the three months ended September 30, 2006 would have been a net loss attributable to stockholders of $1.6 million on total revenues of $2.9 million.

Gas sales volume.

Gas sales volume increased 42%, from 627 MMcf in the three months ended September 30, 2006 to 893 MMcf in the three months ended September 30, 2007. Daily sales volume was 9.7 MMcf for the three months ended September 30, 2007 as compared to 6.8 MMcf for the three months ended September 30, 2006, a 2.9 MMcf per day increase. The increase was primarily due to production coming online in our Cabin Creek, Kirby and Deer Creek project areas. On average, we have a greater working and net revenue interest in these areas compared to some of our other areas.

Gas sales revenue.

Revenue from gas sales decreased $0.2 million during the three months ended September 30, 2007, to $2.7 million, a 7% decrease compared to the three months ended September 30, 2006. This decrease was primarily due to a decrease in the average realized price per Mcf which was partially offset by an increase in gas sales volume. The average realized price per Mcf decreased 34%, from $4.64 per Mcf in the three months ended September 30, 2006 to $3.05 per Mcf in the three months ended September 30, 2007.

Derivatives.

For the three months ended September 30, 2007, we had an unrealized loss on derivatives of $0.02 million compared to an unrealized gain of $2.5 million for the three months ended September 30, 2006. The unrealized loss is a noncash expense based primarily on the Black-Scholes model for valuing future cash flows utilizing price volatility with a normal discount rate. Hedges settled in the three months ended September 30, 2007 resulted in a realized gain of $1.6 million compared to hedging gains of $0.3 million in the three months ended September 30, 2006. The hedge gains were primarily due to the fact that gas prices were lower than the weighted average floor price of our hedges in place.

Lease operating expenses.

Lease operating expenses increased $0.5 million in the three months ended September 30, 2007 to $1.3 million, a 70% increase compared to the three months ended September 30, 2006. This increase resulted from an increase in the number of wells in the productive cycle during the three months ended September 30, 2007. On an Mcf basis, lease operating expenses increased 19% from $1.24 per Mcf in the three months ended September 30, 2006 to $1.48 per Mcf in the three months ended September 30, 2007. The increase per Mcf was primarily due to a number of wells being in the early stages of their productive life cycle as production did not increase proportionately to the number of wells coming online. Additionally, increases in generator rentals and associated fuel while waiting on permanent power contributed to the increase.

Production taxes.

Production taxes decreased $0.05 million in the three months ended September 30, 2007 to $0.3 million, a 16% decrease from the three months ended September 30, 2006. Production taxes generally correlate to gross sales revenue because production taxes are based on a percentage of sales value. In Wyoming, the percentage averages 11% to 13%, depending on rates in effect for the respective year. The decrease in production taxes for the three months ended September 30, 2007 was primarily due to Montana production taxes, which are 1% for the first year of production and 9% thereafter, as well as a decrease in the average realized price per Mcf. On an Mcf basis, production taxes were $0.31 per Mcf for the three months ended September 30, 2007 and $0.53 per Mcf for the three months ended September 30, 2006, a 42% decrease, which correlates to the decrease in the price per Mcf received in the three months ended September 30, 2007 from the three months ended September 30, 2006.

Marketing and transportation.

Marketing and transportation expenses increased $0.4 million in the three months ended September 30, 2007 to $0.9 million, a 70% increase from the three months ended September 30, 2006. The increase related primarily to the increased sales volume in the three months ended September 30, 2007, together with a slight increase in transportation fees and compression due to inflationary adjustments in the contracts along with fees paid for compression design capacity which was not used. On an Mcf basis, marketing and transportation expenses increased 19% to $1.02 per Mcf in the three months ended September 30, 2007 from $0.86 per Mcf in the three months ended September 30, 2006.

General and administrative expenses, net.

General and administrative expenses are offset by operating income from drilling and production activities for which we can charge an overhead fee to nonoperating working interest owners. These well operating overhead fees increased 55% in the three months ended September 30, 2007, from $0.3 million to $0.4 million, due to increased productive wells which we operate and for which we charge an overhead fee. General and administrative expenses, net increased $0.07 million in the three months ended September 30, 2007 to $1.5 million. On an Mcf basis, general and administrative expenses, net decreased 26% from $2.27 per Mcf in the three months ended September 30, 2006 to $1.67 per Mcf in the three months ended September 30, 2007.

Depreciation, depletion, amortization and accretion.

Depreciation, depletion, amortization and accretion expense decreased $0.3 million for the three months ended September 30, 2007 to $1.7 million, a 15% decrease compared to the three months ended September 30, 2006. This decrease was due to a decrease in the full cost pool due to the impairments recorded in 2007 coupled with higher quarter-end reserves at September 30, 2007 compared to September 30, 2006. On an Mcf basis, the depreciation, depletion, amortization and accretion rate decreased 41% to $1.91 per Mcf in the three months ended September 30, 2007 from $3.21 per Mcf in the three months ended September 30, 2006.

Impairment.

At September 30, 2007, the capitalized cost of our oil and gas properties exceeded the full cost ceiling limitation by approximately $37.5 million, based upon a natural gas price of approximately $0.35 per Mcf in effect at that date. Based on subsequent price increases to approximately $4.10 per Mcf at the measurement date of November 12, 2007, the capitalized cost of our oil and gas properties exceeded the full cost ceiling limitation by approximately $70,000 and we recorded an impairment of our oil and gas properties of that amount. The impairment of our oil and gas properties resulted from low commodity prices at September 30, 2007. For further information regarding this impairment, please see note 2 included in the accompanying unaudited Notes to Financial Statements.

Nine Months Ended September 30, 2007 Compared To Nine Months Ended September 30, 2006

Net loss attributable to stockholders for the nine months ended September 30, 2007 was $21.4 million, or $0.80 per diluted share, on total revenues of $9.8 million. Net loss attributable to stockholders for the nine months ended September 30, 2007 included a $1.2 million unrealized loss associated with the change in the fair valuation of our natural gas hedges in place in accordance with the provisions of SFAS No. 133. Absent such a change in the valuation, we would have shown a net loss attributable to stockholders of $20.2 million on total revenues of $9.8 million. This compares to net loss attributable to stockholders of $17.9 million for the nine months ended September 30, 2006 on total revenue of $9.9 million. Adjusted for an unrealized gain in the fair valuation of our natural gas hedges in place of $5.7 million, our results for the nine months ended September 30, 2006 would have been a net loss attributable to stockholders of $23.6 million on total revenues of $9.9 million.

Gas sales volume.

Gas sales volume increased 41%, from 1,793 MMcf in the nine months ended September 30, 2006 to 2,527 MMcf in the nine months ended September 30, 2007. Daily sales volume was 9.3 MMcf for the nine months ended September 30, 2007 as compared to 6.6 MMcf for the nine months ended September 30, 2006, a 2.7 MMcf per day increase. The increase was primarily due to production coming online in our Cabin Creek, Kirby and Deer Creek project areas.

Gas sales revenue.

Revenue from gas sales increased $0.3 million during the nine months ended September 30, 2007, to $9.8 million, a 3% increase compared to the nine months ended September 30, 2006. This increase was primarily due to an increase in gas sales volume which was partially offset by a decrease in the average realized price per Mcf. The average realized price per Mcf decreased 27%, from $5.30 per Mcf in the nine months ended September 30, 2006 to $3.88 per Mcf in the nine months ended September 30, 2007.

Derivatives.

For the nine months ended September 30, 2007, we had an unrealized loss of $1.2 million compared to an unrealized gain of $5.7 million for the nine months ended September 30, 2006. The unrealized loss is a noncash expense based primarily on the Black-Scholes model for valuing future cash flows utilizing price volatility with a normal discount rate. Hedges settled in the nine months ended September 30, 2007 resulted in a realized gain of $3.3 million compared to a hedge gain of $0.2 million in the nine months ended September 30, 2006. The hedge gains were primarily due to the fact that gas prices were lower than the weighted average floor price of our hedges in place.

Lease operating expenses.

Lease operating expenses increased $1.5 million in the nine months ended September 30, 2007 to $3.5 million, an 79% increase compared to the nine months ended September 30, 2006. This increase resulted from an increase in the number of wells in the productive cycle during the nine months ended September 30, 2007. On an Mcf basis, lease operating expenses increased 27% from $1.08 per Mcf in the nine months ended September 30, 2006 to $1.37 per Mcf in the nine months ended September 30, 2007. The increase per Mcf was primarily due to a number of wells being in the early stages of their productive life cycle as production did not increase proportionately to the number of wells coming online. Additionally, increases in generator rentals and associated fuel while waiting on permanent power contributed to the increase.

Production taxes.

Production taxes decreased $0.05 million in the nine months ended September 30, 2007 to $1.0 million, a 4% decrease from the nine months ended September 30, 2006. Production taxes generally correlate to gross sales revenue because production taxes are based on a percentage of sales value. In Wyoming, the percentage averages 11% to 13%, depending on rates in effect for the respective year. The decrease in production taxes for the nine months ended September 30, 2007 was primarily due to Montana production taxes, which are 1% for the first year of production and 9% thereafter, as well as a decrease in the average realized price per Mcf. On an Mcf basis, production taxes were $0.41 per Mcf for the nine months ended September 30, 2007 and $0.61 per Mcf for the nine months ended September 30, 2006, a 33% decrease, which correlates to the decrease in the price per Mcf received in the nine months ended September 30, 2007 from the nine months ended September 30, 2006.

Marketing and transportation.

Marketing and transportation expenses increased $1.2 million in the nine months ended September 30, 2007 to $2.6 million, a 86% increase from the nine months ended September 30, 2006. The increase related primarily to the increased sales volume in the nine months ended September 30, 2007, together with a slight increase in transportation fees and compression due to inflationary adjustments in the contracts along with fees paid for compression design capacity which was not used. On an Mcf basis, marketing and transportation expenses increased 32% to $1.03 per Mcf in the nine months ended September 30, 2007 from $0.78 per Mcf in the nine months ended September 30, 2006.

General and administrative expenses, net.

General and administrative expenses are offset by operating income from drilling and production activities for which we can charge an overhead fee to nonoperating working interest owners. These well operating overhead fees increased 46% in the nine months ended September 30, 2007, from $0.8 million to $1.2 million, due to increased productive wells which we operate and for which we charge an overhead fee. General and administrative expenses, net decreased $0.1 million in the nine months ended September 30, 2007 to $3.8 million from $3.9 million in the nine months ended September 30, 2006. This decrease was due primarily to an increase in payroll expenses due to the hiring of additional employees during the nine months ended September 30, 2006 along with bonuses paid to certain executive officers during the second quarter of 2006 in connection with our private placement. On an Mcf basis, general and administrative expenses, net decreased 31% from $2.18 per Mcf in the nine months ended September 30, 2006 to $1.51 per Mcf in the nine months ended September 30, 2007.

Depreciation, depletion, amortization and accretion.

Depreciation, depletion, amortization and accretion expense decreased $0.3 million for the nine months ended September 30, 2007 to $4.8 million, a 5% decrease compared to the nine months ended September 30, 2006. This decrease was due to an decrease in the full cost pool due to the impairments recorded in 2007 coupled with higher quarter-end reserves at September 30, 2007 compared to September 30, 2006. On an Mcf basis, the depreciation, depletion, amortization and accretion rate decreased 33% to $1.90 per Mcf in the nine months ended September 30, 2007 from $2.83 per Mcf in the nine months ended September 30, 2006.

Impairment.

At September 30, 2007, the capitalized cost of our oil and gas properties exceeded the full cost ceiling limitation by approximately $37.5 million, based upon a natural gas price of approximately $0.35 per Mcf in effect at that date. Based upon subsequent price increases to approximately $4.10 per Mcf at the measurement date of November 12, 2007, the capitalized cost of our oil and gas properties exceeded the full cost ceiling limitation by approximately $70,000 and we recorded an impairment of this amount. This impairment, along with the impairment recorded for the six months ended June 30, 2007 of approximately $18.2 million, resulted in a total impairment for the nine months ended September 30, 2007 of approximately $18.2 million. The impairment of our oil and gas properties resulted from low commodity prices at September 30, 2007. For further information regarding this impairment, please see note 2 included in the accompanying unaudited Notes to Financial Statements.

Liquidity and Capital Resources

Our primary source of liquidity since our formation has been the sale of our equity. During the period from our formation in June 2003 through September 2005, DLJ Merchant Banking contributed $44.1 million cash in exchange for shares of our common stock, shares of our Series A Redeemable Preferred Stock and detachable warrants to purchase additional shares of common stock. The proceeds were used to fund our acquisitions and capital expenditures. In April 2006, we completed a private placement of an aggregate of 12,835,230 shares of our common stock at a price per share of $11.00, or $10.23 net of the initial purchaser's discount and placement fee. In May 2007, we completed an initial public offering of an aggregate of 3,750,000 shares of our common stock at a price per share of $9.00, or $8.37 net of the underwriters' discounts and commissions. Please see "—Cash Flow from Financing Activities—Sales and Issuances of Equity."

Credit Facility. Effective February 12, 2007, we entered into a $100 million credit facility with an initial commitment of $27 million which permits borrowings up to the borrowing base as designated by the administrative agent. As of September 30, 2007, the initial borrowing base was $22 million although our borrowing availability is less than our initial borrowing base due to covenant limitations. As of September 30, 2007, the actual borrowing availability was $16.7 million. The borrowing base is determined on a semi-annual basis and at such other additional times, up to twice yearly, as may be requested by either the borrower or the administrative agent and is determined by the administrative agent in accordance with customary practices and standards for loans of a similar nature; provided that such determination is at the administrative agent's discretion as the credit agreement does not provide a specific borrowing base formula. Based on future reserve reports, low CIG prices and possible title defects on certain of our properties, we expect that our borrowing base and borrowing availability could be further reduced below the initial levels. Borrowings under this credit facility may be used solely to acquire, explore or develop oil and gas properties and for general corporate purposes. The credit facility matures February 12, 2011. At September 30, 2007 and November 13, 2007, we had no indebtedness outstanding under our credit facility.

Our obligations under the credit facility are secured by liens on (i) no less than 90% of the net present value of the oil and gas to be produced from our oil and gas properties that are included in the borrowing base determination, calculated using a discount rate of 10% per annum and reserve estimates, prices and production rates and costs, (ii) options to lease, seismic options, permits, and records related to such properties, and (iii) seismic data.

Borrowings under our credit facility may be either (i) a domestic bank rate plus an applicable margin between 0.25% and 1.25% per annum based on utilization, or (ii) the London interbank offered rate, or LIBOR, plus an applicable margin between 1.25% and 2.25% per annum based on utilization. The credit agreement provides for various fees, including a quarterly commitment fee of 1⁄2 of 1.00% per annum and engineering fees to the administrative agent in connection with a borrowing base determination. In addition, the credit agreement provides for an up front fee of $27,000, which was paid on the closing date of the credit agreement, and an additional arrangement fee of up to 1% based on utilization. Borrowings under this credit facility may be prepaid without premium or penalty, except on Eurodollar advances. If an event of default exists, the default rate shall be equal to 2% plus the floating rate.

The credit agreement contains covenants that, among other things, restrict our ability, subject to certain exceptions, to do the following:

- incur liens;
- incur debt;
- make investments in other persons;
- declare dividends or redeem or repurchase stock;
- engage in mergers, acquisitions, consolidations and asset sales or amend our organizational documents;
- enter into certain hedging arrangements;
- amend material contracts; and
- enter into related party transactions.

With regard to hedging arrangements, the credit facility provides that acceptable commodity hedging arrangements cannot be greater than 80 to 85%, depending on the measurement date, of our monthly production from our hydrocarbon properties that are used in the borrowing base determination and that the fixed or floor price of our hedging arrangements must be equal to or greater than the gas price used by the lenders in determining the borrowing base.

The credit agreement also requires that we satisfy certain affirmative covenants, meet certain financial tests, maintain certain financial ratios and make certain customary indemnifications to lenders and the administrative agent. The financial covenants include requirements to maintain: (i) EBITDA to cash interest expense of not less than 3.00 to 1.00, (ii) current ratio of not less than 1.00 to 1.00, (iii) total debt to annualized EBITDA of not more than 3.0 to 1.0, (iv) quarterly total senior debt to annualized EBITDA equal to or less than 3.0 to 1.0 until June 30, 2007 and 2.00 to 1.0 thereafter, and (v) total proved PV-10 value to total debt of at least 1.50 to 1.00.

The credit agreement contains customary events of default, including, without limitation, payment defaults, covenant defaults, certain events of bankruptcy and insolvency, defaults in the payment of other material debt, judgment defaults, breaches of representations and warranties, loss of material permits and licenses and a change in control. In addition, the credit agreement required us to cure specified title defects within certain time periods. Except for the title defect covenant the compliance with which was waived, we were in compliance with the covenants under our credit agreement as of September 30, 2007.

The credit agreement requires all of our wholly owned subsidiaries to guarantee the obligations under the credit agreement.

Office Building Loan. On November 15, 2005, we entered into a mortgage loan secured by our office building in Sheridan, Wyoming in the aggregate principal amount of $829,000. The promissory note provides for monthly payments of principal and interest in the initial amount of $6,400, and unpaid principal bears interest at 6.875% during the first three years, at a variable base rate thereafter and at 18% upon a default. The variable base rate is based on the lender's base rate. The maturity date of this mortgage is November 15, 2015, at which time a principal and interest payment of $615,400 will become due. As of September 30, 2007, we had $792,000 outstanding in principal and interest on this mortgage.

Capital Expenditure Budget. For 2007, we have reduced our total capital expenditure budget from approximately $52.6 million to approximately $30.0 million. Consequently, we expect to reduce our drilling and completion targets for 2007 from approximately 260 gross (207 net) wells to approximately 140 gross (102 net) wells. In addition, our revised 2007 capital expenditure budget will continue to be used to construct related gas and water infrastructure, to fund plans of development costs for future wells, to fund undeveloped leasehold acquisition costs carried over from 2006, to recomplete certain wells, and to fund infrastructure and completion costs related to wells drilled in 2006. We incurred capital expenditures of $14.9 million during the nine months ended September 30, 2007, which were primarily related to drilling, completion and infrastructure costs on our undeveloped acreage in our Kirby, Deer Creek, Cabin Creek and Green River Basin areas. While we believe we have adequate resources from our credit facility and cash flows from operations to implement the remainder of our revised 2007 drilling plan, our ability to develop future projects will depend on access to additional capital. The CIG index price has been extremely volatile during 2007 and has at times reached unusually low levels. If prices remain low, it would cause our cash flows from operations to decrease and could result in a reduction of the borrowing base and borrowing availability under our credit facility, and if we could not obtain capital through our credit facility or otherwise, our ability to execute our development and acquisition plans, replace our reserves and maintain production levels could be greatly limited.

During the nine months ended September 30, 2007, we drilled 67 gross (43 net) wells and we are actively developing the Kirby, Deer Creek, Cabin Creek and Green River Basin areas of our undeveloped acreage.

Cash Flow from Operating Activities

Net cash used by operating activities was $10.3 million for the nine months ended September 30, 2007, compared to net cash provided by operating activities of $3.7 million for the nine months ended September 30, 2006. This decrease was primarily due to a reduction in our accounts payable balance and a lower unrealized gain on derivative instruments, partially offset by a decrease in our accounts receivable. .

While we believe that cash flows from operations and borrowings under our credit facility will be sufficient to meet our 2007 revised capital expenditures and our other cash needs during the remainder of 2007, the CIG index price has been extremely volatile during 2007 and has at times reached unusually low levels. If prices remain low, it would cause our cash flows from operations to decrease and could result in further reductions of the borrowing base and borrowing availability under our credit facility.

Cash Flow from Investing Activities

Net cash used in investing activities was $11.8 million for the nine months ended September 30, 2007 compared to $52.9 million for the nine months ended September 30, 2006. Net cash used in investing activities decreased by approximately $41.1 million compared to the nine months ended September 30, 2006 primarily due to the acquisition of the Green River Basin acreage in April 2006, a larger realized gain on hedge settlements, a decrease in inventory used for development and a decrease in the purchase of restricted assets.

Cash Flow from Financing Activities

During the period from our formation in June 2003 through September 2005, DLJ Merchant Banking contributed $44.1 million in cash in exchange for shares of our common stock, shares of our Series A Redeemable Preferred Stock and detachable warrants to purchase additional shares of common stock. As of September 30, 2006 and September 30, 2007, we had 25,131,301 and 29,025,751 shares of common stock issued and outstanding, respectively, of which 27,270 and 171,720 shares, respectively, were shares of restricted stock issued to employees and directors.

Net cash provided by financing activities was $29.6 million for the nine months ended September 30, 2007 as compared to $59.8 million for the nine months ended September 30, 2007. The change was primarily due to our April 2006 private placement and our May 2007 initial public offering.

In April 2006, we completed a private placement, exempt from registration under the Securities Act of 1933, as amended, or the Securities Act, of 12,835,230 shares of our common stock to qualified institutional buyers, non-U.S. persons and accredited investors at a price of $11.00 per share, or $10.23 per share net of the initial purchaser's discount and placement fee. Out of the aggregate of approximately $129.9 million of net proceeds (after the initial purchaser's discount and placement fee and offering expenses) we received in the private placement, we used (i) approximately $53.6 million to redeem all of the outstanding shares of our Series A Redeemable Preferred Stock, including the payment of all accrued and unpaid dividends and a redemption premium, (ii) approximately $27.0 million for our acquisition of the Green River Basin assets, (iii) approximately $16.3 million to repurchase an aggregate of 1,593,783 shares of common stock at a price of $10.23 per share from DLJ Merchant Banking and Gary W. Uhland, our former President, and (iv) approximately $33.0 million to fund our development drilling program and pay additional offering expenses and for general corporate purposes.

Immediately prior to the initial closing of our private placement, DLJ Merchant Banking exchanged all of its outstanding warrants for 6,894,380 shares of our common stock in a tax-free reorganization based on the private placement price of $11.00 per share. As of September 30, 2006 and 2007, we had no warrants or escalating options issued and outstanding.

In April 2006, following the initial closing of our private placement, we redeemed all of the outstanding shares of Series A Redeemable Preferred Stock with a portion of the proceeds from our private placement including the payment of accrued and unpaid dividends of $1.4 million. The difference between the redemption price and the carrying value of the Series A Redeemable Preferred Stock resulted in a $19.6 million redemption premium that was recorded as a dividend expense in our statement of operations for the three months ended September 30, 2006. As of September 30, 2006 and 2007, we had no shares of preferred stock issued and outstanding.

In May 2007, we completed an initial public offering of 3,750,000 shares of our common stock at a price of $9.00 per share, or $8.37 per share net of underwriters' discounts and commissions. Out of the approximately $30.3 million of net proceeds (after underwriters' discounts and commissions and offering expenses) we received in our initial public offering, we used $7.0 million to pay down all of the outstanding indebtedness under our credit facility. We have used and intend to continue to use the remainder of the net proceeds from our initial public offering for capital expenditures, infrastructure development and general corporate purposes.

Contractual Obligations

With the exception of borrowings and repayment of indebtness under our credit facility and the payment of property taxes, there have been no significant changes in our schedule of contractual obligations for the year ended December 31, 2006 included in our amended registration statement on Form S-1 declared effective on May 10, 2007. Please see note 7 of the unaudited Financial Statements for information regarding our credit facility and other indebtedness.

The following table summarizes by period our contractual obligations as of September 30, 2007:

	Total	2007	2008-2009	2010-2011	Thereafter
			(in thousands)		
Notes payable in connection with the mortgage	$ 792	$ 5	$ 47	$ 54	$ 686
Asset retirement obligations	2,655	—	219	758	1,678
Non-current production and property taxes	925	—	925	—	—
Total	$ 4,372	$ 5	$ 1,191	$ 812	$ 2,364

At September 30, 2007, the commodity derivatives asset was valued at $1,627,000 of which $1,719,000 represents a current receivable attributable to 2007 and $92,000 represents an obligation attributable to 2008.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas prices. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposure. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas production. The prices we receive for our production depend on many factors beyond our control. We seek to reduce our exposure to unfavorable changes in natural gas prices, which are subject to significant and often volatile fluctuation, through the use of fixed-price contracts. The fixed-price contracts are comprised of energy swaps and collars. These contracts allow us to predict with greater certainty the effective natural gas prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided by the contracts. However, we will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production. Collar structures provide for participation in price increases and decreases to the extent of the ceiling prices and floors provided in those contracts.

The following table summarizes the estimated volumes, fixed prices, fixed price sales and fair value attributable to the fixed price contracts as of September 30, 2007. At September 30, 2007, we had hedged volumes through December 2008. Please see Note 5 included in the accompanying unaudited Notes to Financial Statements.

	Year Ending December 31, 2007 (Unaudited)	Year Ending December 31, 2008 (Unaudited)
Natural Gas Collars:		
Contract volumes (MMBtu):		
Floor	368,000	1,098,000
Ceiling	368,000	1,098,000
Weighted-average fixed price per MMBtu(1):		
Floor	$ 6.87	$ 6.50
Ceiling	$ 9.41	$ 8.20
Fixed-price sales(2)	$ 9.41	$ 8.20
Fair value, net (thousands)(3)	$ 1,421	$ 206
Total Natural Gas Contracts:		
Contract volumes (MMBtu)	368,000	1,098,000
Weighted-average fixed price per MMBtu(1)	$ 6.87	$ 6.50
Fixed-price sales(2)	$ 9.41	$ 8.20
Fair value, net (thousands)(3)	$ 1,421	$ 206

(1) Volumes hedged using the CIG index price published in the first issue of Inside FERC's Gas Market Report for each calendar month of the derivative transaction.
(2) Assumes ceiling prices for natural gas collar volumes.
(3) Fair value based on CIG index price in effect for each month as of September 30, 2007.

ITEM 4T. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Based on their evaluation as of the end of the period covered by this report, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Changes in Internal Control Over Financial Reporting

During the most recent fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For a discussion of certain of our current legal proceedings, please read note 9 included in the accompanying unaudited Notes to Financial Statements.

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of our business. While the outcome of these proceedings cannot be predicted with certainty, we do not expect them to have a material adverse effect on the financial statements.

ITEM 1A. RISK FACTORS

The following information updates and supplements the information under the heading "Risk Factors - Risks Related to Our Business - The volatility of natural gas and oil prices could have a material adverse effect on our business" in our amended registration statement on Form S-1 (File No. 333-139556), which was declared effective on May 10, 2007:

Historically, natural gas prices have been extremely volatile, and we expect that volatility to continue. For example, during the three months ended September 30, 2007, the NYMEX natural gas index price ranged from a high of $7.01 per MMBtu to a low of $5.43 per MMBtu, while the CIG natural gas index price ranged from a high of $4.50 per MMBtu to a low of $0.27 per MMBtu. During the nine months ended September 30, 2007, the NYMEX natural gas index price ranged from a high of $8.19 per MMBtu to a low of $5.43 per MMBtu, while the CIG natural gas index price ranged from a high of $7.11 per MMBtu to a low of $0.27 per MMBtu. During the year ended December 31, 2006, the NYMEX natural gas index price ranged from a high of $11.23 per MMBtu to a low of $4.20 per MMBtu, while the CIG natural gas index price ranged from a high of $7.90 per MMBtu to a low of $1.30 per MMBtu. Changes in natural gas pricing have impacted our revenue streams, production taxes, prices used in reserve calculations, borrowing base calculations and the valuation of potential property acquisitions. During the three and nine months ended September 30, 2007, estimated future gas prices had an impact on both our revenues and the costs attributable to our future operations. We expect that changing natural gas prices will continue to impact our operations and financial results in the future.

There have been no other material changes to the risk factors disclosed in such registration statement.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

On May 10, 2007, our registration statement on Form S-1 (File No. 333-139556), as amended, relating to our initial public offering was declared effective by the Securities and Exchange Commission. The managing underwriters of the offering were Friedman, Billings, Ramsey & Co., Inc., RBC Capital Markets Corporation, A.G. Edwards & Sons, Inc. and Johnson Rice & Company L.L.C. The closing date of our initial public offering was May 18, 2007, and on that date we sold 3,750,000 shares of our common stock, par value $0.01 per share, at a price per share of $9.00, or $8.37 net of the underwriters' discounts and commissions. Out of the approximately $30.3 million of net proceeds (after underwriters' discounts and commissions of approximately $2.3 million and estimated offering expenses of approximately $1.1 million) we received in our initial public offering, we used $7.0 million to repay all of the outstanding indebtedness under our credit facility. We have used and intend to continue to use the remainder of the net proceeds for capital expenditures, infrastructure development and general corporate purposes.

Effective February 12, 2007, we granted and issued an aggregate of 12,000 shares of restricted common stock to our non-employee directors and 25,000 shares of restricted common stock to certain employees pursuant to our stock incentive plan. In addition, on March 26, 2007, we granted and issued an additional 10,000 shares of restricted common stock to an employee pursuant to the stock incentive plan. The 12,000 restricted shares issued to the non-employee directors will be fully vested on February 12, 2008. The restricted shares issued to employees will vest 20%, 30% and 50% on the first, second and third anniversary of the date of grant, respectively. Effective July 1, 2007, we granted and issued an aggregate of 54,000 shares of restricted common stock to certain employees. These shares will vest equally over three years. In addition, on July 20, 2007, we entered into employment agreements with certain of our executive officers. In conjunction with the employment agreements, these executive officers were granted and issued 50,000 shares of restricted common stock. These shares will vest 33.34%, 33.33% and 33.33% on the third, fourth and fifth anniversary of the grant date. Effective August 22, 2007, the Company granted and issued 4,500 shares of restricted common stock to a new board member. These shares will vest equally over three years. The issuances of these securities were exempt from the registration requirements of the Securities Act pursuant to Rule 701.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS

Exhibit No.	Description
3.1	—Second Amended and Restated Certificate of Incorporation of Pinnacle Gas Resources, Inc. (incorporated herein by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
3.2	—Amended and Restated Bylaws of Pinnacle Gas Resources, Inc. (incorporated herein by reference to Exhibit 3.2 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
4.1	—Amended and Restated Securityholders Agreement, dated February 16, 2006 (incorporated herein by reference to Exhibit 4.1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
4.2	—Registration Rights Agreement, dated April 11, 2006 (incorporated herein by reference to Exhibit 4.2 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
*31.1	—Certification of President and Chief Executive Officer of Pinnacle Gas Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	—Certification of Senior Vice President, Chief Financial Officer and Secretary of Pinnacle Gas Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	—Certification of President and Chief Executive Officer of Pinnacle Gas Resources, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	—Certification of Senior Vice President, Chief Financial Officer and Secretary of Pinnacle Gas Resources, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Filed herewith

Management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements 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.

PINNACLE GAS RESOURCES, INC.

By:	/s/ Peter G. Schoonmaker
Name:	Peter G. Schoonmaker
Title:	*President, Chief Executive Officer and Director* (Principal Executive Officer)
Date:	November 14, 2007
By:	/s/ Ronald T. Barnes
Name:	Ronald T. Barnes
Title:	*Senior Vice President, Chief Financial Officer and Secretary* (Principal Financial Officer and Principal Accounting Officer)
Date:	November 14, 2007

Exhibit No.	Description
3.1	—Second Amended and Restated Certificate of Incorporation of Pinnacle Gas Resources, Inc. (incorporated herein by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (File No. 333-133983) filed by Pinnacle Gas Resources, Inc. on May 10, 2006).
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*32.2	—Certification of Senior Vice President, Chief Financial Officer and Secretary of Pinnacle Gas Resources, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

Management contract or compensatory plan or arrangement

**CERTIFICATION BY CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT**

I, Peter G. Schoonmaker, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pinnacle Gas Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 14, 2007

/s/Peter G. Schoonmaker
Peter G. Schoonmaker
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION BY CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT

I, Ronald T. Barnes, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pinnacle Gas Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 14, 2007

/s/Ronald T. Barnes
Ronald T. Barnes
Senior Vice President, Chief Financial
Officer and Secretary

Exhibit 32.1

**CERTIFICATION BY CHIEF EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the quarterly report on Form 10-Q of Pinnacle Gas Resources, Inc. (the "Company") for the period ending September 30, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Peter G. Schoonmaker, President and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: November 14, 2007

/s/Peter G. Schoonmaker
Peter G. Schoonmaker
President and Chief Executive Officer

Exhibit 32.2

**CERTIFICATION BY CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the quarterly report on Form 10-Q of Pinnacle Gas Resources, Inc. (the "Company") for the period ending September 30, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ronald T. Barnes, Senior Vice President, Chief Financial Officer and Secretary of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: November 14, 2007

/s/Ronald T. Barnes
Ronald T. Barnes
Senior Vice President, Chief Financial
Officer and Secretary