PYR ENERGY CORP
Form 10-Q
January 16, 2007

U.S. Securities And Exchange Commission
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended November 30, 2006

OR

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

For the transition period from ________________ to ________________

Commission File No. 001-15511

PYR ENERGY CORPORATION
(Exact name of small business issuer as specified in its charter)

Maryland	95-4580642
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1675 Broadway, Suite 2450, Denver, CO	80202
(Address of principal executive offices)	(Zip Code)

(303) 825-3748
(Registrant's telephone number, including area code)

Indicate by check mark whether the issuer (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

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

Large accelerated filer [ ]   Accelerated filer [ ]   Non-accelerated filer [X]

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Class	Outstanding as of January 11, 2007
Common stock, $0.001 par value	37,993,259

ITEM 1. FINANCIAL STATEMENTS

PYR ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share data)

	November 30, 2006 (Unaudited)
ASSETS	
CURRENT ASSETS	
Cash	$ 4,872
Accounts receivable	1,707
Prepaid expenses and other current assets	27
Total current assets	6,606
PROPERTY AND EQUIPMENT	
Oil and gas properties under full cost, net	22,115
Furniture and equipment, net	61
	22,176
OTHER ASSETS	
Deferred financing costs and other assets	28
TOTAL ASSETS	$ 28,810
LIABILITIES AND STOCKHOLDERS' EQUITY	
CURRENT LIABILITIES	
Accounts payable	$ 329
Amounts due oil and gas property owners	48
Accrued net profits interest payable	203
Other accrued liabilities	565
Asset retirement obligation	907
Total current liabilities	2,052
LONG TERM LIABILITIES	
Convertible notes	7,493
Asset retirement obligation	373
COMMITMENTS AND CONTINGENCIES	
STOCKHOLDERS' EQUITY	
Preferred stock, $.001 par value; authorized 1,000,000 shares; issued and outstanding - none	--
Common stock, $.001 par value; authorized 75,000,000 shares; issued and outstanding - 37,993,259 at 11/30/06 and 8/31/06, respectively	38
Capital in excess of par value	51,350
Accumulated deficit	(32,496)
Total stockholders' equity	18,892
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 28,810

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

PYR ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended November 30, 2006	2005
	(in thousands, except per share data)	
REVENUES		
Gas and oil production revenues	$ 2,619	$ 2,003
OPERATING EXPENSES		
Lease operating expenses	424	244
Production taxes, gathering and transportation	193	124
Net profits interest expense	62	259
Depletion, depreciation, amortization and accretion	897	357
General and administrative	626	504
Total operating expenses	2,202	1,488
INCOME FROM OPERATIONS	417	515
OTHER INCOME (EXPENSE)		
Interest and other income	58	47
Interest (expense)	(92)	(99)
Other (expense)	--	(7)
Total other income (expense)	(34)	(59)
NET INCOME	$ 383	$ 456
NET INCOME PER COMMON SHARE -BASIC AND DILUTED	$ 0.01	$ 0.01
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING-		
BASIC	37,993	35,417
DILUTED	38,264	36,010

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

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PYR ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended November 30, 2006	2005
	(in thousands)	

CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 383	$ 456
Adjustments to reconcile net income to net cash provided by operating activities		
Depletion, depreciation, amortization and accretion	897	357
Amortization of financing costs	1	1
Interest expense converted into debt	184	175
Non-cash employee and director stock option expense	58	--
Stock option expense for non-qualifying options issued	--	5
Changes in current assets and liabilities		
Decrease in accounts receivable	139	403
Decrease in prepaids and other current assets	37	103
Increase (decrease) in accounts payable	40	(73)
Increase in amounts due oil and gas property owners	10	--
Decrease in net profits interest liability	(28)	(616)
(Decrease) increase in accrued liabilities	(306)	100
Net cash provided by operating activities	1,415	911
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions of furniture and equipment	(20)	(21)
Additions to oil and gas properties	(2,811)	(1,773)
Proceeds from sale of properties	34	--
Net cash used in investing activities	(2,797)	(1,794)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from sale of common stock	--	8,164
Offering costs	--	(161)
Other	--	30
Net cash provided by financing activities	--	8,033
NET (DECREASE) INCREASE IN CASH	(1,382)	7,150
BEGINNING CASH	6,254	2,934
ENDING CASH	$ 4,872	$ 10,084

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

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PYR ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(continued)

SUPPLEMENTAL CASH FLOW INFORMATION:

	Three Months Ended November 30,	
	2006	2005

	(Unaudited)	
Cash paid for interest and income taxes	$ --	$ 11
Non-cash financing activities:		
Net increase in payables for capital expenditures	--	99
Debt issued for interest	184	175
Non-cash employee and director stock option expense	58	--

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

PYR ENERGY CORPORATION
Notes to Consolidated Financial Statements
November 30, 2006
(Unaudited)

1. ORGANIZATION

PYR Energy Corporation (referred to as "PYR," the "Company," "we," "us" and "our") is an independent oil and gas exploration and production company, engaged in the exploration, development and acquisition of crude oil and natural gas reserves and conducts its activities principally in the Rocky Mountain, Texas and Gulf Coast regions of the United States. The Company was incorporated in March 1996 in the state of Delaware under the name Mar Ventures Inc. Effective as of August 6, 1997, the Company purchased all the ownership interests of PYR Energy, LLC, an oil and gas exploration company. On November 12, 1997, the name of the Company was changed to PYR Energy Corporation. Effective July 2, 2001, the Company was re-incorporated in Maryland through the merger of the Company into a wholly owned subsidiary, PYR Energy Corporation, a Maryland corporation. On February 18, 2004, PYR Cumberland LLC, PYR Mallard LLC, and PYR Pintail LLC were formed as wholly owned subsidiaries of PYR Energy Corporation. PYR Mallard LLC owns and is developing the Company's Mallard project in Uinta County, Wyoming. PYR Cumberland LLC and PYR Pintail LLC are currently inactive.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation. The accompanying interim financial statements of PYR Energy Corporation are unaudited. In the opinion of management, the interim data includes all adjustments, consisting only of normal recurring adjustments, necessary for a fair presentation of the results for the interim period. The results of operations for the three months ended November 30, 2006 are not necessarily indicative of the operating results for the entire year.

We have prepared the financial statements included herein pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosure normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to such rules and regulations. We believe the disclosures made are adequate to make the information not misleading and recommend that these condensed financial statements be read in conjunction with the audited financial statements and notes included in our Form 10-KSB for the year ended August 31, 2006.

Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Our financial statements are based on a number of significant estimates, including collectibility of receivables, selection of the useful lives for property and equipment, timing and costs associated with its retirement obligations and oil and gas reserve quantities which are the basis for the calculation of depreciation, depletion and impairment of oil and gas properties.

The oil and gas industry is subject, by its nature, to environmental hazards and clean-up costs. At this time, management knows of no substantial costs from environmental accidents or events for which the Company may be currently liable. In addition, our oil and gas business makes it vulnerable to changes in wellhead prices of crude oil and natural gas. These prices have been volatile in the past and can be expected to be volatile in the future. By definition, proved reserves are based on current oil and gas prices and estimated reserves, which are considered significant estimates by us, and which are subject to changes. Price declines reduce the estimated quantity of proved reserves and increase annual amortization expense (which is based on proved reserves) and may impact the impairment analysis of our full cost pool.

Earnings Per Share. Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during the applicable period. Diluted earnings per share incorporates the dilutive impact, if any, of outstanding stock options by including the effect of

outstanding vested and unvested options in the average number of common shares outstanding during the period. The following table sets forth the computation of basic and diluted earnings per share (in thousands except per share data):

	Three Months Ended November 30, 2006	Three Months Ended November 30, 2005
Net income	$ 383	$ 456
Basic weighted-average common shares outstanding in period	37,993	35,417
Add dilutive effect of stock options and warrants	271	593
Diluted weighted-average common shares outstanding in period	38,264	36,010

Basic and diluted earnings per common share	$ 0.01	$ 0.01

Share Based Compensation. The Company has three share-based compensation plans, which are described in the Company's Form 10-KSB for the year ended August 31, 2006. Stock options are granted to employees and directors at exercise prices equal to the fair market value of the Company's stock at the dates of grants. Generally, options vest annually over various periods up to five years of continuous service and expire over various periods up to ten years from the date of grant. On occasion, the Company has issued warrants not covered under plans approved by the shareholders to individuals for services performed. As of November 30, 2006, the Company had 727,500 warrants outstanding with exercise prices ranging from $0.65 to $1.49 that expire over various periods up to October 17, 2010.

In October 1995, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation (SFAS 123), effective for fiscal years beginning after December 15, 1995. This statement defines a fair value method of accounting for employee stock options and encouraged entities to adopt that method of accounting for its stock compensation plans. SFAS 123 allowed an entity to continue to measure compensation costs for these plans using the intrinsic value based method of accounting as prescribed in Accounting Pronouncement Bulletin Opinion No. 25, Accounting for Stock Issued to Employees (APB 25). We elected to continue to account for our employee stock compensation plans as prescribed under APB 25. Under APB 25, no compensation expense was recorded for stock options issued under qualified plans. Had compensation cost for our stock-based compensation plans been determined based on the fair value at the grant dates for awards under those plans consistent with the method prescribed in SFAS 123, our net income and income per share for the quarter ended November 30, 2005 would have been decreased to the pro forma amounts indicated below (in thousands, except per share data):

	Three Months Ended November 30, 2005
Net income as reported	$ 456
Deduct total compensation cost determined under the fair value base method for all awards	(231)
Pro forma net income	$ 225
Net pro forma income (loss) per share:	
As reported - Basic and Dilutive	$0.01
Pro forma - Basic and Dilutive	$0.01

In December 2004, the Financial Accounting Standards Board issued its final standard on accounting for employee stock options, SFAS No. 123 (Revised 2004), Share-Based Payment (SFAS 123R). SFAS 123R replaces SFAS No. 123 and supersedes APB 25. SFAS 123R requires companies to measure compensation costs for all share-based payments, including grants of employee stock options, based on the fair value of the awards on the grant date and to recognize such expense over the period during which an employee is required to provide services in exchange for the award. Effective September 1, 2006, the Company adopted SFAS 123R using the modified prospective transition method. Under this transition method, compensation costs are recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123R for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123R. Prior periods have not been restated. Total share-based compensation expense for vested equity-based awards in the three months ended November 30, 2006, was approximately $ 58,000 and is reflected in "General and Administrative" expense in the Consolidated Statement of Operations. There was no impact on income tax expense. Total unrecognized compensation expense from unvested stock options, as of November 30, 2006, was approximately $350,000, which is expected to be recognized over a period of a weighted average period of 2.0 years.

The Company uses the Black-Scholes valuation model to determine the fair value of each option award. Expected volatilities are based on the historical volatility of the Company's stock over a period consistent with that of the expected terms of the options. The expected terms of the options are estimated based on factors such as vesting periods, contractual expiration dates, historical trends in stock price and historical exercise behavior. The risk-free rates for periods within the contractual life of the options are based on the yields of U.S. Treasury instruments with terms comparable to the estimated option terms. The following assumptions were used in estimating fair value of share-based awards for the periods indicated:

	November 30, 2006	November 30, 2005
Expected life	5 years	5 years
Risk-free interest rate	4.6%	4.4%
Dividend yield	0.0%	0.0%
Expected volatility	85.7%	91.7%

The following table summarizes option activity during the three months ended November 30, 2006:

Options	Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggrega Intrins Value
Outstanding at September 1, 2006	2,331,750	$1.07		
Options granted	79,014	0.97		
Options forfeited	(300,000)	1.11		
Outstanding at November 30, 2006	2,110,764	$1.06	3.5	$267,7
Exercisable at November 30, 2006	1,649,259	$1.05	3.1	$14,6

The weighted-average grant-date fair value of options granted during the three months ended November 30, 2006 was $0.68. The fair value of options vested during the three months ended November 30, 2006 was $96,000.

	Options Outstanding			Options Exercisable	
Exercise Price Range	Number of Options Outstanding	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Number of Options Exercisable	Weighted Average Exercise P
$0.29 - $0.29	275,000	3.2	$0.29	275,000	$0.29

$0.46 - $0.97	686,014	4.4	$0.91	436,508	$0.88
$1.12 - $1.15	383,000	3.8	$1.13	231,000	$1.14
$1.24 - $1.82	766,750	2.6	$1.43	706,751	$1.42
	2,110,764	3.5	$1.06	1,649,259	$1.05

Recently Issued Accounting Pronouncements. In May 2005, the Financial Accounting Standards Board ("FASB"), as part of an effort to conform to international accounting standards, issued Statement of Financial Accounting Standards ("SFAS") No. 154, Accounting Changes and Error Corrections ("SFAS No.

154"), which was effective for us beginning on September 1, 2006. SFAS No. 154 requires that all voluntary changes in accounting principles be retrospectively applied to prior financial statements as if that principle had always been used, unless it is impracticable to do so. When it is impracticable to calculate the effects on all prior periods, SFAS No. 154 requires that the new principle be applied to the earliest period practicable. The adoption of SFAS No. 154 has not had a material effect on our financial position or results of operations.

On July 13, 2006, the FASB released Interpretation No. 48, Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement 109 ("FIN 48"). FIN 48 requires companies to evaluate and disclose material uncertain tax positions it has taken with various taxing jurisdictions. We are currently reviewing and evaluating the effect, if any, of adopting FIN 48 on our financial position and results of operations. We will be required to adopt FIN 48 for our fiscal year ended August 31, 2008.

In September 2006, the SEC issued Staff Accounting bulletin ("SAB") No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements. SAB 108 provides guidance on the consideration of effects of the prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. The SEC Staff believes registrants must quantify errors using both a balance sheet and income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB 108 will be effective for the Company as of September 1, 2006; however, it is not expected to have a material affect on the Company's financial statements.

In September 2006, FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 defines fair value, establishes a framework for measuring fair value, and expands disclosure requirements regarding fair value measurement. Where applicable, this Statement simplifies and codifies fair value related guidance previously issued within GAAP. Although this Statement does not require any new fair value measurements, its application may, for some entities, change current practice. SFAS No. 157 will be effective for the Company beginning September 1, 2008. The adoption of SFAS No. 157 is not expected to have a material impact on our financial statements.

3. CONTINGENCIES

On July 29, 2005, the Company filed a lawsuit in the U.S. District Court for the Eastern District of Texas, Beaumont Division against Samson Lone Star Limited Partnership ("Samson") and Samson's parent company, Samson Resources Corp. The Company alleged in its complaint that Samson, the operator of a producing gas well in Jefferson County, Texas named the Sun Fee GU #1-ST well (the "Sun Fee Well"), had breached its obligations to the Company, which owns interests in the property on which the Sun Fee Well is located, by joining, without authorization, the Sun Fee Well into a unit (the "Sidetrack Unit") with other properties in which the Company had no interest, many of which are non-productive. Samson has a large interest in the properties that Samson had joined into the unit. Pursuant to Samson's proposed pooling configuration, the Company's working and overriding royalty interests in the Sun Fee Well would be reduced substantially. The Company believes that Samson has no legal or contractual right to reduce the Company's interests in this manner. The Company is seeking monetary damages for all payments due and owing to the Company based on the proper, undiluted interests in the property.

Until approximately August 1, 2005, Samson had been paying the Company its share of oil and gas revenues based on Samson's calculation of the Company's net revenue interest (5.7%) in the Sun Fee Well after dilution for the disputed pooling of the non-productive properties, when it ceased paying the Company any portion of the production proceeds from the Sun Fee Well. On September 13, 2005, the Court entered a Preliminary Injunction ordering Samson to return the Company to pay status for the amounts upon which Samson had been paying the Company prior to the filing of the suit. On December 23, 2005, Samson filed a motion for summary judgment on the Company's claims, to which the Company filed its response on January 3, 2006, rigorously denying that Samson has grounds in law or fact for the requested relief. Further, on January 17, 2006, Samson filed a counterclaim for an unspecified overpayment to the Company, which was clarified by a subsequent filing on February 14, 2006, that it was disputing the unit interest originally attributed to the Company and now asserting that the Company's net revenue unit interest is approximately 4.7%. On March 28, 2006, the Court denied a motion by Samson to modify the present injunction to allow payment upon the lower amount. The Company has also filed additional claims against Samson for breach of contract or reformation of the certain assignment issued by Samson to the Company in April 2005 upon which Samson bases its present counterclaim. The outcome of the litigation will determine whether PYR's ownership in the Sun Fee Well consists of (a) the 5.7% net revenue interest (consisting of a 5.19% working and a 1.5% overriding royalty interest) that was formerly the portion that was not contested by Samson and represents the amount of the payments that Samson, as operator, has been paying PYR and that PYR has been recording in its financial statements; or (b) the 4.7% net revenue interest that Samson asserted in its February 14, 2006 filing; or (c) a net revenue interest higher than 5.7% as a result of the Company's prevailing on part or all

of its claims that it owns an 8.33% working interest as well as an overriding royalty interest greater than 1.5%. On September 15, 2006, the U.S. District Court for the Eastern District of Texas issued its ruling on the outstanding motions for summary judgment that had been filed by both PYR and Samson. In its ruling, the Court held (1) that Samson did not have authority to pool PYR's 3.5% overriding royalty interest in the Sun Fee Well into the Sidetrack Unit and, therefore, that PYR is entitled to the full, undiluted interest in all production from the Sun Fee Well based on this overriding royalty; and (2) that although Samson controlled PYR's working interest at the time the Sidetrack Unit was formed, PYR would be able to maintain its claim for breach of contract against Samson for joining non-productive acreage into the unit. The Court also left for trial PYR's claims that Samson had also breached the underlying agreements by failing to assign to PYR its working interest in all properties as called for in the underlying contracts and by failing to give PYR geologic and other technical information applicable to the Sun Fee Well and the Sidetrack Unit. The Court held that PYR's alternate claim that Samson owed PYR a fiduciary duty in forming the Sidetrack Unit was fully resolved by its other rulings. Following a brief scheduling conference, the Court has requested that the parties discuss next steps, including (i) resuming the trial schedule for the issues and claims that remain unresolved by the Court's order, (ii) the immediate appeal on the rulings made to date in the order and/or (iii) mediation of the issues in dispute.

On August 11, 2006, the State District Court for Jefferson County, Texas, 58th Judicial District, issued a final summary judgment in the Company's favor against Samson in Samson's suit to enjoin the Company's drilling of the Tindall Well, located in Jefferson County, Texas on property directly adjacent to and east of the Sun Fee Well. As previously reported, on the grounds that it had the exclusive right to serve as operator to drill the proposed Tindall Well, Samson had filed suit to enjoin or prevent the Company from drilling the planned well on the approximately 400-acre property in which the Company holds 100% of the oil and gas interest. Upon mutual agreement of the parties, no appeal will be taken from the final judgment.

On February 15, 2006, the Company filed a motion in the ongoing bankruptcy proceeding involving Venus Exploration Company ("Venus") in the U.S. Bankruptcy Court for the Eastern District of Texas requesting that the Bankruptcy Court uphold its Order of April 9, 2004 approving the Company's purchase of Venus' remaining assets free and clear of any obligations under a pre-bankruptcy Operating Agreement between Venus and Trail Mountain Inc. ("Trail Mountain") that required Venus and Trail Mountain to offer each other participation in subsequently acquired oil and gas properties. The Company believes and has asserted in its motion that the pre-bankruptcy Operating Agreement was not listed among the contracts that were assigned to it under the sale in and under the approval of the Bankruptcy Court. Trail Mountain has filed an adversary proceeding against the Company requesting that the Bankruptcy Court find that the pre-bankruptcy Operating Agreement was still effective and that the Company is obligated to offer an opportunity to Trail Mountain to share in the lease upon which the proposed Tindall well is to be drilled. If Trail Mountain is successful, it will lead to a potential 50% reduction in the Company's interest in the lease, but could also lead to a corresponding assignment of interests in properties acquired by Trail Mountain, including certain properties assigned to the Sidetrack Unit. A ruling by the Court should also clarify whether the parties' rights to operate their interests in the Cotton Creek Prospect are subject to an existing operating agreement or are free to enter into a new operating agreement. The parties have submitted the matter to the Bankruptcy Court on motions for summary and partial summary judgment.

The Company will continue to vigorously pursue and defend its rights with respect to the foregoing matters.

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

The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas and oil, economic and competitive conditions, regulatory changes, estimates of proved reserves, potential failure to achieve production from development projects, capital expenditures and other uncertainties, as well as those factors discussed below and in our Annual Report on Form 10-KSB for the year ended August 31, 2006. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

The following discussion should be read in conjunction with the Financial Statements and Notes thereto referred to in "Item 1. Financial Statements" of this Form 10-Q.

Overview

PYR Energy Corporation (referred to as "PYR," the "Company," "we," "us" and "our") is an independent oil and gas exploration and production company, engaged in the exploration, development and acquisition of crude oil and natural gas reserves. Our current focus is on the Rocky Mountain, Texas and Gulf Coast regions.

Liquidity and Capital Resources

Our primary sources of liquidity historically have been from sale of our common stock, issuance of convertible notes, and net cash provided by operating activities. Our primary use of capital has been for the acquisition, development, and exploration of oil and natural gas properties. As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations, planned capital expenditure activities and liquidity. Our future success in growing proved reserves and production is highly dependent on capital resources available to us and our success in finding or acquiring additional reserves. At November 30, 2006, we had approximately $4.6 million in working capital and cash of $4.9 million.

Cash Flow from Operating Activities

Net cash provided by operating activities was $1.4 million and $911,000 for the three months ended November 30, 2006 and 2005, respectively. The increase in net cash provided by operating activities was substantially due to the increase in production revenues, net of increases in expenses. See "Results of Operations" for discussion of changes in revenues and expenses. Non-cash charges increased principally due to higher depreciation, depletion and amortization associated with increased production and higher depletion rates and the recognition of compensation expense associated with unvested options resulting from the adoption of FASB 123R effective September 1, 2006 as discussed in the Notes to Consolidated Financial Statements. Changes in current assets and liabilities decreased cash flow from operations by approximately $109,000 and $83,000 in the three months ended November 30, 2006 and 2005, respectively. The decrease in current assets and liabilities for the current period is principally attributed to a decrease in accrued liabilities offset, in part, by a decrease in accounts receivable. Decreases in the three month period in 2005 are attributed principally to a reduction in the net profits liability resulting from payments made offset by a decrease in accounts receivable.

Operating cash flows are impacted by many variables, the most significant of which are production levels and the volatility of prices for natural gas and oil produced. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence production levels and market conditions for these products. These factors are beyond our control and are difficult to predict.

Capital Expenditures

Our capital expenditures approximated $2.8 million and $1.8 million for the three months ended November 30, 2006 and 2005, respectively. The total for the current three month period includes principally $2.0 million for drilling, development, exploration and exploitation, and $800,000 for leasehold costs including capitalized litigation costs incurred related to our Nome project. Drilling costs for the current period were incurred principally on two wells located in Texas, the Wall #1 well and the Nome-Long #1, and on the exploratory #1-30 Duck Federal well located in Wyoming. Included in drilling costs is a drilling pre-payment of $493,000 for the UPRC #25-1 well located in Wyoming. The operator of this well released the rig that it expected to use to drill the re-entry of UPRC #25-1 resulting in delaying the drilling of this well.

We anticipate our capital budget for the year ended August 31, 2007 will be approximately $10.0 million of which $2.8 million has been incurred through the first quarter for fiscal year 2007 and will be used for a diverse portfolio of development and exploration wells in our core areas of operation. In addition to the capital budget in fiscal 2007, the Company expects to pay its share of plugging costs of approximately $900,000 for six wells located in the East Lost Hills area of California. In accordance with FASB 143, Accounting for Asset Retirement Obligations, discussed in the Company's Form 10-KSB for the year ended August 31, 2006, the Company has previously recognized this plugging obligation as an asset retirement obligation, a current liability, on its balance sheet.

Financing Activities

In mid-October 2005, we completed a private placement in which we sold 6,327,250 shares of common stock at a price of $1.30 per share, to a group of accredited institutional and individual investors. Net proceeds from this placement of approximately $8.0 million has been and will continue to be used for general corporate purposes and costs associated with our development drilling portfolio located principally in the Rocky Mountains and Texas.

It is anticipated that the continuation and future development of our business will require additional, and possibly substantial, capital expenditures. We have no reliable source for additional funds for administration and operations to the extent our existing funds have been utilized. In addition, our capital expenditure budget for the fiscal year ending August 31, 2007 will depend on our success in selling additional prospects for cash, the level of industry participation in our exploration projects, the availability of debt or equity financing, cash on hand and the results of our activities. We anticipate spending approximately $10.0 million, of which $2.8 million has been spent through the first quarter of 2007, on exploration and development activities during our fiscal year ending August 31, 2007. To limit capital expenditures, we intend to form industry alliances and exchange an appropriate portion of our interest for cash and/or a carried interest in our exploration projects. We may need to raise additional funds to cover capital expenditures. These funds may come from cash flow, equity or debt financings, a credit facility, or sales of interests in our properties, although there is no assurance additional funding will be available or that it will be available on satisfactory terms.

Our future financial results continue to depend primarily on (1) our ability to discover commercial quantities of hydrocarbons; (2) the market price for oil and gas; (3) our ability to continue to source and screen potential projects; and (4) our ability to fully implement our exploration and development program with respect to these and other matters. There can be no assurance that we will be successful in any of these respects or that the prices of oil and gas prevailing at the time of production will be at a level allowing for profitable production.

Off-Balance Sheet Financing

The Company had no off-balance sheet financing arrangements as of November 30, 2006.

Summary of Development and Exploration Projects

Our development, exploration, and acquisition activities are focused primarily in select areas of the Rocky Mountains, Texas and the Gulf Coast. A number of these projects offer multiple drilling opportunities with individual wells having the potential of encountering multiple reservoirs.

The following is an update of our production and exploration areas and significant projects. While actively pursuing specific production and exploration activities in each of the following areas, we continually review additional acquisition opportunities in our core areas that meet our production and exploration criteria. Currently, PYR's net production is 5.2 MMcfe per day.

Rocky Mountain Region

Mallard Project. The Company's Mallard Project is located within the Whitney Canyon-Carter Creek field complex in the Overthrust Belt area of Uinta County, Wyoming. Of the more than 2.1 Tcfe that has been produced to date by all operators from this field, over 80% of the production is from the Mission Canyon formation, which is the primary producing formation of the #1-30 Duck Federal well. The #1-30 Duck Federal well is currently producing approximately 6.0 MMcf of gas, 90 barrels of associated condensate and 350 barrels of water per day. Production has improved since recently running a tubing string after an extended shut-in. Following the successful completion of the Duck well, the Company and its partners shot 23 square miles of 3-D seismic to define future drilling locations, and the data is now being processed. The Company has a 28.75% working interest in the #1-30 Duck Federal well and the 3-D seismic.

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In addition, the Company has agreed to participate for a 28.75% working interest in the re-drilling of an existing well, the UPRC #25-1, which directly offsets the #1-30 Duck well. The Company was informed by the operator that the drilling rig it expected to use to drill the re-entry of the UPRC #25-1 well has been released temporarily to drill an intervening well for another operator.

North Stockyard Project. The Company has recently acquired a 20% working interest in 3116 gross acres in the North Stockyard Creek field in Williams County, North Dakota where the operator has used horizontal drilling techniques. It is anticipated that extended reach horizontal drilling can significantly improve the production rates of wells in this field. The Company's first development well in the North Stockyard Creek field, the Harstad #1-15H, has been drilled to a depth of 10,000' to evaluate the hydrocarbon potential of the Bluell formation. The Company has determined that the Bluell zone is capable of commercial production and intermediate casing has been set in the curved portion of the hole. The zone will then be horizontally drilled in a southeasterly direction to a maximum of 5,800'. With a successful completion of this well, the Company expects that additional development wells may be drilled on the acreage in which the Company has an interest.

Texas and Gulf Coast Region

Nome Field. The Company has producing interests in the Nome Field in Jefferson County, Texas, which produces from the Yegua formation. This field was discovered in 1994, and our interpretation of 3D seismic over the field has identified undeveloped fault blocks, structural closures, and associated bright spot locations. The Company's first well, the Sun Fee GU #1-ST ("Sun Fee Well"), currently produces from the upper Yegua at an average rate of 7.2 MMcf/day and 365 BO/day (9.4 MMcfe/day). At the end of December 2006, the well had cumulative production of over 12.3 Bcfe. When the well reached payout on October 13, 2004 (production at that time was over 19.0 MMcfe per day), PYR was placed in pay status as a working interest participant in the well. Based on pooling of lands into the Sun Fee Sidetrack Unit (the "Sidetrack Unit") by the operator, our current net revenue interest in the well and associated lands is 5.7%, consisting of a 5.19% working interest with a 1.5% overriding royalty interest. We and the other working interest partners control approximately 4,200 of gross leasehold acres in the project. Our revenues and costs associated with the production from the Sun Fee Well, as well as our costs incurred on the Nome Project, are subject to a net profits agreement with Venus Exploration Trust ("Trust").

We are currently in litigation with the operator of the Sun Fee Well, Samson Lone Star L.P. ("Samson"), concerning, among other matters, Samson's pooling of certain lands into the production unit and the corresponding reduction in our working interest. The outcome of the litigation will determine our working interest and revenue interest. See Part II, Item 1 of this document for further details.

An additional well, in which the Company has an 8.33% working interest, the Nome-Long #1, has been completed in the Nome Field. The well logged about 135 feet of potential Yegua gas sand. Sales from this well had been delayed pending the construction of the Nome Central Facility by the operator. With this facility now complete, the Nome-Long #1 well is currently producing at January 15, 2007, 7.0 MMcf and 230 BO per day on a 13/64th choke from limited perforations (26feet) in the Yegua Formation. The operator has indicated that it will flow test this lower interval for approximately 30 to 45 days before adding an additional 97 feet of uphole perforations to the flow stream. Our interests in wells drilled in this prospect are subject to the Trust's initial net profits interest of 50%.

PYR has signed an AFE with the operator to drill the Nome-Harder #1, which will offset the Nome-Long #1well by approximately 2685 feet to the northeast. We expect drilling operations to begin on the Nome-Harder #1 within the next couple months. PYR is participating with an approximate 4.167% working interest in this planned 15,000 feet test of the Yegua Formation. Our interest in this well will be subject to the aforementioned Trust net profits interest of 50%.

Madison Prospect. At the Madison project in the northern part of the Constitution Field, located in Jefferson County, Texas, the Maness Gas Unit #1 well is currently producing approximately 350 BO/day and 1.2 MMcf/day (3.3 MMcfe/day). The production rate continues to improve steadily after the well was shut in for an extended period over a year ago. The Company has a 12.5% working interest in the Maness Gas Unit #1 well.

Also in the Madison prospect, the Company participated in drilling the Wall #1 well, in which the Company has a 17.5% working interest. This well is a development well that offsets the Maness GU#1 well. The Wall well was completed during December 2006 and is producing small volumes of hydrocarbons. It is currently undergoing further testing procedures. During completion, the well suffered significant near well bore damage. Following planned mitigation measures, the Company will determine whether the well is commercial. Our interests in wells drilled in this prospect are subject to the Trust's initial net profits interest of 50%.

Bayou Duralde Project is located in Evangeline Parish, Louisiana. The Fontenot # 1 exploration well was spud on May 12th and reached a total depth of 10,650 feet on June 6, 2006. Based on log and core analysis, casing has been set to total depth, and the first Yegua/Cockfield zone has been perforated. The operator has indicated that it is developing plans to test this well, but has not indicated when it expects to perform the test. Should the Company elect to participate in the evaluation of this well, and once it is tested, the economic viability of the well will be determined. PYR has a 15% working interest before payout (17.5% after payout) in the project. Our interests in wells drilled in this prospect are subject to the Trust's initial net profits interest at 25%.

West Westbury Prospect, located in Jefferson County, Texas, targets Yegua sand reservoirs. The prospect, based on 3D seismic interpretation and amplitude analysis, is located approximately 1.5 miles to the southwest of an analog well, in which PYR does not have an interest, completed in October of 2004. This analog well had cumulative production of 28.6 Bcfe through September 2006, averaging 36.8 MMcf of gas and 1655 barrels of condensate per day at that time. Recently, a second well, in which PYR also does not have an interest, the Paggi Broussard #2, was drilled and was producing 30.1 MMcfd and 1477 barrels of condensate per day according to an October report. Both of these wells, along with PYR's West Westbury prospect, are interpreted to be in the same general structural block. Within this same area an additional well, the #1 Mixson Land, is currently being drilled. While PYR does not own an interest in this test, the well offsets our West Westbury prospect area by approximately 3600 feet, and will be the third recent test by the operator on this structure. PYR is evaluating the viability of drilling a well on its West Westbury prospect based on these nearby wells and our technical interpretation of how they relate geologically. PYR owns 100% working interest in the prospect and is currently marketing a portion of this prospect to industry partners

California

In California, the operator of the East Lost Hills prospect area located in Kern County has commenced plugging operations of six wells drilled in 1998 through 2002, in which the Company has a 12.1193% working interest. The Company's net plugging costs are expected to be approximately $900,000. The Company has previously recognized this obligation as an asset retirement obligation, a current liability, on its balance sheet and does not expect the payment of these plugging costs to impact its Consolidated Statements of Operations.

Results of Operations

The financial information with respect to the three months ended November 30, 2006 that is discussed below is unaudited. The results of operations for interim periods are not necessarily indicative of the results of operations for the full fiscal year.

Three Months Ended November 30, 2006 Compared to Three Months Ended November 30, 2005

The first quarter ended November 30, 2006 for the fiscal year ending August 31, 2007 ("fiscal 2007") resulted in net income of $383,000 compared to net income of $456,000 for the first quarter ended November 30, 2005 for the fiscal year ended August 31, 2006 ("fiscal 2006").

	Three Months Ended November 30, 2006	Three Months Ended November 30, 2005	Increase Amount
	($ in thousands, except for per unit pr		
Operating Results:			
Revenues			
Gas production revenues	$ 1,731	$ 1,241	$ 490
Oil production revenues	840	760	80
Natural gas liquids revenues	39	2	37
Other products	9	--	9
Total revenues	$ 2,619	$ 2,003	$ 616
Operating Expenses			
Lease operating expense	$ 424	$ 244	$ 180
Production taxes, gathering and transportation expense	193	124	69
Net profits expense	62	259	(197)
Depletion, depreciation, amortization and accretion	897	357	540
General and administrative	626	504	122
Total operating expenses	$ 2,202	$ 1,488	$ 714
Interest Expense	$ 92	$ 99	($ 7)
Production Data:			
Natural gas (Mcf)	264,106	130,244	133,862
Oil (Bbls)	14,736	12,542	2,194
Natural gas liquids (Bbls)	770	60	710
Combined volumes (Mcfe)	357,142	205,856	151,286
Daily combined volumes (Mcfe/d)	3,925	2,262	1,663
Average Prices:			
Natural gas (per Mcf)	$ 6.56	$ 9.53	($ 2.97)
Oil (per Bbl)	56.98	60.62	(3.64)
Natural gas liquids (per Bbl)	50.39	28.43	21.96
Combined (per Mcfe)	7.33	9.73	(2.40)
Average Costs (per Mcfe):			
Lease operating expense	$ 1.19	$ 1.19	$ --
Production taxes, gathering and transportation expense	0.54	0.60	(0.06)
Net profit expense	0.17	1.26	(1.09)
Depletion, depreciation, amortization and accretion	2.49	1.70	0.79
General and administrative	1.75	2.45	(0.70)
Interest Expense	0.26	0.48	(0.22)

Oil and Gas Revenues. Oil and gas revenues increased 31% to approximately $2.6 million for the three months ended November 30, 2006 from approximately $2.0 million for the same period in 2005. This increase is attributed to a 73% increase in Mcf equivalent ("Mcfe") production, which was offset, in part, by a 25% decrease in average Mcfe prices.

Although natural gas prices declined by 31% from $9.53 per Mcf in the first quarter of fiscal 2006 to $6.56 per Mcf in the first quarter of fiscal 2007, the Company's gas production for the first quarter of fiscal 2007 increased 103% over the same period in fiscal 2006, which offset the price declines and resulted in a 39% increase in revenues over the same period in fiscal 2006. Comparing first quarter of fiscal 2007 with the same period in fiscal 2006, the gas production increases are attributed primarily to new production from three wells located in Oklahoma, two wells located in Texas and one well located in Wyoming that commenced production during fiscal 2006.

The Company's first quarter of fiscal 2007 oil revenues increased $80,000, or 10%, over the same period in fiscal 2006 due to a 17% increase in production, which was offset, in part, by a 6% decrease in average oil prices compared with the first quarter of fiscal 2006. Increases in natural gas liquids ("NGLs") revenues and production were generated from new production from the #1-30 Duck Federal well located in Wyoming which commenced production in March 2006.

Oil and Gas Revenues - comparison of the first quarter in fiscal 2007 to the fourth quarter in fiscal 2006. Total oil and gas revenues for the first quarter of fiscal 2007 are 3% higher than the fourth quarter fiscal 2006. Gas revenues for the first quarter fiscal 2007 are 1% lower than the previous quarter due to a 6% decrease in production, which was offset, in part, by a 5% increase in average gas prices. Compared to the previous quarter, the current quarter gas production was lower principally due to natural production decline in the Sun Fee well (Texas) and a decline in production from the Chisum well (Texas). The Maness well (Texas), which, due to a workover, was shut-in for nearly three months from mid-May 2006, commenced post- workover production in late August. The post-workover production volumes are gradually improving to approximately pre-workover volumes. The #1-30 Duck Federal well (Wyoming) gas and oil production was curtailed from August through October 2006 due to running a tubing string. Oil revenues for the current quarter are 4% higher than the previous quarter due to a 35% increase in production, which was offset, in part, by a 23% decrease in average oil prices.

Lease Operating Expenses. Our per unit of production lease operating expenses remained unchanged at $1.19 per Mcfe for the first quarters of both fiscal 2006 and 2007. Total lease operating expenses increased 74% principally due to the addition of new producing wells and workover expenses incurred on the Maness well.

Production Taxes, Gathering and Transportation Expenses. Production taxes as a percentage of natural gas and oil revenues were approximately 6.5% for the current quarter in fiscal 2007 compared to 5.3 % for the same quarter in fiscal 2006. Production taxes are primarily based on wellhead values of production and vary across the different areas that our wells are located. Total production taxes increased $61,000, or 57%, over the same period in fiscal 2006 as a result of higher production revenues, attributed to increased production volumes, and increased revenues in areas with higher production tax rates. Gathering, transportation and other sales expenses increased by $8,000 in fiscal 2007 compared with the same period in fiscal 2006.

Net Profits Expense. The net profits interest agreement with Venus Exploration Trust ("Trust") arose out of the acquisition of properties from Venus Exploration Inc. ("Venus") in May 2004. The amount of the Trust net profits interest is either 25% or 50% with respect to different Venus exploration and exploitation project areas, and decreases by one-half of its original amount after an aggregate total of $3.3 million in net profits. The 76% decrease in net profits expense for the first quarter ended November 30, 2006 compared with the same period in 2005 resulted principally from capital expenditures for drilling the Wall #1 well and the Nome-Long #1 well which have not been fully offset from current operating profits on the wells that are subject to the net profits obligation and will reduce any future net profits obligation until fully offset. As of November 30, 2006, the Company has paid net profits expenses totaling approximately $2.0 million.

Depletion, Depreciation, Amortization and Accretion Expense. Depletion, depreciation, amortization and accretion expense was $897,000 for the first quarter ended November 30, 2006 compared with $357,000 for the same period in the prior year. The increase is principally attributed to depletion expense which increased $539,000. Depletion expense increase is the result of a 73% increase in production volumes in the first quarter in fiscal 2007 as compared to the same period in the prior year. The weighted average depletion rate for the Company's full cost pool increased from $1.69 per Mcfe in the first quarter of fiscal 2006 to approximately $2.48 per Mcfe in the first quarter of the fiscal 2007. The rate increase is attributed to the inclusion of costs of certain impaired unevaluated properties in the amortizable base of the full cost

pool and additional costs, principally capitalized legal costs associated with the Nome prospect, for which no additional reserves have been added. Under the full cost pool method of accounting, impairment costs of unevaluated properties, previously excluded from the amortizable base of the depletable full cost pool, are added to the full cost pool depletable base resulting in an increase in the depletion rate.

General and Administrative Expenses. General and administrative expenses during the quarter ended November 30, 2006 increased by approximately $122,000, or 24% from the same period in 2005. The principal costs contributing to the increase were higher Texas franchise taxes associated with increased sales in Texas, AMEX registration fee associated with registering the Company's 2006 Stock Incentive Plan and non-cash stock-based compensation expense of $58,000 associated with the adoption of FASB 123R. See discussion of adoption of FASB 123R in Notes to Consolidated Financial Statements in Item 1 of this report. As a result of higher production volume levels, general and administrative costs per unit of production decreased from $2.45 per Mcfe in the first quarter of fiscal 2006 to $1.75 per Mcfe in the first quarter of fiscal 2007.

Effective January 1, 2007, the Company and its former employees located in San Antonio, Texas entered into a consulting arrangement whereby the former employees, together with two consulting geologists and one consulting engineer, will provide consulting services, upon request, to the Company on the Company's strategic properties in Texas and other areas. This arrangement is expected to reduce our general and administrative expenses while allowing us to access the technical expertise of these consultants.

Interest Expense. During the quarters ended November 30, 2006 and 2005, we recorded interest expense of $92,000 and $99,000, respectively. Interest expense on the Company's convertible notes due May 24, 2009 increased by approximately $4,000 in the first quarter of fiscal 2007 compared with the same period in fiscal 2006 due to an increase in convertible note principal balances (resulting from adding previously accrued interest to the principal). In November 2006, the Company elected to pay accrued interest due on the convertible notes of approximately $184,000 by increasing the outstanding balance of the Convertible Notes. Other interest expense paid totaled nil and $11,000 for the first quarter of fiscal 2007 and fiscal 2006, respectively.

Critical Accounting Policies And Estimates

We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our Financial Statements.

Reserve Estimates:

Our estimates of oil and natural gas reserves, by necessity, are projections based on geological and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance and excise taxes, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected from there may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Many factors will affect actual net cash flows from production, including the following: the amount and timing of actual production; curtailments due to weather; supply and demand for natural gas; curtailments or increases in consumption by natural gas purchasers; and changes in governmental regulations or taxation.

Property, Equipment and Depreciation:

We follow the full cost method to account for our oil and gas exploration and development activities. Under the full cost method, all costs associated with acquisition, exploration and development activities, including costs of

unsuccessful exploration and legal costs incurred to defend the Company's revenue interest in the Nome prospect, are capitalized and subjected to depreciation and depletion. Depletable costs also include estimates of future development costs of proved reserves. Costs related to undeveloped oil and gas properties may be excluded from depletable costs until those properties are evaluated as either proved or unproved. The net capitalized costs are subject to a ceiling limitation based on the estimated present value of discounted future net cash flows from proved reserves. As a result, we are required to estimate our proved reserves at the end of each quarter, which is subject to the uncertainties described in the previous section. Gains or losses upon disposition of oil and gas properties are treated as adjustments to capitalized costs, unless the disposition represents a significant portion of the Company's proved reserves.

Revenue Recognition:

The Company recognizes oil and gas revenues from its interests in producing wells as oil and gas is produced and sold from these wells. The Company has no gas balancing arrangements in place. Oil and gas sold is not significantly different from the Company's product entitlement. As of November 30, 2006, the

Company has sold more than its entitlement by 17 MMcfs with a fair market value of approximately $114,000.

Deferred Tax Allowance:

As of November 30, 2006, the Company had a substantial deferred tax asset, consisting principally of tax loss carryforwards valued at approximately $16.0 million. This deferred tax asset is fully offset by a deferred tax allowance as the Company continues to believe it is more likely than not that such asset will be realized due to the historical uncertainty in the volatility of oil and gas prices, the industry in general and past historical losses. The Company continues to re-evaluate this estimate.

Recently Issued Accounting Pronouncements

In May 2005, the Financial Accounting Standards Board ("FASB"), as part of an effort to conform to international accounting standards, issued Statement of Financial Accounting Standards ("SFAS") No. 154, Accounting Changes and Error Corrections ("SFAS No. 154"), which was effective for us beginning on September 1, 2006. SFAS No. 154 requires that all voluntary changes in accounting principles be retrospectively applied to prior financial statements as if that principle had always been used, unless it is impracticable to do so. When it is impracticable to calculate the effects on all prior periods, SFAS No. 154 requires that the new principle be applied to the earliest period practicable. The adoption of SFAS No. 154 has not had a material effect on our financial position or results of operations.

On July 13, 2006, the FASB released Interpretation No. 48, Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement 109 ("FIN 48"). FIN 48 requires companies to evaluate and disclose material uncertain tax positions it has taken with various taxing jurisdictions. We are currently reviewing and evaluating the effect, if any, of adopting FIN 48 on our financial position and results of operations. We will be required to adopt FIN 48 for our fiscal year ended August 31, 2008.

In September 2006, the SEC issued Staff Accounting bulletin ("SAB") No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements. SAB 108 provides guidance on the consideration of effects of the prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. The SEC Staff believes registrants must quantify errors using both a balance sheet and income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB 108 will be effective for the Company as of September 1, 2006; however, it is not expected to have a material affect on the Company's financial statements.

In September 2006, FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 defines fair value, establishes a framework for measuring fair value, and expands disclosure requirements regarding fair value measurement. Where applicable, this Statement simplifies and codifies fair value related guidance previously issued within GAAP. Although this Statement does not require any new fair value measurements, its application may, for some entities, change current practice. SFAS No. 157 will be effective for the Company beginning September 1, 2008. The adoption of SFAS No. 157 is not expected to have a material impact on our financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the information set forth in this Item 3 is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas and oil production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. natural gas production. Pricing for natural gas and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control. For the three months ended November 30, 2006, our income would have changed by $26,000 for each $.10 per Mcf change in natural gas prices and $16,000 for each $1.00 per Bbl change in crude oil prices.

We do not currently enter into hedging of our production prices.

Interest Rate Risks

At November 30, 2006, we had approximately $7.5 million in convertible notes payable outstanding. These notes bear a fixed interest rate of 4.99% and are convertible, together with accrued interest, into shares of the Company's common stock at the rate of $1.30 per share, at the option of the holder. We do not have any debt with fluctuating interest rates.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, we conducted an evaluation under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")). Based on this evaluation, our Chief Executive Officer and Chief Financial Officer believe that our disclosure controls and procedures were, as of the end of the period covered by this report, to the best of their knowledge effective.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal controls over financial reporting during our most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II.

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

On July 29, 2005, the Company filed a lawsuit in the U.S. District Court for the Eastern District of Texas, Beaumont Division against Samson Lone Star Limited Partnership ("Samson") and Samson's parent company, Samson Resources

Corp. The Company alleged in its complaint that Samson, the operator of a producing gas well in Jefferson County, Texas named the Sun Fee GU #1-ST well (the "Sun Fee Well"), had breached its obligations to the Company, which owns interests in the property on which the Sun Fee Well is located, by joining, without authorization, the Sun Fee Well into a unit (the "Sidetrack Unit") with other properties in which the Company had no interest, many of which are non-productive. Samson has a large interest in the properties that Samson had joined into the unit. Pursuant to Samson's proposed pooling configuration, the Company's working and overriding royalty interests in the Sun Fee Well would be reduced substantially. The Company believes that Samson has no legal or contractual right to reduce the Company's interests in this manner. The Company is seeking monetary damages for all payments due and owing to the Company based on the proper, undiluted interests in the property.

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Until approximately August 1, 2005, Samson had been paying the Company its share of oil and gas revenues based on Samson's calculation of the Company's net revenue interest (5.7%) in the Sun Fee Well after dilution for the disputed pooling of the non-productive properties, when it ceased paying the Company any portion of the production proceeds from the Sun Fee Well. On September 13, 2005, the Court entered a Preliminary Injunction ordering Samson to return the Company to pay status for the amounts upon which Samson had been paying the Company prior to the filing of the suit. On December 23, 2005, Samson filed a motion for summary judgment on the Company's claims, to which the Company filed its response on January 3, 2006, rigorously denying that Samson has grounds in law or fact for the requested relief. Further, on January 17, 2006, Samson filed a counterclaim for an unspecified overpayment to the Company, which was clarified by a subsequent filing on February 14, 2006, that it was disputing the unit interest originally attributed to the Company and now asserting that the Company's net revenue unit interest is approximately 4.7%. On March 28, 2006, the Court denied a motion by Samson to modify the present injunction to allow payment upon the lower amount. The Company has also filed additional claims against Samson for breach of contract or reformation of the certain assignment issued by Samson to the Company in April 2005 upon which Samson bases its present counterclaim. The outcome of the litigation will determine whether PYR's ownership in the Sun Fee Well consists of (a) the 5.7% net revenue interest (consisting of a 5.19% working and a 1.5% overriding royalty interest) that was formerly the portion that was not contested by Samson and represents the amount of the payments that Samson, as operator, has been paying PYR and that PYR has been recording in its financial statements; or (b) the 4.7% net revenue interest that Samson asserted in its February 14, 2006 filing; or (c) a net revenue interest higher than 5.7% as a result of the Company's prevailing on part or all of its claims that it owns an 8.33% working interest as well as an overriding royalty interest greater than 1.5%. On September 15, 2006, the U.S. District Court for the Eastern District of Texas issued its ruling on the outstanding motions for summary judgment that had been filed by both PYR and Samson. In its ruling, the Court held (1) that Samson did not have authority to pool PYR's 3.5% overriding royalty interest in the Sun Fee Well into the Sidetrack Unit and, therefore, that PYR is entitled to the full, undiluted interest in all production from the Sun Fee Well based on this overriding royalty; and (2) that although Samson controlled PYR's working interest at the time the Sidetrack Unit was formed, PYR would be able to maintain its claim for breach of contract against Samson for joining non-productive acreage into the unit. The Court also left for trial PYR's claims that Samson had also breached the underlying agreements by failing to assign to PYR its working interest in all properties as called for in the underlying contracts and by failing to give PYR geologic and other technical information applicable to the Sun Fee Well and the Sidetrack Unit. The Court held that PYR's alternate claim that Samson owed PYR a fiduciary duty in forming the Sidetrack Unit was fully resolved by its other rulings. Following a brief scheduling conference, the Court has requested that the parties discuss next steps, including (i) resuming the trial schedule for the issues and claims that remain unresolved by the Court's order, (ii) the immediate appeal on the rulings made to date in the order and/or (iii) mediation of the issues in dispute.

On August 11, 2006, the State District Court for Jefferson County, Texas, 58th Judicial District, issued a final summary judgment in the Company's favor against Samson in Samson's suit to enjoin the Company's drilling of the Tindall Well, located in Jefferson County, Texas on property directly adjacent to and east of the Sun Fee Well. As previously reported, on the grounds that it had the exclusive right to serve as operator to drill the proposed Tindall Well, Samson had filed suit to enjoin or prevent the Company from drilling the planned well on the approximately 400-acre property in which the Company holds 100% of the oil and gas interest. Upon mutual agreement of the parties, no appeal will be taken from the final judgment.

On February 15, 2006, the Company filed a motion in the ongoing bankruptcy proceeding involving Venus Exploration Company ("Venus") in the U.S. Bankruptcy Court for the Eastern District of Texas requesting that the Bankruptcy Court uphold its Order of April 9, 2004 approving the Company's purchase of Venus' remaining assets free and clear of any obligations under a pre-bankruptcy Operating Agreement between Venus and Trail Mountain Inc. ("Trail Mountain") that required Venus and Trail Mountain to offer each other participation in subsequently acquired oil and gas properties. The Company believes and has asserted in its motion that the pre-bankruptcy Operating Agreement was not listed among the contracts that were assigned to it under the sale in and under the approval of the Bankruptcy Court. Trail Mountain has filed an adversary proceeding against the Company requesting that the Bankruptcy Court find that the pre-bankruptcy Operating Agreement was still effective and that the Company is obligated to offer an opportunity to Trail Mountain to share in the lease upon which the proposed Tindall well is to be drilled. If Trail Mountain is successful, it will lead to a potential 50% reduction in the Company's interest in the lease, but could also lead to a corresponding assignment of interests in properties acquired by Trail Mountain, including certain properties assigned to the Sidetrack Unit. A ruling by the Court should also clarify whether the parties' rights to operate their interests in the Cotton Creek Prospect are subject to an existing operating agreement or are free to enter into a new operating agreement. The parties have submitted the matter to the Bankruptcy Court on motions for summary and partial summary judgment.

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The Company will continue to vigorously pursue and defend its rights with respect to the foregoing matters.

Item 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in "Risk Factors" in part I, Item 1 of the Company's Annual Report on Form 10-KSB for the fiscal year ended August 31, 2006, which could materially affect the Company's business, financial condition or future results. The risks described in the Company's Annual Report on Form 10-KSB are not the only risks facing the Company. Additional risks and uncertainties not currently known to the Company or that the Company currently deems to be immaterial also may materially adversely affect the Company's business, financial condition and/or operating results.

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

None

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

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

None

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

Exhibit Index

Number	Description
3.1*	Articles of Incorporation, filed with the Maryland Secretary of State on June 18, 2001(1)
3.2*	Articles of Merger, filed with the Maryland Secretary of State on July 3, 2001(1)
3.3*	Bylaws(1)
4.1*	Specimen Common Stock Certificate(2)
4.2*	Subscription and Registration Rights Agreement between Wellington parties and the Company, September 2005(3)
31.1	Rule 13a-14(a) Certifications of Chief Executive Officer
31.2	Rule 13a-14(a) Certifications of Chief Financial Officer
32	Certification of Chief Executive Officer and Chief Financial Officer 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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* Previously filed.
(1) Incorporated by reference from the Company's Form 10-KSB for the year ended August 31, 2001.
(2) Incorporated by reference from the Company's Form 10-KSB/A1 for the year ended August 31, 1997.
(3) Incorporated by reference from the Company's Report on Form 8-K filed on October 8, 2005.

SIGNATURES

In accordance with the requirements of the Exchange Act, the Registrant has caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Signatures	Title	Date

/s/ Kenneth R. Berry Jr. Kenneth R. Berry Jr.	President and Chief Executive Officer	January 16, 2007
/s/ Jane M. Richards Jane M. Richards	Chief Financial Officer	January 16, 2007

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