PYR ENERGY CORP
Form 10QSB
January 14, 2005

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

FORM 10-QSB

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

For the quarterly period ended November 30, 2004

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)

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

Check 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 an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes [ ] No [X]

(APPLICABLE ONLY TO CORPORATE REGISTRANTS)

The number of shares outstanding of each of the issuer's classes of common equity as of November 30, 2004 is as follows:

$.001 Par Value Common Stock	31,564,426

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PYR ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

ASSETS

	November 30, 2004 (Unaudited)	August 31, 2004
CURRENT ASSETS		
Cash	$ 5,978,834	$ 6,038,156
Oil and gas receivables	1,067,912	477,176
Other receivable	--	750,000
Prepaid expenses and other assets	27,986	102,239
Total current assets	7,074,732	7,367,571

PROPERTY AND EQUIPMENT, at cost		
Furniture and equipment, net	32,143	26,736
Oil and gas properties under full cost, net	9,893,754	8,851,351
	9,925,897	8,878,087
OTHER ASSETS		
Deferred financing costs and other assets	64,273	65,070
	64,273	65,070
TOTAL ASSETS	$ 17,064,902	$ 16,310,728

LIABILITIES AND STOCKHOLDERS' EQUITY

CURRENT LIABILITIES		
Accounts payable	$ 181,587	$ 83,042
Accrued expenses:		
Ad valorem tax payable	67,135	65,068
Accrued interest payable	5,570	89,644
Accrued net profits interest payable	122,366	--
Other accrued liabilities	568,045	199,688
	763,116	354,400
Asset retirement obligation	868,163	868,163
Total current liabilities	1,812,866	1,305,605
LONG TERM LIABILITIES		
Convertible notes	6,789,962	6,623,351
Asset retirement obligation	308,758	289,489
Total long term liabilities	7,098,720	6,912,840
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 - 31,564,426 at 11/30/04 and 31,564,426 shares at 8/31/04	31,564	31,564
Capital in excess of par value	43,221,391	43,221,391
Accumulated deficit	(35,099,639)	(35,160,672)
Total stockholders' equity	8,153,316	8,092,283
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 17,064,902	$ 16,310,728

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PYR ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

Three Months Ended November 30,

	2004	2003
REVENUES		
Oil and gas revenues	$ 1,082,510	$ 40,018
	1,082,510	40,018
OPERATING EXPENSES		
Lease operating expenses	280,576	15,271
Accretion expense	6,300	21,152
Net profits interest expense	122,366	--
Depreciation and amortization	38,037	40,120
General and administrative	511,387	251,490
Total operating expenses	958,666	328,033
INCOME (LOSS) FROM OPERATIONS	123,844	(288,015)
OTHER INCOME (EXPENSE)		
Interest income	20,299	5,567
Other income	4,140	--
Interest (expense)	(83,333)	(79,354)
Other (expense)	(3,918)	
Total other income (expense)	(62,812)	(73,787)
NET INCOME (LOSS)	$ 61,032	$ (361,802)
NET INCOME (LOSS) PER COMMON SHARE -BASIC AND DILUTED	$ 0.00	$ (0.02)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING	31,564,426	23,701,357

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PYR ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended November 30,	
	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ 61,032	$ (361,802)
Adjustments to reconcile net income (loss) to net cash provided (used) by operating activities		
Depreciation and amortization	38,037	40,120
Amortization of financing costs	797	797
Interest expense converted into debt	166,611	158,577
Accretion of asset retirement obligation	6,300	21,152
Changes in assets and liabilities		

(Increase) in accounts receivable	(590,736)	--
Decrease (increase) in prepaids and other receivables	74,253	(78,684)
Increase (decrease) in accounts payable	101,015	(7,381)
Increase in net profits interest liability	122,366	--
Increase (decrease) in accrued expenses	415,031	(40,045)
Net cash provided (used) by operating activities	394,706	(267,266)
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid for furniture and equipment	(8,622)	--
Cash paid for oil and gas properties	(1,220,406)	(276,389)
Proceeds from exercise of exploration options	750,000	--
Proceeds from sale of oil and gas properties	25,000	--
Net cash used in investing activities	(454,028)	(276,389)
CASH FLOWS FROM FINANCING ACTIVITIES	--	--
NET DECREASE IN CASH	(59,322)	(543,655)
CASH, BEGINNING OF PERIODS	6,038,156	3,657,938
CASH, END OF PERIODS	$ 5,978,834	$ 3,114,283

PYR ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(continued)
THREE MONTHS ENDED NOVEMBER 30, 2004 AND 2003
(Unaudited)

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES

During the three months ended November 30, 2004, the asset retirement obligation increased by $12,969.

PYR ENERGY CORPORATION
Notes to Consolidated Financial Statements
November 30, 2004
(Unaudited)

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, 2004 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 financial statements and notes included in our Form 10-KSB for the year ended August 31, 2004.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

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.

The Company's financial statements are based on a number of significant estimates, including reliability 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 it may be currently liable. In addition, the Company's oil and gas business makes it vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future. By definition, proved reserves are based on current oil and gas prices and estimated reserves, which is considered a significant estimate by the Company, which is 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 the Company's full cost pool.

Earnings (Loss) Per Share - Basic earnings (loss) per common share is computed by dividing net earnings (loss) attributed to common stock by the weighted average number of common shares outstanding during each period. Diluted earnings (loss) per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of convertible equity instruments, such as convertible notes payable, stock options and warrants. The dilutive effect of such securities was insignificant for the three months ended November 30, 2004 and was not considered for the three months ended November 30, 2003 because it would have been anti-dilutive.

Share Based Compensation - 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 encourages entities to adopt that method of accounting for its stock compensation plans. SFAS 123 allows 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). The Company has elected to continue to account for its employee stock compensation plans as prescribed under APB 25. Had compensation cost for the Company's 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, the Company's net income (loss) and income (loss) per share for the quarters ended November 30, 2004 and 2003 would have been increased (decreased) to the pro forma amounts indicated below:

	November 30, 2004	November 30, 2003
Net income (loss):		
As reported	$ 61,032	$(361,802)
Pro forma equity compensation expense	(82,839)	(132,620)
Pro forma net loss	$ (21,807)	$(494,422)
Net pro forma loss per share:		
As reported	$ 0.00	$ (0.02)
Pro forma	$ 0.00	$ (0.02)

The calculated value of stock options granted under these plans, following calculation methods prescribed by SFAS 123, uses the Black-Scholes stock option pricing model with the following assumptions used:

	November 30, 2004	November 30, 2003
Expected option life-years	5	5-7
Risk-free interest rate	3.3 - 3.5%	3.0 %
Dividend yield	0.00%	0.00%
Volatility	67-83%	107%

Reclassification - Certain reclassifications have been made to the November 30, 2003 financial statements to conform to November 30, 2004 presentation.

Such reclassifications had no effect on net loss.

Recent Accounting Pronouncements - In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 123(R), "Share-Based Payment". This statement requires all entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. SFAS No. 123(R) is effective the first reporting period beginning after December 15, 2005. Due to the recent adoption of SFAS No. 123(R), the Company has not determined the future impact on its financial statements; however, it will result in additional future financial reporting expense to the Company when implemented.

2. ACQUISITION OF PROPERTIES:

In May 2004, the Company acquired certain oil and gas properties from Venus Exploration Inc. ("Venus") for cash consideration of $3,230,000. The financial statements therefore reflect the revenue and other operating expenses associated with these properties since the date of acquisition. The purchase also provides for the Company to pay a net profits interest payable to the Venus Exploration Trust ("Trust"). During the quarter ended November 30, 2004, the Company accrued $122,366, which is payable to the Trust based on the net profits interest agreement; however, the company does not anticipate that it will be required to pay this amount as the Company intends to drill additional wells in the future on the property subject to payout. Costs incurred in connection with additional drilling would reduce this liability; however, in the unlikely event the Company does not incur additional drilling costs, such amount would then be payable to the Trust. The net profits interest, which applies only to the exploration and exploitation projects on the Venus acreage acquired, varies from 25% to 50% with respect to different Venus exploration and exploitation project areas, and decreases by one-half of its original amount after a total of $3,300,000 in net profits proceeds has been paid to the Trust.

3. CONTINGENCY

We are currently in dispute with the operator of the Sun Fee #1, Sampson Lone Star L.P. ("Sampson"), concerning the pooling of certain lands into the production unit at Nome Field. The pooling of these lands in which the

Company does not own an interest, comprises approximately 32% of the unit area, and may result in a reduction of working interest and net revenue interest, relative to production from the Sun Fee #1, attributable to the Company. If the current pooling were to stand, our working interest in the well would be reduced from 8.33% to 5.66%. The Company strongly believes that the lands in question are `Non-Productive', and therefore not eligible for pooling, based on all available geological, seismic, and existing well data. As a result of this dispute, we will vigorously pursue and defend our rights to our proportionate share of production and revenue from the Sun Fee #1 with all legal avenues and remedies available. For this reason, the Company has not signed any of the proposed production and revenue division orders, and has not received any revenue, attributable to the well, to date. If we undertake legal action against the operator relative to this issue, which we currently intend, it may result in all revenues attributable to the Sun Fee #1 well being held in suspense until the legal action is completed. If the outcome of the dispute results in the operator recognizing our working interest of 8.33%, the increased working interest could potentially result in increased revenue to the Company and increased net profits liability to Venus Exploration Trust, subject to the net profits interest agreement.

For the quarter ended November 30, 2004, we accrued approximately $325,000 in royalty and working interest revenues from the Sun Fee #1. As a result of the dispute with Sampson, revenues were accrued at the lower working interest percentage (5.66%) as stated by the operator.

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

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-QSB.

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. We continue to focus our exploration efforts and advanced technical expertise on the pre-drill phases of our high potential exploration projects in the Rocky Mountain region. In May 2004, we acquired interests from Venus Exploration, Inc. ("Venus") in certain producing properties and undeveloped acreage for approximately $3,230,000 (excluding acquisition expenses and subject to retention, by the Venus Exploration Trust, of a net profits interest covering the non-productive exploration projects) with estimated proved reserves of 4.78 Bcfe. This equates to $0.67 per Mcf, with a PV-10 value of $6.94 million. The Venus assets acquired include interests in 80 non-operated wells in Utah, Oklahoma and Texas. New drilling and workovers have been conducted since the acquisition date and include two recent discoveries. As a result of the acquisition of the Venus assets, PYR has undertaken a transformation from a development stage company to a producing oil and gas company. Previously our primary drilling activity had been in the San Joaquin Basin of California and on our East Lost Hills project.

Liquidity and Capital Resources

Our primary sources of liquidity historically have been from placements of common stock and convertible notes, and to a much lesser extent, 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, 2004, we had approximately $5,261,866 in working capital.

During the quarter ended November 30, 2004, our capitalized costs for oil and gas properties increased by approximately $1,042,000. The increase reflects net costs incurred for undeveloped leasehold, drilling and completion, workover, geological and geophysical costs, delay rentals and other related direct costs with respect to our exploration and development prospects, which is further discussed in Capital Expenditures and Summary of Exploration Projects.

During the quarter ended November 30, 2003, capitalized costs for oil and gas properties increased by approximately $198,000. This increase reflects net costs incurred for drilling and completion, geological and geophysical costs, delay rentals and other related direct costs with respect to our exploration and development prospects, of approximately $236,000, less depreciation of asset retirement obligation assets of approximately $38,000.

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, 2005 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, and the results of our activities. We anticipate spending a minimum of approximately $2,000,000 on exploration and development activities during our fiscal year ending August 31, 2005. 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.

CAPITAL EXPENDITURES

During the quarter ended November 30, 2004, we incurred approximately $1,089,000 of capital costs for our oil and gas properties. This amount includes costs associated with undeveloped leasehold, drilling and completion, workover, geological and geophysical costs, delay rentals, and other related direct costs with respect to our exploration and development prospects. Revenues from oil and gas production during the quarter were approximately $1,082,510.

We currently anticipate that we will participate in the drilling of up to six exploration wells during our fiscal year ending August 31, 2005, although the number of wells may increase as additional projects are added to our portfolio. However, there can be no assurance that any such wells will be drilled and if drilled that any of these wells will be successful.

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.

SUMMARY OF EXPLORATION PROJECTS

Our exploration activities are focused primarily in select areas of the Rocky Mountains, Texas and Gulf Coast, Southeast Alberta, and in the San Joaquin Basin of California. Advanced seismic imaging of the structural and stratigraphic complexities common to these regions provides us with the enhanced ability to identify significant oil and gas reserve potential. A number of these projects offer multiple drilling opportunities with individual wells having the potential of encountering multiple reservoirs.

The following is a summary of our exploration areas and significant projects. While actively pursuing specific exploration activities in each of the following areas, we continually review additional opportunities in these core areas and in other areas that meet our exploration criteria.

ROCKY MOUNTAIN EXPLORATION

Montana Foothills Project. This extensive natural gas exploration project, located in west-central Montana, is part of the southern Alberta basin, and has been classified as the southern extension of the Alberta Foothills producing province. The USGS and numerous Canadian industry sources have estimated

significant recoverable reserves for the Montana portion of the Foothills trend. Based on extensive geologic and seismic analysis, we have identified numerous structural culminations of similar size, geometry, and kinematic history as prolific Canadian foothills fields, such as Waterton and Turner Valley.

The geologic setting and hydrocarbon potential of this area was not recognized by the industry until the early 1980s. At that time, a number of companies initiated exploration efforts, including Exxon, Arco, Chevron, Amoco, Conoco, and Unocal. This initial exploration phase culminated in a deep test by Unocal, the Unocal #1-B30, drilled in 1989 to a depth of 17,817 feet, which was plugged and abandoned after testing. Although this well was unsuccessful, recent improvements in seismic imaging and pre-stack processing have resulted in our belief that this test well was drilled based upon a misleading seismic image and was located significantly off-structure. Within the Rogers Pass acreage block, we have undertaken extensive seismic analysis and geological study, resulting in the identification of multiple untested, prospective structures.

In March 2004, we signed an Exploration Option Agreement with a subsidiary of Suncor Energy, Incorporated, covering our Rogers Pass exploration project We currently control approximately 241,800 gross and 226,300 net leasehold acres in the Rogers Pass project. Pursuant to our agreement with the subsidiary of Suncor Energy, Suncor Energy Natural Gas America, Inc. ("SENGAI"), SENGAI has paid us a $500,000 option fee for a technical evaluation period of up to three months. On August 31, 2004 SENGAI exercised its option to drill an initial test well at Rogers Pass, and paid us $750,000 in the form of a prospect fee (received in September 2004). It is anticipated that the initial test well will begin drilling operations in late February or March 2005, depending on rig availability. SENGAI will bear 100% of the costs of the well, to a depth sufficient to evaluate the Mississippian, to earn a 100% working interest in 100,000 acres of the project area. SENGAI will have the option to pay a second prospect fee of $1,250,000 and drill a second test well, to be spud by December 31, 2005. By paying this second prospect fee and bearing 100% of the costs of the second well, SENGAI will earn a 100% working interest in the remaining acreage within the project area. We will retain a 12.5% overriding royalty interest, subject to amortized recovery of gas plant and certain transportation costs, covering all earned acreage within the Rogers Pass project area.

Mallard Project. The Mallard project, located within the Overthrust Belt of southwest Wyoming, is a sour gas and condensate exploration prospect in Uinta County, Wyoming. We believe that Mallard is within the Paleozoic trend of productive fields on the Absaroka thrust. Mallard directly offsets and is adjacent to the giant sour gas field of Whitney Canyon-Carter Creek.

We interpret the Mallard prospect to occupy a separate fault block, adjacent to the Whitney Canyon field, generated by a complex imbricated system of faults splaying off of the Absaroka thrust. Paleozoic targets at the Mallard prospect include the Mississippian Mission Canyon, as well as numerous secondary objectives in the Ordovician, Pennsylvanian, and Permian sections.

The agreement we entered into with two private companies ("the Participants") in December 2003 requires the Participants to drill the initial test well at the Mallard Prospect to earn part of our acreage position within a designated area of mutual interest. We currently control 4,160 net leasehold acres within the AMI. During the fiscal year ended 2004, the partners paid us approximately $450,000 in prospect fees and pro-rata development costs. The Mallard well started drilling in mid-July and Intermediate casing was set to 9,735 feet in the Thaynes Formation. The Bureau of Land Management has suspended drilling activities at Mallard, effective December 1, 2004, due to wildlife critical winter range restrictions. As a result, the well has been temporarily suspended and secured in compliance with applicable federal and state regulations, until the wildlife restrictions are lifted in mid - 2005. We are participating with a 5% working interest in the drilling of Mallard, and will be carried to casing point, at an estimated total depth of 15,500 feet, for an additional 23.75% working interest. After casing point, we will have a 28.75% working interest in the initial test well and all subsequent wells in the prospect.

Cumberland Project. The Cumberland project, located within the Overthrust Belt of southwest Wyoming, is a gas-condensate exploration prospect in Uinta County, Wyoming. Cumberland is at the northern end of the historically productive Nugget trend on the hangingwall of the Absaroka thrust fault. We believe that the prospect is along geologic trend of and just north of Ryckman Creek field, which was discovered in 1975.

Drilling at the Cumberland prospect started in early November 2004. The Cumberland #1-16 State well reached total drilling depth of 10,860 feet in the Nugget Sandstone. Based on preliminary log analysis, the Nugget zone of interest appears to be nonproductive, and the well will be plugged and abandoned. Further evaluation of the log data will be analyzed and studied to determine any remaining prospective targets within our 6,233 net leasehold area of mutual interest ("AMI"). PYR participated in the drilling of the well at a 10% working interest and was carried for an additional 22.5% working interest to casing point.

Ryckman Creek Project. We have recently leased approximately 1,820 net acres, covering the majority of the abandoned Ryckman Creek field, in the Overthrust of southwestern Wyoming. Ryckman Creek, located 5 miles southwest of our Cumberland prospect, was discovered in 1975 and produced approximately 250 Bcfe prior to abandonment. We believe that significant remaining recoverable gas reserves were stranded in Ryckman Creek upon abandonment. We are currently analyzing production and geologic data to determine potential reserves in multiple zones, including the Twin Creek, Nugget, and Thaynes Formations, in the field. Due to winter activity restrictions, it is anticipated that a well may be drilled at Ryckman Creek in mid-2005, and based on our analysis, we may decide to sell part of our 100% working interest in the project.

INTERESTS ACQUIRED FROM VENUS EXPLORATION, INC.:

In May 2004, we acquired interests from Venus Exploration, Inc. ("Venus") in certain producing properties with estimated proved reserves of 4.784 Bcfe for approximately $3,230,000 (excluding acquisition expenses and subject to retention, by the Venus Exploration Trust, of a net profits interest covering the non-productive exploration projects). This equates to $0.67 per Mcf, with a PV-10 value of $6.94 million. The purchase also provides for us to pay a net profits interest payable to the Venus Exploration Trust. The net profits interest, which applies only to the exploration and exploitation projects on the Venus acreage being acquired, varies from 25% to 50% with respect to different

Venus exploration and exploitation project areas, and decreases by one-half of its original amount after a total of $3,300,000 in net profits proceeds has been paid to the Trust. Venus was in Chapter 11 Bankruptcy, and the properties were acquired through public auction as approved by the United States Bankruptcy Court. To finance the purchase, we primarily used existing cash reserves and also a portion of the proceeds from a private placement of common stock.

Oil and gas interests acquired from Venus include producing oil and gas properties, exploitation drilling projects, and exploration acreage. The assets acquired include interests in 80 non-operated wells in Utah, Oklahoma and Texas.

In Texas, we have interests in three projects that were drilled and completed over this past summer. Two of the three wells, the Nome and Madison Prospects, were completed as producers and are currently flowing to sales lines. These two successful projects are, upon reaching payout, subject to a 50% net profits interest payable to the Venus Exploration Trust.

Tortuga Grande prospect, located in east Texas, is a project to test the productivity of the Cotton Valley Sand section at depths ranging from 13,000 to 14,500 feet. Drilled originally in 1984 for deeper targets, the Brady #1 is the only deep well on the structure, and had shows in the Cotton Valley Sand, but was never fracture stimulated. Log analysis indicates that the well contains approximately 322 feet of potential pay greater than 8% porosity. The Brady #1 was re-entered and the middle Cotton Valley Sand section was fracture stimulated and tested. Results of the test were inconclusive and the partners continue to evaluate the test data. The partners may decide at a future date to drill another well to test the Cotton Valley within the project area. Should this occur, PYR would be responsible for 20% of the costs of any additional well. In all additional locations within the Tortuga Grande area of mutual interest, we will participate with a cost bearing 20% working interest. We currently control approximately 5,600 net leasehold acres within the project. It is anticipated that the partners will drill another test well at Tortuga Grande during the second quarter of 2005.

Nome Field was discovered in 1994, and our interpretation of subsequently acquired 3D seismic over the field indicates the presence of numerous undeveloped fault blocks. Multiple structural closures and associated bright spot locations have been identified at Nome based on the 3D seismic. PYR owns a 1.5% overriding royalty interest with an additional 8.33% working interest, after project payout, in the project. Production in the Sun Fee #1 well, from the upper Yegua, was initiated in late May 2004, and over the past three months (October through December), the well has averaged production of 15.34 Mmcfe per day. Cumulative production since inception is in excess of 2.5 Bcfe. After project payout, it is estimated that the well will add approximately 1MMcfe of net daily production to PYR, given current production rates. During the quarter ended November 30, 2004, we received confirmation from the operator that the Sun Fee #1 well and project reached payout, and that PYR is currently a working interest participant in the well. We and our partners control approximately 4,200 acres of gross leasehold acres in the project.

We are currently in dispute with the operator of the Sun Fee #1, Sampson Lone Star L.P. ("Sampson"), concerning the pooling of certain lands into the production unit. The pooling of these lands in which the Company does not own an interest, comprises approximately 32% of the unit area, and may result in a reduction of working interest and net revenue interest, relative to production from the Sun Fee #1, attributable to the Company. If the current pooling were to stand, our working interest in the well would be reduced from 8.33% to 5.66%. The Company strongly believes that the lands in question are `Non-Productive', and therefore not eligible for pooling, based on all available geological, seismic, and existing well data. As a result of this dispute, we will vigorously pursue and defend our rights to our proportionate share of production and revenue from the Sun Fee #1 with all legal avenues and remedies available. For this reason, the Company has not signed any of the proposed production and revenue division orders, and has not received any revenue, attributable to the well, to date. If we undertake legal action against the operator relative to this issue, which we currently intend, it may result in all revenues attributable to the Sun Fee #1 well being held in suspense until the legal action is completed.

For the quarter ended November 30, 2004, we accrued approximately $325,000 in royalty and working interest revenues from the Sun Fee #1. As a result of the dispute with Sampson, revenues were accrued at the lower working interest percentage (5.66%) as stated by the operator. Both revenues and costs associated with the production from the Sun Fee #1, as well as the costs incurred on the Nome Project, are subject to the net profits interest agreement we hold with Venus Exploration Trust ("Trust"). The net profits interest agreement arose out of the acquisition of properties from Venus Exploration Inc. ("Venus") in May 2004. The agreement varies from 25% to 50% with respect to different Venus exploration and exploitation project areas, and decreases by one-half of its original amount after a total of $3,300,000 in net profits proceeds has been paid to the Trust. The amount of net profits interest liability recognized over time is subject to fluctuation, because both revenues and costs associated with production from any wells and other costs incurred on the designated exploration and exploitation project areas will increase or decrease over a given period of time. As of November 30, 2004, we accrued a net profits interest liability of $122,366 payable to the Trust.

Madison prospect, located in the northern part of the Constitution Field, is an exploitation project to test multiple sand intervals within the expanded Yegua section, downthrown to a major growth fault. The prospect involves sidetracking an existing cased hole updip to test multiple sand targets at a location offsetting, but significantly high to Doyle sand production from the Texaco #1 Doyle well within the field. The location is also offset to the Texaco #1 Sanders Gas Unit well, which tested the Doyle sand interval at a rate of 1,176 Bc/d and 2.7 MMcf/d with no water. This well was subsequently plugged and abandoned in the Doyle interval and never produced from the zone. The Maness Gas Unit location represents a proved undeveloped location for Doyle sand, 183 feet structurally high to the equivalent produced zone in the Texaco Doyle #1 well. The current well has been drilled to total depth, production casing has been run, and the well is currently producing at a rate of approximately 5.00 MMcfe per day. We own a 0.5% overriding royalty interest that converts to a 12.5% working interest in the project after payout (which has not been reached) of the initial test well. The operator has converted an existing wellbore within the project area into a water disposal well, and is planning to drill an offset development well (Maness GU#2). The cost of the water disposal well will be covered under the payout account, and we will participate for 12.5% working interest in the drilling of this low risk development well. It is anticipated that the offset well will begin drilling operations in late January 2005.

The Cotton Creek prospect, located in Jefferson County, Texas, is adjacent to the Nome project. The prospect is located approximately one mile west of the productive Sun Fee #1 well in the same structural fault block. PYR owns a 50% working interest in the project and controls with its partner approximately 500 acres of leasehold.

The South Wharton prospect, located in Wharton County, Texas, is an exploration project designed to test several stratigraphic intervals within the expanded Yegua section in multiple structural features as defined by 3D seismic data. Drilling targets are estimated to be at depths between 11,000 and 13,500 feet. PYR owns a 58% working interest in the project and in excess of 1,065 gross acres are currently under lease.

The Merganser prospect, located in Leon County, Texas, targets Cotton Valley and Bossier sandstone reservoirs in an undrilled structural feature defined by 3D seismic data. The prospect occupies a fault-bounded salt-withdrawal trough resulting in potential significant thickening of the Bossier and Cotton Valley sand sections. The prospect location is structurally and stratigraphically downdip from Cotton Valley production as well as updip from recent Bossier productive discoveries. PYR owns 100% of the prospect and controls in excess of 1,500 gross acres of leasehold.

The Orbison #3-11 development well is a low risk prospect located in eastern Oklahoma. PYR hopes to spud this by the end of January and has a working interest of 29% in the well.

The Bayou Duralde Project, located in Evangeline Parish, LA, is an exploration program to identify and drill potential gas reservoirs in Yegua/Cockfield channel complexes. PYR owns a 25% working interest in the project and controls, along with its partner, in excess of 3,000 net acres of leasehold. It is anticipated that the initial test well in the project will be drilled in the next few months, and PYR will participate with a 15% cost bearing interest and farm-out the remainder of its working interest.

The Canadian River Project, located in Oklahoma, we are preparing to drill a Cromwell development well. PYR has a 28.98% WI in the well, and drilling activities are expected to begin by late January 2005.

SOUTHEAST ALBERTA SHALLOW GAS REDEVELOPMENT PROJECT:

We have entered into two joint ventures, the Atlas Joint Venture and the Blue River Joint Venture, to redevelop shallow gas reserves in southeastern Alberta, Canada. Southeastern Alberta has been the site of significant shallow gas development drilling and production over the last two decades. We have undertaken geologic and engineering studies of the region, and believe that many wellbores in the region were prematurely suspended and/or abandoned due to water coning and production. These premature well abandonments suggest the possibility that significant additional reserves may remain in a number of shallow gas reservoirs in local areas within the Southeastern Alberta.

We own a 5% working interest in the Atlas Joint Venture, which has identified multiple potential re-entry and redevelopment opportunities for which the Joint Venture intends to acquire the right to participate. The first well has been re-entered, re-perforated, and completed in the upper Bow Island sand. The well is currently producing into a sales line during long term testing. An offset wellbore is currently being permitted for re-entry based on results from the initial well. A number of other prospects are being leased and permitted at this time.

We also own a 25% working interest in the Blue River Joint Venture, which intends to operate in different areas of southeastern Alberta. Initial investigation indicates multiple wells that exhibit an appropriate production type decline curve, potential disposal interval, and gas reservoir. We are currently undertaking detailed geologic and production analysis to refine certain areas, for which the Joint Venture will undertake to acquire and develop prospects for recompletion or drilling.

SAN JOAQUIN BASIN, CALIFORNIA

Wedge Prospect. This is a seismically identified Temblor prospect located northwest of and adjacent to the East Lost Hills deep gas discovery. During the first fiscal quarter of 2001, we acquired approximately 17 miles of proprietary, high effort 2D seismic data and combined this data with existing 2D seismic data in order to refine what we interpret as the up-dip extension of the East Lost Hills structure. Our seismic interpretation shows that the same trend at East Lost Hills extends approximately ten miles further northwest of the East Lost Hills Area of Mutual Interest and can be encountered as much as 3,000 feet higher. Despite repeated attempts to facilitate drilling interest at Wedge during 2003, no industry interest was generated sufficient to put together a drilling partnership during the year. As a result, PYR re-evaluated its acreage position at Wedge and made the decision to consolidate the leasehold by abandoning non-core prospect acreage in the project area. We currently control approximately 3,500 gross and net acres here. Our approach is to sell down our working interest to industry partners, and retain a 25% to 50% working interest in this prospect.

Bulldog Prospect. This project is a 2D seismically identified natural gas and condensate prospect located adjacent to the giant Kettleman North Dome field in the San Joaquin Basin. This prospect can be best characterized as a classic footwall fault trap, similar to the many known footwall fault trap accumulations that have produced significant quantities of hydrocarbons throughout the San Joaquin basin. During 2003, we re-evaluated our acreage position at Bulldog and consolidated the leasehold by releasing approximately 3,200 non-core acres in the project area. We currently control approximately 11,900 gross and net acres here. We expect to sell down our working interest in this project and retain a 25% to 50% working interest in the prospect acreage.

Blizzard Prospect. This project is a 3D seismic derived exploration and exploitation program offsetting the Rio Viejo field at the south end of the San Joaquin Basin. A linear sand body, stratigraphically higher than any of the productive Rio Viejo sands, has been identified, north of the field, on the seismic data and represents an exploration opportunity for new reserves. Additionally, analysis of the seismic data over the field suggests that up to two additional undrilled field exploitation locations may exist. PYR owns 100% of the prospect and controls approximately 2,500 net and gross acres.

CASH FLOW

The three months ended November 30, 2004 ("2004") compared with the three months ended November 30, 2003 ("2003").

CASH FLOWS FROM OPERATING ACTIVITIES

Net cash provided (used) by operating activities was $394,706 and ($267,266) for the quarters years ended November 30, 2004 and 2003, respectively. A discussion of these and other items are presented below.

Net loss. See discussion of net income (loss) in "Results of Operations" section below.

Depreciation and amortization. Depreciation and amortization expense was $38,037 for the quarter ended November 30, 2004, compared to $40,120 for the quarter ended November 20, 2003. The 2004 expense includes $34,822 of depletion of oil and gas properties. The 2003 expense includes depreciation of Asset Retirement Obligation assets of $37,821.

Accounts receivable. For the quarters ended November 30, 2004 and 2003, accounts receivable increased $590,736 and $0, respectively. The increase in

2004 related principally to receivables generated from the properties acquired from Venus Exploration, Inc. in May 2004.

Accrued interest converted into debt. For the quarter ended November 30, 2004, accrued interest converted into debt was $166,611 compared to $158,577 for the quarter ended November 30, 2003. Both amounts reflect interest accrued on the $6,000,000 convertible notes issued May 24, 2002.

Accretion of asset retirement obligation. During the quarters ended November 30, 2004 and 2003, accretion of unamortized discount of the Asset Retirement Obligation liability was $6,300 and $21,152, respectively. The prior quarter is higher because the estimated lives of the East Lost Hills properties escalated the accretion rate, while the current quarter includes properties (acquired from Venus Exploration Inc. in May 2004) with longer estimated lives, and hence a lower accretion rate.

Prepaid expenses and other. During the quarter ended November 30, 2004, prepaid expenses decreased $74,253, compared to a increase of $78,684 during the quarter ended November 30, 2003. The decrease in 2004 primarily reflects timing of payments. The increase in 2003 reflected the payment of Directors and Officers liability insurance premiums during the quarter.

Accounts payable. During the quarter ended November 30, 2004, accounts payable and accruals increased $101,015 compared to a decrease of $7,381 during the quarter ended November 30, 2003. The change in the current quarter primarily reflects increased payables activity as a result of the properties acquired from Venus in May 2004. The decrease in 2003 primarily reflected timing of payments.

Net profits interest liability. During the quarter ended November 30, 2004, the net profits interest liability increased $122,366, compared to $0 in the quarter ended November 30, 2003. The net profits interest agreement with Venus Exploration Trust ("Trust") agreement arose out of the acquisition of properties from Venus Exploration Inc. ("Venus") in May 2004. The current quarter increase resulted from an accrued liability to the Trust for net profits realized on the Sun Fee #1 well in the Nome Project.

Accrued expenses. During the quarter ended November 30, 2004, accrued expenses increased $415,031, compared to a decrease of $40,045 in the quarter ended November 30, 2003. The change in the current quarter primarily reflects increased lease operating and capital costs incurred as a result of the properties acquired from Venus in May 2004, as well as accrued costs for the Cumberland and Mallard prospects. The increase was partially offset by the conversion of accrued interest payable into convertible debt. The $6,000,000 convertible notes were issued on May 24, 2002. The decrease in 2004 also relates to the same conversion of accrued interest payable into convertible debt.

CASH FLOWS FROM INVESTING ACTIVITIES

Cash paid for oil and gas properties. During the quarter ended November 30, 2004, we paid $1,220,406 for oil and gas properties, compared to $276,389, during the year ended August 31, 2003. The increase in 2004 principally reflects activity resulting from the acquisition of properties from Venus in May 2004. The increase in 2003 relates to costs incurred on exploration projects in the California and the Rocky Mountain regions.

Proceeds from sale of exploration options. During the year ended August 31, 2004, we signed an Exploration Option Agreement with Suncor Energy Natural Gas America, Inc. ("SENGAI"), covering our Rogers Pass exploration project in the Foothills of west-central Montana. On August 31, 2004, SENGAI exercised its option to drill an initial test well and paid us $750,000 in the form of a prospect fee, which was received in September 2004. We received $0 in proceeds from the sale of exploration options during the quarter ended November 30, 2003.

Proceeds from sale of oil and gas properties. We received $25,000 in prospect fees from a private company in connection with our Madison project during the quarter ended November 30, 2004. We received $0 in proceeds from the sale of oil and gas properties during the quarter ended November 30, 2003.

CASH FLOWS FROM FINANCING ACTIVITIES

Cash provided by financing activities was $0 for the quarters ended November 30, 2004 and 2003, respectively.

Results of Operations

The three months ended November 30, 2004 ("2004") compared with the three months ended August 31, 2003 ("2003"). Operations during the quarter ended November 30, 2004 resulted in net income of $61,032 compared to a net loss of ($361,802) for the quarter ended November 30, 2003.

Oil and Gas Revenues and Expenses. During the quarter ended November 30, 2004, we recorded $1,082,510 in total oil and gas revenues. Of this amount, we recorded $445,986 from the sale of 63,057 mcf of natural gas for an average price of $7.07 per mcf, and $636,523 from the sale of 13,978 bbls of hydrocarbon liquids for an average price of $45.54 per bbl. During the quarter ended November 30, 2003, we recorded $40,018 in total oil and gas revenues. Of this amount, we recorded $30,717 from the sale of 7,487 mcf of natural gas for an average price of $4.10 per mcf and $9,301 from the sale of 402 bbls of hydrocarbon liquids for an average price of $23.13 per barrel. 2004 revenues increased largely due to the acquisition of properties from Venus Exploration Inc. in May 2004, while 2003 revenues related wholly to the Company's interest in East Lost Hills in California. Comparable revenues for the East Lost Hills property during the quarter ended November 30, 2004 were $42,898. Lease operating expenses during the quarters ended November 30, 2004 and 2003, respectively, were $280,576 and $15,271.

Interest Income. We recorded $20,299 and $5,567 in interest income for the quarters ended November 30, 2004 and 2003, respectively. The increase was due to interest on the funds received from the private placement of our common stock in May 2004.

General and Administrative Expenses. General and administrative expenses during the quarters ended November 30, 2004 and 2003 were $511,387 and $251,490, respectively. The increase principally reflects an increase in salaries as a result of hiring additional personnel and an increase in audit and legal fees, both of which resulted from the acquisition of properties from Venus Exploration Inc. in May 2004.

Depreciation Depletion and Amortization. We recorded $34,822 and $0, respectively, in depreciation, depletion and amortization expense from oil and gas properties for the quarters ended November 30, 2004 and 2003. We recorded no depreciation, depletion and amortization expense from oil and gas properties for the quarter ended November 20, 2003, due to an impairment taken against our entire amortizable full cost pool at August 31, 2003, and accordingly, there were no costs to amortize; however, included in depreciation expense reported for 2003, is $37,821 of depreciation of Asset Retirement Obligation assets. The current fiscal quarter increase in depreciation, depletion and amortization expense was attributable to the properties acquired from Venus Exploration, Inc. We recorded $3,215 and $2,299 in depreciation expense associated with capitalized office furniture and equipment during the quarters ended November 30, 2004 and 2003, respectively.

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Accretion Expense. We recorded $6,300 and $21,152, respectively, for the quarters ended November 30, 2004 and 2003, of accretion of the unamortized discount of the Asset Retirement Obligation liability. The prior quarter is higher because the estimated lives of the East Lost Hills properties escalated the accretion rate, while the current quarter includes properties (acquired from Venus Exploration Inc. in May 2004) with longer estimated lives, and hence a lower accretion rate.

Net Profits Interest Expense. The net profits interest agreement with Venus Exploration Trust ("Trust") agreement arose out of the acquisition of properties from Venus Exploration Inc. ("Venus") in May 2004. The agreement varies from 25% to 50% with respect to different Venus exploration and exploitation project areas, and decreases by one-half of its original amount after a total of $3,300,000 in net profits proceeds has been paid to the Trust. As of November 30, 2004, we accrued net profits interest expense of $122,366, in connection with net profits realized for the Sun Fee #1 well at November 30, 2004. For the quarter ended November 30, 2003, there was no net profits interest expense recognized.

Interest Expense. During the quarters ended November 30, 2004 and 2003, we recorded interest expense of $83,333 and $79,354, respectively. The interest expense for each year is associated with the May 24, 2002 sale of outstanding convertible notes due on May 24, 2009. The Company elected to add $166,611 and $158,577 of accrued interest to the balance of the debt for the quarters ended November 30, 2004 and 2003, respectively. We have reflected the outstanding balance of these notes as Convertible Notes under Long Term Debt on our November 30, 2004 and 2003 consolidated balance sheets.

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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, including the following: the amount and timing of actual production; 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 incurred which are directly related to oil and gas exploration and development 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.

Asset Retirement Obligations:

In 2001, the FASB issued SFAS 143, Accounting for Asset Retirement Obligations. SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This statement requires companies to record the present value of obligations associated with the retirement of tangible long-lived assets in the period in which it is incurred. The liability is capitalized as part of the related long-lived asset's carrying amount. Over time, accretion of the liability is recognized as an operating expense and the capitalized cost is depreciated over the expected useful life of the related asset. The Company's asset retirement obligations relate primarily to the plugging, dismantlement, removal, site reclamation and similar activities of its oil and gas properties. Prior to adoption of this statement, such obligations were accrued ratably over the productive lives of the assets through depreciation, depletion and amortization of oil and gas properties without recording a separate liability for such amounts.

Recent Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 123(R), "Share-Based Payment". This statement requires all entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. SFAS No. 123(R) is effective the first reporting period beginning after December 15, 2005. Due to the recent adoption of SFAS No. 123(R), the Company has not determined the future impact on its financial statements; however, it will result in additional future financial reporting expense to the Company when implemented.

ITEM 3. 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 the principal executive officer and principal 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, the principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to ensure that the information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. There was 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
Not Applicable

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
31	Rule 13a-14(a) Certifications of Chief Executive Officer and Principal Financial Officer
32	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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/ D. Scott Singdahlsen D. Scott Singdahlsen	President, Chief Executive Officer and Principal Financial Officer	January 14, 2005