PYR ENERGY CORP
Form 10QSB
July 15, 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 May 31, 2005

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 May 31, 2005 is as follows:

$.001 Par Value Common Stock	31,625,259

PART I

ITEM 1. FINANCIAL STATEMENTS

PYR ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	May 31, 2005 (Unaudited)	August 31, 2004
ASSETS		
CURRENT ASSETS		
Cash	$ 3,971,213	$ 6,038,156

Oil and gas receivables	2,227,978	477,176
Other receivables	131,060	--
Exploration option receivable	--	750,000
Prepaid expenses and other assets	88,419	102,239
Total Current Assets	6,418,670	7,367,571
PROPERTY AND EQUIPMENT, at cost		
Oil and gas properties, full cost method	41,041,767	38,146,298
Furniture and equipment	149,308	138,699
	41,191,075	38,284,997
Less accumulated depreciation, depletion, amortization and impairment	(29,859,607)	(29,406,910)
Property and equipment, net	11,331,468	8,878,087
OTHER ASSETS		
Deferred financing costs and other assets	62,679	65,070
	$ 17,812,817	$ 16,310,728
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable, trade	$ 699,027	$ 83,042
Accrued liabilities	404,417	354,400
Net profits interest liability	638,545	--
Asset retirement obligation	868,163	868,163
Total Current Liabilities	2,610,152	1,305,605
LONG TERM LIABILITIES		
Convertible notes	6,957,979	6,623,351
Asset retirement obligation	319,257	289,489
Total Long Term Liabilities	7,277,236	6,912,840
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 - 31,625,259 at 5/31/05 and 31,564,426 shares at 8/31/04	31,625	31,564
Capital in excess of par value	43,278,211	43,221,391
Accumulated deficit	(35,384,407)	(35,160,672)
	7,925,429	8,092,283
	$ 17,812,817	$ 16,310,728

See accompanying notes to Consolidated Financial Statements.

PYR ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(UNAUDITED)

	Three Months Ended 5/31/2005	Three Months Ended 5/31/2004	Nine Months Ended 5/31/2005
REVENUES			
Oil and gas revenues	$ 1,637,202	$ 184,551	$ 3,915,383
OPERATING EXPENSES			
Lease operating expenses	283,851	77,958	767,580
Impairment, dry hole, and abandonments	579,792	--	579,792
Depreciation and amortization	247,614	43,955	452,697
Asset retirement obligation accretion expense	3,500	27,858	16,107
Net profits interest expense	283,591	--	638,545
General and administrative	487,854	350,377	1,496,910
	1,886,202	500,148	3,951,631
LOSS FROM OPERATIONS	(249,000)	(315,597)	(36,248)
OTHER INCOME (EXPENSE)			
Interest income	26,045	4,921	71,177
Other income (expense)	(5,660)	1,020	(4,632)
Interest (expense)	(86,358)	(82,234)	(254,033)
	(65,973)	(76,293)	(187,488)
NET LOSS	$ (314,973)	$ (391,890)	$ (223,736)
NET LOSS PER COMMON SHARE -BASIC AND DILUTED	(0.01)	(0.02)	(0.01)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING - BASIC AND DILUTED	31,616,772	24,930,795	31,582,213

See accompanying notes to Consolidated Financial Statements

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PYR ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Nine Months Ended 5/31/2005	Nine Months Ended 5/31/2004
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$ (223,736)	$(1,155,550)

Adjustments to reconcile net loss to net cash used by operating activities		
Depreciation and amortization	452,697	125,879
Impairment, dry hole and abandonments	579,792	--
Accretion of asset retirement obligation	16,107	70,162
Amortization of financing costs	2,391	2,390
Interest converted to debt	334,628	319,376
Stock options granted for director services	15,248	--
Changes in assets and liabilities		
(Increase) in accounts receivable	(1,884,704)	(328,787)
(Increase) decrease in prepaid and other assets	16,662	(51,382)
Increase in accounts payable and accrued liabilities	189,429	88,891
Increase in net profits liability	638,545	--
Other	--	(10,000)
Net cash provided (used) by operating activities	137,059	(939,021)
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures for furniture and equipment	(10,609)	(3,161)
Capital expenditures for oil and gas properties	(3,034,306)	(3,887,304)
Proceeds from exercise of exploration options	750,000	500,000
Proceeds from sale of oil and gas properties	49,280	186,014
Net cash used in investing activities	(2,245,635)	(3,204,451)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from sale of common stock	--	4,430,269
Proceeds from exercise of stock options	41,633	12,084
Net cash provided by financing activities	41,633	4,442,353
NET (DECREASE) INCREASE IN CASH	(2,066,943)	298,881
CASH, BEGINNING OF PERIOD	6,038,156	3,657,938
CASH, END OF PERIOD	$ 3,971,213	$ 3,956,819

See accompanying notes to Consolidated Financial Statements.

PYR ENERGY CORPORATION
Notes to Consolidated Financial Statements
May 31, 2005
(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 and nine months ended May 31, 2005 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 recoverability 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.

Loss Per Share - Basic loss per common share is computed by dividing net loss attributed to common stock by the weighted average number of common shares outstanding during each period. Diluted 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. Dilutive loss per share for the quarters ended and nine month period ended May 31, 2005 and 2004 equal basic loss per common share as the effect of convertible equity instruments would be 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 loss and loss per share for the periods ended May 31, 2005 and May 31, 2004 would have been increased to the pro forma amounts indicated below:

	Three Months Ended 5/31/2005	Three Months Ended 5/31/2004	Nine Months Ended 5/31/2005	Nine Months Ended 5/31/2004
Net loss as reported	$ (314,973)	$ (391,890)	$ (223,736)	$(1,155,550)
Deduct: stock-based compensation costs under SFAS No. 123	(82,839)	(184,070)	(248,517)	(479,134)
Pro forma net loss	$ (397,812)	$ (575,960)	$ (472,253)	$(1,634,684)
Pro forma basic and diluted net loss per share:				
As reported	$ (0.01)	$ (0.02)	$ (0.01)	$ (0.05)
Pro forma	$ (0.01)	$ (0.02)	$ (0.01)	$ (0.06)

Reclassification - Certain reclassifications have been made to the May 31, 2004 financial statements to conform to May 31, 2005 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 August 31, 2006. 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 which the Company believes will be somewhat comparable to the proforma amounts presented in the Share Based Compensation table above.

2. OIL AND GAS PROPERTIES:

In May 2004, the Company acquired certain oil and gas properties from Venus Exploration Inc. ("Venus") for cash consideration of $3.2 million. 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"). 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 $3.3 million in net profits proceeds has been paid to the Trust.

As of May 31, 2005, the Company accrued approximately $639,000 net profits interest expense which is payable to the Trust based on the net profits interest agreement.

The Company decided to cease future expenditures on its Canadian properties and projects and to abandon its Canadian full cost pool projects. In accordance to the full cost pool accounting, the Company's Canadian and U.S. projects are accounted for in separate pools. As a result of the decision to abandon the Canadian full cost pool, the Company wrote-off its investment in its Canadian full cost pool and recognized a non-cash impairment expense of approximately $580,000 during the three month period ended May 31, 2005.

3. CONVERTIBLE NOTES PAYABLE:

In May 2002, the Company sold 4.99% convertible promissory notes due May 2009 in the aggregate principal amount of $6.0 million. The notes 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. No beneficial interest has been accrued to the notes, as the conversion price approximates the fair market value of the common shares as of the transaction date. Interest is payable semiannually in May and November.

At the option of the Company, accrued interest can be paid in cash or added to the principal amount of the notes. At November 24, 2004 and May 24, 2005, the Company elected to add accrued interest of approximately $167,000 and $168,000, respectively, to the balance of the notes. As of May 31, 2005, the balance of the notes is approximately $7.0 million.

4. STATEMENT OF CASH FLOWS SUPPLEMENTAL INFORMATION:

	For nine months ended May 31, 2005	2004
Non-cash investing and financing activities:		
Increase in asset retirement obligation	$ 13,661	$169,874
Net increase in payables for capital expenditures	475,000	--
Debt issued for interest	334,628	319,376

5. 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 5.19%. 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 had not received any revenue, attributable to the well, as of May 31, 2005. (See paragraph below concerning payment subsequent to May 31, 2005.) If the operator recognizes our working interest of 8.33%, the increased working interest could potentially result in increased revenue to the Company and increased net profits interest liability to Venus Exploration Trust, subject to the net profits interest agreement (see Note 2).

As of May 31, 2005, the Company had accrued approximately $1.6 million 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 (5.19%) as stated by the operator. Subsequent to May 2005, the Company received approximately $1.4 million of net revenues attributable to the well at the lower working interest percentage for production months of October 2004 through April 2005.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION OR PLAN OF OPERATION

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 exploration activities are focused in select areas of the Rocky Mountains, Texas and Gulf Coast. 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.

Liquidity and Capital Resources

Historically, 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 May 31, 2005, we had approximately $3.8 million in working capital.

As of May 31, 2005, we had cash of approximately $4.0 million, compared to approximately $6.0 million as of August 31, 2004. We principally funded operations and capital expenditures for the nine month period ended May 31, 2005, using (a) $2.0 million of cash on hand at August 31, 2004 and (b) proceeds from the exercise of exploration options, the sale of oil and gas properties and the exercise of stock options. Capital expenditures for oil and gas exploitation activities total approximately $3.0 million for the nine month period ended May 31, 2005 compared with approximately $3.9 million for the same period in 2004. See "Capital Expenditures" and "Summary of Exploration Projects" below for further discussion regarding our current exploitation activities.

Net cash provided by operating activities was approximately $137,000 during the nine month period ended May 31, 2005, compared to approximately $1.0 million of net cash used by operating activities during the same period in 2004. The increase in cash provided by operations is attributed to new revenues net of operating expenditures added from the acquisition of producing properties from Venus in 2004 and new wells drilled. The increase in net operating revenues from oil and gas properties was offset, in part, by an increase in general and administrative expenses.

Net cash used in investing activities decreased from approximately $3.2 million for the nine month period ended May 31, 2004 to approximately $2.2 million for the same period in 2005. Investing activities for the nine month period ended May 31, 2005 consist principally of oil and gas property exploration and development costs and lease acquisition costs which were reduced, in part, by proceeds received from the sale of oil and gas properties and proceeds received from the exercise of an exploration option. Investing activities for the nine month period ended May 31, 2004 was principally comprised of acquisition costs associated with the purchase of the Venus properties offset, in part, from the sale of oil and gas properties and proceeds received from the exercise of exploration options.

Net cash flows provided by financing activities totaled approximately $42,000 for the nine period ended May 31, 2005 compared with approximately $4.4 million for the same period in 2004. The financing activities for the nine month period in 2005 consisted principally of proceeds received from the exercise of stock options. Financing activities for the same period in 2004 consisted principally of funds received from the sale of common stock.

In May 2002, the Company sold 4.99% convertible promissory notes due May 2009 in the aggregate principal amount of $6.0 million (the "Convertible Notes"). The Convertible Notes 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.

At the option of the Company, accrued interest can be paid in cash or added to the principal amount of the notes. At November 24, 2004 and May 24, 2005, the Company elected to add interest of approximately $167,000 and $168,000, respectively, to the balance of the Convertible Notes.

Pursuant to requirements of the American Stock Exchange, we are requesting at our annual meeting to be held on August 8, 2005 that our stockholders approve the issuance, in connection with conversion of the Convertible Notes, of up to 1,780,702 shares. These shares would be available for the payment of interest by the Company to the extent that the Company elects to finance the Convertible Notes' interest expense by increasing the principal amount of the Convertible Notes and the Convertible Notes are subsequently converted to shares of the Company's common stock. If this proposal is not approved, the Company may be required to pay in cash a portion of the interest expense incurred on the Convertible Notes and would be limited as to how much interest could be financed through the increase of Convertible Note principal.

It is anticipated that the continuation and future development of our business will require additional, and possibly substantial, capital expenditures. We currently have cash of approximately $4.0 million. As discussed in this report, we currently intend to further develop our business by commencing or increasing our involvement in a variety of projects, all of which require substantial capital. We currently have not secured an additional line of credit available for these projects, nor have we identified sources of funding for these projects. Further, we have no reliable source for additional funds for administration and operations to the extent our existing funds have been utilized. 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 May 31, 2005, we incurred approximately $1.4 million 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.

We currently are participating in the drilling of two exploration wells and anticipate that we may participate in the drilling of up to four additional exploration wells during the calendar year ending December 31, 2005. We also anticipate drilling up to five developmental wells by the end of the calendar year ending December 31, 2005. To date, two development wells in Oklahoma have been drilled and completed, and two additional development wells in Texas have been proposed and approved for drilling prior to calendar year end. However, there can be no assurance that any of these wells will be drilled and, if drilled, that any of these wells will be successful. We anticipate spending a minimum of $3.0 million, possibly up to $7.0 million, on exploration and development activities during the calendar year ending December 31, 2005.

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.

PRODUCTION AND RESERVES

For the quarter ended May 31, 2005, net production totaled 17,482 barrels of oil and 104,033 Mcf of natural gas or 208,925 Mcfe compared to 12,615 barrels of oil and 81,655 Mcf of natural gas (157,343 Mcfe) for the quarter ended February 28, 2005, resulting in a 33% increase in net production quarter to quarter. Average daily production for the quarter ended May 31, 2005 increased 30% to 2,271 Mcfe per day from 1,748 Mcfe per day for the previous quarter. The increases in net and daily production was primarily due to continued strong production at the Nome field and production from the Maness GU #1 well in the Constitution field, in which the Company gained a 12.5% working interest upon reaching payout of the well during the quarter. As of May 31, 2005, current Company net production is in excess of 2,400 Mcfe per day.

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Estimated total proved reserves, at calendar year end (December 31, 2004), were 6.73 Bcfe based on external estimation. Estimated 'total proved' reserves at December 31, 2004 increased by 22% when compared to estimates made at August 31, 2004, and by 41% when compared to the estimated 'total proved' reserves on May 31, 2004. The increase in 'total proved' reserves results from additions to the 'proved developed producing' and 'proved undeveloped' classification attributable to several new discoveries resulting from drilling, primarily in South Texas. The external estimated 'total proved' reserves includes the addition of 'proved developed producing' reserves at the Sun Fee #1-ST well in Jefferson County, Texas, where the Company's working interest is currently under dispute with the operator of the well. Reserves for the well were estimated using the Company's claimed higher working interest of 8.33%. Reserve estimations using the operator's proposed working interest of 5.19%, currently being used to accrue revenue, results in a reduction of 'proved developed producing' reserves of 101 MMcfe giving 'total proved' reserves estimated at 6.63 Bcfe. Present value, discounted at 10%, for the 'total proved' reserves is estimated to be $14.49 million at December 31, 2004, compared to $6.94 million estimated at May 31, 2004. The 109% increase in estimated present value is attributable to higher product prices and increased reserves from drilling.

SUMMARY OF EXPLORATION PROJECTS

Our exploration activities are focused primarily in select areas of the Rocky Mountains, Texas and the Gulf Coast. 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).

On March 11, 2005, drilling activities began at the Company's Rogers Pass Project in the Montana Foothills. The Suncor Energy Natural Gas America, Inc #14063-12 Flesher Pass well, located approximately twenty-five miles northwest of Helena, Montana, will test a potential structural closure within the Montana Foothills trend. Anticipated target depth for the prospect is estimated to be approximately 16,000 feet. 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 approximately $1.3 million and drill a second test well, expected 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.

The Flesher Pass well has reached total drilling depth of approximately 16,000 feet and is currently being evaluated. Due to the frontier wildcat nature of this project, extensive drilling and evaluation of results will be required to determine the economic viability of the project. As such, the Company will not release nor comment on any preliminary drilling results until SENGAI, the project operator, reaches a conclusion on the viability of the project. The evaluation process for the project will take an undetermined amount of time to analyze and complete.

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 suspended drilling activities at Mallard, effective December 1, 2004, due to wildlife critical winter range restrictions. As a result, the well was temporarily suspended and secured in compliance with applicable federal and state regulations, until the wildlife restrictions are lifted in mid - 2005. A drilling rig has been contracted, and it is anticipated that the well will be re-entered in mid-August 2005, and drilled to a location that geological analysis has suggested is more structurally advantageous to test the southern end of the Whitney Canyon Field. PYR will participate in the drilling activity with a 28.75% cost-bearing working interest. The Company will also participate in the acquisition of approximately 20 square miles of 3-D seismic data over the

Mallard prospect to help delineate additional drilling opportunities.

Cumberland Project. Drilling at the Cumberland prospect located within the Overthrust Belt of southwest Wyoming, 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 log analysis, the Nugget zone of interest was nonproductive and the well has been plugged and abandoned. As a result, PYR has included the abandoned well and acreage costs in its full cost pool depletable asset base in accordance with U.S. GAAP rules.

Ryckman Creek Project. We have 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 rig availability timing, it is anticipated that re-development of the Ryckman Creek project will not occur until sometime in 2006.

TEXAS AND GULF COAST EXPLORATION:

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 $3.3 million (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 net profits interest that we are required to pay to the Trust, 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 $3.3 million in net profits proceeds has been paid to the Trust. Venus was in Chapter 11 Bankruptcy, and we acquired the properties through public auction as approved by the United States Bankruptcy Court. To finance the purchase, we primarily used existing cash reserves and 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 during the summer of 2004. Two of the three wells, the Nome and Madison Prospects, were completed as producers and are currently flowing to sales lines. Having reached payout, these two successful projects are 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 well, recompleted last summer, tested a combination of gas and water during the re-entry and fracture stimulation of the Cotton Valley Sand section. PYR was carried for 20% working interest in the Brady re-entry. On June 7, 2005, drilling activity began on a second well in the Tortuga Grande project. The Chisum #1 well, operated by Carrizo Oil and Gas Inc, is projected to a target depth of approximately 14,000 feet, and is designed to test a potentially thicker section of Cotton Valley Sand in a more favorable structural position to the Brady #1 well. PYR exercised its rights to acquire additional working interest in the prospect, and has increased its participation in the well to 28.57% working interest. We currently control approximately 5,600 net leasehold acres within the project.

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 the well began averaging approximate production of 19MMcfe per day beginning in early June 2005. Cumulative production since inception is in excess of 5.2 Bcfe through mid-June, 2005. Payout on the Sun Fee #1 occurred on October 13th, 2004 and 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. A drilling AFE has been circulated and approved for the drilling of a well (Tindall #1) offsetting by approximately 1600 feet, the Sun Fee GU #1-ST. It is anticipated that this development well will be drilled in late summer 2005. PYR believes this offset well could be as productive as the Sun Fee #1 and our working interest in the Tindall #1 is 77.08%.

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 5.19%. 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.

As a result of the dispute with Sampson, revenues were paid at the lower working interest percentage (5.19%) as stated by the operator. As of June 30, 2005 PYR has been paid nearly $1.4 million on the Sun Fee #1 and has attained regular pay status, but only with respect to the lower working interest percentage. Both our revenues and costs associated with the production from the Sun Fee #1, as well as our 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 our 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 $3.3 million 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 May 31, 2005, we had accrued a net profits interest liability of $639,000 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 Bcf/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 Maness GU#1 well started production in mid-August 2004, and since inception, the well has cumulative production in excess of 1.2 Bcfe, through mid-June 2005. Payout has been reached in the Maness GU #1 well, and PYR has been placed in pay status with a 12.5% working interest. The well is currently producing at a rate of approximately 5.00 MMcfe per day The operator has converted an existing well bore 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 development well.

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. It is anticipated that an initial test well will be drilled in the second half of 2005. PYR will retain approximately 25% working interest in the well and intends to farmout the remainder of its interest to an industry partner.

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.

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. PYR intends to participate with a 15% cost bearing interest and farmout the remainder of its working interest. It is anticipated that the initial test well at Bayou Duralde will begin drilling operations in late summer 2005, contingent upon contracting an available drilling rig.

In the Canadian River Project, located in eastern Oklahoma, the Orbison #3-11, a Cromwell development well operated by Questar, started drilling in mid-March. The well has been completed and is hooked up to a sales line for commingled production from the Cromwell and Wapanucka zones at an approximate rate of 600 Mcf per day. PYR has a 28.98% WI in the well.

At the Wilburton Field in Latimer County, Oklahoma, BP America Inc., recently drilled and completed the Scharff #4-1 well. Initial completion of the Lower Atoka (Cecil) formation has resulted in production rates of approximately 25 MMcf per day. Perforation and stimulation of additional zones within the Cecil are expected in the near future which may increase the production rate substantially. PYR owns a 2.42% working interest in the Scharff #4-1 well.

Hansford Project, located in the Texas panhandle, is a development project at the southern end of the Houghton Embayment. Main producing horizons within the Hansford area include the upper and lower Morrow as well as the Chester. Purchased originally as part of the Venus Exploration acquisition, the Company has recently purchased additional working interest in two wells and associated undeveloped acreage at Hansford. Approximately 42% working interest in the Lackey #152-1 well and acreage, as well as 15% working interest in the Archer Trust well and acreage, were purchased for approximately $440,000. The Company believes that proved undeveloped drilling opportunities targeting gas are available on the acreage that was purchased at Hansford.

SOUTHEAST ALBERTA SHALLOW GAS REDEVELOPMENT PROJECT:

As part of its ongoing business strategy, PYR had been attempting to consolidate and increase its working interest participation in core projects. As a result of these efforts, the Company has decided to cease capital expenditures on certain early stage projects, such as our two joint ventures in southern Alberta, Canada. These joint ventures were intended to employ certain production equipment to limit water production and increase shallow gas production rates. At this point, management has decided to cease future expenditures in Canada and apply the capital to our core projects in the Gulf Coast, East Texas, and the Rocky Mountains. In accordance with US GAAP, the Company wrote down all investments in its Canadian full cost pool as a non-cash charge to earnings of approximately $580,000 in its third quarter ended May 31, 2005.

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 farther 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 intend 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.

Approximately all of the costs associated with the Company's capital expenditures in the San Joaquin Basin are included in the Company's full cost pool depletable asset base in accordance with U.S. GAAP rules.

RESULTS OF OPERATIONS

The quarter ended May 31, 2005 ("2005") compared with the quarter ended May 31, 2004 ("2004").

Operations during the quarter ended May 31, 2005 resulted in a net loss of approximately $242,000 compared to a net loss of approximately $392,000 for the quarter ended May 31, 2004.

Oil and Gas Revenues and Expenses. For the quarter ended May 31, 2005, we recorded approximately $1.6 million in total oil and gas revenues compared with approximately $185,000 for the same period in 2004. The increase in revenues is attributed to the acquisition of oil and gas properties from Venus Exploration Inc. in May 2004 and subsequent drilling. Gas revenues for the third quarter 2005 totaled $748,000 from the sale of 104,333 Mcf of natural gas at an average price of $7.19 per Mcf compared with gas revenues of approximately $61,000 in third quarter of 2004 from the sale of 11,435 Mcf at an average price of $5.32 per Mcf. Oil and plant product revenues for the third quarter 2005 totaled approximately $889,000 from sale of approximately 17,500 Bbls at an average price of $50.84 per Bbl compared with oil and plant product revenues of approximately $124,000 from the sale of 3,362 Bbls at an average price of $ 36.81 per Bbls in the third quarter 2004.

Lease operating expenses during the third quarter ended 2005 and 2004, respectively, were approximately $284,000 and $78,000. The increase is attributable to the Venus wells acquired in 2004 and to new wells drilled.

Impairment, dry hole and abandonments. For the third quarter ended May 31, 2005, we recognized a non-cash impairment of approximately $580,000 for the write-off of the costs incurred on our Canadian properties and projects. As a result of our decision to cease capital expenditures on our Canadian properties and projects, we wrote off our initial investment in our Canadian full cost pool and recognized a non-cash impairment expense.

Depreciation, Depletion and Amortization. We recorded approximately $248,000 and $44,000, respectively, in depreciation, depletion and amortization expense for the third quarter ended 2005 and 2004, respectively. Of these

amounts, we recorded approximately $246,000 and $2,000, respectively, in depreciation, depletion and amortization of oil and gas properties for the quarters ended 2005 and 2004, respectively. The 2005 increase was attributable to the properties acquired from Venus Exploration, Inc. in May 2004, which increased the amount of oil and gas production, and an increase in the amortizable oil and gas asset base due to increased future development costs. Depreciation expense reported for 2004 also includes approximately $39,000 of depreciation of Asset Retirement Obligation assets. We recorded $2,000 and $3,000 in depreciation expense associated with capitalized office furniture and equipment during the quarters ended 2005 and 2004, respectively.

Asset Retirement Obligation Accretion Expense. We recorded $3,500 and $27,858, respectively, for the third quarter ended 2005 and 2004, of accretion of the unamortized discount of the Asset Retirement Obligation liability. The accretion expense for the third quarter 2004 was higher due to an escalation in the accretion rate caused by a reduction in the estimated lives of the East Lost Hills properties. The accretion expense for the third quarter 2005 relates primarily to the properties acquired in 2004 with longer estimated lives resulting in lower accretion rates.

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 net profits interest of the Trust 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 $3.3 million in net profits proceeds has been paid to the Trust. For the quarter ended May 31, 2005, we accrued net profits interest expense of approximately $284,000. For the quarter ended May 31, 2004, there was no net profits interest expense recognized.

General and Administrative Expenses. General and administrative expenses during the quarters ended 2005 and 2004 were approximately $488,000 and $350,000, respectively. The increase principally reflects an increase in salaries as a result of hiring additional personnel, costs of implementation of a new computer system, and an increase in audit and legal fees, all of which resulted from the acquisition of properties from Venus Exploration, Inc. in May 2004.

Interest Income. We recorded approximately$26,000 and $5,000 in interest income for the quarters ended May 31, 2005 and 2004, respectively. The increase was due to interest on the funds received from the private placement of our common stock in May 2004.

Interest Expense. During the quarters ended May 31, 2005 and 2004, we recorded interest expense of approximately $86,000 and $82,000, respectively. The interest expense for each year is associated with the May 24, 2002 sale of outstanding 4.99% convertible notes due on May 24, 2009. We have reflected the outstanding balance of these notes as Convertible Notes under Long Term Debt on our May 31, 2005 and August 31, 2004 consolidated balance sheets.

The nine months ended May 31, 2005 ("2005") compared with the nine months ended May 31, 2004 ("2004").

Operations during the nine months ended May 31, 2005 resulted in a net loss of approximately $151,000 compared to a net loss of approximately $1.2 million for the nine months ended May 31, 2004.

Oil and Gas Revenues and Expenses. For the nine month period ended May 31, 2005, we recorded approximately $3.9 million in total oil and gas revenues compared with approximately $269,000 for the same period in 2004. The increase in revenues is attributed to the acquisition of oil and gas properties from Venus Exploration Inc. in May 2004 and subsequent drilling. Gas revenues for the nine month period in 2005 totaled $1.8 million from the sale of 248,743 Mcf of natural gas at an average price of $7.03 per Mcf compared with gas revenues of approximately $124,000 in the nine month period of 2004 from the sale of 26,035 Mcf at an average price of $4.77 per Mcf. Oil and plant product revenues for the third quarter 2005 totaled approximately $2.2 million from sale of approximately 45,000 Bbls at an average price of $48.03 per Bbl compared with oil and plant product revenues of approximately $145,000 from the sale of 4,162 Bbls at an average price of $ 35.76 per Bbl in the nine month period of 2004.

Lease operating expenses during the nine month period in 2005 increased to $768,000 from $115,000 for the same period in 2004. The increase is attributable to the Venus wells acquired in 2004 and to new wells drilled.

Impairment, dry hole and abandonments. For the nine months ended May 31, 2005, we recognized a non-cash impairment of approximately $580,000 for the write-off of the costs incurred on our Canadian properties and projects. As a result of our decision to cease capital expenditures on our Canadian properties and projects, we wrote off our initial investment in our Canadian full cost pool and recognized a non-cash impairment expense.

Depreciation Depletion and Amortization. We recorded approximately $453,000 and $126,000, respectively, in depreciation, depletion and amortization expense for the nine months ended 2005 and 2004. Of these amounts, we recorded approximately $445,000 and $1,700, respectively, in depreciation, depletion and amortization expense from oil and gas properties for the nine months ended 2005 and 2004. The 2005 increase was attributable to the properties acquired from Venus Exploration, Inc. in May 2004, which increased the amount of oil and gas production and the amortizable oil and gas asset base including future development costs. Depreciation expense reported for the nine months ended 2004, includes approximately $115,000 of depreciation of Asset Retirement Obligation assets. We recorded approximately $8,000 and $10,000 in depreciation expense associated with capitalized office furniture and equipment during the nine months ended 2005 and 2004, respectively.

Asset Retirement Obligation Accretion Expense. We recorded $16,000 and $70,000, respectively, for the nine months ended 2005 and 2004, of accretion of the unamortized discount of the Asset Retirement Obligation liability. The accretion expense for the nine months ended May 31, 2004 was higher due to an escalation in the accretion rate caused by a reduction in the estimated lives of the East Lost Hills properties. The accretion expense for the nine months ended May 31, 2005 relates primarily to the properties acquired in 2004 with longer estimated lives resulting in lower accretion rates.

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 net profits interest of the Trust 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. For the nine months ended May 31, 2005, we accrued net profits interest expense of approximately $639,000. For the nine months ended May 31, 2004, there was no net profits interest expense recognized.

General and Administrative Expenses. General and administrative expenses during the nine months ended May 31, 2005 and 2004 were approximately $1.5 million and $900,000, respectively. The increase principally reflects an increase in salaries as a result of hiring additional personnel, costs of implementation of a new computer system, and an increase in audit and legal fees, all of which resulted from the acquisition of properties from Venus Exploration, Inc. in May 2004.

Interest Income. We recorded approximately 71,000 and $16,000 in interest income for the nine months ended May 31, 2005 and 2004, respectively. The increase was due to interest on the funds received from the private placement of our common stock in May 2004.

Interest Expense. During the nine months ended May 31, 2005 and 2004, we recorded interest expense of approximately $254,000 and $243,000, respectively. The interest expense for each year is associated with the sale of outstanding 4.99% convertible notes due on May 24, 2009. We have reflected the outstanding balance of these notes as Convertible Notes under Long Term Debt on our May 31, 2005 and August 31, 2004 consolidated balance sheets.

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.

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

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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	July 15, 2005