

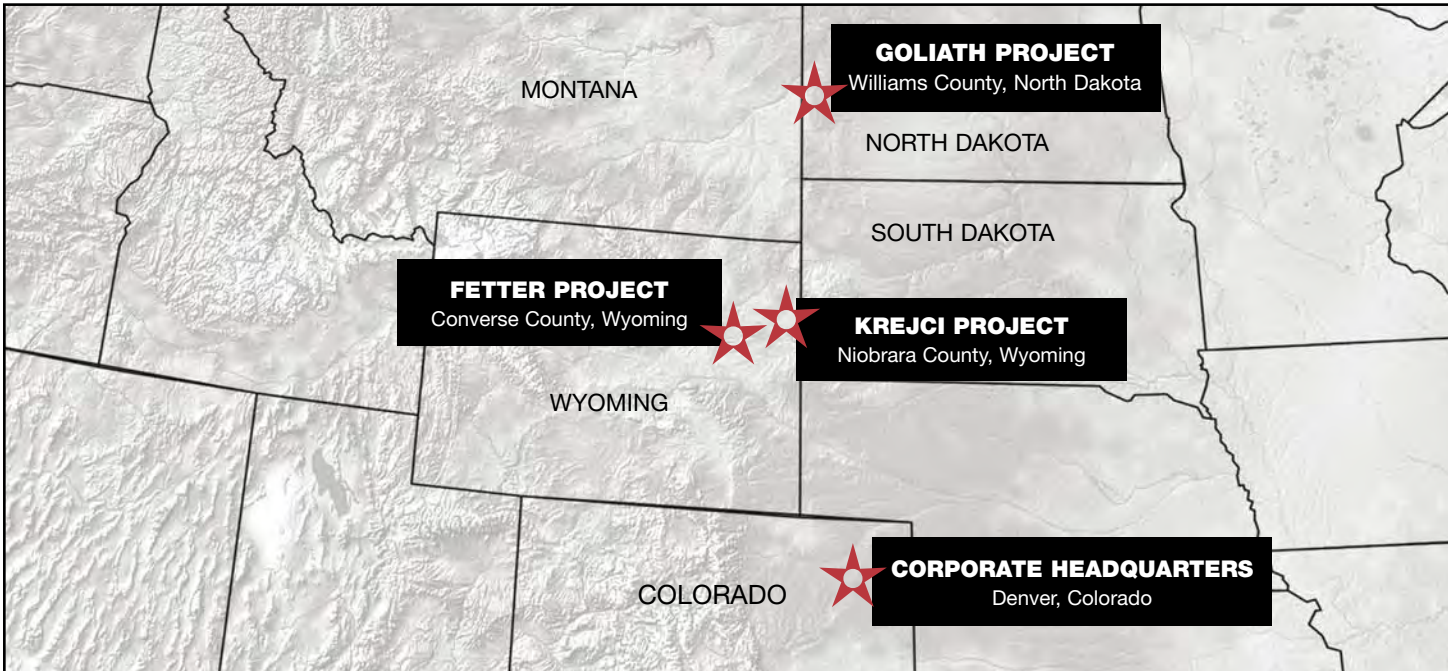
2006 ANNUAL REPORT



PARTNERSHIPS + PRODUCTIVITY

POSITIONED FOR GROWTH

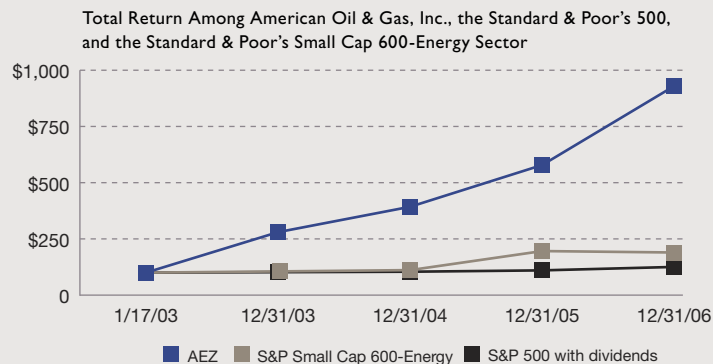
AMERICAN
Oil & Gas Inc.



Corporate PROFILE

American Oil & Gas, Inc. (AMEX: AEZ) is a Denver based independent oil and natural gas exploration and production company focused on building shareholder value from projects and properties located in the western United States. The majority of its current and planned activity is centered in the Rocky Mountain Region. The company commenced oil and gas operations in January of 2003 with the purchase of oil and gas leasehold interests in several properties from Tower Colombia Corporation and North Finn, LLC, two private E&P companies active in the Western U.S. In April of 2005, Tower was merged into American. North Finn continues to be a strategic partner in many of American's projects. Since the merger with Tower, American has substantially increased its project inventory and acreage positions. American currently owns interests in approximately 420,000 gross acres located primarily within three core project areas: Douglas (which includes Fetter), Krejci and Goliath. Drilling and/or completion and production testing operations are underway in all three. Early results, in total, have been favorable and support continued drilling on all three projects. Through various partnership agreements, American has been able to reduce or completely eliminate its financial exposure in the early stages of drilling while maintaining large ownership interests in each project.

Management believes that each of these three projects hold the potential for a large multi-year inventory of drilling locations. With initial and continued drilling success, American's current acreage positions hold the potential to drill over 100 gross wells at Goliath, over 300 gross wells at Fetter and over 700 gross wells at Krejci. In addition to the ongoing efforts on the three core project areas, American continues to evaluate new opportunities that may fit well within the Company's business model.





To Our Fellow Stockholders

Though still in the early stages of evaluating and developing our three core project areas (Fetter, Krejci and Goliath), 2006 was a year of considerable progress and achievement. Before we address those achievements, let us first take a few moments to review the strategies and the business model we are pursuing.

Unlike many early stage companies in our industry that tie their growth potential to high risk exploration projects, we have pursued a strategy of focusing on areas where past, and in some cases current, drilling and production activity by others indicate the presence of large hydrocarbon accumulations. Therefore, the primary challenge that we face is not one of finding oil and natural gas, but bringing together the right mix of advanced drilling and completion technologies to unlock these resources in the most economically viable manner. As a result, we enter into the early phases of drilling and development with an eye towards research and experimentation, which is carried out over a series of wells with the goal of identifying which technologies will prove most effective. With success, projects like those we control can offer many years worth of low risk development.

To mitigate the costs and risks involved with the early stages of advancing our projects, we have pursued a strategy of bringing in industry partners who shoulder most or all of the initial costs, in return for earning an interest in the acreage that we control. In addition to bringing capital to the project, we have aligned ourselves with partners that bring skills and operating experience that complement our own.

In 2006, drilling activity commenced on two of our core projects and continued on the third. In total, results to date have been favorable and support the continuing effort now underway in all three projects.

- At our Goliath project, Evertson Operating successfully drilled and completed our first well into the targeted Bakken formation. After drilling the 10,500 foot vertical portion of the well, three horizontal lateral legs were drilled which provided us with over 15,000 feet of Bakken penetration. The three laterals were then fracture stimulated followed by a flow back and clean up phase. Drilling activity is underway in and around our acreage by other operators. We are closely monitoring the various drilling, completion and stimulation techniques being used around us in addition to the results from our own well as we formalize plans for continued drilling at Goliath.

- At our Krejci project, Brigham Exploration Company successfully drilled the Krejci 3-29 and the Mill Trust 1-12 wells, both of which were drilled horizontal into the targeted Mowry formation. Extensive testing of both the cased hole and the open hole sections of both laterals is ongoing. Both wells have yielded very favorable early production. As a result, we have commenced an eight well 2007 continuous drilling program at Krejci, that we feel will transition from an experimentation focus to a true developmental focus.

- At our Fetter project, the State 4-36 well was drilled into the targeted Frontier formation and, as was the case with our previously drilled Sims 16-26 well, encountered significant flows of oil and natural gas while drilling horizontally. Recognizing the technical challenges and financial exposure that still remain in order to unlock the productive potential of this exciting project, we reached an agreement with Red Technology Alliance, LLC to fund 100% of the next three to four well program at Fetter. With RTA's funding and Halliburton Energy Services acting as project manager, we believe we have the right people and technologies in place to finally demonstrate the productive potential of this field. Drilling of the first well under this agreement commenced in February 2007. Upon completion of the three to four well drilling program, RTA will earn a 25% ownership in the Fetter project, and we retain a compelling approximate 70% Fetter project ownership.

The year 2006 was a year of transitioning our projects to the research and experimentation drilling stage and we see 2007 as a transition toward developmental drilling. With the continued dedication of our employees, and with the assistance of strong and determined partners, we are confident 2007 will prove to be an active and exciting year.

Sincerely,



Patrick D. O'Brien
Chairman and CEO

Andrew P. Calerich
President and Director

Committed + **STRONG**

Fetter Project New Agreement with Red Technology Alliance, LLC Project Management Agreement with Halliburton Energy Services

Drilling at Fetter has been technically challenging. Although there still remain engineering hurdles to overcome, the Fetter project continues to show strong geological success. We view our recent agreement with Red Technology Alliance, LLC ("RTA") as confirmation that we own a compelling and potentially significant resource. RTA's focus is to invest in technically demanding development and exploitation projects, primarily in the Rocky Mountains and Offshore Gulf of Mexico, that it believes hold the potential for significant upside utilizing Halliburton's cutting edge expertise and technology. The first well under this new agreement, the Sims 15-26 well, started drilling in early February. The well design includes extensive reservoir evaluation to be conducted through coring and logging operations that will be followed by drilling a horizontal lateral and completing in the Frontier formation. The second well will evaluate the merits of a vertical wellbore combined with a multi stage fracture stimulation program across a number of potentially productive zones in the well.

DRILLING UPDATE

FIRST WELL: Sims 16-26H

- Commenced drilling on May 5, 2005.
- Drilled only 255 feet of horizontal wellbore, out of a planned 2,000 feet.
- While horizontal, the well flowed up to 12 mmcf/d of natural gas and 300 to 500 Bbls/d of condensate.
- Wellbore and mechanical problems require a sidetrack to be drilled vertically (not horizontally) to total depth.

SECOND WELL: State 4-36H

- Commenced drilling on July 7, 2006.
- Ultimately drilled through the Frontier Formation at a 53 degree angle versus the desired 90 degrees (horizontal).
- Well demonstrated strong flows of natural gas and condensate while horizontal.

THIRD WELL: Sims 15-26H

- Funded 100% by RTA. American carried for a 23.125% working interest.
- Commenced drilling in February 2007.
- Extensive reservoir analysis planned.
- Goal of drilling a 2,000 foot horizontal lateral drilled into the Frontier Formation.
- Drill deep to evaluate formations below the Frontier.

LOOKING AHEAD

American has been able to completely remove its capital exposure in the next phase of drilling at Fetter. On January 22, 2007 American Oil and Gas, Inc. signed a participation agreement with Red Technology Alliance LLC ("RTA"), which gives RTA the option to fund 100% of the drilling, completion and equipping of the next three to four wells at Fetter, which could exceed \$20 million, and a project management agreement under which Halliburton Energy Services has been engaged to manage the operations funded by RTA. Upon completion of this program, RTA will have earned a 25% ownership interest in approximately 56,000 gross (approximately 46,000 net) acres in the Fetter project area, where American currently owns a 92.5% ownership interest. Drilling of the first well, the Sims 15-26 well, commenced in early February.

The Sims 15-26 well is planned to be drilled horizontally into the 11,500' deep Frontier formation. Drilling of the next two to three wells will be at the option of RTA, with the second well designed to be drilled vertically to test the productive potential of completing the well in up to three separate gas bearing formations, the Steele, Niobrara and Frontier. After this vertical well is drilled, RTA has the option to fund the drilling of one additional horizontal well or two additional vertical wells. In all these wells, RTA will own a 75% working interest and will carry American through tanks for a 23.125% interest. All operations will be managed by Halliburton. Upon completion of this three to four well program, RTA will have earned a 25% ownership interest in the undrilled acreage. American retains a 69.375% ownership interest.

Our goal in 2007 is to understand how to best drill, complete and stimulate wells at Fetter. If successful, this could lead to an aggressive multi-year developmental drilling program with the potential for over 300 gross horizontal wells or over 1,000 gross vertical wells, depending on which drilling method proves most effective.





Krejci Project
Industry Partner: Brigham Exploration Company

The Krejci project currently consists of approximately 116,000 gross acres located on the Southeastern edge of the Powder River Basin near the Lance Creek thrust fault. It is believed that the fracturing mechanism and sandstone, which are both present in the Krejci area, make this an excellent area for seeking to establish commercial production from the approximate 7,500 foot deep Mowry Shale. Mowry oil production was established on the Krejci project acreage in the early 1960s when three wells drilled to a lower formation were completed in the Mowry after excellent oil shows were noted during drilling. We believe that by employing modern drilling and completion techniques, production rates and ultimate recoveries of wells drilled in this area could be improved.

On March 17, 2006 American signed a drilling and participation agreement with Brigham Oil & Gas, L.P., a wholly owned subsidiary of Austin, Texas based Brigham Exploration Company, to participate in the initial drilling on our Krejci project. Under the terms of the agreement, Brigham funded 100% of the drilling and completion costs (including surface oil production facilities), of a two well horizontal drilling program. Brigham carried American for its 45% ownership in all drilling and completion costs. Brigham owns a 50% interest in each of the first two wells and American owns 45%. Upon completion of the two well program, plus an additional \$1 million of capital expenditures by Brigham, Brigham earned 50% of American's original 90% working interest.

DRILLING UPDATE

Brigham Exploration Company has successfully drilled the Krejci 3-29 and the Mill Trust 1-12 wells, both of which were drilled horizontal into the targeted Mowry formation. Extensive testing of both the cased hole and the open hole sections of the horizontal laterals in each well is ongoing. Both wells have yielded very favorable early production.

LOOKING AHEAD

As a result of these favorable production results, Brigham has commenced an eight well continuous drilling program for 2007 at Krejci. This program, which will be spread out over a large portion of our acreage position, is designed to obtain extensive reservoir information through coring and logging operations as well as to evaluate additional drilling and completion methods in order to determine which are most effective. With continued success, American's acreage position holds the potential for over 700 gross horizontal wells.



Aligned + **FOCUSED**

Goliath Project Industry Partners: Evertson Operating Company and Teton Energy Company

The Goliath project currently consists of approximately 90,000 gross acres located primarily in Williams and Dunn Counties, North Dakota in an emerging horizontal drilling play in the North Dakota Williston Basin. The Goliath Project's primary target is the Mississippian Bakken Formation which has certain geological similarities to the Mississippian Bakken Formation at the Elm Coulee field in Richland County, Montana where American owned its Big Sky project.

On May 5, 2006 American entered into a participation agreement with Teton Energy Corporation to participate in the project. Under the terms of the agreement, Teton purchased a 25% working interest (one-third of American's then 75% working interest) in the Goliath acreage position for approximately \$6 million. Evertson Operating Company, which has extensive oil and gas operating experience, owns a 25% working interest and is operating the initial wells.

DRILLING UPDATE

Evertson has successfully drilled the first well in the project, the Evertson AOG Champion 1-25H well. After drilling the 10,500 foot vertical portion of the well, three horizontal lateral legs were drilled which provided us with over 15,000 feet of Bakken penetration. The three laterals were then fracture stimulated followed by a flow back and clean up. By drilling three laterals in three different directions, information can be obtained that may assist in determining which directions are optimal on future wells.

LOOKING AHEAD

Drilling activity is underway in and around our acreage by other operators. We are closely monitoring the various drilling, completion and stimulation techniques being used around us in addition to the results from our own well as we formalize plans for additional drilling. We expect our next well in the Goliath project will be designed in a fashion that capitalizes on information obtained from this additional drilling.



Form 10-K

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K/A
(Amendment No. 1)

- ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2006
- OR**
- TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

COMMISSION FILE NUMBER 001-31900

AMERICAN OIL & GAS INC.

(Exact name of registrant as specified in its charter)

Nevada
(State or other jurisdiction of
incorporation or organization)

88-0451554
(I.R.S. Employer
Identification Number)

1050 17th Street, Suite 2400 Denver, Colorado 80265
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (303) 991-0173

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class:	Name of Each Exchange on Which Registered:
Common Stock, \$.001 par value per share	American Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Act).

Large accelerated filer

Accelerated filer

Non-accelerated filer

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

The aggregate market value of the registrant's common stock held by non-affiliates of the registrant on June 30, 2006 was \$127,060,584.

The number of shares of registrant's common stock outstanding as of March 29, 2007 was 39,650,551 shares.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the registrant's definitive proxy statement filed under Regulation 14A promulgated by the Securities and Exchange Commission under the Securities Exchange Act of 1934, which definitive proxy statement is to be filed within 120 days after the registrant's fiscal year ended December 31, 2006, are incorporated by reference in Part III hereof.

EXPLANATORY NOTE

We are filing this Amendment No. 1 on Form 10-K/A to our Annual Report on Form 10-K for the year ended December 31, 2006, originally filed on April 2, 2007 (“Original 2006 Form 10-K”) to reflect the following:

- Hein & Associates LLP’s recent audit of our 2004 financial statements herein,
- Changes on page F-28 to Note 15 *Unaudited Supplemental Quarterly Financial Data* to conform the data to the financial statements contained in Amendment No. 1 on Forms 10-Q/A being filed April 11, 2007 for the three-month periods ended March 31, 2006, June 30, 2006 and September 30, 2006, respectively.

We were unable to obtain the consent of Wheeler Wasoff, P.C. to currently refer in our registration statements (or amendments thereto) to Wheeler Wasoff, P.C.’s audit report of our 2004 financial statements set forth in the Original 2006 Form 10-K. Accordingly, we engaged Hein & Associates to audit those financial statements and have included herein (page F-2) Hein & Associates’ audit report dated April 2, 2007 with regard to the 2006 and 2005 audited financial statements herein and dated April 10, 2007 with regard to the 2004 audited financial statements herein. Hein & Associates’ related consent with regard to its audit opinion on page F-2 can be found in Exhibit 23(ii) to this Form 10-K/A.

This Amendment No. 1 corrects the Rental Obligation table on page 17 to reflect that our delay rental obligations for 2010 total \$141,717 and not \$21,984 as reported in the Original Form 10-K. Our consolidated statement of cash flows for 2005 herein shows the \$643,485 net drilling prepayments as cash flow from investing activities (rather than prepaid expenses, as reflected in the Original Form 10-K) since the drilling prepayments were used to pay for oil and gas wells, which are long-term assets.

Other than the aforementioned, this Amendment does not reflect events occurring after the filing of the Original 10-K and does not modify or update the disclosures therein in any way other than as required to reflect the changes described above.

**AMERICAN OIL & GAS INC.
FORM 10-K/A
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As used in this document, “American”, “Company”, “we”, “us” and “our” refer to American Oil & Gas Inc. and its subsidiaries.

For abbreviations or definitions of certain terms used in the oil and gas industry and in this annual report, please refer to the section entitled “Glossary of Abbreviations and Terms”.

PART I

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The statements contained in this annual report on Form 10-K that are not historical are “forward-looking statements,” as that term is defined in Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), that involve a number of risks and uncertainties.

These forward-looking statements include, among others, the following:

- our business and growth strategies;
- our oil and natural gas reserve estimates;
- our ability to successfully and economically explore for and develop oil and gas resources;
- our exploration and development drilling prospects, inventories, projects and programs;
- availability and costs of drilling rigs and field services;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions; and
- the impact of environmental and other governmental regulation.

These statements may be found under “Risk Factors”, “Management’s Discussion and Analysis of Financial Condition and Results of Operation”, “Business and Properties” and other sections of this annual report. Forward-looking statements are typically identified by use of terms such as “may”, “could”, “should”, “expect”, “plan”, “project”, “intend”, “anticipate”, “believe”, “estimate”, “predict”, “potential”, “pursue”, “target” or “continue”, the negative of such terms or other comparable terminology, although some forward-looking statements may be expressed differently.

The forward-looking statements contained in this annual report are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this annual report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to a number of factors, including:

- the failure to obtain sufficient capital resources to fund our operations;
- an inability to replace our reserves through exploration and development activities;
- unsuccessful drilling activities;

- a decline in oil or natural gas production or oil or natural gas prices;
- incorrect estimates of required capital expenditures;
- increases in the cost of drilling, completion and gas gathering or other costs of production and operations;
- impact of environmental and other governmental regulation, including delays in obtaining permits;
- hazardous and risky drilling operations; and
- an inability to meet growth projections.

You should also consider carefully the statements under “Risk Factors” and other sections of this annual report, which address additional factors that could cause our actual results to differ from those set forth in the forward-looking statements.

All forward-looking statements speak only as of the date of this annual report. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Item 1: Business

General Overview

We are an independent oil and gas exploration and production company, engaged in the exploration, development and acquisition of crude oil and natural gas reserves and production in the western United States. We currently hold the following prospects:

- We control approximately 128,000 gross (90,000 net) acres in the Douglas Project area, located in the southern Powder River Basin, Wyoming which includes approximately 56,000 gross (43,000 net) acres in the Fetter Prospect.
- We control approximately 116,000 gross (41,000 net) acres in the Krejci AMI Project, located in Niobrara County, Wyoming.
- We control approximately 87,000 gross (32,000 net) acres in the Goliath Project, located in the Williston Basin, North Dakota.

For more information relating to our operational activities, please see “Item 2. — Description of Property.”

We operate in one industry segment, which is the exploration, development and production of natural gas and crude oil, and all of our operations are conducted in the United States. Consequently, we currently report a single industry segment. See “Financial Statements” and the notes to our consolidated financial statements for financial information about this industry segment.

Competition

We operate in the highly competitive oil and gas areas of acquisition and exploration, areas in which other competing companies have substantially larger financial resources, operations, staffs and facilities. Such companies may be able to pay more for prospective oil and gas properties or prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit.

Proved Reserves

As of December 31, 2006, our future cash flows from oil and gas operations have been estimated by Ryder Scott Company Petroleum Consultants, an independent petroleum engineering firm, to be \$6,428,667. Ryder Scott has estimated the present value of these future cash flows, discounted at ten percent to be \$4,692,808, and our proved oil and gas reserves are estimated to be 91,850 barrels of oil and 809,847 mcf of gas.

As of December 31, 2005, our future cash flows from oil and gas operations have been estimated by Ryder Scott Company Petroleum Consultants, an independent petroleum engineering firm, to be \$26,565,846. Ryder Scott has estimated the present value of these future cash flows, discounted at ten percent to be \$13,798,930, and our proved oil and gas reserves are estimated to be 554,702 barrels of oil and 378,213 mcf of gas. The decrease from 2005 to 2006 is attributable to the sale of our Big Sky Project. Our Big Sky project accounted for approximately 88% of our proved reserve value at December 31, 2005. As a result of this sale, we will not have any significant proved reserves unless and until we are able to establish proved reserves in connection with our new drilling activities planned for 2007 as described in this Form 10-K.

As of December 31, 2004, our future cash flows from oil and gas operations were estimated by Ryder Scott to be \$10,750,547. Ryder Scott had estimated the present value of these future cash flows, discounted at ten percent to be \$5,656,119, and our proved oil and gas reserves were estimated to be 321,710 barrels of oil and 346,270 mcf of gas. The increase in 2005 is attributable to reserve extensions and discoveries, primarily associated with development activity at our Big Sky project.

Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment and the existence of development plans. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, prices, future production levels and cost that may not prove correct over time. Predictions about prices and future production levels are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based.

Reconciliation of Standardized Measure to Pre-tax PV10%

Pre-tax PV10% is the estimated present value of the future net revenues from our proved oil and natural gas reserves before income taxes discounted using a 10% discount rate. Pre-tax PV10% is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that Pre-tax PV10% is an important measure that can be used to evaluate the relative significance of our oil and natural gas properties and that Pre-tax PV10% is widely used by security analysts and investors when evaluating oil and natural gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and natural gas industry calculate Pre-tax PV10% on the same basis. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes. The table below provides a reconciliation of our standardized measure of discounted future net cash flows to our Pre-tax PV10% value.

	At December 31,		
	2006	2005	2004
Standardized measure of discounted future net cash flows	\$ 4,598,000	\$ 13,709,930	\$ 5,432,119
Add present value of future income tax discounted at 10%	94,808	89,000	224,000
Pre-tax PV10%	<u>\$ 4,692,808</u>	<u>\$ 13,798,930</u>	<u>\$ 5,656,119</u>

Customers

During fiscal year 2006 and 2005, we had one major customer: Eighty Eight Oil, LLC. Sales to this customer accounted for approximately 71% and 75% of oil and gas sales in 2006 and 2005, respectively. During fiscal year 2004, we had two major customers: Eighty Eight Oil, LLC and Enserco Energy, Inc. Sales to these customers accounted for approximately 70% and 17%, respectively, of oil and gas sales in 2004. Because there are other purchasers that are capable of and willing to purchase our oil and gas and because we have the option to change purchasers on our properties if conditions so warrant, we believe that our oil and gas production can be sold in the market in the event that it is not sold to our existing customers.

Environmental Matters

Operations on properties in which we have an interest are subject to extensive federal, state and local environmental laws that regulate the discharge or disposal of materials or substances into the environment and otherwise are intended to protect the environment. Numerous governmental agencies issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial administrative, civil and criminal penalties and in some cases injunctive relief for failure to comply.

Some laws, rules and regulations relating to the protection of the environment may, in certain circumstances, impose “strict liability” for environmental contamination. These laws render a person or company liable for environmental and natural resource damages, cleanup costs and, in the case of oil spills in certain states, consequential damages without regard to negligence or fault. Other laws, rules and regulations may require the rate of oil and gas production to be below the economically optimal rate or may even prohibit exploration or production activities in environmentally sensitive areas. In addition, state laws often require some form of remedial action, such as closure of inactive pits and plugging of abandoned wells, to prevent pollution from former or suspended operations.

Legislation has been proposed in the past and continues to be evaluated in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as “hazardous wastes.” This reclassification would make these wastes subject to much more stringent storage, treatment, disposal and clean-up requirements, which could have a significant adverse impact on operating costs. Initiatives to further regulate the disposal of oil and gas wastes are also proposed in certain states from time to time and may include initiatives at the county, municipal and local government levels. These various initiatives could have a similar adverse impact on operating costs.

The regulatory burden of environmental laws and regulations increases our cost and risk of doing business and consequently affects our profitability. The federal Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the “Superfund” law, imposes liability, without regard to fault, on certain classes of persons with respect to the release of a “hazardous substance” into the environment. These persons include the current or prior owner or operator of the disposal site or sites where the release occurred and companies that transported, disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for the federal or state government to pursue such claims.

It is also not uncommon for neighboring landowners and other third parties to file claims for personal injury or property or natural resource damages allegedly caused by the hazardous substances released into the environment. Under CERCLA, certain oil and gas materials and products are, by definition, excluded from the term “hazardous substances.” At least two federal courts have held that certain wastes associated with the production of crude oil may be classified as hazardous substances under CERCLA. Similarly, under the federal Resource, Conservation and Recovery Act, or RCRA, which governs the generation, treatment, storage and disposal of “solid wastes” and “hazardous wastes,” certain oil and gas materials and wastes are exempt from the definition of “hazardous wastes.” This exemption continues to be subject to judicial interpretation and increasingly stringent state interpretation. During the normal course of operations on properties in which we have an interest, exempt and non-exempt wastes, including hazardous wastes, that are subject to RCRA and comparable state statutes and implementing regulations are generated or have been generated in the past. The federal Environmental Protection Agency and various state agencies continue to promulgate regulations that limit the disposal and permitting options for certain hazardous and non-hazardous wastes.

We believe that the operator of the properties in which we have an interest is in substantial compliance with applicable laws, rules and regulations relating to the control of air emissions at all facilities on those properties. Although we maintain insurance against some, but not all, of the risks described above, including insuring the costs of clean-up operations, public liability and physical damage, there is no assurance that our insurance will be adequate to cover all such costs, that the insurance will continue to be available in the future or that the insurance will be available at premium levels that justify our purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and operations. Compliance with environmental requirements, including financial assurance requirements and the costs associated with the cleanup of any spill, could have a material adverse effect on our capital expenditures, earnings or competitive position. We do believe, however, that our operators are in substantial compliance with current applicable environmental laws and regulations. Nevertheless, changes in environmental laws have the potential to adversely affect operations. At this time, we have no plans to make any material capital expenditures for environmental control facilities.

Employees

At December 31, 2006, we had thirteen (13) full time employees. None of our employees is covered by a collective bargaining agreement and we consider our relationship with our employees to be good.

Corporate History

We were incorporated on February 15, 2000 under the laws of the State of Nevada for the purpose to promote and carry on any lawful business for which a corporation may be incorporated under the laws of the State of Nevada. On January 17, 2003, we entered into a Purchase and Sale Agreement to acquire undeveloped oil and gas prospects in Montana and Wyoming. With the purchase of the oil and gas prospects, we became an independent energy company engaged in the exploration, development and acquisition of crude oil and natural gas reserves and production. Our resources and assets are reported as one operating segment and we conduct our operations primarily in the western United States with current properties in Wyoming, Montana, and North Dakota.

Website and Code of Ethics

Our website address is <http://www.americanog.com>. We make available free of charge through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after electronically filed or furnished to the Securities and Exchange Commission. Additionally, our Code of Ethics, which includes our code of ethics for senior financial management, and our Audit Committee Charter are posted on our website and are available in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at 1050 17th Street, Suite 2400 Denver, Colorado 80265.

Glossary of Abbreviations and Terms

Unless otherwise indicated in this document, oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids so that six Mcf of natural gas are referred to as one barrel of oil equivalent.

AMI. Area of Mutual Interest.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bbl/d. One Bbl per day.

Bc/d. Barrels of condensate daily.

Bcf. One Billion cubic feet of natural gas at standard atmospheric conditions.

Bcfe. One billion cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capital Expenditures. Costs associated with exploratory and development drilling (including exploratory dry holes); leasehold acquisitions; seismic data acquisitions; geological, geophysical and land related overhead expenditures; delay rentals; producing property acquisitions; other miscellaneous capital expenditures; compression equipment and pipeline costs.

Carried Working interest. The owner of this type of working interest in the drilling of a well incurs no liability for drilling costs associated with a well until the well is drilled.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed Acreage. The number of acres that are allocated or assignable to producing wells or wells capable of production.

Development Well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Exploitation. The continuing development of a known producing formation in a previously discovered field. To make complete or maximize the ultimate recovery of oil or natural gas from the field by work including development wells, secondary recovery equipment or other suitable processes and technology.

Exploration. The search for natural accumulations of oil and natural gas by any geological, geophysical or other suitable means.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding and Development Costs. The total capital expenditures, including acquisition costs, and exploration and abandonment costs, for oil and gas activities divided by the amount of proved reserves added in the specified period.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which we have a working interest.

Lease. An instrument which grants to another (the lessee) the exclusive right to enter to explore for, drill for, produce, store and remove oil and natural gas on the mineral interest, in consideration for which the lessor is entitled to certain rents and royalties payable under the terms of the lease. Typically, the duration of the lessee's authorization is for a stated term of years and "for so long thereafter" as minerals are producing.

Mcf. One thousand cubic feet of natural gas at standard atmospheric conditions.

Mcf/d. One Mcf per day.

Mcfe. One thousand cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

MMcf. One million cubic feet of natural gas.

Net Acres or Net Wells. A net acre or well is deemed to exist when the sum of our fractional ownership working interests in gross acres or wells, as the case may be, equals one. The number of net acres or wells is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

Operator. The individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

Participant Group. The individuals and/or companies that, together, comprise the ownership of 100% of the working interest in a specific well or project.

PV-10 value. The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated lease operating expense, production taxes and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization or federal income taxes, and discounted using an annual discount rate of 10%.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves (PUD). Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Re-entry. Entering an existing well bore to redrill or repair.

Reserves. Natural gas and crude oil, condensate and natural gas liquids on a net revenue interest basis, found to be commercially recoverable.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/ or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Royalty. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage, or of the proceeds of the sale thereof, but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Undeveloped Acreage. Lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether or not such acreage contains proved reserves.

Working Interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties.

Title to Properties

As is customary in the oil and gas industry, only a preliminary title examination is conducted at the time we acquire leases or enter into other agreements to obtain control over interests in acreage believed to be suitable for drilling operations. In many instances, our partners have acquired rights to the prospective acreage and we have a contractual right to have our interests in that acreage assigned to us. In some cases, we are in the process of having those interests so assigned. Prior to the commencement of drilling operations, a thorough title examination of the drill site tract is conducted by independent attorneys. Once production from a given well is established, the operator will prepare a division order title report indicating the proper parties and percentages for payment of production proceeds, including royalties. We believe that titles to our leasehold properties are good and defensible in accordance with standards generally acceptable in the oil and gas industry.

Item 1A: Risk Factors

You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this annual report or in any other of our filings with the Securities and Exchange Commission (“SEC”) could have a material adverse effect on our business, financial position, liquidity and results of operations. In evaluating us, you should consider carefully, among other things, the factors and the specific risks set forth below and in documents we incorporate by reference. This annual report contains forward-looking statements that involve risks and uncertainties. Some of the following risks relate principally to the industry in which we operate and to our business. Other risks relate principally to the securities markets and ownership of our common shares. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially adversely affected, the trading price of your shares could decline, and you may lose all or part of your investment.

Risks related to our industry, business and strategy

We have a limited operating history in the oil and gas business, and we cannot predict our future operations with any certainty.

Our oil and gas operations commenced in 2003. Our future financial results depend primarily on (1) our ability to discover commercial quantities of oil and gas; (2) the market price for oil and gas; (3) our ability to continue to generate potential exploration prospects; and (4) our ability to fully implement our exploration and development program. We cannot predict that our future operations will be profitable. In addition, our operating results may vary significantly during any financial period. These variations may be caused by significant periods of time between discovery and development of oil or gas reserves in commercial quantities.

We may be unable to replace reserves, production and revenues associated with our Big Sky project, which we sold on March 31, 2006.

88% of our oil and gas proved reserves for 2005 were attributable to our Big Sky Project. If we are unable to replace this production, revenue and reserves by acquiring properties containing proved reserves or conducting successful exploration and development activities, or both, our ability to grow will be limited. In addition, the sale of a significant portion of our reserve value may increase the likelihood of recording an impairment against our evaluated oil and gas properties in the future.

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas and oil reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures primarily with sales of our securities, sale of our interest in the Big Sky Project, and cash generated by operations. We intend to finance our capital expenditures for 2007 primarily with existing capital and additional sales of our securities. We may not be able to obtain equity financing on terms favorable to us, or at all. Our ability to grow our oil and natural gas reserves and cash flow would be severely impacted if we are unable to obtain equity financing as we would need to sell down a portion of our ownership interests or, if selling down is not possible, we may not be able to continue to drill at all in some or all of our projects.

Oil and natural gas prices are volatile and a decline in oil and natural gas prices can significantly affect our financial results and impede our growth.

Our revenues, profitability and liquidity are substantially dependent upon prevailing prices for oil and natural gas, which can be extremely volatile and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a wide variety of additional factors that are beyond our control, such as the domestic and foreign supply of oil and natural gas; the price of foreign imports; the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; technological advances affecting energy consumption; domestic and foreign governmental regulations; and the variations between product prices at sales points and applicable index prices.

We have incurred losses from operations in the past and may do so in the future.

Although we have had net income in 2006 and 2005, we incurred net losses of \$499,651 and \$819,002 for the fiscal years ended December 31, 2004 and 2003, respectively. Our development of and participation in additional prospects will require additional capital expenditures. The uncertainty and factors described throughout this section may impede our ability to economically find, develop, exploit, and acquire natural gas and oil reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future.

We could be adversely impacted by changes in the oil and gas market.

The marketability of our oil and gas production depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. Federal and state regulation of oil and gas production and transportation, general economic conditions, changes in supply and changes in demand all could adversely affect our ability to produce and market oil and natural gas. If market factors were to change dramatically, the financial impact could be substantial because we would incur expenses without receiving revenues from the sale of production. The availability of markets is beyond our control.

We may be unable to find additional reserves.

Our revenues depend on whether we acquire or find additional reserves. Unless we acquire properties containing proved reserves or conduct successful exploration and development activities, or both, our proved reserves will decline as reserves are produced. Our planned exploration and development projects may not result in significant additional reserves. We may be unable to drill productive wells at low reserve replacement costs.

Oil and gas operations are inherently risky.

The nature of the oil and gas business involves a variety of risks, including the risks of operating hazards such as fires, explosions, cratering, blow-outs, and encountering formations with abnormal pressures. The occurrence of any of these risks could result in losses. The occurrence of any one of these significant events, if it is not fully insured against, could have a material adverse effect on our financial position and results of operations.

We are subject to extensive government regulations.

Our business is affected by numerous federal, state and local laws and regulations, including energy, environmental, conservation, tax and other laws and regulations relating to the oil and gas industry. These include, but are not limited to:

- the prevention of waste,
- the discharge of materials into the environment,
- the conservation of oil and natural gas,
- pollution,
- permits for drilling operations,
- drilling bonds and
- reports concerning operations, the spacing of wells, and the unitization and pooling of properties.

Failure to comply with any laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of injunctive relief or both. Moreover, changes in any of these laws and regulations could have a material adverse effect on our business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to us, we cannot predict the overall effect of such laws and regulations on our future operations.

New government regulation and environmental risks could increase our costs.

Many jurisdictions have at various times imposed limitations on the production of oil and gas by restricting the rate of flow for oil and gas wells below their actual capacity to produce. Because current regulations covering our operations are subject to change at any time, we may incur significant costs for compliance in the future.

Our prices may be impacted adversely by new taxes.

The federal, state and local governments in which we operate impose taxes on the oil and gas products we sell. In the past, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals. In addition, many states have raised state taxes on energy sources and additional increases may occur. We cannot predict whether any of these measures would have an adverse impact on oil and natural gas prices.

Shortages of rigs, equipment, supplies and personnel could delay or otherwise adversely affect our cost of operations or our ability to operate according to our business plans.

We may experience shortages of drilling and completion rigs, field equipment and qualified personnel which may cause delays in our ability to continue to drill, complete, test, and connect wells to processing facilities. These costs have sharply increased in various areas. The demand for and wage rates of qualified drilling rig crews generally rise in response to the increased number of active rigs in service and could increase sharply in the event of a shortage. Shortages of drilling and completion rigs, field equipment or qualified personnel could delay, restrict or curtail our exploration and development operations, which may materially adversely affect our business, financial condition and results of operations.

Shortages of transportation services and processing facilities may result in our receiving a discount in the price we receive for oil and natural gas sales or may adversely affect our ability to sell our oil and natural gas.

We may experience limited access to transportation lines, trucks or rail cars in order to transport our oil and natural gas to processing facilities. We may also experience limited access to processing facilities. If either or both of these situations arise, we may not be able to sell our oil and natural gas at prevailing market prices or we may be completely unable to sell our oil and natural gas, which would may materially adversely affect our business, financial condition and results of operations.

Risks Related to our Common Stock

Our common stock is illiquid, so investors may not be able to sell any significant number of shares of our stock at prevailing market prices.

The average daily trading volume of our common stock was approximately 140,000 shares per day over the 90 day period ended March 29, 2007. If limited trading in our stock continues, it may be difficult for investors to sell their shares in the public market at any given time at prevailing prices.

Our stock price and trading volume may be volatile, which could result in losses for our stockholders.

The equity trading markets may experience periods of volatility, which could result in highly variable and unpredictable pricing of equity securities. The market of our common stock could change in ways that may or may not be related to our business, our industry or our operating performance and financial condition. In addition, the trading volume in our common stock may fluctuate and cause significant price variations to occur. Some of the factors that could negatively affect our share price or result in fluctuations in the price or trading volume of our common stock include:

- Actual or anticipated quarterly variations in our operating results;
- Changes in expectations as to our future financial performance or changes in financial estimates, if any;
- Announcements relating to our business or the business of our competitors;
- Conditions generally affecting the oil and natural gas industry;
- The success of our operating strategy; and
- The operating and stock performance of other comparable companies.

Many of these factors are beyond our control, and we cannot predict their potential effects on the price of our common stock. If the market price of our common stock declines significantly, you may be unable to resell your shares of common stock at or above the price you acquired those shares. We cannot assure you that the market price of our common stock will not fluctuate or decline significantly.

We may issue preferred stock with rights that are preferential to, and could cause a decrease in the value of, our common stock.

We may issue up to 25 million shares of preferred stock without action by our stockholders. Rights or preferences could include, among other things:

- The establishment of dividends which must be paid prior to declaring or paying dividends or other distributions to our common stockholders;
- Greater or preferential liquidation rights which could negatively affect the rights of common stockholders; and
- The right to convert the preferred stock at a rate or price which would have a dilutive effect on the outstanding shares of common stock.

Item 1B: Unresolved Staff Comments.

The Company has not received any unresolved written comments from the SEC regarding its periodic or current reports not less than 180 days before the end of its fiscal year to which this Form 10-K relates.

Item 2: Properties

Oil and Natural Gas Assets

We have built a portfolio of exploration and exploitation projects targeting both oil and natural gas. Because our expertise in the oil and gas industry is primarily engineering related, we tend to focus in areas where we have some historical evidence that hydrocarbons exist. We believe that there is potential for commercial development in areas where historical drilling attempts resulted in indications of oil and gas but ultimate development was not pursued. We believe that the application of advanced drilling, completion and stimulation technologies combined with a strong commodity pricing environment could make development of our project areas economically viable. The following is a description and current status of our specific oil and gas projects:

Fetter Prospect and the Greater Douglas Project Area — Powder River Basin, Wyoming

Within our approximate 128,000 gross (approximately 90,000 net) acre Douglas project, our initial focus is on the approximate 56,000 gross (43,000 net) acre Fetter area. The Fetter area has a history of various exploration and development attempts. Numerous wells in the area, which have been drilled by others over four decades, have encountered and/or produced natural gas and condensate, including four wells drilled in the 1990s (owned by others) that are still producing from the Niobrara and Frontier formations. We believe that prior development efforts were negatively affected by various factors including inordinately long single well drill times, drilling techniques and delays in connecting wells that resulted in the potential for significant reservoir damage, and low commodity pricing environments.

Our history of drilling in the Fetter area dates back to May 2005, when we commenced drilling the Sims 16-26 well. This well was drilled to test the Niobrara and Frontier formations to a total depth of approximately 11,500 feet. During June 2005, after the Sims 16-26 well was drilled into our target formation, natural gas flow rates encountered during a subsequent two day period of intermittent testing ranged from three to twelve million cubic feet per day and condensate flow rates were estimated to be 300 to 500 barrels per day with flowing pressures of up to 2,500 PSI at surface. The higher than expected condensate flow rates and reservoir pressures that were encountered prevented drilling completely through the target formation. The original plan for this well was to intersect the targeted formations and drill as much as 2,000 feet of horizontal lateral wellbore. The actual lateral wellbore drilled was only approximately 255 feet. Ultimately, we were unable to complete the well in a fashion as originally planned.

Our second well at the Fetter project commenced drilling in August 2005. The Hageman 16-34 well had been drilled to a total depth of 11,234 feet. However, while drilling the final footage of the directional leg of the wellbore, mechanical problems with the drilling rig required us to pull out of the hole and await repairs. After the required repairs were made, we found that the bottom portion of the wellbore had collapsed, and continued drilling was no longer possible. After attempting to resume drilling operations, continued rig related limitations and delays caused us to temporarily suspend drilling operations until such time that a rig more suitable to drill the remaining portion of the well can be secured and mobilized to the site. The upper portion of the well, which is cased to 8,625 feet, is in excellent condition and we intend to re-enter the Hageman 16-34 well to resume drilling operations in the future.

We commenced drilling the third well at Fetter, which is the State 4-36 well, in July 2006. This well was drilled into the target Frontier formation in December 2006. During the completion process, it was determined that the wellbore was drilled through the targeted Frontier formation at an approximate 53 degree angle instead of the desired horizontal angle of approximately 90 degrees. As a result of this reduced angle and limited footage drilled into the target interval within the Frontier formation, production results were not representative of what we believe is possible from a 2,000 foot horizontal lateral wellbore drilled and completed in a fashion as originally planned.

In January 2007, we signed a participation agreement with Red Technology Alliance LLC (“RTA”), which gives RTA the option to fund 100% of the drilling, completion and equipping of the next three to four wells at Fetter, and a project management agreement under which Halliburton Energy Services has been engaged to manage the operations funded by RTA. Upon the completion of this drilling program, RTA will have earned assignment of 25% ownership in the Fetter acreage position, where we currently own a 92.5% ownership interest.

We and North Finn, LLC (project operator and owner of the remaining 7.5% ownership interest in the Fetter net acreage position) have agreed to allow RTA to fund the next well at Fetter, which is targeted to be drilled horizontally into the 11,500’ deep Frontier formation. Drilling of the next two to three wells will be at the option of RTA, with the second well designed to be drilled vertically to test the productive potential of completing the well in three separate gas bearing formations, the Steele, Niobrara and Frontier formations. After this vertical well is drilled, RTA has the option to fund the drilling of one additional horizontal well or two additional vertical wells. In all these wells, RTA will own a 75% working interest and will carry us and North Finn through the tanks for 23.125% and 1.875%, respectively, and the operations will be managed by Halliburton. Upon completion of this three to four well program, RTA will have earned a 25% ownership interest in the Fetter area undrilled acreage, and we will retain a 69.375% ownership interest in the Fetter area undrilled acreage.

The first well funded by RTA, the Sims 15-26 well, commenced drilling on February 7, 2007. 9-5/8 inch casing has been cemented to a depth of 10,852 feet. Drilling operations continue in order to drill the horizontal leg into the Frontier formation. We expect that the drilling program funded by RTA will take place during 2007, and as a result, we do not expect to bear any cost associated with drilling and completion at our Fetter project during 2007.

Krejci Oil Project (Powder River Basin, Wyoming)

We are pursuing the productive potential of the Mowry formation at a depth approximately 7,500 feet, and we are focusing our efforts in and around the Krejci Field in Niobrara County, Wyoming. Currently, our acreage position consists of approximately 116,000 gross (approximately 41,000 net) leasehold acres.

Our acreage position is located on the Southeastern edge of the Powder River Basin near the Lance Creek (basin-bounding) thrust fault. This fault shifts in strike from north-south to east-west in the prospect area, causing the area to be greatly stressed and potentially fractured. In addition, a brittle and clean siliceous sandstone lies stratigraphically in the center of the Mowry formation. We believe that the fracturing mechanism (out of basin faulting) and sandstone, which are both present in the Krejci area, make this an excellent choice for seeking to establish commercial production from the Mowry formation. Nevertheless, it is possible for reservoirs to be fractured only in isolated areas, and we are not assured that all wells we drill in this area will be productive.

Mowry oil production was established on the prospect in the Krejci Field in the early 1960s when three wells drilled to the lower Dakota formation were completed in the Mowry formation after excellent oil shows were noted during drilling. These three wells, in which we have no interest, produced commercial quantities of oil without the benefit of modern stimulation techniques. We believe that by employing modern drilling and completion techniques, production rates and ultimate recoveries of wells drilled in this area could be improved.

Commercial production from the Mowry formation has also been established in another area of the Powder River Basin. Located approximately 60 miles north of our Krejci acreage, the ARCO Fee #1 well in the Dillinger Ranch area has produced 125,000 barrels of oil and 115 mmcf of gas from the Mowry formation. Although the ARCO Fee #1 well is an example of potential for commercial production from the Mowry formation, there is no assurance that the success of this well is indicative of commercial production on our Krejci acreage.

On March 17, 2006 we signed a drilling and participation agreement with Brigham Oil & Gas, LP, a wholly owned subsidiary of Austin Texas based Brigham Exploration Company, to participate in the initial drilling in our Krejci project. Under the terms of the agreement, Brigham funded 100% of the drilling and completion costs (including surface oil production facilities), of an initial two well horizontal drilling program. Brigham carried us for our 45% ownership in all drilling and completion costs in these two wells. Brigham owns a 50% interest in each of the first two wells, we own 45% and North Finn, LLC owns the remaining 5%.

These two initial wells, the Krejci 3-29 and the Mill Trust 1-12, were each drilled horizontally into the targeted Mowry formation. Extensive testing of both the cased hole and the open hole sections of the horizontal laterals in each well is ongoing. Both wells have yielded very favorable early production. As a result, Brigham has commenced an eight well continuous drilling program for 2007 that began on March 15th with the spudding of the Werner 1-14H well. This eight well program, which will be spread out over a large portion of our acreage position, is designed to obtain extensive reservoir information through coring and logging operations as well as to evaluate additional drilling and completion methods in order to determine which are most effective. We expect that our working interest in each of the eight wells drilled in 2007 will be approximately 45% and we expect our share of drilling and completion costs in this eight well program to be approximately \$9 million.

Goliath Project, Williston Basin, North Dakota

Our Goliath project is located primarily in Williams and Dunn Counties, North Dakota. We currently control approximately 87,000 gross (32,000 net) acres in this area that targets the middle member of the Bakken Formation in an emerging horizontal drilling play in the North Dakota Williston Basin. In addition to the Bakken Formation, we see opportunity for exploration in the Mission Canyon, Nisku, Birdbear, Duperow, Interlake and Red River Formations.

On October 2, 2006, we commenced initial drilling activities in our Goliath project with the spudding of the Evertson AOG Champion 1-25H well. We own a 50% working interest in this well, privately held Evertson Operating Company, which has extensive oil and gas operations experience, is a participant and is operator of this well and Denver, Colorado based Teton Energy Corporation is also a participant in the well. The Champion 1-25H well, was drilled into the Bakken formation at a measured depth of approximately 10,200 feet and three horizontal laterals totaling approximately 15,000 feet were drilled into the Bakken formation. Flow back and clean up operations continue as the well is prepared for a stabilized production test. Drilling activity is underway in and around the Goliath acreage by other operators, and we are closely monitoring the various drilling, completion and stimulation techniques being used.

We expect to drill at least two additional wells in our Goliath project during 2007 and we expect our share of the cost to drill and complete these wells will be approximately \$5 million.

Big Sky Project, Williston Basin, Montana

On March 31, 2006, we sold (effective February 1, 2006) our ownership interest in our Big Sky project for a contract price of \$11,500,000. After effective date adjustments, we received cash proceeds at closing of \$10,678,504. The Big Sky project is a horizontal drilling program targeting the Mississippian Bakken Formation in the Elm Coulee field in Richland County, Montana. We sold our interests in approximately 1,660 net undeveloped acres, approximately 1,410 net developed acres, and 25 gross (approximately 1.11 net) producing wells at our Big Sky project. At the time of sale, the Big Sky production did account for approximately 95% of our oil and gas production and revenues and 88% of our proved reserves. As a result of the sale, we will not have any significant production revenue unless and until we are able to establish commercial production in our other areas.

Bear Creek Coal Bed Methane Prospect (Big Horn Basin, Montana)

In April 2006, we sold our entire ownership interest in our Bear Creek Project to GSL Energy Corporation and received a convertible note in the amount of \$1,080,000. Subsequent to closing, the note was converted into 2,160,000 shares of restricted common stock of GSL Energy Corporation, which is now PetroHunter Energy Corp. PetroHunter is a publicly traded company that trades on the US electronic bulletin board under the ticker symbol "PHUN."

Oil and Gas Drilling Activities

During 2006, we participated in the drilling of 10 gross (1.9 net) successful wells and two gross (.68 net) unsuccessful wells. Three (0.10 net) of the successful wells were drilled in our Big Sky project, and we sold our interest in these with the sale of the Big Sky project in March 2006. We participated in the drilling of four gross

(0.32) successful wells, and two (.68 net) unsuccessful wells in projects we deem as peripheral projects to our main focus areas. In our main focus areas, we drilled the productive State 4-36 well (.54 net) in our Fetter project, we drilled the productive Krejci 3-29 well (.45 net) in our Krejci project and we drilled the productive Champion 1-25 well (.50 net) in our Goliath project.

During 2005, we participated in the drilling of 13 gross (.64 net) successful wells at our Big Sky Project. We participated in the drilling of the Sims 16-26 well at our Fetter Project, which resulted in production of natural gas and liquid hydrocarbon, and we participated in the Hageman 16-34 well where drilling operations have been temporarily suspended pending receipt of proper drilling equipment. We participated in two gross unsuccessful wells during 2005. We participated with an 87.5% working interest in the unsuccessful drilling of the Rollman 1-29 at our South Glenburn Prospect. We also participated with a 37.5% working interest in the unsuccessful Strock 1-20 well, drilled at our Fort Fetterman prospect.

During 2004, we participated in the successful drilling of seven gross (.44 net) wells at our Big Sky Project. On September 30, 2004, we sold 90% of our interest in our Powder River Basin Coal Bed Methane acreage and 90% of our interest in the existing seven producing West Recluse wells. As part of the agreement, we retained a 5% carried working interest in all additional wells drilled on this acreage. During 2004, the new operator of this project drilled a total of 21 gross successful wells (1.05 wells, net to our interest). During 2005, we assigned our 5% carried working interest to the company that purchased our interest in 2004.

Oil and Gas Wells

The following table sets forth the number of oil and natural gas wells in which we had a working interest at December 31, 2006. All of these wells are located in the United States.

Location	Productive Wells As of December 31, 2006					
	Gross ^(a)			Net ^(b)		
	Oil	Gas	Total	Oil	Gas	Total
Montana.....	—	—	—	—	—	—
Wyoming.....	1	4	5	.45	2.9	3.35
North Dakota.....	5	—	5	.82	—	.82
Total.....	6	4	10	1.27	2.9	4.17

- (a) The number of gross wells is the total number of wells in which a working interest is owned.
- (b) The number of net wells is the sum of fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

Oil and Gas Interests

We currently own interest in the following developed and undeveloped acreage positions. Undeveloped acreage refers to acreage that has not been placed in producing units.

State	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Montana.....	—	—	640	480
Wyoming.....	2,560	1,612	316,203	148,038
North Dakota.....	2,400	735	104,296	33,044
Total.....	4,960	2,347	421,139	181,562

The following table presents the net undeveloped acres that we control, the type of lease and the year the leases are scheduled to expire.

	<u>Year of Expiration</u>	<u>Fee Leases</u>	<u>State Leases</u>	<u>Federal Leases</u>	<u>Totals</u>
Total Montana	2009	480	—	—	480
Wyoming	2007	3,885	1,185	5,355	10,425
	2008	3,420	492	9,067	12,979
	2009	15,225	588	1,191	17,004
	2010	15,404	2,875	3,477	21,756
	2011	9,920	3,524	41,166	54,610
	2012	1,380	—	3,149	4,529
	2013	—	—	3,707	3,707
	2014	—	—	6,421	6,421
	2015	—	—	4,782	4,782
	2016	—	—	11,187	11,187
	2017	—	—	638	638
Total Wyoming		49,234	8,664	90,140	148,038
North Dakota	2007	251	—	—	251
	2008	9,414	—	—	9,414
	2009	10,134	469	—	10,603
	2010	8,930	2,487	—	11,417
	2011	1,239	—	—	1,239
	2016	—	—	120	120
Total North Dakota		29,968	2,956	120	33,044
Totals		79,682	11,620	90,260	181,562

The types of leases represented in this table are comprised of more than 2,000 separate lease agreements and no one single lease is considered a material component of our acreage position. Fee leases consist of acreage leased from other individuals or companies that own the mineral rights underlying that acreage position. State leases consist of mineral rights underlying acreage controlled by the particular state where the acreage position is located, while federal leases consist of mineral rights underlying acreage controlled by the federal government and managed by the Bureau of Land Management.

Generally, the lease agreements provide that we pay an annual fee, called a delay rental, to retain these leases until such time that a well has been drilled and is producing from the leased lands. At that time, the leased lands are considered to be “held by production” and the lease continues for as long as oil and/or gas production continues. During the period that there is production, we will pay the lessor a royalty based on the revenues received from production. Generally, fee leases provide for royalties of 12.5% to 25%, and state and federal leases provide for royalties of 12.5 %. If the leases do not become held by production within the period set forth in the lease, or if we fail to pay the required delay rental obligations, the lease terminates. Generally, fee leases have terms of three to five years, state leases have terms of five to ten years and federal leases have terms of ten years. We can elect not to pay the yearly delay rental fee, but the lease would terminate. We could elect not to pay the delay rental fee if we did not believe an area was promising after completing preliminary work or if we did not have sufficient funds.

Our annual aggregate delay rental obligations, if we desire to continue to keep all our leases in effect, are as follows:

<u>Year</u>	<u>Rental Obligation</u>
2007	\$ 194,269
2008	179,569
2009	160,205
2010	141,717
2011	38,623
Thereafter	107,289

Production Volumes, Sales Prices and Production Costs

The following table summarizes our net natural gas and oil production volumes, our average sales prices and expenses for the periods indicated. Our production is attributable to our direct interests in producing properties and the production we are allocated from our interest in our drilling programs. For these purposes, our net production will be production that is owned by us either directly or indirectly through our drilling programs, after deducting royalty, limited partner and other similar interests. The lease operating expenses shown relates to our net production.

	<u>Years Ended December 31,</u>		
	<u>2006</u>	<u>2005</u>	<u>2004</u>
Production:			
Natural gas (MMcf)	48.2	59.7	49.0
Oil (Bbls)	34,578	78,954	12,849
Total equivalents (Bbls)	42,603	88,910	21,010
Average Sales Price Per Unit:			
Natural gas (per Mcf)	\$ 7.53	\$ 7.31	\$ 4.33
Oil (per Bbl)	\$ 54.79	\$ 53.89	\$ 41.58
Weighted average (per Boe)	\$ 52.97	\$ 52.77	\$ 35.52
Expenses (per Boe):	\$ 6.83	\$ 2.77	\$ 3.83

Office Facilities

We lease 6,844 square feet at 1050 17th Street, Suite 2400, Denver, Colorado. We believe that our facilities are adequate for our current operations and that we can obtain additional leased space if needed. Our obligation to provide aggregate monthly rental payments is as follows:

<u>Year</u>	<u>Annual Rental Amount</u>
2007	\$ 149,142
2008	152,564
2009	155,986
2010	159,408
2011	162,820
Thereafter	236,118

Item 3: Legal Proceedings

There are no legal proceedings filed, or to our knowledge, threatened against or involving the Company.

Item 4: Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2006.

PART II

Item 5: Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information.

Our common stock began trading on the OTC Bulletin Board under the symbol "AOGI" on January 17, 2003. On May 17, 2005, our common shares began trading on the American Stock Exchange under the ticker symbol "AEZ." The table below sets forth the high and low sales prices for our common stock in each quarter of the last two fiscal years.

	Common Stock Price	
	High	Low
2005		
Quarter ended March 31, 2005	\$ 3.42	\$ 2.11
Quarter ended June 30, 2005	6.40	2.50
Quarter ended September 30, 2005.....	8.20	4.40
Quarter ended December 31, 2005	7.50	3.90
2006		
Quarter ended March 31, 2006	\$ 5.29	\$ 3.20
Quarter ended June 30, 2006	5.19	4.10
Quarter ended September 30, 2006.....	6.55	4.57
Quarter ended December 31, 2006	8.01	4.70

On March 29, 2007 the closing sales price for our common stock as reported by AMEX was \$5.34 per share.

Holdings

As of March 29, 2007, there were approximately 62 holders of record of our common stock.

Dividend Policy

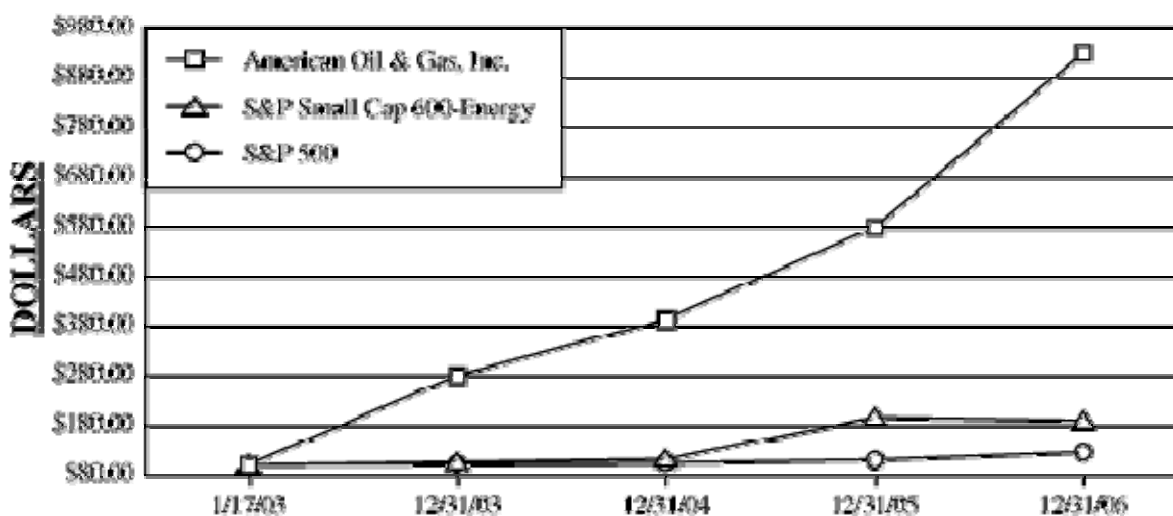
We have not declared a cash dividend on our common stock, and we do not anticipate the payment of future dividends. There are no restrictions that currently limit our ability to pay dividends on our common stock other than those generally imposed by applicable state law.

Issuer Purchases of Equity Securities

We did not repurchase any of our equity securities in 2006.

Performance Graph

As required by applicable rules of the SEC, the performance graph shown below was prepared based upon the assumption that \$100 was invested in our common stock at \$0.25 per share on January 17, 2003, and \$100 was invested in each of the Standard & Poor's 500 Index and the Standard and Poor's Small Cap 600 Index-Energy Sector at the closing price on January 17, 2003. January 17, 2003 is the day we changed our name to American Oil & Gas, Inc. and began trading under the ticker symbol "AOGI", to more accurately reflect the expected change in our operational focus to oil and gas exploration and production.



	<u>1/17/03(1)</u>	<u>12/31/03</u>	<u>12/31/04</u>	<u>12/31/05</u>	<u>12/31/06</u>
American Oil & Gas, Inc.	\$ 100.00	\$ 280.00	\$ 392.86	\$ 578.57	\$ 930.00
S&P Small Cap 600-Energy	\$ 100.00	\$ 105.44	\$ 111.18	\$ 195.87	\$ 189.48
S&P 500	\$ 100.00	\$ 102.00	\$ 104.03	\$ 110.03	\$ 125.35

(1) January 17, 2003 is the day in which we began trading under the ticker symbol "AOGI."

Item 6: Selected Consolidated Financial Data

The following tables present selected financial and operating data for the Company as of and for the periods indicated. You should read the following selected data along with "Item 7-Management's Discussion and Analysis of Financial Condition and Results of Operations," our financial statements and the related notes and other information included in this annual report. The selected financial data as of December 31, 2006, 2005, 2004, 2003 and 2002 has been derived from our financial statements, which were audited by our independent auditors, and were prepared in accordance with accounting principles generally accepted in the United States of America. The historical results presented below are not necessarily indicative of the results to be expected for any future period.

	<u>Year Ended December 31,</u>				
	<u>2006</u>	<u>2005</u>	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(in thousands, except per share data)				
Statement of Operations Data:					
Production Revenues	\$ 2,257	\$ 4,691	\$ 746	\$ 98	\$ —
Other revenues	1,530	—	—	—	—
Operating expenses:					
Lease operating expenses.....	291	246	80	38	—
Impairment expense.....	4,360	—	—	—	—
Depreciation, depletion and amortization	1,153	1,532	188	33	—
Accretion of asset retirement obligation	11	6	5	3	—
General and administrative	2,487	1,618	539	684	5
Non-cash based compensation expense	1,522	414	406	141	144
Total operating expenses.....	<u>9,824</u>	<u>3,816</u>	<u>1,218</u>	<u>899</u>	<u>149</u>
Operating income (loss).....	(6,037)	875	(472)	(801)	(149)
Other income (expense).....					
Investment income	393	204	34	—	—
Gain on sale of oil and gas properties	7,159	—	—	—	—
Total other income (expense)	<u>7,552</u>	<u>204</u>	<u>34</u>	<u>—</u>	<u>—</u>
Income (loss) before income taxes	1,515	1,079	(438)	(801)	(149)
Provision for income taxes	304	46	—	—	—
Net Income (loss).....	1,211	1,033	(438)	(801)	(149)
Less: dividends on preferred stock	1,080	479	62	18	—
Net Income (loss) attributable to common stockholders.....	<u>\$ 131</u>	<u>\$ 554</u>	<u>\$ (500)</u>	<u>\$ (819)</u>	<u>\$ (149)</u>

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(in thousands, except per share data)				
Income (loss) per common share:					
Basic	\$ 0.00	\$ 0.02	\$ (0.02)	\$ (0.03)	\$ (0.01)
Diluted	\$ 0.00	\$ 0.02	\$ (0.02)	\$ (0.03)	\$ (0.01)
Weighted average number of common shares outstanding:					
Basic	37,429	34,148	25,211	23,781	33,197
Diluted	38,142	34,956	25,211	23,781	33,197
Selected Cash Flow and Other Financial Data:					
Net income (loss)	\$ 1,211	\$ 1,033	\$ (438)	\$ (801)	\$ (149)
Less gains on sales of oil and gas properties	(7,159)	—	—	—	—
Depreciation, depletion and amortization	1,153	1,532	188	33	—
Impairment	4,360	—	—	—	—
Other non-cash items	(128)	466	411	237	144
Changes in assets and liabilities	1,496	(520)	(567)	(67)	—
Net cash provided (used) by operating activities	<u>\$ 1,369</u>	<u>\$ 2,511</u>	<u>\$ (406)</u>	<u>\$ (598)</u>	<u>\$ (5)</u>
Capital expenditures	\$ 16,142	\$14,791	\$ 2,895	\$ 1,734	\$ —
Cash proceeds from sales of oil and gas properties	\$ 16,067	—	\$ 1,582	—	—

	As of December 31,				
	2006	2005	2004	2003	2002
	(in thousands)				
Balance Sheet Data:					
Cash and cash equivalents	\$ 7,488	\$ 6,023	\$ 5,252	\$ 1,066	\$ 84
Other current assets	10,013	1,679	313	113	—
Oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment	38,869	24,921	3,481	1,924	—
Other property and equipment, net of depreciation	252	58	6	7	—
Other assets	12,514	13,094	—	—	—
Total assets	<u>\$ 69,136</u>	<u>\$ 45,775</u>	<u>\$ 9,052</u>	<u>\$ 3,110</u>	<u>\$ 84</u>
Current liabilities	4,656	1,434	127	426	—
Long term liabilities	2,392	2,010	41	31	—
Stockholders' equity	62,088	42,331	8,884	2,653	84
Total liabilities and stockholders' equity	<u>\$ 69,136</u>	<u>\$ 45,775</u>	<u>\$ 9,052</u>	<u>\$ 3,110</u>	<u>\$ 84</u>

Item 7: Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction

The following discussion and analysis should be read in conjunction with the "Selected Financial Data" and the accompanying financial statements and related notes included elsewhere herein. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas and oil, economic and competitive conditions, regulatory changes, estimates of proved reserves, potential failure to achieve production from development projects, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in "Item 1A. Risk Factors" and the "Cautionary Note Regarding Forward-Looking Statements", all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We focus our oil and natural gas exploration, exploitation and developmental operations on projects located in the Rocky Mountain region of the United States. We have funded our operations with a combination of cash received from the sale of our equity, cash flow generated from oil and gas operations, and from proceeds received from the sale of certain of our oil and gas assets. We intend to increase stockholder value by profitably growing reserves and production, primarily through drilling operations. Our company began oil and gas operations in January

2003, with the purchase of interests in undeveloped acreage from two private companies, Denver, Colorado based Tower Colombia Corporation (“TCC”) and Casper, Wyoming based North Finn LLC. In April 2005, we completed a merger with TCC and we currently retain a strategic alliance with North Finn. We currently own interests in approximately 421,000 gross (182,000 net) acres primarily in the Powder River Basin of Wyoming and in the Williston Basin of North Dakota. During 2006, we commenced initial drilling in our Krejci project, located in Wyoming and in our Goliath project, located in North Dakota. We also continued drilling in our Fetter project, located in Wyoming. We expect that we will continue to drill in these areas through 2007, in order to best understand the optimum drilling, completion and stimulation methods to use in our attempt to produce oil and natural gas in an economic fashion. In addition to focusing on drilling within our existing projects, we expect to continue to evaluate opportunities to expand our project portfolio.

We have not yet begun to establish meaningful reserves or cash flow. However, we believe that our existing project portfolio provides us with the opportunity to rapidly grow reserves and cash flow if we are able to prove that our acreage positions can be developed in a commercial fashion. A number of unprofitable wells may need to be drilled while we test various drilling, completion and stimulation methods.

We have been able to reduce or eliminate our financial exposure in the initial drilling in our projects by creating joint ventures arrangements that provide for others to pay for all or a disproportionate share of the initial drilling costs. This has allowed us to move forward in drilling a greater number of wells than if we were to drill these wells on our own. We expect to continue to use industry relationships to partially or completely fund initial drilling.

Within the main focus areas of our existing project portfolio, we expect the following drilling activity, and our share of the cost of that drilling activity to occur in 2007:

Project	Expected 2007 wells	Approximate working interest	Expected net capital required (in millions)
Fetter project — Converse County, WY	3 - 4	24%	\$ 0(a)
Krejci project — Niobrara County, WY	8	45%	\$ 9
Goliath project — Williams County, ND	2	50%	\$ 5
Total drilling activity	13 - 14	40%	\$ 14

(a) As a result of our participation agreement with Red Technology Alliance, as further explained in “Item 2: Properties,” we will have no capital exposure in the drilling or completion of these wells.

We expect that our projected capital expenditures relating to our oil and gas drilling operations, general and administrative expenses and other oil and gas related activities such as land and lease costs and geological costs, will require us to access additional capital in 2007. Although there is no assurance that we will be able to access additional capital, additional capital may come from the sale of debt and/or equity instruments, or from the sale of certain oil and gas assets. We may expand or reduce our capital expenditures depending on our available capital.

We have not entered into any commodity derivative arrangements or hedging transactions. Although we have no current plans to do so, we may enter into commodity swap and/or hedging transactions in the future in conjunction with oil and gas production. We have no off-balance sheet arrangements.

Liquidity and Capital Resources

We do not currently generate meaningful cash flow from our oil and natural gas operating activities, although our future depends on our ability to generate oil and natural gas operating cash flow. We recognize that net cash generated from operating activities is a function of production volumes and commodity prices, both of which are inherently volatile and unpredictable, as well as operating efficiency and capital spending. Our business is a depleting one in which each barrel of oil equivalent produced must be replaced or our asset base and capacity to generate revenues in the future will shrink.

Our primary cash requirements are for exploration, development and acquisition of oil and gas properties. We have historically funded our oil and natural gas activities primarily through the sale of our equity, from the sale of certain of our oil and gas assets and to a lesser extent, internally generated cash flows.

Due to our active oil and natural gas activities, we have experienced, and expect to continue to experience, substantial working capital requirements. We currently anticipate capital requirements in 2007 to be approximately \$22 million. Approximately \$16 million is allocated to our expected drilling and production activities (which include \$14 million to be used for drilling new wells within our main focus areas); \$3 million is allocated to land, and geological and geophysical activities; and \$3 million relates to our general and administrative expenses. We intend to fund these capital expenditures, other commitments and working capital requirements with existing capital, funds raised from the sale of our equity and to a lesser extent, expected cash flow from operations.

We do not expect to fund our oil and gas operations with debt unless and until we generate sufficient cash flow from oil and natural gas operations to service the debt. At December 31, 2006, we had cash and cash equivalents of \$7.5 million consisting primarily of short-term money market investments, as compared to \$6.0 million at December 31, 2005. Working capital was \$12.8 million as of December 31, 2006, as compared to \$9.1 million at December 31, 2005.

Net Cash Provided By Operating Activities

Cash flows provided (used) by operating activities were \$1.4 million, \$2.5 million and (\$400,000) for the years ended December 31, 2006, 2005, and 2004, respectively. The significant increase in cash flows provided by operating activities for the year ended December 31, 2005 compared to 2004 was primarily due to higher oil and gas production revenue relating to our Big Sky Project, and the decrease from 2005 to 2006 occurred due to our sale of our Big Sky project in March of 2006.

Net Cash Used In Investing Activities

Our oil and natural gas operations are extremely capital intensive and we invest a substantial portion of our available capital in our drilling, acquisition, land and geophysical activities. As a result, we used \$15.9 million during 2006 relating to our oil and natural gas operations, and we used \$240,000 primarily for the acquisition of furniture and equipment relating to our office move in 2006. We offset these amounts by selling oil and gas assets for approximately \$16.1 million, so our net capital used in investing activities for 2006 was \$86,000. Capital expenditures of \$11.1 million were attributable to the drilling of 12 gross wells, 10 of which were apparently successful. Other spending included \$4.8 million primarily attributable to land holdings and capitalized G&A.

During the year ended December 31, 2005, we used \$14.8 million in investing activities. Capital expenditures of \$9.9 million were attributable to the drilling of 17 gross wells, 15 of which were apparently successful. Other spending included \$4.2 million attributable to land holdings and \$0.6 million in prepayments of drilling costs incurred in 2006. \$56,000 of capital expenditures were associated with computer hardware, office furniture and equipment.

During the year ended December 31, 2004, we used \$1.3 million in investing activities. Capital expenditures of \$1.6 million were attributable to the drilling of 28 gross wells, all of which were successful. Other spending included \$1.3 million in expenditures primarily attributable to land holdings. The expenditures were partially offset by sales proceeds of 1.6 million from the sale of our interests in a coalbed methane project.

Net Cash Provided By Financing Activities

Cash flows provided by financing activities totaled \$183,000 for the year ended December 31, 2006 which amount came from the exercise of warrants and options. For the year ended December 31, 2005, cash flows provided by financing activities totaled \$13.1 million. We received \$12.9 million in net proceeds from the sale of our series AA convertible preferred stock and received \$153,000 from the exercise of common stock warrants exercised in 2005. For the year ended December 31, 2004, cash flows provided by financing activities totaled \$5.9 million. We received \$5.9 million in proceeds from the sale of common stock and received \$25,000 from common stock warrants exercised in 2004.

Results of Operations

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

We recorded net income attributable to common stockholders of \$131,223 (\$0.00 per common share, basic and diluted) for the year ended December 31, 2006, as compared to net income attributable to common stockholders of \$553,629 (\$.02 per common share, basic and diluted) for the year ended December 31, 2005. Included in the net income for 2006 are (i) \$7,159,470 in gains (\$4,431,712 after tax effect) from the sale of oil and gas properties, (ii) \$1,530,000 in service fee revenue and (iii) impairment expense of \$4,360,000. For the year ended December 31, 2005, we had no recognized gain from property sales, no service fee revenue and no impairment expense.

Oil and Gas Operations

For the year ended December 31, 2006, we recorded total oil and gas revenues of \$2,256,839 compared with \$4,691,381 for the year ended December 31, 2005. The primary reason for the revenue decline is the sale on March 31, 2006 of our interest in the Big Sky producing property that accounted for substantially all of our revenues in 2005 and through March 31, 2006. Oil and gas sales and production costs are summarized in the table that follows.

	Year ended December 31,	
	2006	2005
Oil sold (barrels).....	34,578	78,954
Average oil price	\$ 54.79	\$ 53.89
Oil revenue	\$ 1,894,386	\$ 4,254,944
Gas sold (mcf)	48,149	59,733
Average gas price	\$ 7.53	\$ 7.31
Gas revenue	\$ 362,453	\$ 436,437
Total oil and gas revenues	\$ 2,256,839	\$ 4,691,381
Less lease operating expenses	(290,803)	(246,134)
Less oil & gas amortization expense	(937,821)	(1,406,856)
Less accretion of discount	(11,213)	(5,608)
Less impairments.....	<u>(4,360,000)</u>	<u>—</u>
Producing revenues less direct expenses	(3,333,816)	3,032,783
Less intangible asset amortization	(180,000)	(120,000)
Less depreciation of office facilities.....	(35,412)	(5,555)
Less general and administrative expenses	(4,009,119)	(2,032,256)
Add service fee revenue	<u>1,530,000</u>	<u>—</u>
Income (loss) from operations	<u>\$ (6,037,429)</u>	<u>\$ 874,972</u>
Total barrels of oil equivalent (“boe”) sold	42,603	88,910
Lease operating expense per boe sold.....	\$ 6.83	\$ 2.77
Amortization expense per boe sold.....	\$ 21.80	\$ 17.17

Service Fee Income

For the year ended December 31, 2006, we received a \$1,530,000 convertible note from GSL Energy Corp. as a Service Fee under an October 2005 agreement with MAB Resources to receive a \$1,530,000 finder's fee upon successfully assisting MAB Resources in acquiring additional Montana lease acreage that was not suitable for our acreage portfolio. We subsequently converted the \$1,530,000 note into 3,060,000 shares of GSL common stock at \$0.50 per share, which was subsequently exchanged on May 12 for 3,060,000 shares of unregistered shares in common stock of publicly held PetroHunter Energy Corp. (OTCBB “PHUN”). We did not generate any service fee income during the year ended December 31, 2005.

General and Administrative Expenses

We recorded \$4.0 million and \$2.0 million in general and administrative expenses for the year ended December 31, 2006 and December 31, 2005, respectively. The primary differences is \$1.2 million recorded for the year ended December 31, 2006 pursuant to our January 1, 2006 adoption of FAS 123(R) share based payments; an increase in

salaries and salaries related expense of \$600,000 which results from increasing the number of full time employees hired to support our expanding oil and gas operations, from eight employees at December 31, 2005, to thirteen employees at December 31, 2006; and an increase in accounting and audit related expenses of \$151,000 due to our implementation of controls and procedures required pursuant to Sarbanes-Oxley.

Impairments

For the year ended December 31, 2006, we recorded an impairment against our evaluated oil and gas properties in the amount of \$4.36 million. A substantial portion of the impairment occurred during the fourth quarter and results from being unable to complete the Fetter project State 4-36 well in a fashion as originally planned, which reduced the estimate of proved reserves as of December 31, 2006 for the well. We did not record any impairment for the year ended December 31, 2005.

Gain on Sale of Oil and Gas Properties

We recorded \$7.2 million in gains from the sale of oil and gas properties (\$4.4 million after tax effect) during the year ended December 31, 2006. The reconciliations of the gains on the sales are as follows:

	<u>Big Sky</u>	<u>Bear Creek</u>	<u>Goliath</u>	<u>Totals</u>
Contract sales price.....	\$ 11,500,000	\$ 1,080,000	\$ 6,165,520	\$ 18,745,520
Effective date adjustments.....	<u>(821,496)</u>	<u>0</u>	<u>0</u>	<u>(821,496)</u>
Adjusted sales price.....	10,678,504	1,080,000	6,165,520	17,924,024
Allocated capitalized costs using the relative fair market value method required under full cost accounting.....	<u>(6,416,650)</u>	<u>(648,443)</u>	<u>(3,699,461)</u>	<u>(10,764,554)</u>
Recognized gains on sales of oil and gas properties...	<u>\$ 4,261,854</u>	<u>\$ 431,557</u>	<u>\$ 2,466,059</u>	<u>\$ 7,159,470</u>

We did not record any gain from the sale from oil and gas properties during the year Ended December 31, 2005.

Investment Income

We recorded \$304,000 and \$46,000 in investment income for the years ended December 31, 2006 and 2005, respectively. We typically invest our excess cash in short term investments and money market accounts. The increase in investment income results from a higher excess cash balance and from higher interest rates in 2006 over 2005.

Income Taxes

For the year ended December 31, 2006, we recorded a \$303,748 provision for deferred income taxes and recorded a \$46,245 provision for the year ended December 31, 2005. The \$303,748 provision reflects a projected 20% effective deferred tax rate for 2006. The effective rate is lower than the 38.1% statutory rate due primarily to percentage depletion in excess of cost depletion.

Preferred Dividends

For the year ended December 31, 2006, we recorded \$1.08 million from dividends attributable to our outstanding Series AA Convertible Preferred Stock, which was outstanding for the full year. For the year ended December 31, 2005, we recorded \$478,498 in preferred dividends attributable to our outstanding Series AA Convertible Preferred Stock, which represents dividends payable from July 22, 2005 through December 31, 2005 and \$844 from our then outstanding Series A Convertible Preferred Stock. The Series A Convertible Preferred Stock was converted into common shares during January 2005.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

We recorded net income attributable to common stockholders of \$553,629 (income of \$0.02 per common share, basic and diluted) for the year ended December 31, 2005, as compared to a net loss attributable to common stockholders of \$499,651 (loss of \$.02 per common share, basic and diluted) for the year ended December 31, 2004.

Oil and Gas Operations

For the year ended December 31, 2005, we recorded total oil and gas revenues of \$4,691,381 compared with \$746,242 for the year ended December 31, 2004. The increase in revenue is attributable to our participation in successful wells drilled during 2005 in our Big Sky project, which we sold in March 2006. Oil and gas sales and production costs are summarized in the table that follows.

	<u>Year ended December 31,</u>	
	<u>2005</u>	<u>2004</u>
Oil sold (barrels).....	78,954	12,849
Average oil price	\$ 53.89	\$ 41.58
Oil revenue	\$ 4,254,944	\$ 534,288
Gas sold (mcf)	59,733	48,965
Average gas price	\$ 7.31	\$ 4.33
Gas revenue	\$ 436,437	\$ 211,954
Total oil and gas revenues	\$ 4,691,381	\$ 746,242
Less lease operating expenses	(246,134)	(80,461)
Less oil & gas amortization expense	(1,406,856)	(188,189)
Less accretion of discount	(5,608)	(4,520)
Less impairments	—	—
Producing revenues less direct expenses	3,032,783	473,072
Less intangible asset amortization	(120,000)	—
Less depreciation of office facilities	(5,555)	(129)
Less general and administrative expenses	(2,032,256)	(945,114)
Income (loss) from operations	\$ 874,972	\$ (472,171)
Total barrels of oil equivalent (“boe”) sold	88,910	21,010
Lease operating expense per boe sold.....	\$ 2.77	\$ 3.83
Amortization expense per boe sold.....	\$ 17.17	\$ 8.95

General and administrative expenses.

During 2005 and 2004, we recorded general and administrative expenses in the amount of \$2.03 million and \$945,000, respectively. The increase in general and administrative expenses results from increased costs associated with our merger with Tower Colombia Corporation, and from continued expanding operations to support our oil and gas operations. Our payroll related expenses increased by approximately \$461,000 from 2004 to 2005 due to the addition of new employees. Our accounting related expenses increased by approximately \$90,000, which was related primarily to design and implementation of controls over financial reporting pursuant to Sarbanes-Oxley. We incurred a management fee of \$90,000 prior to the merger with Tower Colombia Corporation, and paid an additional \$46,000 for fees directly related to the merger. We paid \$72,000 for listing fees related to the listing of our common stock on the American Stock Exchange. Our Directors related expenses increased by \$113,000, due to the value assigned to shares that vested during 2005 on behalf of one of our Directors. The remaining increase is primarily attributable to increases in investor relations expenses, rent and travel expenses.

Income taxes.

A deferred tax liability or asset is recognized for the estimated future tax effects attributable to (i) NOLs and (ii) existing temporary differences between book and taxable income. Realization of net deferred tax assets is dependent upon generating sufficient taxable income within the carryforward period available under tax law. For the year ended December 31, 2005, we recorded a \$46,245 income tax provision consisting entirely of deferred income taxes. For the year ended December 31, 2004, we recorded no income tax provision, having cumulative losses for

both financial and income tax reporting. The \$46,245 deferred tax provision for 2005 equate to approximately a 4% effective tax rate on the 2005 net income of \$874,972. This is significantly below the 35% federal statutory rate primarily due to reversal in 2005 of the \$290,000 valuation allowance on the December 31, 2004 deferred tax asset. The \$1,893,581 deferred income tax liability at December 31, 2005 is due primarily to a \$1,847,300 deferred tax liability recorded in the acquisition of Tower Colombia Corporation in a non-taxable merger.

Preferred Dividends.

We are obligated to pay an 8% dividend on our Series AA Convertible Preferred Stock. For the year ended December 31, 2005, we incurred \$478,498 in dividends in conjunction with this obligation, and \$844 in dividends associated with our now retired, Series A Preferred Stock. During 2004, we reflected \$61,640 in dividends associated with our now retired, Series A Preferred Stock.

Critical Accounting Policies and Estimates

Full Cost Accounting Method

We use the full cost method of accounting for our oil and gas properties. Under this method, all acquisition, exploration, development and estimated abandonment costs, including certain related employee costs and general and administrative costs (less any reimbursements for such costs), incurred for the purpose of acquiring and finding oil and gas are capitalized. Unevaluated property costs are excluded from the amortization base until we have made a determination as to the existence of proved reserves on the respective property or impairment. We review our unevaluated properties at the end of each quarter to determine whether the costs should be reclassified to the full cost pool and thereby subject to amortization. Sales of oil and gas properties are accounted for as adjustments to the net full cost pool with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves. We amortize our investment in oil and gas properties through DD&A using the units of production method. Under the units of production method, the quarterly provision for DD&A is computed by dividing production volumes for the period by the total proved reserves as of the beginning of the period, and applying the respective rate to the net cost of proved oil and gas properties, including future development costs. We capitalize the portion of salaries, general and administrative expenses that are attributable to our acquisition, exploration and development activities. Under the full cost method of accounting, we compare, at the end of each financial reporting period, the present value of estimated future net cash flows from proved reserves (based on period-end hedge adjusted commodity prices and excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and gas properties, net of related deferred taxes. This comparison is referred to as a "ceiling test." If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows.

Revenue Recognition

We record revenues from the sales of natural gas and oil when in the month that delivery to the customer has occurred and title has transferred. This occurs when natural gas or oil has been delivered to a pipeline or a tank lifting has occurred. We receive payment from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. However, differences have been insignificant.

Natural Gas Imbalances

We may have an interest with other producers in certain properties, in which case we use the sales method to account for natural gas imbalances. Under this method, revenue is recorded on the basis of natural gas we actually sell. In addition, we may record revenue for our share of natural gas sold by other owners that cannot be volumetrically balanced in the future due to insufficient remaining reserves. We also reduce revenue for other owners' natural gas we sell that cannot be volumetrically balanced in the future due to insufficient remaining reserves. Our remaining over-and-under-produced gas balancing positions are considered in our proved reserves. As of December 31, 2005 and 2006 our produced natural gas volumes were in balance.

Asset Retirement Obligation

Our accounting for asset retirement obligations is governed by SFAS No. 143, "Accounting for Asset Retirement Obligations". This statement requires us to record our estimate of the fair value of liabilities related to future asset retirement obligations in the period the obligation is incurred. Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of an oil and gas property's useful life. The adoption of SFAS No. 143 requires the use of management's estimates with respect to future abandonment costs, inflation, market risk premiums, useful life and cost of capital. As required by SFAS No. 143, our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or settled. Deferred income taxes are also recognized for tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statement and income tax reporting. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices).

Stock-based Compensation

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), which revises SFAS No. 123, *Accounting for Stock-Based Compensation*, and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*. We adopted the provisions of the new standard effective January 1, 2006. Prior to the adoption of SFAS No. 123(R), we used the intrinsic value method in accordance with APB Opinion No. 25 and the disclosure only provisions of SFAS No. 123. We recorded non-cash stock-based compensation of \$1.5 million, \$414,000, and \$406,000 in 2006, 2005 and 2004, respectively.

Recently Issued Accounting Pronouncements

In March 2006, the FASB issued SFAS No. 156, *Accounting for Servicing of Financial Assets*, which requires all separately recognized servicing assets and servicing liabilities be initially measured at fair value. SFAS No. 156 permits, but does not require, the subsequent measurement of servicing assets and servicing liabilities at fair value. Adoption is required as of the beginning of the first fiscal year that begins after September 15, 2006. Early adoption is permitted. The adoption of SFAS No. 156 is not expected to have a material effect on our consolidated financial position, results of operations or cash flows.

In June 2006, the FASB issued FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109*, which clarifies the accounting for uncertainty in income taxes recognized in accordance with SFAS No. 109, *Accounting for Income Taxes*. FIN 48 prescribes a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. FIN 48 also requires that the amount of interest expense to be recognized related to uncertain tax positions be computed by applying the applicable statutory rate of interest to the difference between the tax position recognized in accordance with FIN 48 and the amount previously taken or expected to be taken in a tax return. The change in net assets as a result of applying this pronouncement will be considered a change in accounting principle, with the cumulative effect of the change treated as an offsetting adjustment to the opening balance of retained earnings or goodwill, if allowed under existing accounting standards, in the period of transition. FIN 48 is effective as of January 1, 2007 and we are currently evaluating the effects, if any, that FIN 48 will have on our financial statements.

In September 2006, the SEC issued Staff Accounting Bulletin (“SAB”) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. SAB 108 provides guidance on the consideration of effects of the prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. Under SAB 108, registrants must quantify errors using both a balance sheet and income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB 108 was effective for us as of December 31, 2006, and the adoption did not have an impact on our financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which provides guidance for using fair value to measure assets and liabilities. The standard also gives expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect of fair value measurements on earnings. SFAS No. 157 does not expand the use of fair value in any new circumstances. SFAS No. 157 establishes a fair value hierarchy that prioritizes the information used to develop fair value assumptions. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Early adoption is encouraged. We are currently assessing the impact, if any, that SFAS No. 157 will have on our financial statements.

In September 2006, the FASB issued SFAS 158, *Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans*. We do not have postretirement plans.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits entities to choose to measure many financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 applies to all entities and is effective for fiscal years beginning after November 15, 2007. Adoption of SFAS No. 159 is not required for these financial statements and we are currently determining the impact, if any, that SFAS No. 159 will have on our future financial statements.

Item 7A: Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Because of our relatively low level of current oil and gas production, we are not exposed to a great degree of market risk relating to the pricing applicable to our oil and natural gas production. However, our ability to raise additional capital at attractive pricing, our future revenues from oil and gas operations, our future profitability and future rate of growth depend substantially upon the market prices of oil and natural gas, which fluctuate widely. We expect commodity price volatility to continue. We do not currently utilize hedging contracts to protect against commodity price risk. As our oil and gas production grows, we may manage our exposure to oil and natural gas price declines by entering into oil and natural gas price hedging arrangements to secure a price for a portion of our expected future oil and natural gas production.

Operating Cost Risk

We have experienced rising operating costs which impacts our cash flow from operating activities and profitability.

We recognize that rising operating costs could continue and continued rising operating costs would negatively impact our oil and gas operations.

Item 8: Financial Statements and Supplementary Data

AMERICAN OIL & GAS, INC.
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors
American Oil & Gas, Inc.
Denver, Colorado

We have audited the consolidated balance sheets of American Oil & Gas, Inc. as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We have also audited the consolidated statements of operations, stockholders' equity, and cash flows for the year ended December 31, 2004 of American Oil & Gas, Inc. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of American Oil & Gas, Inc. as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of American Oil & Gas, Inc.'s internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated April 2, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of American Oil & Gas, Inc.'s internal control over financial reporting and an unqualified opinion on the effectiveness of American Oil & Gas, Inc.'s internal control over financial reporting.

As discussed in Note 7 to the accompanying consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment*.

/s/ HEIN & ASSOCIATES LLP

Denver, Colorado
April 2, 2007, except for the second paragraph above, which is dated April 10, 2007

AMERICAN OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2006 AND 2005

	<u>2006</u>	<u>2005</u>
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	\$ 7,488,474	\$ 6,022,822
Short-term investment.....	8,456,400	—
Trade receivables	336,188	1,481,543
Receivable for sale of oil and gas properties.....	777,461	—
Prepaid expenses.....	402,287	156,475
Inventory.....	<u>40,904</u>	<u>40,904</u>
Total current assets	<u>17,501,714</u>	<u>7,701,744</u>
PROPERTY AND EQUIPMENT, AT COST		
Oil and gas properties, full cost method (including unevaluated costs of \$33,263,390 at 12/31/06 and \$17,843,133 at 12/31/05)	41,424,253	26,547,922
Other property and equipment	<u>295,485</u>	<u>68,023</u>
Total property and equipment.....	41,719,738	26,615,945
Less accumulated depreciation, depletion and amortization	<u>(2,598,581)</u>	<u>(1,636,246)</u>
Net property and equipment.....	<u>39,121,157</u>	<u>24,979,699</u>
INTANGIBLE AND OTHER ASSETS		
Goodwill	11,670,468	11,670,468
Other intangible asset.....	600,000	780,000
Drilling prepayments	233,058	643,485
Other assets.....	<u>10,000</u>	<u>—</u>
	<u>\$ 69,136,397</u>	<u>\$ 45,775,396</u>
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	\$ 1,964,000	\$ 954,544
Asset retirement obligations	40,321	—
Deferred income taxes	2,172,785	—
Preferred dividends payable.....	<u>479,342</u>	<u>479,342</u>
Total current liabilities	<u>4,656,448</u>	<u>1,433,886</u>
LONG-TERM LIABILITIES		
Asset retirement obligations	194,947	117,011
Deferred income taxes	<u>2,197,329</u>	<u>1,893,581</u>
Total long-term liabilities	<u>2,392,276</u>	<u>2,010,592</u>
COMMITMENTS AND CONTINGENCIES (Note 13)		
STOCKHOLDERS' EQUITY		
Series AA preferred stock, \$.001 par value, authorized 400,000 shares; issued and outstanding 250,000 shares at 12/31/06 and at 12/31/05; redemption value of \$13,979,342 at 12/31/2006 and at 12/31/2005	250	250
Common stock, \$.001 par value, authorized 100,000,000 shares; issued and outstanding 38,927,114 at 12/31/2006 and 36,476,202 at 12/31/2005	38,927	36,476
Additional paid-in capital	59,210,784	43,225,408
Deferred compensation	(35,910)	—
Accumulated deficit.....	(799,993)	(931,216)
Accumulated other comprehensive income	<u>3,673,615</u>	<u>—</u>
Total equity	<u>62,087,673</u>	<u>42,330,918</u>
	<u>\$ 69,136,397</u>	<u>\$ 45,775,396</u>

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

AMERICAN OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004

	2006	2005	2004
REVENUES			
Oil and gas sales.....	\$ 2,256,839	\$ 4,691,381	\$ 746,242
Service fee.....	<u>1,530,000</u>	<u>—</u>	<u>—</u>
Total revenues.....	<u>3,786,839</u>	<u>4,691,381</u>	<u>746,242</u>
OPERATING EXPENSES			
Lease operating	290,803	246,134	80,461
General and administrative	4,009,019	2,032,256	945,114
Depletion, depreciation and amortization	1,153,233	1,532,411	188,318
Accretion of asset retirement obligation	11,213	5,608	4,520
Impairments	<u>4,360,000</u>	<u>—</u>	<u>—</u>
Total operating expenses.....	<u>9,824,268</u>	<u>3,816,409</u>	<u>1,218,413</u>
INCOME (LOSS) FROM OPERATIONS	<u>(6,037,429)</u>	<u>874,972</u>	<u>(472,171)</u>
OTHER INCOME			
Gains on sales of oil and gas properties	7,159,470	—	—
Investment income	<u>392,930</u>	<u>204,244</u>	<u>34,160</u>
Total other income	<u>7,552,400</u>	<u>204,244</u>	<u>34,160</u>
INCOME (LOSS) BEFORE INCOME TAXES	1,514,971	1,079,216	(438,011)
Income tax expense—current.....	—	—	—
Income tax expense—deferred.....	<u>303,748</u>	<u>46,245</u>	<u>—</u>
NET INCOME (LOSS)	1,211,223	1,032,971	(438,011)
Less dividends on preferred stock	<u>1,080,000</u>	<u>479,342</u>	<u>61,640</u>
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	<u>\$ 131,223</u>	<u>\$ 553,629</u>	<u>\$ (499,651)</u>
NET INCOME (LOSS) PER COMMON SHARE:			
Basic.....	\$ 0.00	\$ 0.02	\$ (0.02)
Diluted	\$ 0.00	\$ 0.02	\$ (0.02)
Weighted average common shares outstanding:			
Basic.....	37,428,506	34,148,065	25,211,447
Diluted	38,142,011	34,955,624	25,211,447

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

AMERICAN OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2005 AND 2004

	<u>2006</u>	<u>2005</u>	<u>2004</u>
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	\$ 1,211,223	\$ 1,032,971	\$ (438,011)
Adjustments to reconcile net income (loss) to net cash provided (used) by operating activities:			
Gains on sales of oil and gas properties.....	(7,159,470)	—	—
Service fee received in the form of a convertible note.....	(1,530,000)	—	—
Depletion, depreciation and amortization.....	1,153,233	1,532,411	188,318
Accretion of asset retirement obligation.....	11,213	5,608	4,520
Deferred income taxes	303,748	46,245	—
Share-based compensation.....	1,522,219	413,764	406,258
Impairment provision.....	4,360,000	—	—
Changes in assets and liabilities:			
Decrease (increase) in trade receivables.....	1,145,355	(1,222,695)	(213,106)
Decrease (increase) in yard inventory	—	(40,904)	—
Decrease (increase) in advances and prepaid expenses.....	(245,812)	(101,940)	12,252
Increase (decrease) in accounts payable and accrued liabilities.....	596,935	845,933	(365,785)
Net cash provided (used) by operating activities	<u>1,368,644</u>	<u>2,511,393</u>	<u>(405,554)</u>
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash proceeds from sales of oil and gas properties.....	16,066,563	—	1,582,171
Cash paid for oil and gas properties	(15,913,075)	(14,091,540)	(2,894,560)
Drilling prepayments	—	(643,485)	—
Cash paid for office equipment and software.....	(229,178)	(55,913)	—
Cash paid for other long-term asset.....	(10,000)	—	—
Net cash used in investing activities.....	<u>(85,690)</u>	<u>(14,790,938)</u>	<u>(1,312,389)</u>
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from sale of preferred stock	—	13,499,927	—
Proceeds from sale of common stock	—	—	6,025,000
Cash paid for stock offering and issuance costs	(2,283)	(584,980)	(84,986)
Proceeds from warrant exercise.....	55,508	152,600	25,000
Proceeds from employee stock option exercise.....	24,800	—	—
Proceeds from stock option exercises by a consultant	104,673	—	—
Preferred dividends paid in cash.....	—	(18,864)	(61,640)
Cash received from acquired company.....	—	1,795	—
Net cash provided by financing activities	<u>182,698</u>	<u>13,050,478</u>	<u>5,903,374</u>
NET INCREASE IN CASH	1,465,652	770,933	4,185,431
CASH, BEGINNING OF YEAR	6,022,822	5,251,889	1,066,458
CASH, END OF YEAR	<u>\$ 7,488,474</u>	<u>\$ 6,022,822</u>	<u>\$ 5,251,889</u>
Supplemental Schedule of Cash Flow Information			
Cash paid for interest expense	\$ —	\$ —	\$ —
Cash paid for income taxes incurred	\$ —	\$ —	\$ —
Supplemental Disclosures of Non-Cash Activities			
Common stock issued to acquire oil and gas properties	\$ 13,079,000	\$ 4,211,911	\$ 328,050
Common stock issued to acquire Tower Colombia Corp.....	\$ —	\$ 15,196,000	\$ —
Preferred stock dividends paid in common stock.....	\$ 1,080,000	\$ —	\$ —
Share-based compensation expense.....	\$ 1,522,219	\$ 413,764	\$ 406,258
Service fee received in the form of a convertible note.....	\$ 1,530,000	\$ —	\$ —
Oil and gas properties sold in exchange for a convertible note	\$ 1,080,000	\$ —	\$ —
Notes converted into PetroHunter Energy common stock	\$ 2,610,000	\$ —	\$ —
Warrants issued for financing costs.....	\$ —	\$ 575,544	\$ 60,192
Common stock issued for financing costs	\$ —	\$ —	\$ 56,400
Warrants issued for oil and gas property consulting	\$ —	\$ 31,564	\$ 31,611
Warrant issued to acquire oil and gas properties.....	\$ 88,000	\$ —	\$ —
Drilling prepayments applied to drilling costs	\$ 410,427	\$ —	\$ —

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

AMERICAN OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004

	Preferred Shares	Stock Amount	Common Shares	Stock Amount	Paid-in Capital	Deferred Compensation	Comprehensive Income		Total Equity
							Accumulated Deficit	Accumulated Other Income	
December 31, 2003 balances	67,000	\$ 67	24,388,702	\$ 24,389	\$ 4,036,621	\$(423,750)	\$(984,350)	\$ —	\$ 2,652,977
Sale of stock at \$1.00 per share.....			1,525,000	1,525	1,523,475				1,525,000
Costs of offering.....					(7,429)				(7,429)
Sale of stock at \$1.50 / share.....			3,000,000	3,000	4,497,000				4,500,000
Costs of offering.....					(133,957)				(133,957)
Stock for private placement costs....			30,000	30	56,370				56,400
Shares issued for oil prospect.....			135,000	135	327,915				328,050
Warrant exercise at \$1.00 / share ...			25,000	25	24,975				25,000
Warrants for oil project consulting					31,611				31,611
Options for investor relations service.....					38,632				38,632
Dividends on preferred stock							(61,640)		(61,640)
Deferred compensation recognized						282,500			282,500
Shares issued to Director.....			50,000	50	85,076				85,126
Net loss							(438,011)		(438,011)
December 31, 2004 balances	67,000	\$ 67	29,153,702	\$ 29,154	\$10,480,289	\$(141,250)	\$(1,484,001)	\$ —	\$ 8,884,259
Dividends, Series A Preferred Stock.....							(844)		(844)
Series A Preferred Stock conversion	(67,000)	(67)	670,000	670	(603)				—
Warrants exercised at \$1.09 / share.....			140,000	140	152,460				152,600
Options for investor relations service.....					77,264				77,264
Warrants for oil project consulting					31,564				31,564
Deferred Compensation recognized						141,250			141,250
Stock issued for Tower merger			5,800,000	5,800	15,190,200				15,196,000
Sale of Series AA Preferred Stock ..	250,000	250			13,499,677				13,499,927
Costs of preferred stock offering.....					(1,160,524)				(1,160,524)
Accrued dividends, Series AA Pref.							(479,342)		(479,342)
Warrants issued for placement costs.....					575,544				575,544
Shares issued for oil prospect.....			675,000	675	4,184,325				4,185,000
Shares issued to Director.....			37,500	37	195,212				195,249
Net income							1,032,971		1,032,971
Balance December 31, 2005	250,000	\$ 250	36,476,202	\$ 36,476	\$43,225,408	\$ —	\$(931,216)	\$ —	\$ 42,330,918
Series AA preferred stock dividends paid in common stock....			239,493	240	1,079,760				1,080,000
Accrued dividends, Series AA Pref.							(1,080,000)		(1,080,000)
Shares issued for oil and gas properties			2,050,000	2,050	13,076,950				13,079,000
Share issuance costs					(2,283)				(2,283)
Warrant issued for properties					88,000				88,000
Stock option compensation expense					1,230,788				1,230,788
Shares to new employees			20,000	20	96,280				96,300
Stock option exercised by employee			10,000	10	24,790				24,800
Stock options exercised by consultant.....			32,010	32	104,641				104,673
Warrants exercised			46,004	46	55,462				55,508
Shares issued for consulting services			26,405	26	123,285				123,311
Deferred stock-based compensation.....			27,000	27	107,703	(107,730)			—
Deferred compensation recognized						71,820			71,820
Comprehensive income:									
Net income.....							1,211,223		1,211,223
Unrealized gain on short-term investment, net of tax								3,673,615	3,673,615
Total comprehensive income....									4,884,838
Balance December 31, 2006	<u>250,000</u>	<u>\$ 250</u>	<u>38,927,114</u>	<u>\$ 38,927</u>	<u>\$59,210,784</u>	<u>\$(35,910)</u>	<u>\$(799,993)</u>	<u>\$ 3,673,615</u>	<u>\$ 62,087,673</u>

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

AMERICAN OIL & GAS, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
as of December 31, 2006 and 2005 and for the years ended December 31, 2006, 2005 and 2004

NOTE 1 — ORGANIZATION AND BASIS OF PRESENTATION

ORGANIZATION

American Oil & Gas, Inc. is an independent energy company engaged in the acquisition, exploration and development of crude oil and natural gas reserves and production in the western United States. In these Notes, the terms “Company”, “American”, “we”, “us”, “our” and terms of similar import refer to American Oil & Gas, Inc.

Our operations are currently focused in Wyoming, North Dakota and Montana. We own a wholly-owned subsidiary, Tower American Corporation, for conducting oil and gas exploration and production operations in Colorado. We do not anticipate operating outside the United States. The Company’s resources and assets are reported as one operating segment. Our fiscal year end is December 31.

We were incorporated on February 15, 2000, under the laws of the State of Nevada. We began oil and gas operations in January 2003, with the acquisition of undeveloped oil and gas prospects in Montana and Wyoming from Tower Colombia Corporation and North Finn, LLC. In April 2005, we acquired Tower Colombia Corporation.

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. Declines in oil and gas prices reduce the estimated quantity of proved reserves and increase annual amortization expense (which is based on proved reserves). Declines in expected oil and gas prices can reduce the value of our oil and gas properties.

The oil and gas industry is subject, by its nature, to environmental hazards and clean-up costs. At this time, management knows of no substantial costs from environmental accidents or events for which the Company may be currently liable.

BASIS OF PRESENTATION

Our consolidated financial statements are prepared in accordance with United States generally accepted accounting principles, or GAAP. Preparation in accordance with GAAP requires us to (1) adopt accounting policies within accounting rules set by the Financial Accounting Standards Board and by the US Securities and Exchange Commission and (2) make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and other disclosed amounts. Note 2 describes our significant accounting policies. Our management believes the major estimates and assumptions impacting our financial statements are the following:

- Estimates of proven (i.e., reasonably certain) oil and gas reserve quantities, which affect the calculations of amortization and impairment of capitalized costs of oil and gas properties,
- Estimates of the fair value of oil and gas properties we own, particularly properties that we have not yet explored, or fully explored, by drilling and completing wells,
- Estimates of the fair value of stock options at date of grant, and
- The assumption required by GAAP that proved reserves and generally proved reserve value for measuring capitalized cost impairment be based on the prices of oil and gas at the end of the reporting period.

The estimated fair values of our unevaluated oil and gas properties affect the calculation of gain on the sale of material properties and affect our assessment as to whether portions of unevaluated capitalized costs are impaired, which also affects the calculation of recorded amortization and impairment expenses.

The fair value of stock options at the date of grant to employees is based on judgment as to expected future volatility of our common stock and expected future choices by employees that impact option vesting and exercising.

Actual results may differ from estimates and assumptions of future events. Future production may vary materially from estimated oil and gas proved reserves. Actual future prices may vary significantly from price assumptions used for determining proved reserves and for financial reporting.

NOTE 2 — SIGNIFICANT ACCOUNTING POLICIES

CASH AND CASH EQUIVALENTS — For purposes of reporting cash flows, we consider cash equivalents to be all highly liquid investments with a maturity of three months or less at the time of purchase. On occasion, the Company may have cash in banks in excess of federally insured amounts.

At December 31, 2006 and 2005, \$693,450 of the cash balance is restricted to the drilling, completion and connection of oil and gas wells in our Krejci oil project located in Niobrara County, Wyoming.

FAIR VALUE — The carrying amounts reported in the consolidated balance sheets for cash, accounts receivable, prepaid expenses, accounts payable and accrued liabilities approximate fair value because of the immediate or short-term maturity of these financial instruments.

SHORT-TERM INVESTMENTS — Short-term investments consist of (i) readily marketable securities expected to be sold within one year and (ii) unregistered securities expected to be readily marketable and sold within one year. Short-term investments are carried at fair value. For investments bought and held principally to sell short-term, changes in fair value are reflected in current income. For other short-term investments, referred to as “available-for-sale,” changes in fair value are reflected, net of related deferred income taxes, in Other Comprehensive Income in the Equity section of the Balance Sheet. If an available-for-sale investment has a net unrealized loss that is considered permanent, such loss is recognized in the current income statement.

ACCOUNTS RECEIVABLE AND CREDIT POLICIES — We have certain trade receivables consisting of oil and gas sales obligations due under normal trade terms. Our management regularly reviews trade receivables and reduces the carrying amount by a valuation allowance that reflects management’s best estimate of the amount that may not be collectible. At December 31, 2006 and 2005, management had determined no allowance for uncollectible receivables is necessary.

ASSET RETIREMENT OBLIGATIONS — When we incur an obligation for future asset retirement costs, we record as a liability and as a cost of the acquired asset the present value of the estimated future asset retirement obligation. For example, when we drill a well, we record a liability and an asset cost for the present value of estimated costs we will incur at the end of the well’s life to plug the well, remove surface equipment and provide restoration of the well site’s surface. Over time, accretion of the liability is recognized as an operating expense, and the capitalized cost is amortized over the expected useful life of the related asset. Our asset retirement obligations (“ARO”) relate primarily to the plugging, dismantlement, removal, site reclamation and similar activities of our oil and gas properties.

The following table reflects the change in ARO for the years ended December 31, 2006 and 2005:

	2006	2005
Asset retirement obligation beginning of year	\$ 117,011	\$ 40,702
Liabilities incurred	81,831	81,065
Liabilities settled	(7,745)	(10,364)
Accretion	11,213	5,608
Revisions in estimated liabilities	<u>32,958</u>	<u>—</u>
Asset retirement obligation end of year	<u>\$ 235,268</u>	<u>\$ 117,011</u>
Current portion of obligation end of year	\$ 40,321	\$ —

OIL AND GAS PROPERTIES — We use the full cost method of accounting for oil and gas activities. Under this method, subject to a limitation based on estimated value, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, are capitalized within cost centers, generally by country. At December 31, 2006 and 2005, all of the Company's oil and gas properties and operations are located in one cost center, the United States.

Under the full cost method, no gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of oil and gas properties and unless the gain significantly alters the relationship between capitalized costs and proved oil and gas reserves of the cost center.

Capitalized costs of oil and gas properties evaluated as having, or not having, proved reserves are amortized in the aggregate by country using the unit-of-production method based upon estimated proved oil and gas reserves. The costs of properties not yet evaluated are not amortized until evaluation of the property. For amortization purposes, relative volumes of oil and gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. Amortizable costs include estimates of future development costs of proved undeveloped reserves.

Capitalized costs of oil and gas properties (net of related deferred income taxes) may not exceed an amount equal to the present value, discounted at 10% per annum, of the estimated future net cash flows from proved oil and gas reserves plus the cost of unevaluated properties (adjusted for related income tax effects). Should capitalized costs exceed this ceiling, impairment is recognized. The present value of estimated future net cash flows is computed by applying period-end prices of oil and natural gas to estimated future production of proved oil and gas reserves as of period-end, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions. Such present value of proved reserves' future net cash flows excludes future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet (following SEC Staff Accounting Bulletin No. 106). Should this comparison indicate an excess carrying value, the excess is charged to earnings as an impairment expense.

As discussed in Note 4, we sold on March 31, 2006, a property having approximately 90% of our proved reserves and production prior to the sale. As is consistent for full cost accounting companies, the related revenues and expenses for 2006 associated with the property sold were reflected as continuing operations since we did not sell our entire U.S. full cost pool.

OTHER PROPERTY AND EQUIPMENT — We record at cost any long-lived tangible assets that are not oil and gas property. Depreciation is recorded using the straight-line method over the estimated useful lives of the related assets of three to five years. Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to operations as incurred. Long-lived assets, other than oil and gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate the carrying amount may not be recoverable. We have not recognized any impairment losses on non oil and gas long-lived assets.

IMPAIRMENT — Statement of Financial Accounting Standards (SFAS) 144, *Accounting for the Impairment and Disposal of Long-Lived Assets*, requires that long-lived assets to be held and used be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Oil and gas properties accounted for using the full cost method of accounting (which we use) are excluded from this requirement but continue to be subject to the full cost method's impairment rules.

BUSINESS COMBINATIONS — We account for business combinations in accordance with SFAS 141, *Business Combinations*, whereby combinations of companies not previously under common control are regarded as a purchase by the acquiring or surviving company. The purchase is recorded at fair value with the purchase price allocated to the acquired company's assets and liabilities at their estimated fair values. Goodwill is recognized to the extent the acquired company's fair value exceeds the net fair value of its assets and liabilities, including intangible assets with limited life. We acquired Tower Colombia Corporation in 2005 recognizing goodwill, as more fully discussed in Note 3.

GOODWILL — We account for goodwill in accordance with SFAS 142, *Goodwill and Other Intangible Assets*. SFAS 142 requires an annual impairment assessment. A more frequent assessment is required if certain events occur that reasonably indicate an impairment may have occurred. The impairment assessment requires us to make estimates regarding the fair value of the reporting unit to which goodwill is assigned. If the fair value of the reporting unit exceeds its carrying value (including the carrying value of its assigned goodwill), then under SFAS 142 no impairment of goodwill exists.

We have only one business segment, oil and gas exploration and production. Within that segment we have only one reporting unit. Accordingly, the fair value of our one reporting unit generally approximates the fair value of our company's stock. Since recording goodwill in 2005 through December 31, 2006, the fair value of the Company's outstanding preferred and common stock has substantially exceeded the carrying value (i.e., book value) of stockholders' equity for the Company, and no impairment of recorded goodwill existed in 2005 or 2006 under the accounting rules of SFAS 142.

OTHER INTANGIBLE ASSETS — Intangible assets, other than Goodwill, are amortized over their expected useful lives.

INCOME TAXES — We account for income taxes under the provisions of SFAS No. 109, *Accounting for Income Taxes*. Under the asset and liability method of SFAS 109, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted income tax rates expected to apply to taxable income in the years in which those differences are expected to be recovered or settled. Under SFAS 109, the effect on deferred tax assets and liabilities of a change in income tax rates is recognized in the results of operations in the period that includes the enactment date.

REVENUE RECOGNITION AND GAS BALANCING — We recognize oil and gas revenues from our interests in producing wells when production is delivered to, and title has transferred to, the purchaser and to the extent the selling price is reasonably determinable. We use the sales method of accounting for gas balancing of gas production and would recognize a liability if the existing proven reserves were not adequate to cover the current imbalance situation. As of December 31, 2006 and 2005, our gas production was in balance, i.e., our cumulative portion of gas production taken and sold from wells in which we have an interest equaled our entitled interest in gas production from those wells.

NET INCOME (LOSS) PER SHARE — Basic net income (loss) per share is computed by dividing net income(loss) attributable to common stockholders by the weighted number of common shares outstanding during the period. Diluted net income (loss) per share reflects per share amounts that would have resulted if dilutive potential common stock had been converted to common stock.

CONCENTRATION OF CREDIT RISK — Financial instruments which potentially subject the Company to concentrations of credit risk consist of cash. We maintain cash assets at one financial institution. We periodically evaluate the credit worthiness of financial institutions, and maintain cash accounts only in large high quality financial institutions. We believe that credit risk associated with cash is remote. The Company is exposed to credit risk in the event of nonpayment by counter parties, a significant portion of which are concentrated in energy related industries. The creditworthiness of customers and other counter parties is subject to continuing review.

SHARE-BASED COMPENSATION — Effective January 1, 2006, we adopted SFAS 123 (R), *Share-Based Payment*, on a modified prospective basis, as discussed further in Note 7. SFAS 123(R) requires publicly-held companies to recognize in their statements of operations the grant-date fair value of stock options and other equity-based compensation to employees, consistent with the rules under SFAS 123 for options to non-employees.

For 2004 and 2005 we accounted for employee stock options using the intrinsic value method of accounting prescribed under Accounting Principles Board Opinion No. 25, as allowed by SFAS 123, before its revision by SFAS 123(R). A stock option's intrinsic value is the fair value of the underlying stock, if any, in excess of the option exercise price to acquire the stock. We typically granted employee stock options with an exercise price equal to the stock's market price at date of grant, whereby such options had an intrinsic value of zero when granted.

Accordingly, for 2004 and 2005, we recognized no compensation expense for employee stock options which had zero intrinsic value at date of grant, but we did recognize compensation expense for the estimated fair value of stock options and warrants when granted to non-employees as compensation.

OFF BALANCE SHEET ARRANGEMENTS — We have no off balance sheet arrangements.

SEGMENT REPORTING — We follow SFAS 131, *Disclosure about Segments of an Enterprise and Related Information*, which amended the requirements for a public enterprise to report financial and descriptive information about its reportable operating segments. Operating segments, as defined in the pronouncement, are components of an enterprise about which separate financial information is available that is evaluated regularly by the Company in deciding how to allocate resources and in assessing performance. The financial information is required to be reported on the basis that is used internally for evaluating segment performance and deciding how to allocate resources to segments. The Company operates in one segment, oil and gas producing activities.

COMPREHENSIVE INCOME — For 2004 and 2005, there are no adjustments necessary to the net income (loss) as presented in the accompanying consolidated statements of operations to derive comprehensive income in accordance with SFAS 130, “Reporting Comprehensive Income.” For 2006, comprehensive income is disclosed in the Consolidated Statements of Shareholders’ Equity.

RECLASSIFICATION — Certain amounts in the 2004 and 2005 consolidated financial statements have been reclassified to conform to the 2006 financial statement presentation. Such reclassifications have had no effect on net income (loss).

RECENT ACCOUNTING PRONOUNCEMENTS

In March 2005, the FASB issued Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations — An Interpretation of SFAS No. 143*, which clarifies the term “conditional asset retirement obligation” used in SFAS No. 143, *Accounting for Asset Retirement Obligations*, and specifically when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. Adoption did not have an impact on our financial statements.

In December 2004, the FASB issued SFAS 153, *Exchanges of Nonmonetary Assets*, which changes the guidance in APB 29, *Accounting for Nonmonetary Transactions*. This Statement amends APB 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. We adopted SFAS 153 effective January 1, 2006, but it did not have a material impact on our financial statements for 2006.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Correction*, which provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes retrospective application, or the latest practicable date, as the required method for reporting a change in accounting principle and the reporting of a correction of an error. We adopted SFAS 154 effective January 1, 2006, but it did not have a material impact on our financial statements.

In February 2006, the FASB issued SFAS 155, *Accounting for Certain Hybrid Financial Instruments*, which eliminates the exemption from applying SFAS 133 to interests in securitized financial assets so that similar instruments are accounted for similarly regardless of the instrument’s form. SFAS 155 allows the election of fair value measurement at acquisition, at issuance, or when a previously recognized financial instrument is subject to a re-measurement event. Adoption is required for all financial instruments acquired or issued by the Company after 2006. Early adoption is permitted. We plan to adopt SFAS 156 beginning with financial statements issued for periods in 2007. Management does not expect the adoption to have a material effect on our financial statements.

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). It will be effective for the Company on January 1, 2007. FIN 48 clarifies the accounting for income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on measurement, classification, interim accounting and disclosure. Our application of Interpretation No. 48 is not expected to have a material effect on our financial statements.

In September 2006, the FASB issued SFAS 157, *Fair Value Measurements*, which defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. It will be effective for the Company beginning with financial statements issued for periods in 2008. Management does not expect the adoption to have a material effect on our financial statements.

In September 2006, the FASB issued SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. We do not have postretirement plans.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108 ("SAB 108"). SAB 108 expresses the SEC staff's views regarding the process of quantifying financial statement misstatements. The SEC staff believes registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB 108 is effective for fiscal years ending on or after November 15, 2006. Management does not expect the adoption to have a material effect on our financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits entities to choose to measure many financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 applies to all entities and is effective for fiscal years beginning after November 15, 2007. Adoption of SFAS No. 159 is not required for these financial statements and we are currently determining the impact, if any, that SFAS No. 159 will have on our future financial statements.

NOTE 3 — ACQUISITION OF TOWER COLOMBIA CORPORATION

In April 2005 Tower Colombia Corporation ("TCC") merged into American with our exchange of 5,800,000 of restricted American common stock for all outstanding TCC stock. TCC was owned by Pat O'Brien, Bob Solomon and Ken Tholstrom. Prior to the merger, TCC was the oil and gas exploration and production company most closely associated with American in that (1) Pat O'Brien was American's CEO and TCC's President, Ken Tholstrom was American's Secretary and a Director, (2) American acquired its oil and gas properties from or with TCC and North Finn LLC (See Note 11 *Related Party Transactions*), (3) American and TCC shared corporate office space and (4) American provided land administration functions for jointly owned properties. With the merger, Pat O'Brien, Bob Solomon and Ken Tholstrom became full time employees of American, serving as CEO and Vice-Presidents, respectively.

Benefits to American in acquiring TCC for 16.2% of American's outstanding stock at the time of merger included:

- Increasing by 50% American's share of prospective and key current exploration opportunities identified by American, TCC or North Finn (See Note 11),
- Absorbing an oil and gas exploration and production company with a longer operating history and a stronger technical team — a team that had already worked well with American in 2003 and 2004,
- Eliminating the potential conflicts of interest that existed when TCC was a separate company advising American but having the right to take interests that American chose to decline, and
- Capturing for American's benefit the goodwill and recognition the TCC team had in the Rocky Mountain oil and gas community from many years of working with oil and gas companies as a purchaser of deals, as a co-owner in deals and as a drilling service company for exploration groups.
- The acquisition increased American's working interest from 50% to 75% in the following oil and gas projects:
 - The Douglas project, which includes the Fetter Field natural gas prospect,

- The Krejci oil project,
- The Bear Creek coalbed methane project, and
- The West Rozel oil field project.

We accounted for the merger of TCC as a business combination of entities not under “common control” as that term is used in SFAS 141 *Business Combinations* and SEC Staff Accounting Bulletin Topic 2D on roll-ups of oil and gas exploration and production entities. The accounting has the merger recorded as a business acquisition at fair value, whereby the estimated \$15,196,000 fair value of the restricted stock issued to TCC’s three shareholders is allocated to the underlying assets acquired and liabilities assumed at their estimated fair values, with the excess recorded as goodwill. The following table summarizes those values for the acquisition of TCC:

Current assets.....	\$ 10,700
Oil and gas property:	
Proved and evaluated.....	210,000
Unproved.....	4,279,700
Office equipment.....	2,800
Goodwill.....	11,670,500
Other intangible asset.....	900,000
Current liabilities.....	(30,400)
Deferred income tax liability.....	(1,847,300)
Total.....	<u>\$ 15,196,000</u>

The other intangible asset relates to non-compete provisions and performance-based compensation terms reflected in five-year employment agreements with Pat O’Brien, Bob Solomon and Ken Tholstrom as officers of American. The recorded \$900,000 estimated fair value of the intangible asset is amortized over five years on a straight-line basis, equating to a \$15,000 monthly amortization expense.

The merger was a statutory merger for income tax purposes whereby American received the tax bases TCC had in the acquired assets and liabilities, and American recognized a deferred income tax liability for the recorded fair values in excess of tax bases of the net assets acquired other than goodwill.

NOTE 4 — PROPERTY AND EQUIPMENT

On June 1, 2004, the Company entered into an agreement which allowed the opportunity to earn a 50% working interest in the Douglas project, which is comprised of undeveloped leasehold acres in Converse County, Wyoming. The Company spent \$250,000 on June 1, 2004 for its share of the initial option payment and paid \$323,000 on May 24, 2005 for its share of the second option payment. The Company timely paid its share of the final option payment of \$1,166,535, in order to own the leases in the Douglas project.

On September 30, 2004, the Company sold 90% of its interests in the Powder River Basin coal bed methane acreage referred to as West Recluse, Glasgow and Bill. Included in this sale was 90% of the Company’s interest in seven existing producing West Recluse wells. As part of the agreement, the Company retained a 10% working interest in seven producing coal bed methane wells and retained a 5% carried working interest in all additional wells drilled on this acreage. The Company received sales proceeds of approximately \$1.255 million. During 2005, the Company assigned its remaining 10% working interest in the seven producing coal bed methane wells and the 5% carried working interest in all additional wells drilled on this acreage to the buyer of the 90% interest.

During December 2004, the Company acquired a working interest in an oil prospect located in McHenry County, North Dakota. The Company called this prospect the South Glenburn Prospect. During April 2005, the Company participated in the drilling of an unsuccessful test well in this acreage with an 87.5% working interest and spent a total of \$347,785 for the drilling of this well.

In December 2005, the Company participated in the drilling of an unsuccessful test well at its Fort Fetterman prospect. The Company spent \$354,783 to acquire a 37.5% working interest in this prospect and spent a total of \$174,686 for drilling related costs in the initial test well.

In October 2005, the Company purchased a 75% working interest in undeveloped acreage position located primarily in Williams and Dunn Counties, North Dakota, in a project that the Company calls Goliath. The Company paid a total of \$2,970,000 in cash and issued 675,000 shares of its common stock valued at \$4,185,000 as consideration for the acreage position.

In September 2006, the Company purchased an additional 25% working interest in its Fetter project for 2,050,000 shares of unregistered common stock which was valued at \$13.1 million based on the price of the Company's common stock on the closing date of the transaction.

Property and equipment at December 31, 2006, 2005 and 2004 consisted of the following:

	2006	2005	2004
Oil and gas properties, full cost method			
Unevaluated costs, not subject to amortization or ceiling test	\$ 33,263,390	\$ 17,843,133	\$ 2,022,367
Evaluated costs	7,958,908	8,600,696	1,645,133
Asset retirement costs	201,955	104,093	33,392
	<u>41,424,253</u>	<u>26,547,922</u>	<u>3,700,892</u>
Furniture, equipment and software	295,485	68,023	7,221
	<u>41,719,738</u>	<u>26,615,945</u>	<u>3,708,113</u>
Less accumulated depreciation, depletion and amortization	<u>(2,598,581)</u>	<u>(1,636,246)</u>	<u>(221,793)</u>
Property and equipment.....	<u>\$ 39,121,157</u>	<u>\$ 24,979,699</u>	<u>\$ 3,486,320</u>

Unevaluated Oil and Gas Properties

Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until they are evaluated. The following table shows, by year incurred, the unevaluated oil and gas property costs (net of transfers to the full cost pool and sales proceeds) excluded from the amortization computation:

	<u>Net Costs Incurred</u>
Year ended December 31, 2006.....	\$ 17,314,778
Year ended December 31, 2005.....	15,279,762
Prior to 2005	668,850
	<u>\$ 33,263,390</u>

Unevaluated properties consist primarily of lease acquisition and maintenance costs. Prospect leasing and acquisition normally requires one to two years and the subsequent evaluation normally requires an additional one to two years.

Information relating to the Company's costs incurred in its oil and gas operations during the year ended December 31, 2006, 2005 and 2004 are summarized as follows:

	2006	2005	2004
Property acquisition costs, unproved properties	\$ 19,887,879	\$ 13,906,210	\$ 1,279,364
Property acquisition costs, proved properties	163,569	210,000	—
Exploration costs	9,285,354	7,011,666	194,413
Asset retirement costs	86,649	70,701	5,494
Development costs.....	691,626	2,932,459	1,846,494
	<u>\$ 30,115,077</u>	<u>\$ 24,131,036</u>	<u>\$ 3,325,765</u>

Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire a property. Exploration costs include the costs of geological and geophysical activity, and drilling and equipping exploratory wells. Development costs include drilling and other costs incurred within a proved area of oil and gas. The Company reviews and determines the cost basis of drilling prospects on a drilling location basis.

Furniture and equipment depreciation expenses for the years ended December 31, 2006, 2005 and 2004 were \$35,412, \$5,555 and \$1,073, respectively.

During 2006 and 2005, our largest customer was Eighty-Eight Oil LLC, accounting for 71% of 2006 sales and 75% of 2005 sales. During fiscal year 2004, our two largest customers were Eighty Eight Oil LLC and Enserco Energy, Inc. Sales to these customers accounted for 70% and 17%, respectively, of oil and gas sales in 2004. Because there are other purchasers that are capable of and willing to purchase our oil and gas and because we have the option to change purchasers on properties if conditions so warrant, we believe our oil and gas production can be sold in the market in the event that it is not sold to our existing customers.

Significant Property Sales in 2006

On March 31, 2006, we sold our interest in the Big Sky project, which at the time of sale represented approximately 95% of our oil and gas production revenue and approximately 88% of our proved oil and gas reserves and their standardized measure. The contract sales price was \$11.5 million and the effective date of the sale was February 1, 2006.

In April 2006, we sold our 8,653 net acres in unproved Montana leases referred to as the Bear Creek prospect. Our lease interests were sold to privately owned MAB Resources in exchange for a convertible \$1,080,000 note from GSL Energy Corp., a private affiliate of MAB Resources. That same month we converted the note into 2,160,000 shares of GSL common stock. In May 2006, GSL merged into a publicly-traded company whereby as of December 31, 2006 we owned (in lieu of the \$1,080,000 note receivable) 2,160,000 unregistered shares of the merged company renamed PetroHunter Energy Corporation (See Note 5).

In May 2006, we sold to Teton Energy Corporation for \$6.2 million a 25% working interest in our Goliath project. The project consisted of unproved leases of approximately 58,000 gross acres in the Williston Basin of North Dakota. Teton paid us \$2.46 million in cash at closing and is paying an additional \$3.69 million as we incur that amount of costs in drilling and completing the project's first two wells. At December 31, 2006, Teton owed us \$777,461 of the \$3.69 million.

The reconciliations of the gains on the sales are as follows:

	<u>Big Sky</u>	<u>Bear Creek</u>	<u>Goliath</u>	<u>Totals</u>
Contract sales price.....	\$ 11,500,000	\$ 1,080,000	\$ 6,165,520	\$ 18,745,520
Effective date adjustments.....	<u>(821,496)</u>	<u>0</u>	<u>0</u>	<u>(821,496)</u>
Adjusted sales price.....	10,678,504	1,080,000	6,165,520	17,924,024
Allocated capitalized costs using the relative fair market value method required under full cost accounting.....	<u>(6,416,650)</u>	<u>(648,443)</u>	<u>(3,699,461)</u>	<u>(10,764,554)</u>
Recognized gains on sales of oil and gas properties.....	<u>\$ 4,261,854</u>	<u>\$ 431,557</u>	<u>\$ 2,466,059</u>	<u>\$ 7,159,470</u>

Significant Property Acquisitions in 2006

On January 5, 2006, we entered into a participation agreement with North Finn LLC ("North Finn"). Under the agreement, we will fund 60% of North Finn's future lease, drilling and other project related capital obligations in jointly owned project areas, in order to earn 60% of North Finn's interest in that particular lease or well, including offset locations. We paid \$535,000, and reimbursed approximately \$976,000 to North Finn for 60% of all project related costs that North Finn has incurred in jointly owned project areas after the effective date of August 1, 2005.

Under the participation agreement, the Company and North Finn each has the right (an option), during specified time periods, to trigger the transfer to the Company by North Finn of 60% of North Finn's interests in any unearned project areas in which the Company already has an interest, and a simultaneous issuance by the Company to North Finn of 2,900,000 restricted shares of the Company's common stock. North Finn's right of exchange is exercisable at any time on or before July 31, 2012, and the Company's right of exchange is exercisable at any time beginning August 1, 2010 and ending July 31, 2012. If the exchange occurs and the Company receives the 60% interest from North Finn, the Company will not earn or fund any additional interests in the North Finn acreage under the participation agreement. In many of the joint project areas, North Finn owns a 25% working interest and the Company owns a 75% working interest.

On September 1, 2006, we issued 2,050,000 shares of common stock to SunStone Oil & Gas, LLC (based in Oklahoma City) in exchange for all its interests in the Fetter Project. The acquired interests equate to approximately 13,300 net undeveloped acres and 320 net developed acres. The acquisition raised our project ownership interest from 67.5% to 92.5% in lease rights on approximately 53,000 net acres. On September 1, 2006, our stock closed at \$6.38 per share, and that price sets the total value of the acquisition at \$13,079,000.

Impairment of Oil and Gas Properties

We use the full-cost accounting method, which requires recognition of an impairment of oil and gas properties when the total capitalized costs (net of related deferred income taxes) exceed a "ceiling" as described in Note 2. We recognized impairments at September 30, 2006 and at December 31, 2006, totaling \$4,360,000 and related reductions in deferred income taxes totaling \$1,663,000. A substantial portion of the impairment occurs from being unable to complete the Fetter Project State 4-36 well in a fashion as originally planned, reducing the estimate of proved reserves for the well as of December 31, 2006. To a lesser extent, the initial low reserve value attributable to the Goliath project Champion 1-25 well, and the costs associated with two unsuccessful wells at our peripheral North Walker Creek prospect also contributed to the impairment.

Amortization Rate

Amortization of oil and gas property is calculated quarterly based on the quarter's production in barrels of oil equivalent ("boe") times an amortization rate. The amortization rate is an amortization base divided by the boe sum of proved reserves at the end of the quarter and production during the quarter. The amortization base consists of (i) the capitalized evaluated oil and gas costs at the end of the quarter before recording any impairment at quarter's end, plus (ii) estimated future development costs for the proved reserves, less (iv) accumulated amortization at the beginning of the quarter. For 2006, 2005 and 2004, the annual average amortization rates were \$21.80, \$17.17 and \$8.95, respectively, per boe. After 2006 amortization and the recognized impairments noted above, the amortization base at December 31, 2006 was \$25.38 per boe of proved reserves at December 31, 2006.

NOTE 5 — SERVICE FEE REVENUE AND SHORT-TERM INVESTMENTS

In April 2006, we took a \$1,530,000 convertible note from GSL Energy Corp. in payment of a service fee under an October 2005 agreement with MAB Resources. As we did with the \$1,080,000 convertible note discussed in Note 4, we converted the \$1,530,000 note into 3,060,000 shares of GSL common stock at \$0.50 per share. When privately held GSL merged into publicly held PetroHunter Energy Corporation ("PetroHunter") in May 2006, we exchanged the GSL shares for 3,060,000 shares of unregistered shares of PetroHunter common stock .

At December 31, 2006, we owned 5,220,000 unregistered PetroHunter shares. These shares are less than 2% of the PetroHunter shares outstanding at December 31, 2006. Registered shares of PetroHunter common stock are traded on the US over-the-counter bulletin board under the symbol PHUN. The stock price closed at \$1.62 per share on Friday December 29, 2006. Our investment is available for sale but absent PetroHunter's registration of the stock, we expect to begin selling the shares in May 2007 (after a one-year holding under Rule 144 exemption from registration). We expect to have all shares sold by before December 31, 2007. Our president is a director of a publicly traded company, Falcon Oil & Gas, whose president and largest shareholder is also the largest shareholder of PetroHunter and the majority owner of MAB Resources. However, we do not believe that relationship provides us with significant influence in the management of PetroHunter.

The 5,220,000 shares reasonably expected to become exempt from registration and sold in 2007 are shown on the consolidated balance sheet as short-term investments available for sale. In accordance with Statement of Financial Accounting Standards No. 115, unregistered shares that are reasonably expected to be sold within one year are recorded at the trading price of registered, marketable shares. Therefore, the 5,220,000 shares acquired for \$2,610,000 in convertible notes are carried at \$8,456,400 at December 31, 2006 (\$1.62 per share). The \$5,846,000 gain is unrealized and is recorded (net of \$2,172,785 related deferred income taxes) as a \$3,673,615 increase in Accumulated Other Comprehensive Income in the Equity section of our December 31, 2006 consolidated balance sheet. The realized sales price from our future sales of the 5,220,000 PetroHunter shares may vary materially from the \$1.62 per share price at December 31, 2006. In the first half of March 2007, PetroHunter common stock traded in the range of \$0.98 to \$1.33, closing at \$1.01 on March 15th.

NOTE 6 — INCOME TAXES

Income tax expense for the years ended December 31 consists of the following:

	2006	2005	2004
Current taxes.....	\$ —	\$ —	\$ —
Deferred taxes.....	303,748	46,245	37,000
Less: valuation allowance.....	—	—	(37,000)
Income tax expense	<u>\$ 303,748</u>	<u>\$ 46,245</u>	<u>\$ —</u>

The effective income tax rate for the years ended December 31 differs from the U.S. Federal statutory income tax rate as follows:

	2006	2005	2004
Federal statutory income tax rate.....	35.0%	35.0%	34.0%
State income taxes	3.1%	3.5%	3.3%
Permanent differences:			
Percentage depletion.....	(22.0%)	—	—
Other	7.7%	2.9%	0.5%
Change in average state tax rate	(3.8%)	—	—
Increase (decrease) in valuation allowance.....	—	(37.1%)	(37.8%)
Effective income tax rate	<u>20.0%</u>	<u>4.3%</u>	<u>—</u>

The components of the deferred tax assets and liabilities as of December 31 are as follows:

	2006	2005	2004
Deferred tax assets:			
Federal and state net operating loss carryovers	\$ 1,219,868	\$ 1,462,000	\$ 746,000
Federal percentage depletion carryovers	324,431	—	—
Oil and gas property amortization	753,000	443,000	(453,000)
Timing differences — charitable contributions and non qualified options	118,369	29,000	—
Deferred compensation.....	—	—	(3,000)
Total deferred tax assets	<u>2,415,668</u>	<u>1,934,000</u>	<u>290,000</u>
Less: valuation adjustment.....	—	—	(290,000)
Deferred tax asset	<u>\$ 2,415,668</u>	<u>\$ 1,934,000</u>	<u>\$ —</u>
Deferred tax liabilities:			
Intangible drilling costs and other exploration costs capitalized for financial reporting purposes	\$ (4,376,646)	\$(3,530,323)	\$ —
Unrealized gain on investment	(2,172,785)	—	—
Other intangible asset, net of amortization	(222,987)	(297,258)	—
Other	(13,364)	—	—
Total deferred liabilities	<u>(6,785,782)</u>	<u>(3,827,581)</u>	<u>—</u>
Net deferred tax asset	<u>2,415,668</u>	<u>1,934,000</u>	<u>—</u>
Deferred tax asset (liability)	<u>\$ (4,370,114)</u>	<u>\$ (1,893,581)</u>	<u>\$ —</u>

The Company has approximately \$3,340,000 net operating loss carryover as of December 31, 2006. The net operating losses may offset against taxable income through the year ended December 2026. A portion of the net operating loss carryovers begins expiring in 2020. The valuation allowance decreased by approximately \$290,000 in 2005 and increased by approximately \$37,000 in 2004.

NOTE 7 — ADOPTION OF SFAS 123(R) SHARE-BASED PAYMENT

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS 123(R) using the modified prospective transition method. In applying SFAS 123(R), we considered the SEC Staff Accounting Bulletin No. 107, *Share-Based Payment*, issued in March 2005, which provides supplemental SFAS 123(R) application guidance based on the views of the SEC.

Under the modified prospective transition method, results for prior periods have not been restated, and compensation costs recognized in year ended December 31, 2006 include (a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123; and (b) compensation cost for all share-based payments granted beginning January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R).

The adoption of SFAS 123(R) resulted in share-based compensation expense for 2006 of \$1,522,219. This consisted of \$1,230,787 for stock options, \$195,132 in common stock issued for consulting services and \$96,300 in common stock issued to new employees. This expense reduced basic and diluted income per share by \$0.04.

For 2005 and 2004, we applied the intrinsic value method of accounting for stock options as prescribed by APB 25. Since all options granted in 2005 had an exercise price equal to the closing market price of the underlying common stock on the grant date, no compensation expense was recognized for options granted to employees. If compensation expense had been recognized based on the estimated fair value of each option granted in accordance with the provisions of SFAS 123 as amended by Statement of Financial Accounting Standard 148, our net income and net income per share would have been reduced to the following pro-forma amounts for the years ended December 31, 2005 and 2004:

	2005	2004
Net income (loss) — as reported	\$ 553,629	\$ (438,011)
Add stock based compensation included in reported net loss.....	413,765	38,632
Deduct stock based compensation expense determined under the fair value method.....	<u>(841,567)</u>	<u>(133,321)</u>
Pro forma net loss	<u>\$ 125,827</u>	<u>\$ (532,700)</u>
Net income (loss) per common share — Basic:		
As reported	<u>\$ 0.02</u>	<u>\$ (0.02)</u>
Pro forma	<u>\$ —</u>	<u>\$ (0.02)</u>
Net income (loss) per common share — Diluted:		
As reported	<u>\$ 0.02</u>	<u>\$ (0.02)</u>
Pro forma	<u>\$ —</u>	<u>\$ (0.02)</u>

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:

	2006	2005	2004
Expected option life-years	5-8	5.0	5.0
Risk-free interest rate.....	4.5% to 5.2%	2.6% to 4.5%	3.36%
Dividend yield	N/A	N/A	N/A
Volatility.....	33% to 63%	47% to 78%	71%
Pre-vesting forfeiture rate	0%	0%	0%

NOTE 8 — STOCKHOLDERS' EQUITY

PREFERRED STOCK

We are authorized to issue up to 25 million shares of \$.001 par value preferred stock, the rights and preferences of which are to be determined by the Board of Directors at or prior to the time of issuance.

Series AA Convertible Preferred Stock

On July 22, 2005, we sold to accredited investors, a total of 250,000 Units for \$13,500,000, with each Unit consisting of one share of Series AA Convertible Preferred Stock ("Preferred Stock") and warrants to purchase shares of its \$.001 par value common stock. This private placement was made pursuant to exemptions from registration under the Securities Act of 1933, including but not limited to, Sections 3(b) and 4(2), as well as Rule 506 of Regulation D under the Securities Act of 1933. The Units were sold without a general solicitation pursuant to Blue Sky limited offering exemptions and were issued with a legend restricting resale. We are obligated to pay an 8% annual dividend on the Preferred Stock in cash or in equivalent shares of common stock, at our discretion.

Each share of Preferred Stock is convertible into nine shares of common stock for a total of 2,250,000 shares, which is a conversion rate of \$6.00 per share. We also issued warrants to purchase 2.7 shares of common stock for each share of Preferred Stock, which resulted in warrants to purchase a total of 675,000 shares of common stock exercisable at \$6.00 per share. We extended the expiration date of the warrants to December 31, 2007. We can call the warrants if the daily weighted average trading price of its common stock averages at least \$7.40 for 25 consecutive trading days.

The Preferred Stock automatically converts into common stock on the third anniversary of closing or anytime sooner at the discretion of the preferred holders. We can require conversion of the Preferred Stock if the daily weighted average trading price of our common stock averages at least \$9.00 for 25 consecutive trading days. In connection with the funding, we paid placement fees of \$510,000 and issued 3-year warrants to purchase 281,250 shares of common stock at an exercise price of \$6.00 per share. The warrants are valued at \$575,544, using the Black-Scholes option pricing model.

Series A Convertible Preferred Stock

The Series A Convertible Preferred Stock issued in 2003 automatically converted into 670,000 shares of common stock in January 2005.

COMMON STOCK

Our Consolidated Statements of Shareholders' Equity provide a listing of changes in the common shares outstanding from December 31, 2003 through December 31, 2006. Further explanation of these changes is provided below:

- On September 1, 2006, we issued 2,050,000 shares of our common stock to SunStone Oil and Gas, LLC in exchange for Sunstone's 25% working interests in the Fetter project, increasing our Fetter ownership interests from 67.5% to 92.5%.
- On March 1, 2005, warrants to purchase 50,000 shares of our common stock were exercised at an exercise price of \$1.09 per share. We received proceeds of \$54,500 in conjunction with this exercise.
- On January 13, 2005, warrants to purchase 90,000 shares of our common stock were exercised at an exercise price of \$1.09 per share. We received proceeds of \$98,100 in conjunction with this exercise.
- During 2005 we issued 37,500 shares and during 2004 we issued 50,000 shares of our common stock to a Director for serving as Director, Designated Financial Expert and as Chairman of the Audit Committee. The shares were paid to a company wholly owned by the Director, and the shares were valued at \$195,249 and \$85,126, respectively, based on the non-discounted trading price of our common stock as of the date of issuance.

- In September 2004, we sold a total of 3,000,000 shares of common stock at a price of \$1.50 per share. We paid a placement fee of \$45,000 in cash and issued 30,000 shares (valued at the non-discounted trading price of our common stock of \$1.88 per share) to an individual who assisted in securing the private placement. Total costs of the offering were \$133,957, including cash of \$77,557 and common stock valued at \$56,400.
- In March 2004, we sold 1,525,000 units at a price of \$1.00 per unit. Each unit consisted of one share of common stock and one warrant to purchase one share of common stock at \$1.00 per share until August 31, 2004. We did not pay any fees or commissions associated with this financing. Holders of 25,000 of the warrants exercised the warrants prior to August 31, 2004, and 1,500,000 of the warrants expired unexercised. In conjunction with this sale, we sold one-third of our interests in the Big Sky project for cash of \$326,247 to an entity related to the investor that purchased 1.5 million of the units.
- On June 16, 2003, the Company issued 500,000 shares of common stock to its President and Chief Financial Officer, as part of his employment agreement. 250,000 shares vested on June 1, 2004 125,000 shares vested on May 1, 2005 and 125,000 shares vested on July 1, 2005. The 500,000 shares are reflected as issued and outstanding at December 31, 2005 and 2004. The shares were valued at \$565,000 (\$1.13 per share), based on the non-discounted trading price of the Company's common stock as of the date of grant. In 2005 and 2004, \$141,250 and \$282,500, respectively, were charged to operations for the value of shares earned.

WARRANTS

In July 2005, in conjunction with the sale of Series AA Convertible Stock, we issued investor warrants to purchase a total of 675,000 shares of common stock exercisable at \$6.00 per share. The warrants were to expire on January 21 2007 (18 months from the closing date). We have extended the expiration date of these warrants to December 31, 2007. We also issued 3-year placement warrants to purchase 281,250 shares of common stock at an exercise price equal to the exercise price for the investor warrants of \$6.00 per share.

In May 2004, we granted warrants to purchase 163,200 shares of common stock at an exercise price equal to the market price on the date of grant of \$1.09 per share to an individual who assisted us with evaluation and marketing of our West Rozel project. These warrants vested 13,600 per month starting April 2004, and expire one year from date of vesting. These warrants were valued at \$42,147 using the Black-Scholes option pricing model. All of these warrants have been exercised.

In August 2006, we acquired a small working interest in the Fetter project in exchange for a warrant to acquire 100,000 shares of common stock for \$4.90 per share, with the warrant expiring on February 9, 2007. The expiration date was extended to April 9, 2007 in exchange for a first right of refusal to acquire other interests in the general Fetter area held by the warrant holder.

The table below reflects the status of warrants outstanding at December 31, 2006 held by others to acquire our common stock:

Issue Date	Common Shares	Exercise Price	Expiration Date
July 22, 2005	671,880	\$ 6.00	December 31, 2007
July 22, 2005	281,250	\$ 6.00	July 21, 2008
September 15, 2003	20,000	\$ 1.15	September 15, 2008
July 23, 2003 to September 24, 2003.....	54,850	\$ 0.75	July 24, 2008 to September 24, 2008
August 10, 2006.....	<u>100,000</u>	\$ 4.90	April 9, 2007
	<u>1,127,980</u>		

At December 31, 2006, the per-share weighted average exercise price of outstanding warrants was \$5.48 per share and the weighted average remaining contractual life was 1.1 years.

The table below reflects the status of outstanding warrants at December 31, 2005:

Issue Date	Shares Exercisable	Exercise Price	Expiration Date
July 22, 2005	675,000	\$ 6.00	January 21, 2007
July 22, 2005	281,250	\$ 6.00	July 21, 2008
September 15, 2003	30,000	\$ 1.15	September 15, 2008
September 24, 2003	66,450	\$ 0.75	September 24, 2008
May 26, 2004	23,200	\$ 1.09	April 2005 through December 2005

At December 31, 2005, the per-share weighted average exercise price of outstanding warrants was \$5.43 per share and the weighted average remaining contractual life was 2.12 years.

STOCK OPTIONS

Under our 2004 Stock Option Plan (the “Plan”), stock options may be granted at an exercise price not less than the fair market value of our common stock at the date of grant. Options may be granted to key employees and other persons who contribute to our success. We have reserved 2,500,000 shares of common stock for issuance under the Plan. At December 31, 2006, 2005 and 2004 options to purchase 271,990 shares, 1,040,900 shares and 2,097,000 shares, respectively, were available to be granted pursuant to the Plan.

At the Company’s Annual Stockholders meeting in August 2006, the stockholders approved the Company’s 2006 Stock Incentive Plan. The 2006 Plan provides for up to 1,500,000 additional shares of common stock that may be issued to employees, directors and other persons who provide services to the Company. Issuance of those shares may be by stock option awards, restricted stock awards or restricted stock unit awards.

Stock Options as of December 31, 2006

In January 2006, the Company entered into a participation agreement with North Finn (“North Finn”). An element of that agreement is that North Finn has an option until July 31, 2012 to receive 2,900,000 shares of the Company’s common stock in exchange for certain oil and gas rights held by North Finn. A second element is that beginning on August 1, 2010 until July 31, 2012, the Company has an option to require North Finn to exchange those property interests in return for the 2,900,000 shares. North Finn has not exercised its option nor made a commitment to exercise under the AICPA Emerging Issues Task Force Interpretation 96-18, whereby the value of North Finn’s option is not currently recognized in our financial statements. The option and the participation agreement are discussed in Note 12 *Commitments and Contingencies*.

Other than the aforementioned North Finn option, outstanding stock options are those granted under the Company’s 2004 Stock Option Plan. The following table summarizes the status of stock options outstanding under that Plan:

	Number of Shares	Weighted Avg. Exercise Price
Options outstanding — January 1, 2004.....	—	\$ —
Options granted during 2004	<u>403,000</u>	<u>\$ 1.25</u>
Options outstanding — December 31, 2004 (176,000 exercisable)	403,000	\$ 1.25
Options granted during 2005	<u>1,056,010</u>	<u>\$ 3.58</u>
Options outstanding — December 31, 2005 (640,009 exercisable)	1,459,010	\$ 2.94
Options granted during 2006	769,000	\$ 4.83
Less options exercised during 2006.....	<u>(42,010)</u>	<u>\$ 3.27</u>
Options outstanding — December 31, 2006 (985,498 exercisable)	<u>2,186,000</u>	<u>\$ 3.60</u>

The weighted-average, grant-date estimated fair value of stock options granted during the years ended December 31, 2006, 2005 and 2004 were \$2.30, \$1.83 and \$.76, respectively, per underlying common share. We estimated the fair values using the Black-Scholes stock option pricing model, as further discussed in Note 7.

The following table presents additional information related to the stock options outstanding at December 31, 2006 under the 2004 Stock Option Plan:

Exercise price per share	Number of shares		Weighted average remaining contractual life (years)
	Outstanding	Exercisable	
\$ 1.25	403,000	403,000	3.17
2.38	100,000	87,500	4.0
2.48	80,000	50,000	4.0
3.66	750,000	249,998	5.8
4.30	9,000	—	5.9
4.57	9,000	—	6.1
4.65	250,000	50,000	9.1
4.66	60,000	20,000	5.3
4.95	250,000	50,000	9.5
4.98	200,000	50,000	6.8
5.80	75,000	25,000	5.7
	<u>2,186,000</u>	<u>985,498</u>	
Wgtd. Ave. remaining contractual life.....	6.0 years	4.5 years	
Aggregate intrinsic value.....	\$ 6,363,180	\$ 3,696,468	

In February 2007, our Vice President of Land left the Company and forfeited options for 160,000 shares having an exercise price of \$4.65. Taking into effect that forfeiture, the total estimated unrecognized compensation cost from unvested stock options as of December 31, 2006 was \$1,596,191, which is expected to be recognized over a weighted average period of approximately 2.4 years.

NOTE 9 — EARNINGS PER SHARE

The following table summarizes the calculations of basic and diluted net income (loss) per common share for the years ended December 31, 2006, 2005 and 2004:

	2006	2005	2004
Net income to common stockholders.....	\$ 131,223	\$ 553,629	\$ (499,651)
Adjustments for dilution.....	—	—	—
Net income adjusted for effects of dilution	<u>\$ 131,223</u>	<u>\$ 553,629</u>	<u>\$ (499,651)</u>
Basic Weighted Ave. Common Shares.....	37,428,506	34,148,065	25,211,447
Add dilutive effects of options and warrants	713,505	807,559	—
Add dilutive effects of convertible preferred stock	—	—	—
Diluted Weighted Ave. Common Shares Outstanding	<u>38,142,011</u>	<u>34,955,624</u>	<u>25,211,447</u>
Net income per common share — basic	\$ 0.00	\$ 0.02	\$ (0.02)
Net income per common share — diluted	\$ 0.00	\$ 0.02	\$ (0.02)

NOTE 10 — EMPLOYEE BENEFIT PLANS

We maintain and sponsor health care plans and a contributory 401(k) plan for our employees. Our direct costs related to these plans were \$205,712, \$83,002 and \$15,337 for the years ended December 31, 2006, 2005 and 2004, respectively.

NOTE 11 — RELATED PARTY TRANSACTIONS

On January 17, 2003, the Company executed a Purchase and Sale Agreement that was negotiated at arms-length, with Tower Colombia Corporation, a Colorado corporation (“TCC”), and North Finn, LLC, a Wyoming limited liability company (“North Finn”), to acquire an undivided 50% working interest in the Wyoming Krejci Project, the Montana Bear Creek Project and in and to certain coalbed oil and gas leases in the Powder River Basin of Wyoming and the Big Horn Basin of Montana. Subsequent to the acquisition of the oil and gas leases, Patrick D. O’Brien, President of TCC, was appointed Chief Executive Officer, President and Chairman of the Board of Directors of the Company. Mr. O’Brien continued to serve as President of TCC until the merger with TCC, which occurred on April 21, 2005, as described in Note 3.

Also on January 17, 2003, TCC, North Finn and the principals of each entity entered into a Participation and Management Agreement with the Company, in which they agreed to provide the Company with operational and management services at no cost and agreed to grant the Company the right to participate, on an equal basis, in any financing transaction regarding an oil and/or gas exploration and/or production asset, or acquisition or disposition of oil and/or gas exploration and/or production assets that becomes available to them. The Participation and Management Agreement expired on January 16, 2005.

On March 23, 2005, the Company approved and entered into an agreement with TCC pursuant to which TCC provided, effective as of January 17, 2005, certain management services, including, but not limited to, human resource management, asset management services, and accounting and data management services for a monthly management fee of \$30,000. The Company paid TCC a total of \$90,000 pursuant to this agreement from the period January 16, 2005 through the April 21, 2005. This management services agreement terminated on April 21, 2005, the closing date of the merger between the Company and TCC. In addition to the management fee paid to TCC, during 2005, the Company also reimbursed TCC for its share of costs relating to oil and gas operations of \$2,888 and for payroll related costs of \$66,643. During 2004, the Company paid TCC a total of \$232,088 for the Company's share of oil and gas and administrative related expenses.

In 2006, 2005, and 2004, we paid \$58,907, \$75,416 and \$24,504, respectively, to Tower Energy Corporation ("TEC") for our share of administrative related expenditures, primarily the sharing of office space which TEC had leased. Payments to TEC ended in July 2006 in conjunction with American replacing TEC as the Tenant on the office lease. Patrick O'Brien and American vice president Bob Solomon each own 50% of TEC.

NOTE 12 — COMMITMENTS AND CONTINGENCIES

The Company may be subject to various possible contingencies, which are derived primarily from interpretations of federal and state laws and regulations affecting the oil and gas industry. Although management believes it has complied with the various laws and regulations, new rulings and interpretations may require the Company to make future adjustments.

North Finn Option

On January 5, 2006, we entered into a participation agreement with North Finn LLC ("North Finn"). Under the agreement, we will fund 60% of North Finn's future lease, drilling and other project related capital obligations in jointly owned project areas, in order to earn 60% of North Finn's interest in that particular lease or well, including offset locations. We paid \$535,000, and reimbursed approximately \$976,000 to North Finn for 60% of all project related costs that North Finn has incurred in jointly owned project areas after the effective date of August 1, 2005.

Under the participation agreement, the Company and North Finn each has the right (an option), during specified time periods, to trigger the transfer to the Company by North Finn of 60% of North Finn's interests in any unearned project areas in which the Company already has an interest, and a simultaneous issuance by the Company to North Finn of 2,900,000 restricted shares of the Company's common stock. North Finn's right of exchange is exercisable at any time on or before July 31, 2012, and the Company's right of exchange is exercisable at any time beginning August 1, 2010 and ending July 31, 2012. If the exchange occurs and the Company receives the 60% interest from North Finn, the Company will not earn or fund any additional interests in the North Finn acreage under the participation agreement. In many of the joint project areas, North Finn owns a 25% working interest and the Company owns a 75% working interest.

North Finn has not exercised its option nor made a commitment to exercise under the AICPA Emerging Issues Task Force Interpretation 96-18, whereby the value of North Finn's option is not currently recognized in our financial statements.

Drilling Commitment Arising from Issuance of Series A Preferred Stock

In conjunction with the issuance of the Series A Preferred Stock, the Company has a commitment to spend \$693,450 drilling on the Krejci project with the drilling being subject to a 20% net profit interest granted to holders of the Series A Convertible Preferred Stock (which converted to common stock in early 2005). The Company expects to fulfill that expenditure commitment by April 2007 with the drilling of the Werner 1-14H well whereby the 20% net profit interest will be limited to a portion of cash flows from Werner 1-14H production. Drilling of the well began on March 15, 2007. Our expected share of costs to drill the well exceeds \$700,000.

Office Lease

The Company had a sublease agreement, and shared common office space, with Tower Energy Corporation, a related entity, for rent of its general corporate office facilities. In March 2006, the Company signed an amendment to the lease agreement whereby the Company leased and occupied new office space starting in May 2006. Upon occupying the new office space, the Company became the Tenant under the lease. The Company is obligated to pay the following minimum future rental commitments under the noncancelable operating lease of office space:

<u>Year</u>	<u>Office Lease Obligations</u>
2007	\$ 149,142
2008	152,564
2009	155,986
2010	159,408
2011	162,820
Thereafter.....	236,118

Delay Rentals

In conjunction with the Company's working interests in undeveloped oil and gas prospects, the Company must pay approximately \$194,000 in delay rentals during the fiscal year ending December 31, 2007 to maintain the right to explore these prospects. The Company continually evaluates its leasehold interests, therefore certain leases may be abandoned by the Company in the normal course of business.

NOTE 13 — SUBSEQUENT EVENTS

Restatement of Our 2005 Financial Statements, with impact on 2006

In the February 28, 2007 meeting of the Company's Audit Committee, the Audit Committee and management concluded that American should file amended financial statements for the year ended December 31, 2005 and for the quarters ended March 31, June 30 and September 30, 2006. The action came in connection with a comment letter received from the SEC's Division of Corporation Finance and subsequent communications with the staff. The financial statements are being restated to account for the April 2005 merger of Tower Colombia Corporation ("TCC") as a business purchase (at fair values), rather than as a business combination of entities under common control (at TCC's carrying values for its assets and liabilities under full cost accounting). The accompanying audited consolidated financial statements reflect the restatements.

The restatements reduced the 2005 consolidated statement of operations net income by \$49,245 (from \$1,082,216 to \$1,032,971). The restatement did not impact earnings per share for 2005 nor cash flows for 2005. The restatement increased American's net assets and shareholders' equity at December 31, 2005 by \$14.5 million, primarily for the recognition of \$11.7 million of goodwill (see note 7).

The restatement reduced 2006 net income by approximately \$900,000 (primarily \$700,000 in additional impairments, net of related deferred income taxes).

On April 2, 2007, we filed a Form 10-KSB/A reflecting the restated financial statements for 2005 and other, less significant, changes to the Form 10-KSB as summarized in an introductory explanatory note contained in the Form 10-KSB/A. We expect to file in the first week of April 2007, Forms 10-Q/A for the first, second and third quarters of 2006.

RTA Participation Agreement

In January 2007, we signed a participation agreement with Red Technology Alliance LLC (“RTA”), which gives RTA the option to fund 100% of the drilling, completion and equipping of the next three to four wells at Fetter. We also signed a project management agreement under which Halliburton has been engaged to manage the operations funded by RTA. In these three to four wells, RTA will own a 75% working interest and will carry American and North Finn through the tanks for 23.125% and 1.875%, respectively. Upon the completion of this drilling program, RTA will have earned assignment of 25% ownership in approximately 53,000 gross (approximately 50,000 net) acres in the Fetter acreage position, where American currently owns a 92.5% ownership interest. As of March 29, RTA has drilled a vertical well of approximately 11,500 feet depth and has begun operations for the drilling of a horizontal extension into the Frontier formation.

NOTE 14 — INFORMATION REGARDING PROVED OIL AND GAS RESERVES (UNAUDITED)

The information presented below regarding the Company’s oil and gas reserves were prepared by independent petroleum engineering consultants. All reserves are located within the continental United States.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. The determination of oil and gas reserves is highly complex and interpretive. The estimates are subject to continuing change as additional information becomes available.

The complete definition of proved oil and gas reserves appears at Regulation S-X 4-10 (a) (2) (3) and (4). The complete definition of proved developed oil and gas reserves appears at Regulation S-X 4-10 (a) (4), 17 CFR 210. 4-10 (a) (4).

Estimated net quantities of proved developed and undeveloped reserves of oil and gas for the year ended December 31, 2006, 2005 and 2004 are presented in tables below.

<u>December 31, 2006</u>	<u>Oil (BBLs)</u>	<u>Gas (MCF)</u>
Beginning of year	554,702	378,213
Revisions of Previous quantity estimates	(35,347)	136,378
Extensions, discoveries and improved recoveries	76,347	505,832
Sales of reserves in place	(469,274)	(162,387)
Production.....	<u>(34,578)</u>	<u>(48,189)</u>
End of year	<u>91,850</u>	<u>809,847</u>
Proved developed reserves-end of year	<u>86,361</u>	<u>713,236</u>

Sales of reserves in place in 2006 relate to the proved reserves of our Big Sky property interests sold in March 2006. Extensions, discoveries and improved recoveries relate to new wells at our Fetter, Goliath and Krejci projects. These new wells have little or no production history at year-end and their proved reserve estimates may be significantly revised with further production information.

Revisions in 2006 relate primarily to two wells. The Rogers 1-11H well location drilled in early 2006 was assigned proved undeveloped reserves at 12-31-05 that were revised when actual production demonstrated greater gas reserves and less oil reserves. The Bear Creek Unit #1 well’s production in 2006 justified an increase in its proved gas reserves.

<u>December 31, 2005</u>	<u>Oil (BBLs)</u>	<u>Gas (MCF)</u>
Beginning of year	321,710	346,270
Revisions of Previous quantity estimates	4,208	18,958
Extensions, discoveries and improved recoveries	307,773	116,067
Sales of reserves in place	—	(43,585)
Production.....	<u>(78,989)</u>	<u>(59,497)</u>
End of year	<u>554,702</u>	<u>378,213</u>
Proved developed reserves-end of year	<u>320,698</u>	<u>307,000</u>
<u>December 31, 2004</u>	<u>Oil (BBLs)</u>	<u>Gas (MCF)</u>
Beginning of year	70,900	1,526,800
Revisions of Previous quantity estimates	(8,880)	98,027
Extensions, discoveries and improved recoveries	295,944	242,074
Sales of reserves in place	(23,405)	(1,471,666)
Production.....	<u>(12,849)</u>	<u>(48,965)</u>
End of year	<u>321,710</u>	<u>346,270</u>
Proved developed reserves-end of year	<u>147,205</u>	<u>216,867</u>

**STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS
RELATING TO PROVED OIL AND GAS RESERVES**

Future net cash flows presented below are computed using year-end prices and costs. Future corporate overhead expenses and interest expense have not been included.

	<u>2006</u>	<u>2005</u>	<u>2004</u>
Future cash inflows.....	\$ 10,421,519	\$ 35,159,955	\$ 15,565,592
Future costs: Production	(3,276,852)	(5,768,802)	(2,842,441)
Development.....	(716,000)	(2,825,307)	(1,972,604)
Future income tax expense	<u>(230,912)</u>	<u>(706,000)</u>	<u>(696,000)</u>
Future net cash flows	6,197,755	25,859,846	10,054,547
10% discount factor	<u>(1,599,755)</u>	<u>(12,149,916)</u>	<u>(4,622,428)</u>
Standardized measure of discounted future net cash flows	<u>\$ 4,598,000</u>	<u>\$ 13,709,930</u>	<u>\$ 5,432,119</u>

The principal sources of changes in the standardized measure of discounted future net cash flows during the years ended December 31, 2006, 2005 and 2004 are as follows:

	<u>2006</u>	<u>2005</u>	<u>2004</u>
Beginning balance	\$ 13,709,930	\$ 5,432,119	\$ 2,839,143
Sales and transfers of oil and gas produced.....	(1,966,036)	(4,466,663)	(665,781)
Net changes in prices and production costs	(1,637,000)	3,640,869	(148,083)
Sales of minerals in place	(10,800,000)	(135,472)	(1,742,409)
Extensions and discoveries	3,814,000	6,611,421	5,132,883
Development costs incurred during the year	519,000	1,649,396	—
Changes in estimated future development costs	0	(16,255)	19,992
Revisions in previous quantity estimates.....	821,000	178,586	(65,844)
Accretion of discount.....	161,000	565,612	283,914
Change in income taxes	(6,200)	135,000	(224,000)
Change in rates of production and other	<u>(17,694)</u>	<u>115,317</u>	<u>2,304</u>
Ending balance	<u>\$ 4,598,000</u>	<u>\$ 13,709,930</u>	<u>\$ 5,432,119</u>

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with the provisions of SFAS 69. Future cash inflows were computed by applying current prices at year-end to estimated future production. Future production and development costs (including the estimated asset retirement obligation) are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at year-end, based on year-end costs and assuming continuation of existing economic conditions. Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax

cash flows relating to proved oil and gas reserves, less the tax basis of properties involved and tax credits and loss carryforwards relating to oil and gas producing activities. Future net cash flows are discounted at the rate of 10% annually to derive the standardized measure of discounted future cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value of the present value of the Company's oil and gas properties.

As disclosed in Note 4, the Company sold all of its interests in the Big Sky project on March 31, 2006. The sold interests accounted for approximately 88% of the standardized measure at December 31, 2005. Accretion for 2006 shown above does not relate to those proved reserves at December 31, 2005 attributable to the Big Sky interests.

NOTE 15 — UNAUDITED SUPPLEMENTAL QUARTERLY FINANCIAL DATA

2006	First	Second	Third	Fourth
Revenues.....	\$1,570,872	\$1,789,033	\$ 216,347	\$ 210,587
Income (loss) from operations	\$ (168,752)	\$ 820,582	\$(1,858,216)	\$(4,831,043)
Net income (loss).....	\$2,469,655	\$2,231,715	\$(1,261,675)	\$(2,228,472)
Earnings per common share:				
Basic	\$ 0.06	\$ 0.05	\$ (0.04)	\$ (0.05)
Diluted	\$ 0.06	\$ 0.05	\$ (0.04)	\$ (0.05)
2005	First	Second	Third	Fourth
Revenues.....	\$ 686,727	\$ 1,239,041	\$ 1,529,288	\$ 1,236,324
Income (loss) from operations	\$ 38,428	\$ 97,771	\$ 397,535	\$ 341,239
Net income (loss).....	\$ 61,662	\$ 115,411	\$ 478,528	\$ 377,369
Earnings per common share:				
Basic	\$ 0.00	\$ 0.00	\$ 0.01	\$ 0.01
Diluted	\$ 0.00	\$ 0.00	\$ 0.01	\$ 0.01

The sum of the individual quarterly net income per common share amounts may not agree with year-to-date net income per common share because each period's computation is based on the weighted average number of shares outstanding during that period. The information in the table above for the fourth quarter of 2005 reflects amounts in the restated 2005 annual financial statements less amounts reported for the first three quarters in Form 10-Qs that have not been restated. The information in the table above for 2006 reflects the effects of the 2005 restatement. We anticipate filing amended Form 10-Qs in mid April 2007 for the first three quarters of 2006 reflecting the effects of the restated 2005 financial statements.

Item 9: Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A: Controls and Procedures

Disclosure Controls and Procedures.

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Evaluations have been performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a—15(e) and 15d—15(e) of the Exchange Act). Based upon those evaluations, management, including the Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2006 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives and the Chief Executive Officer and the Chief Financial Officer, as of December 31, 2006, have concluded that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives and the Chief Executive Officer and the Chief Financial Officer, as of December 31, 2006, have concluded that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Management's Annual Report on Internal Control over Financial Reporting

In regards to internal control over financial reporting, our management is responsible for the following:

- establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934), and
- assessing the effectiveness of internal control over financial reporting.

The Company's internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and Chief Financial Officer and affected by our Board of Directors, management and other personnel. It was designed to provide reasonable assurance to our management, Board of Directors and external users regarding the fair presentation of financial statements in accordance with accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets,
- provide reasonable assurance that transactions are recorded as to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorization of our management and board of directors, and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, management assessed the effectiveness of our internal control over financial reporting as of December 31, 2006. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework*.

Management's assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of our internal control over financial reporting. Based upon the assessment, management believes that, as of December 31, 2006, our internal control over financial reporting is effective based on those criteria.

HEIN & ASSOCIATES, LLP, the independent registered public accounting firm that audited our financial statements included in this Annual Report on Form 10-K, has also audited our management's assessment of the effectiveness of the Company's internal control over financial reporting and the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 as stated in their report included herein.

Changes in Internal Control over Financial Reporting

During 2006, our management regularly evaluated the Company's internal controls over financial reporting and discussed these matters with our independent accountants and our audit committee. Based on these evaluations and discussions, our management considered what revisions, improvements, or corrections were necessary in order to ensure that our internal controls were effective as our operations and financial reporting requirements changed over time. As a result, we have made significant progress implementing enhancements and corrective actions to our internal controls related to enhancing certain general computer controls over the past year.

We anticipate that implementation of these enhancements will continue through 2007. The principal focus of these enhancements is related to general computer controls which include documenting and adhering to comprehensive system development methodologies when performing system application implementations and upgrades, establishing an off-site repository for enterprise back-up data and enhancing controls to appropriately limit ability to access our network infrastructure.

There have been no other significant changes in internal controls, or other factors that could significantly affect internal controls, that occurred during the fourth quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors
American Oil & Gas, Inc.
Denver, Colorado

We have audited management's assessment, included in the accompanying *Management's Annual Report on Internal Control Over Financial Reporting* (Item 9A), that American Oil & Gas, Inc. maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). American Oil & Gas, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that American Oil & Gas, Inc. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework* issued by COSO. Also in our opinion, American Oil & Gas, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of American Oil & Gas, Inc. as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income for the years then ended, and our report on those statements dated April 2, 2007 expressed an unqualified opinion.

/s/ **HEIN & ASSOCIATES LLP**

Denver, Colorado
April 2, 2007

Item 9B: Other Information.

Not applicable.

PART III

Item 10: Directors, Executive Officers and Corporate Governance

See “Executive Officers, Board of Directors, Committees of the Board and Section 16(a) Beneficial Ownership Reporting Compliance” in the American Oil & Gas Inc. Proxy Statement (“Proxy Statement”), for the Annual Meeting of Stockholders of the Company (to be filed with the SEC within 120 days after the end of the Company’s fiscal year ended December 31, 2006) which is incorporated herein by reference.

Our Code of Ethics can be found on our internet website located at www.americanog.com. If we amend the Code of Ethics or grant a waiver, including an implicit waiver, from the Code of Ethics, we intend to disclose the information on our internet website. This information will remain on the website for at least 12 months.

Item 11: Executive Compensation

Information required by this item will be contained in the Proxy Statement under the caption “Executive Compensation,” and is hereby incorporated by reference thereto.

Item 12: Securities Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item will be contained in the Proxy Statement under the caption “Securities Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” and is incorporated herein by reference.

Item 13: Certain Relationships and Related Transactions, and Director Independence

Information required by this item will be contained in the Proxy Statement under the caption “Certain Transactions” and “Corporate Governance” and is hereby incorporated by reference thereto.

Item 14: Principal Accountant Fees and Services

Information required by this item will be contained in the Proxy Statement under the caption “Auditors’ Fees,” and is hereby incorporated by reference thereto.

PART IV

Item 15: Exhibits, Financial Statement Schedules

(a) (1) Financial Statements (included in Item 8 to this Form 10-K)

	Form 10-K Pages
Reports of Independent Registered Public Accounting Firm	F-2
Consolidated Balance Sheets, December 31, 2006 and 2005	F-4
Consolidated Statements of Operations for the Years Ended December 31, 2006, 2005 and 2004	F-5
Consolidated Statements of Cash Flows for the Years Ended December 31, 2006, 2005 and 2004	F-6
Consolidated Statements of Stockholders’ Equity for the Years Ended December 31, 2006, 2005 and 2004	F-7
Notes to Consolidated Financial Statements, December 31, 2006, 2005 and 2004	F-8

(a)(2) All other schedules have been omitted because the required information is inapplicable or is shown in the Notes to the Financial Statements.

(a)(3) Exhibits required to be filed by Item 601 of Regulation S-K.

<u>Exhibit No.</u>	<u>Description</u>
2(1)	Agreement and Plan of Merger with Tower Colombia Corporation dated effective April 21, 2005. (Incorporated by reference from the Company's Post-Effective Amendment No. 1 to Form SB-2, filed on April 27, 2005.)
3(i)	Articles of Incorporation of the Company. (Incorporated by reference from the Company's Form 10-SB, file number 000-31547, filed on September 18, 2000.)
3(ii)	Amendment to Articles of Incorporation of the Company. (Incorporated by reference from the Company's Current Report on Form 8-K filed on February 3, 2003.)
3(iii)	Certificate of Designation of Series A Preferred Stock. (Incorporated by reference from the Company's Amendment No. 2 to Form SB-2, filed on January 31, 2005.)
3(iv)	Bylaws of the Company (as revised on December 12, 2002). (Incorporated by reference from the Company's Form 10-KSB/A, filed on November 18, 2003.)
3(v)	Certificate of Designation of Series AA 8% Preferred Stock. (Incorporated by reference from the Company's Amendment No. 1 to Form S-3, filed on March 6, 2006.)
10(i)	2004 Stock Option Plan. (Incorporated by reference from the Company's Definitive Proxy Statement, filed on June 16, 2004)
10(ii)	Form of Warrant Certificate issued as part of the private placement completed on July 22, 2005. (Incorporated by reference from the Company's Registration Statement on Form S-3, filed on October 4, 2005.)
10(iii)	Form of Placement Agent Warrant Certificate issued in connection with the private placement completed on July 22, 2005. (Incorporated by reference from the Company's Registration Statement on Form S-3, filed on October 4, 2005.)
10(iv)	January 17, 2003 Purchase and Sale Agreement by and between the Company, Tower Colombia Corporation and North Finn, LLC. (Incorporated by reference from the Company's Form 8-K, filed on February 3, 2003.)
10(v)	January 17, 2003 Participation Agreement by and between the Company, Tower, North Finn, and the principals of Tower and North Finn. (Incorporated by reference from the Company's Form 10-KSB for the calendar ending December 31, 2002, filed on March 31, 2003.)
10(vi)	Model Form Operating Agreement dated February 18, 2003. (Incorporated by reference from the Company's Form 10-KSB/A, filed on November 18, 2003.)
10(vii)	Employment Agreement between the Company and Andrew P. Calerich dated effective April 21, 2005. (Incorporated by reference from the Company's Post-Effective Amendment No. 1 to Form SB-2, filed on April 27, 2005.)
10(viii)	Employment Agreement between the Company and Patrick D. O'Brien dated effective April 21, 2005. (Incorporated by reference from the Company's Post-Effective Amendment No. 1 to Form SB-2, filed on April 27, 2005.)
10(ix)	Employment Agreement between the Company and Bobby G. Solomon dated effective April 21, 2005. (Incorporated by reference from the Company's Post-Effective Amendment No. 1 to Form SB-2, filed on April 27, 2005.)
10(x)	Employment Agreement between the Company and Kendell V. Tholstrom dated effective April 21, 2005. (Incorporated by reference from the Company's Post-Effective Amendment No. 1 to Form SB-2, filed on April 27, 2005.)
10(xi)	Participation Agreement between the Company and North Finn LLC dated January 5, 2006. (Incorporated by reference from the Company's Form 10-KSB for the fiscal year ended December 31, 2005.)
10(xii)	Employment Agreement between the Company and Joseph B. Feiten. (Incorporated by reference from the Company's Current Report on Form 8-K filed on August 31, 2006.)
10(xiii)	Stock Option Agreement between the Company and Joseph B. Feiten. (Incorporated by reference from the Company's Current Report on Form 8-K filed on August 31, 2006.)
10(xiv)	Purchase and Sale Agreement, dated September 1, 2006, between SunStone Oil & Gas, LLC and the Company. (Incorporated by reference from the Company's Current Report on Form 8-K filed on September 6, 2006.)

Exhibit No.	Description
10(xv)	Registration Rights Agreement, dated September 1, 2006, by and among the Company and the investors listed therein. (Incorporated by reference from the Company's Current Report on Form 8-K filed on September 6, 2006.)
10(xvi)	Purchase and Sale Agreement dated March 31, 2006 by and between the Company and Enerplus Resources (USA) Corporation. (Incorporated by reference from the Company's Quarterly Report on Form 10-QSB for the period ended September 30, 2006.)
10(xvii)	Participation Agreement dated January 17, 2007 among the Company, Red Technology Alliance LLC and North Finn LLC. (Incorporated by reference from the Company's Current Report on Form 8-K filed on January 23, 2007.)
10(xviii)	2006 Stock Incentive Plan (Incorporated by reference to the Company's Definitive Proxy Statement, as amended, filed on July 26, 2006)
14(i)	Code of Ethics. (Incorporated by reference from Exhibit 14(i) to the Company's Form 10-KSB for the fiscal year ending December 31, 2003, filed on April 14, 2004).
21(i)	Subsidiary List.
23(i)	Consent from Ryder Scott Petroleum Consultants
23(ii)	Consent of Hein & Associates, LLP
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, this 10th day of April, 2007.

American Oil & Gas, Inc.

/s/ Andrew P. Calerich

Andrew P. Calerich
President

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
<u>/s/ Patrick D. O'Brien</u> Patrick D. O'Brien	Chief Executive Officer and Chairman (Principal Executive Officer)	April 10, 2007
<u>/s/ Andrew P. Calerich</u> Andrew P. Calerich	President and Director	April 10, 2007
<u>/s/ Joseph B. Feiten</u> Joseph B. Feiten	Chief Financial Officer (Principal Financial Officer)	April 10, 2007
<u>/s/ Alan Gelfand</u> Alan Gelfand	Director	April 10, 2007
<u>/s/ Kendell Tholstrom</u> Kendell Tholstrom	Secretary and Director	April 10, 2007
<u>/s/ M.S. ("Moni") Minhas</u> M.S. ("Moni") Minhas	Director	April 10, 2007
<u>/s/ Nick DeMare</u> Nick DeMare	Director	April 10, 2007
<u>/s/ Jon R. Whitney</u> Jon R. Whitney	Director	April 10, 2007

Exhibit Index

<u>Exhibit No.</u>	<u>Description</u>
2(1)	Agreement and Plan of Merger with Tower Colombia Corporation dated effective April 21, 2005. (Incorporated by reference from the Company's Post-Effective Amendment No. 1 to Form SB-2, filed on April 27, 2005.)
3(i)	Articles of Incorporation of the Company. (Incorporated by reference from the Company's Form 10-SB, file number 000-31547, filed on September 18, 2000.)
3(ii)	Amendment to Articles of Incorporation of the Company. (Incorporated by reference from the Company's Current Report on Form 8-K filed on February 3, 2003.)
3(iii)	Certificate of Designation of Series A Preferred Stock. (Incorporated by reference from the Company's Amendment No. 2 to Form SB-2, filed on January 31, 2005.)
3(iv)	Bylaws of the Company (as revised on December 12, 2002). (Incorporated by reference from the Company's Form 10-KSB/A, filed on November 18, 2003.)
3(v)	Certificate of Designation of Series AA 8% Preferred Stock. (Incorporated by reference from the Company's Amendment No. 1 to Form S-3, filed on March 6, 2006.)
10(i)	2004 Stock Option Plan. (Incorporated by reference from the Company's Definitive Proxy Statement, filed on June 16, 2004)
10(ii)	Form of Warrant Certificate issued as part of the private placement completed on July 22, 2005. (Incorporated by reference from the Company's Registration Statement on Form S-3, filed on October 4, 2005.)
10(iii)	Form of Placement Agent Warrant Certificate issued in connection with the private placement completed on July 22, 2005. (Incorporated by reference from the Company's Registration Statement on Form S-3, filed on October 4, 2005.)
10(iv)	January 17, 2003 Purchase and Sale Agreement by and between the Company, Tower Colombia Corporation and North Finn, LLC. (Incorporated by reference from the Company's Form 8-K, filed on February 3, 2003.)
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Exhibit 21(i)

Subsidiary

State of Incorporation

Tower American Corporation

Colorado

**CONSENT OF INDEPENDENT PETROLEUM
ENGINEERS AND GEOLOGISTS**

We hereby consent to the references to our firm, in the context in which they appear, and to our reserve estimates as of December 31, 2006, December 31, 2005, and December 31, 2004, included in the Annual Report on Form 10-K/A of American Oil & Gas Inc. for the fiscal year ended December 31, 2006. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, to our reserve estimates as of December 31, 2006, December 31, 2005 and December 31, 2004, into American Oil & Gas Inc.'s previously filed Registration Statement on Form S-8 (No. 333-121941) and Registration Statements on Form S-3 (No. 333-128812, and No. 333-120987 and No. 333-139648), in accordance with the requirements of the Securities Act of 1933, as amended.

/s/ Ryder Scott Company L. P.

Ryder Scott Company L. P.

Denver, Colorado
April 10, 2007

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference of the following two reports into American Oil & Gas Inc.'s previously filed Registration Statement on Form S-8 (No. 333-121941) and Registration Statements on Form S-3 (No. 333-128812, No. 333-120987 and No. 333-139648.):

- Our report dated April 2, 2007, except for the second paragraph of that report, which is dated April 10, 2007 on the December 31, 2006 and December 31, 2005 consolidated balance sheets and the consolidated statements of operations, stockholders' equity, cash flow and comprehensive income for each of the years in the three-year period ended December 31, 2006, of American Oil and Gas, Inc. ("American") and
- Our report dated April 2, 2007 on American management's assessment of the effectiveness of internal control over American financial reporting as of December 31, 2006 and on the effectiveness of internal control over American financial reporting as of December 31, 2006,

which reports appear in the Annual Report on Form 10-K/A for American for the year ended December 31, 2006.

Hein & Associates LLP

Denver, Colorado
April 10, 2007

CERTIFICATION OF CEO PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Patrick D. O'Brien, certify that:

1. I have reviewed this annual report on Form 10-K/A for the year ended December 31, 2006 of American Oil & Gas, Inc.

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

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

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

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

b) Designed such internal control over financial reporting or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: April 10, 2007

/s/ Patrick D. O'Brien

Patrick D. O'Brien
Chief Executive Officer

CERTIFICATION OF CFO PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Joseph B. Feiten, certify that:

1. I have reviewed this annual report on Form 10-K/A for the year ended December 31, 2006 of American Oil & Gas, Inc.

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

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

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

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

b) Designed such internal control over financial reporting or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: April 10, 2007

/s/ Joseph B. Feiten

Joseph B. Feiten
Chief Financial Officer

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

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

In connection with the Annual Report of American Oil & Gas, Inc. (the "Company") on Form 10-K/A for the year ended December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K/A"), I, Patrick D. O'Brien, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Form 10-K/A fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) The information contained in the Form 10-K/A fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: April 10, 2007

/s/ Patrick D. O'Brien
Patrick D. O'Brien
Chief Executive Officer

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

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

In connection with the Annual Report of American Oil & Gas, Inc. (the "Company") on Form 10-K/A for the quarter ended December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K/A"), I, Joseph B. Feiten, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Form 10-K/A fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) The information contained in the Form 10-K/A fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: April 10, 2007

/s/ Joseph B. Feiten

Joseph B. Feiten
Chief Financial Officer

BOARD OF DIRECTORS

PATRICK D. O'BRIEN
*Chairman of the Board of Directors,
Chief Executive Officer*

ANDREW P. CALERICH
Director and President

KENDELL V. THOLSTROM
Director, Vice-President and Secretary

NICK DEMARE^{(a)(b)(c)}
Director, Audit Committee Chairman

ALAN GELFAND^{(a)(b)(c)}
Director

M.S. ("MONI") MINHAS^{(a)(b)(c)}
*Director, Compensation Committee
Chairman*

JON R. WHITNEY^{(a)(b)(c)}
*Director, Nominating Committee
Chairman*

- a) Member of the Audit Committee
- b) Member of the Compensation Committee
- c) Member of the Nominating Committee

EXECUTIVE OFFICERS

PATRICK D. O'BRIEN
Chief Executive Officer

ANDREW P. CALERICH
President

JOSEPH B. FEITEN
Chief Financial Officer

KENDELL V. THOLSTROM
*Vice-President—Oil and Gas Operations
and Secretary*

BOBBY G. SOLOMON
Vice-President—Oil and Gas Economics

DON E. SCHROEDER
Vice-President—Land

CORPORATE HEADQUARTERS

Independence Plaza
1050 17th Street, Suite 2400
Denver, CO 80265
Phone: 303.991.0173
Facsimile: 303.595.0709

STOCK LISTING

American Oil & Gas, Inc. is traded on the American Stock Exchange under the ticker symbol AEZ.

INDEPENDENT ACCOUNTANTS

Hein & Associates, LLP
Denver, Colorado

OUTSIDE LEGAL COUNSEL

Patton Boggs, LLP
Denver, Colorado

TRANSFER AGENT AND REGISTRAR

Communication concerning stock transfer requirements, lost certificates and changes of address should be directed to the Transfer Agent:

Corporate Stock Transfer
3200 Cherry Creek Drive South
Suite 430
Denver, CO 80209
303.282.4800

WEBSITE

www.americanog.com



Independence Plaza
1050 17th Street, Suite 2400
Denver, CO 80265
Phone: 303.991.0173
Facsimile: 303.595.0709

