ASPEN EXPLORATION CORP
Form 10KSB
September 29, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-KSB

(Mark One)

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

For the fiscal year ended June 30, 2008

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

For the transition period from ______________ to _________________

Commission file number: 001-12531

ASPEN EXPLORATION CORPORATION

(Name of small business issuer in its charter)

Delaware	**84-0811316**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
2050 S. Oneida St., Suite 208 Denver, Colorado	**80224-2426**
(Address of principal executive offices)	(Zip Code)

Issuer s telephone number**(303) 639-9860**

Securities registered pursuant to Section 12(b) of the Exchange Act: None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $0.005 par value

Check whether the issuer is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act: [ ]

Check whether the issuer (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 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 [ ]

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B contained in this form, and no disclosure will 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-KSB or any amendment to this Form 10-KSB. [X]

Indicate by checkmark whether the issuer is a shell company (as defined in Rule 12b-2 of the Exchange Act) (check one): Yes [ ] No [X]

Aspen s revenues for the fiscal year ended June 30, 2008 were $5,390,367.

At August 29, 2008, the aggregate market value of the shares held by non-affiliates was approximately $10,091,355. The aggregate market value was calculated by multiplying the mean of the closing bid and asked prices ($2.12) of the common stock of Aspen on the Over-the-Counter Bulletin Board listing for that date, by the number of shares of stock held by non-affiliates of Aspen (4,760,073).

At August 29, 2008, there were 7,259,622 shares of common stock (Aspen's only class of voting stock) outstanding.

Transitional Small Business Disclosure Format (check one): Yes [ ] No [X]

PART I

ITEM 1. BUSINESS

Because we want to provide you with more meaningful and useful information, this Annual Report on Form 10-KSB contains certain "forward-looking statements" (as such term is defined in Section 21E of the Securities Exchange Act of 1934, as amended). These statements reflect our current expectations regarding our possible future results of operations, performance, and achievements. These forward-looking statements are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, regulation of the Securities and Exchange Commission, and common law.

Wherever possible, we have tried to identify these forward-looking statements by using words such as "anticipate," "believe," "estimate," "expect," "plan," "intend," and similar expressions. These statements reflect our current beliefs and are based on information currently available to us. Accordingly, these statements are subject to certain risks, uncertainties, and contingencies, which could cause our actual results, performance, or achievements to differ materially from those expressed in, or implied by, such statements. These risks, uncertainties and contingencies include, without limitation, the factors set forth under "Item 6. Management's Discussion and Analysis of Financial Conditions or Plan of Operation Factors that may affect future operating results." We have no obligation to update or revise any such forward-looking statements that may be made to reflect events or circumstances after the date of this Form 10-KSB.

Summary of Our Business:

Aspen was incorporated under the laws of the State of Delaware on February 28, 1980 for the primary purpose of acquiring, exploring and developing oil and gas and other mineral properties. Our principal executive offices are located at 2050 S. Oneida St., Suite 208, Denver, Colorado 80224-2426. Our telephone number is (303) 639-9860, and our facsimile number is (303) 639-9863. Our websites are www.aspenexploration.com and www.aspnx.com. Our email address is aecorp2@qwestoffice.net. We are currently engaged primarily in the exploration, development and production of oil and gas properties in California and Montana. We have an interest in an inactive subsidiary: Aspen Gold Mining Co., a company that has not been engaged in business since 1995.

Oil and Gas Exploration and Development. Our major emphasis has been participation in the oil and gas segment, acquiring interests in producing oil or gas properties and participating in drilling operations. We engage in a broad range of activities associated with the oil and gas business in an effort to develop oil and gas reserves. Our participation in the oil and gas exploration and development segment consists of two different lines of business ownership of working interests and operating properties.

- We own working interests in oil and gas wells. We also own working interests in properties, which we explore for oil or natural gas and, if our exploration efforts are successful, we produce and sell oil or natural gas from those properties. Where we hold working interests, we bear a proportionate share of the exploration and development costs of a property and if the property is successful will receive a proportionate return based on our interest percentage. We currently have working interests in 93 wells in the Sacramento Valley of northern California. Additionally, we have non-operating working interest in 84 oil and gas wells located in the Williston Basin of Roosevelt County, Montana, 37 of which are currently productive.
- We also operate oil and gas wells and, where possible, we attempt to be the operator of each property in which we own a working interest. As operator of oil and gas properties, we manage exploration and development activities for the working interest owners (which includes ourselves) and accomplish all of the administrative functions for the joint interest owners. The joint interest owners pay us management fees for those services, which are recorded as a reduction to our general and administrative expenses. All consideration received from sales or transfers of properties in connection with partnerships, joint venture operations, or various other forms of drilling arrangements involving oil and gas exploration and development activities are credited to the full cost account, except to the extent of amounts that represent reimbursement of organization, offering, general and administrative expenses, that are identifiable with the transaction, which are currently incurred and charged to expense. As of June 30, 2008, we act as the operator of 67 wells in the Sacramento Valley of northern California.

With the assistance of our management, independent contractors retained from time to time by us, and, to a lesser extent, unsolicited submissions, we have identified and will continue to identify prospects that we believe are suitable for drilling and acquisition. Currently, our primary areas of interest are in the state of California and in the state of Montana.

On September 4, 2008, we announced that our board of directors decided to investigate strategic alternatives for Aspen, including the possibility of selling Aspen s assets or considering another appropriate merger or acquisition transaction. Aspen s board determined to make this investigation for several reasons, including:

- The disproportionate cost of Aspen s general and administrative expenditures required as a result of compliance with the Securities Exchange Act of 1934, as amended (including the requirements of the Sarbanes-Oxley Act of 2002) when compared to Aspen s revenues and net income;
- The board of directors belief that the market price of Aspen common stock does not adequately reflect the inherent value of Aspen s producing oil and gas assets and undeveloped acreage, and thus the board of directors does not believe that a transaction based on the value of Aspen s common stock would be in the best interest of Aspen s shareholders; and
- The likelihood that Aspen s president will be unable to resume his former role and responsibilities and oversee Aspen s day-to-day operations due to the effects of the stroke he suffered in January 2008.

We have opened a data room in Santa Barbara, California, at which persons interested in acquiring our assets or Aspen itself will be able to review a significant amount of information about Aspen and its properties. Aspen has retained Brian Wolf, a California-licensed mineral, oil and gas broker and consulting geologist, to assemble and operate the data room for Aspen.

As of the date of this Annual Report we have not received any offer from any person for an asset acquisition, merger, or other business combination. We cannot offer any assurance that we will receive an acceptable offer from any person for an asset acquisition, merger, or other business combination. Further, we may later determine that it is in the best interest of our shareholders to investigate other forms of business alternatives or to continue and expand existing business operations with existing or new management. In the meantime, Aspen will continue to carry on its business operations in the normal course.

Company Strategy:

We hold working interests in oil and gas properties, many of which have wells producing oil or natural gas. Where we acquire an interest in a property or acreage on which exploration or development drilling is planned, we will seldom assume the entire risk of acquisition or drilling. Rather, we prefer to assess the relative potential and risks of each prospect and determine the degree to which we will participate in the exploration or development drilling. Generally, we have determined that it is beneficial to invite industry participants to share the risk and the reward of the prospect by financing some or all of the costs of drilling contemplated wells, and as such have entered into industry standard joint operating agreements with other parties. In such cases, we may retain a carried working interest, a reversionary interest, or other promotional interest, and we generally are required to finance all or a portion of our proportional interest in the prospect. Although this approach reduces our potential return should the drilling operations prove successful, it also reduces our risk and financial commitment to a particular prospect. Fees assessed for the participation in these prospects are credited to the full-cost pool.

Conversely, we may from time to time participate in drilling prospects offered by other persons if we believe that the potential benefit from the drilling operations outweighs the risk and the cost of the proposed operations. This approach allows us to diversify into a larger number of prospects at a lower cost per prospect, but these operations (commonly known as farm-ins) are generally more expensive than operations where we offer the participation to others (known as farm-outs). During the year ended June 30, 2008, we participated in the drilling of 6 farm-in wells.

In addition to properties having producing wells or reserves, we also own some unproved properties that we believe might have value for oil and gas exploration and development. These properties are disclosed in more detail, below. We do not believe that our capitalized costs associated with these unproved properties are, at June 30, 2008, material in amount. Such costs include lease acquisition, geological and geophysical work, and delay rentals. These costs are capitalized in our full cost pool and included in our amortization computation. We review the capitalized costs of all properties against our full-cost pool on a quarterly basis.

We also occasionally acquire unevaluated acreage in conjunction with the purchase of oil and gas leases. While unproved properties are properties we believe are valuable for oil and gas exploration based on the exploration work performed, unevaluated properties are properties that have been acquired but which have not been evaluated based on exploration work known to have been performed by others. Costs attributable to unevaluated acreage are considered immaterial at June 30, 2008. These costs are included in our full cost pool and amortization computation.

From time-to-time we may also engage in mineral and natural resource exploration and similar business activities not associated with the oil and gas industry. To date, we have not devoted a material amount of resources to these other business activities nor have we generated material revenues from these other business activities. In January 2007 (effective September 1, 2006) we entered into a joint venture with Hemis Corporation whereby Hemis became the operator of a venture engaged in permit acquisition and exploration for commercial quantities of gold in and near Cook Inlet, Alaska. Hemis paid us $50,000 in January 2007 and another $50,000 in August 2007. Hemis was obligated to pay us another $50,000 on or before September 1, 2008 and on each anniversary date until production of gold begins. Hemis did not make the 2008 payment to us, and we have provided notification to Hemis of our intention to terminate that agreement. The agreement will be terminated unless Hemis cures the payment default and certain other defaults within the 30 day notice period. We do not know if Hemis will cure the payment default or contest the existence of the other defaults that Aspen alleged.

In the agreement with Hemis, we retained a 5% gross royalty on production. In June 2007, Hemis announced that it had begun a preliminary oceanographic survey of the gold project and was optimistic regarding the project s potential. Hemis has provided information to us from the 2007 survey.

As discussed above, we are also considering the possibility of selling our properties or entering into another type of business combination. We are continuing to conduct our business in the ordinary course while we are exploring these alternatives.

Principal Products Produced and Services Rendered. Our principal products during fiscal 2008 were crude oil and natural gas. Crude oil and natural gas are generally sold to various entities, including pipeline companies, which usually service the area in which our producing wells are located. In the fiscal year ended June 30, 2008, our crude oil and natural gas sales totaled $5,390,367.

Both our produced crude oil and natural gas are subject to pricing in the local markets where the production occurs. It is customary that such products are priced based on local or regional supply and demand factors. California heavy crude sells at a discount to WTI, the U.S. benchmark for crude oil, primarily due to the additional cost to refine gasoline or light product out of a barrel of heavy crude. Natural gas field prices are normally priced off of Henry Hub NYMEX price, the benchmark for U.S. natural gas. Aspen s gas prices are based on the PG&E Citygate Index. While we attempt to contract for the best possible price in each of our producing locations, there is no assurance that past price differentials will continue into the future. Numerous factors may influence local pricing, such as refinery capacity, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions, governmental regulations, and other factors. We may be adversely impacted by a widening differential on the products sold.

Distribution Methods of the Products or Services. We are not involved in the distribution aspect of the oil and gas industry. We sell our produced natural gas and oil to third parties for distribution.

Status of any Publicly Announced New Products or Services. During our 2008 fiscal year we did not have a new product or service that would require the investment of a material amount of our assets or which we believe is material to our business. Therefore, during our 2008 fiscal year we did not make a public announcement of, nor have we made information otherwise public about, any such product or service.

Competitive Business Conditions. The exploration for, and development, production and acquisition of, oil, gas, precious metals and other minerals are subject to intense competition. The principal methods of compensation to third parties for the acquisition of oil and gas and other mineral properties are the payment of:

(i) cash bonuses at the time of the acquisition of leases;
(ii) delay rentals and the amount of annual rental payments;
(iii) advance royalties and the use of differential royalty rates; and
(iv) stipulations requiring exploration and production commitments by the lessee.

Some of our current competitors, and many of our potential competitors, in the oil and gas industry have vast experience, are larger and have significantly greater financial resources, existing staff and labor forces, equipment, and other resources than we do. Consequently, these competitors may be in a better position to compete for oil and gas projects. Because of our relatively small size, we have a minimal competitive position in the oil and gas industry.

In addition, the availability of a ready market for oil and gas depends upon numerous factors beyond our control, including the overall amount of domestic production and imports of oil and gas, the proximity and capacity of pipelines, and the effect of federal and state regulation of oil and gas sales, as well governmental environmental regulations applicable to the exploration, production and usage of oil and gas. Further, we expect that competition for leasing of oil and gas prospects will become even more intense in the future.

Sources and Availability of Raw Materials. As part of the business of engaging in the operation of oil and gas properties, we depend on such items as drilling rigs and other equipment, casing pipe, drilling mud and other supplies and equipment necessary for our operations. At the present time, drilling rigs are in short supply, and are demanding a premium price. Nevertheless, we have been able to obtain the services of drilling rigs when needed for our exploration and development activities.

Most other items that we need have been commonly available from a number of sources. Although we do not foresee a shortage in supply or foresee having difficulty in acquiring any equipment relevant to the conduct of business, we cannot offer any assurances that the necessary equipment will be available or that we will be able to acquire the items on economically feasible terms.

Dependence Upon One or a Few Major Customers. We generally sell our oil and gas production to a limited number of companies. In fiscal 2008 we obtained more than 10% of our revenues from sales to Calpine Corporation and Enserco Energy, Inc., (33% and 61%, respectively). We do not believe the loss of these customers would adversely impact our revenues because we believe that oil and gas sales are primarily market driven and are not dependent on particular purchasers. Consequently, we believe that substitute purchasers would be available based on the widespread uses of and the need for oil and gas. However, we cannot guarantee that the loss of either of these major customers would not negatively impact our business operations and revenues.

Need for Governmental Approval of Principal Products or Services. We do not need to seek government approval of our principal products.

Effect of Existing or Probable Governmental Regulation. Oil and gas exploration and production are open to significant governmental regulation including worker health and safety laws, employment regulations and environmental regulations. Part of the regulatory environment in which we operate includes, in some cases, federal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. Operations that occur on public lands may be subject to further regulation by the Bureau of Land Management, the U.S. Army Corps of Engineers, or the U.S. Forest Service as well as other federal and state agencies.

A major risk inherent in our drilling plans is the need to obtain drilling permits from state, and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a negative effect on our ability to explore on or develop its properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

Estimate of Amounts Spent on Research and Development Activities. We have not engaged in any material research and development activities since our inception.

Costs and Effects of Compliance with Environmental Laws (federal, state and local). Because we are engaged in extracting natural resources, our business is subject to various federal, state and local provisions regarding environmental and ecological matters. Therefore, compliance with environmental laws may necessitate significant capital outlays, affect our earnings potential, and cause material changes in our current and proposed business activities.

At the present time, however, the environmental laws do not materially hinder nor adversely affect our business. Capital expenditures relating to environmental control facilities have not been material to our operations since our inception.

Employees:

As of June 30, 2008, we have 2 full-time employees and 1 part-time employee. We also employ independent contractors and other consultants, as needed.

ITEM 2. DESCRIPTION OF PROPERTIES

General Information:

We have a significant amount of information regarding the proven developed and undeveloped oil and gas reserves which can be found below in this Item 2 as well as in the notes to our financial statements.

Drilling and Acquisition Activity:

During the fiscal year ended June 30, 2008, we participated in the drilling of 11 gross (3.295 net) operated wells, 7 of which were completed as gas wells, and 1 is in process, for a 64% success ratio. The estimated lives of the individual wells drilled during the fiscal year range from 1 to 20 years. Of the 7 successful gas wells drilled during the 2008 fiscal year, 2 gas wells were drilled in the West Grimes Field, 1 gas well was drilled in the Grimes Field, 2 gas wells were drilled in the Malton Black Butte Field, 1 gas well was drilled in the Butte Sink Field, and 1 gas well was drilled in the Cache Creek Field.

In February 2007, Aspen purchased an interest in approximately 84 oil wells, 37 of which are currently producing (4.625 net) in certain oil producing assets encompassing 22,600 acres in the East Poplar Unit and the Northwest Poplar Field in Roosevelt County, Montana located in the Williston Basin.

Through December 2007, Aspen was obligated to pay 12.5% of the expenses of operations for a 10% working interest. Since Aspen s investment did not reach payout as of January 1, 2008, Aspen s expense obligation was reduced to 10%. At payout, Aspen s working interest will proportionately be reduced also. As of June 30, 2008, there remains $1,315,211 until Aspen reaches payout, based on total revenues received through June 30, 2008 of $984,590. Commencing February 2008, Aspen (and the other working interest participants) agreed that the operator could retain 60% of the cash flow from the producing wells (after deduction of royalties, taxes, expenses and loan payment) for capital projects, geology and engineering (amounting to a total of $96,250 to Aspen s account as of June 30, 2008). The operator has used these funds for capital expenses, workovers and recompletions. Additionally, in May 2008 Aspen amended its participation agreement in the Poplar Unit to separately market and deal with the deeper rights, oil and gas rights below the base of the Mission Canyon Formation and to grant one of the participants the right to seek to farmout the deeper rights. To the extent that Aspen has available capital and has identified other appropriate drilling or exploration opportunities, Aspen may participate in the drilling of additional wells.

Our decisions to develop and operate prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain. Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or producible economically. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies. Because of these factors, we could incur losses as a result of exploratory drilling expenditures. Poor results from exploration activities could have a material adverse effect on our future cash flows, results of operations and financial position.

Below is a summary of our primary drilling and acquisition activity occurring during our 2008 fiscal year and our activities to-date conducted during our 2009 fiscal year by geographic areas.

West Grimes Field, Colusa County, California

The first 18 wells drilled in the West Grimes Gas Field were successful. These wells were drilled based on a 10.5 square mile 3-D seismic program located over a portion of Aspen s 10,000 plus leased acres in this field. We believe several additional excellent drilling prospects have been identified. The wells in this field produce from multiple Forbes intervals ranging in depth from 6,000 feet to 8,500 feet and have produced over 80 billion cubic feet (BCF) of gas to date. Numerous wells in this immediate area have produced at very prolific flow rates (4,000 MCFPD), have yielded excellent per well reserves (3 to 4 BCF per well), and have long productive well lives. Several of the 10 producing wells that Aspen acquired in this field in 2003 have been producing for 40 years. Aspen believes that several of these wells may have additional gas potential in behind-pipe zones, which have not yet been perforated. Aspen s operated working interests in this field range from 21% to 34%.

The Morris #12-4 well was drilled in July 2007 to a depth of 8,007 feet and encountered approximately 115 feet of potential gross gas pay in several intervals in the Forbes formation. Production casing was run based on favorable mud log and electric log responses. Several of these intervals were perforated and tested gas on a ¼ inch choke at a stabilized flow rate of 500 MCFPD. The shut in tubing and shut in casing pressures were 3,150 psig. Aspen has a 21% operated working interest in this well. Gas sales commenced on September 25, 2007.

In August 2007, the WGU #15-14 well was directionally drilled to a depth of 7,770 feet and encountered approximately 80 feet of potential gross gas pay in several intervals in the Forbes formation. One of these intervals was perforated and tested gas on a 1/4 inch choke at a stabilized flow rate of 1,130 MCFPD. The shut in tubing and shut in casing pressures were 3,200 psig. Aspen has a 34% operated working interest in this well. Gas sales commenced on August 28, 2007.

The Harlan #1-24 well was drilled to a depth of 8,250 feet and encountered approximately 70 feet of potential gross gas pay in several intervals in the Forbes formation. Production casing was run based on favorable mud log and electric log responses. One of these intervals was perforated and tested gas on a 3/16 inch choke at a stabilized flow rate of 1,700 MCFPD. The shut in tubing and shut in casing pressures were 3,740 psig. Aspen has a 34% working interest in this well. Gas sales commenced on February 28, 2008. This was the eighteenth successful gas well out of eighteen attempts by Aspen in this field.

Aspen acquired a 12-square mile 3D-seismic survey directly south of Aspen s successful West Grimes project in Colusa County, California. Seismic processing has been completed on the new Strain Ventures project, which encompasses parts of the West Grimes and Buckeye Gas Fields, and includes a sparsely drilled area west of these fields. Aspen plans to drill at least two prospects identified on the new 3D-survey in the fall of 2008, contingent upon rig availability and approval of necessary permits. Aspen has a 32% working interest in the Strain Ventures project.

Malton Black Butte, Glenn and Tehama Counties, California

Aspen has successfully drilled 10 gas wells out of 12 attempts in this field during the last 5 fiscal years. These wells produce from multiple horizons in the Kione and Forbes formation from depths ranging from 1,700 feet to 5,000 feet. Aspen has operated working interests in these wells ranging from 21% to 36%.

The Johnson Unit #12 well was drilled to a depth of 4,700 feet and encountered potential gas pay in several intervals in the Forbes formation. Production casing was run based on favorable mud log and electric log responses. One of these Forbes intervals was perforated and tested gas on a 3/16 inch choke at a stabilized rate of 141 MCFPD. Gas sales commenced on October 27, 2006. We have a 36% operated working interest in this well

Aspen has drilled the Johnson Unit #13 well in its Johnson Unit of the Malton Black Butte Field. The Johnson Unit #13 well was drilled to a depth of 4,896 feet and encountered approximately 125 feet of potential gross gas pay in several intervals in the Forbes formation. Production casing was run based on favorable mud log and electric log responses. One of the intervals was perforated and tested gas on a 12/64 choke at a rate of 668 MCFPD. Aspen has a 31.00% operated working interest in this well.

This well is in the same Unit as our Johnson #11 well completed in August 2005. Aspen has a 31% working interest in the Johnson #11 and #13 wells. Aspen has a lesser interest in the Elektra Unit which overlaps a portion of the Johnson Unit and which may impact the Merrill #31-1 well (which is not specifically included in the Elektra or the Johnson Unit) in addition to the Johnson #11, #12, and #13 wells. Aspen is attempting to define its interests in those wells and has not commenced producing from the Johnson #13 well. As noted in the Risk Factors of this Form 10-KSB, the existence of a title deficiency can adversely impact the economic results of even a successful well. To the extent that it proves that Aspen s interests in the Johnson #11, #12, and #13 wells or the Merrill #31-1 well are impacted by the overlapping Elektra unit, Aspen (as operator of the wells) will likely have to make certain economic adjustments although those will be determined later based on a full legal review. At the present time, Aspen has not been able to quantify the potential liability, if any, and cannot offer any assessment as to the likelihood that any liability will be recognized or to determine whether the likelihood of an unfavorable outcome on any potential claim regarding the its wells in the Johnson Unit or the Merrill #31-1 well is either probable or remote. However, Aspen believes that it has meritorious defenses to any such potential claim.

The Eastby #1-1 well was drilled to a depth of 5,010 feet and encountered approximately 45 feet of potential gross gas pay in several intervals in the Eocene and Forbes formations. Production casing was run based on favorable mud log and electric log responses. One of the intervals was perforated and tested gas on a 12/64 choke at a rate of 351 MCFPD. Aspen has a 30.00% operated working interest in this well. Gas sales commenced August 1, 2008.

Aspen has agreed to participate in a new exploration program operated by a third party in the Malton area in Glenn and Tehama Counties, California. This area is east of Aspen s Malton Black Butte project. Several prospects have been identified by the Operator in this area, and drilling began in Spring, 2008. To date, the third party has drilled 4 successful gas wells. Aspen has agreed to acquire a non-operated 7% working interest in the project.

Butte Sink Gas Field

The Delta Farms #10 well was directionally drilled to a depth of 5,600 feet and encountered over 100 feet of potential gross gas pay in several intervals in the Forbes and Kione formations. Production casing was run based on favorable mud log and electric log responses. Aspen has additional potential locations based on 3-D seismic data and well control on its 1,000 acre leasehold in this field. Aspen owns a 38% operated working interest before payout and a 44.3% working interest after payout in this well. Gas sales commenced November 28, 2007.

Cache Creek Gas Field, Yolo County, California

The SJDD #11-1 well was drilled to a depth of 4,111 feet and encountered approximately 24 feet of potential gross gas pay in two intervals in the Starkey formation. One of these intervals was perforated and tested gas on a 10/64 choke at a stabilized flow rate of 750 MCFPD and 1380 psig flowing casing pressure. The shut in tubing pressure was 1440 psig and shut in casing pressure was 1500 psig. Aspen has a 30% operated working interest in this well. Gas sales commenced May 20, 2008.

In the Sacramento Valley, Aspen has drilled 49 successful gas wells out of 56 attempts during the last 5 years (88% success rate) and drilled 57 successful gas wells out of 68 attempts during the last 7 years, a success rate of 84%.

Poplar Field, Roosevelt County, Montana

In February 2007, we purchased from Nautilus Poplar, LLC, a non-operating working interest in certain oil producing assets encompassing 22,600 acres in the East Poplar Unit and the Northwest Poplar Field in Roosevelt County, Montana located in the Williston Basin. These properties contain a total of 37 producing oil wells, and 7 salt-water disposal wells. Current production is 230 gross BOPD from the Charles B reservoir.

The crude oil is 40^{o} API sweet and is readily marketed at the lease boundary. All produced water is disposed within the Unit boundary.

Through December 2007, Aspen was obligated to pay 12.5% of the expenses of operations for a 10% working interest. Since Aspen s investment did not reach payout as of January 1, 2008, Aspen s expense obligation was reduced to 10%. At payout, Aspen s working interest will proportionately be reduced also. As of June 30, 2008, there remains $1,315,211 until Aspen reaches payout, based on total revenues received through June 30, 2008 of $984,590. Commencing February 2008, Aspen (and the other working interest participants) agreed that the operator could retain 60% of the cash flow from the producing wells (after deduction of royalties, taxes, expenses and loan payment) for capital projects, geology and engineering (amounting to a total of $96,250 to Aspen s account as of June 30, 2008). The operator has used these funds for capital expenses, workovers, and recompletions.

In May 2008 Aspen amended its participation agreement in the Poplar Unit to separately market and deal with the deeper rights, oil and gas rights below the base of the Mission Canyon Formation and to grant one of the other participants the right to seek to farmout the deeper rights. To the extent that Aspen has available capital and has identified appropriate drilling or exploration opportunities, Aspen may participate in the drilling of additional wells.

We believe that the acquisition has provided us with diversification into long-lived oil reserves. There is also upside reserve potential via increased water disposal capacity, re-activation of old wells, water shut off techniques, behind-pipe potential in the Charles A, B, & C, and drilling potential in the Mission Canyon and Nisku. This acquisition also provides ownership in 3-D seismic data over 22,600 acres.

The initial cost to Aspen for its 12.5% before payout working interest (including its share of the acquisition costs) was approximately $1,450,000, which we paid using our working capital and bank dept (a total of approximately $1,075,000) and our 12.5% share ($375,000) of the $3,000,000 loan obtained by Nautilus in connection with the purchase. We also paid an additional $400,000 of anticipated capital expenditures during the first year and $275,667 during our year ended June 30, 2008.

Drilling Activity:

The following table sets forth the results of our drilling activities during the fiscal years ended June 30, 2006, 2007 and 2008:

	Drilling Activity					
	Gross Wells			Net Wells		
Year	Total	Producing	Dry	Total	Producing	Dry
2006 Exploratory	14	13	1	3.69	3.34	0.35
2007 Exploratory	11	8	3	2.93	2.15	0.78
2008 Exploratory	11	7	4	3.295	2.18	1.115

Aspen did not drill any development wells during the past three fiscal years, or subsequently.

Production Information:

Net Production, Average Sales Price and Average Production Costs (Lifting)

The table below sets forth the net quantities of oil and gas production (net of all royalties, overriding royalties and production due to others) attributable to Aspen for the fiscal years ended June 30, 2008, 2007, and 2006, and the average sales prices, average production costs and direct lifting costs per unit of production.

	Years Ended June 30,		
	2008	2007	2006
Net Production			
Oil (Bbls)	10166	3986	176
Gas (MMbtu)	582	598	696
Average Sales Prices			
Oil (per Bbl)	$ 96.65	$ 58.30	$ 81.12
Gas (per MMbtu)	$ 7.58	$ 7.00	$ 7.76

Average Production Cost[1]						
Per equivalent						
Bbl of oil	$	36.36	$	27.04	$	17.81
Average Lifting Costs[2]						
Per equivalent						
Bbl of oil	$	13.59	$	8.08	$	4.63

[1] Production costs include depreciation, depletion and amortization, lease operating expenses and all associated taxes.

[2] Direct lifting costs do not include impairment expense, ceiling write-down, or depreciation, depletion and amortization.

Productive Wells and Acreage:

Gross and Net Productive Gas Wells, Developed Acres, and Overriding Royalty Interests

Leasehold Interests - Productive Wells and Developed Acres: The tables below set forth Aspen's leasehold interests in productive and shut-in gas wells, and in developed acres, at June 30, 2008:

Producing and Shut-In Wells

	Gross Gas	Net[1] Gas
California	93	19.32824
	Gross Oil	Net[1] Oil
Montana	37	4.62500

[1] A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

Developed Acreage Table

County	Aspen's Developed Acres[1] Gross[2]	Net[3]
California:		
Colusa	6,137	1,434
Glenn	1,356	281
Kern	120	22
Solano	1,431	341
Sutter	1,663	389
Tehama	1,654	396
Yolo	280	78
TOTAL	12,641	2,941

[1] Consists of acres spaced or assignable to productive wells.

[2] A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

[3] A net acre is deemed to exist when the sum of fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Royalty Interests in Productive Wells and Developed Acreage: The following tables set forth Aspen's royalty interest in productive gas wells and developed acres at June 30, 2008:

Overriding Royalty Interests

Prospect	Interest (%)	Productive Wells Gas	Gross Acreage[1]
California:			
Malton Black Butte	5.926365	3	765
Momentum	3.671477	2	320
Grimes Gas	0.101590	1	615
TOTAL		6	1,700

[1] Consists of acres spaced or assignable to productive wells.

Undeveloped Acreage:

Leasehold Interests Undeveloped Acreage: The following table sets forth Aspen's leasehold interest in undeveloped acreage at June 30, 2008:

	Undeveloped Acreage	
	Gross	Net
California:		
Colusa	12,124	3,083
Kern	2,594	338
Solano	1,394	1,273
Sutter	173	52
TOTAL	16,285	4,746

Gas Delivery Commitments:

We have entered into a series of gas sales contracts with Enserco Energy, Inc. and Calpine Producer Services, L.P. In each of the contracts, the purchasers are required to purchase the stated quantities at stated prices, less transportation and other expenses. The contracts contain monetary penalties for non-delivery of the gas. The following table sets forth some additional information about those contracts:

Date of Contract	Purchaser	Term	Fixed Price	Quantity
July 31, 2006	Enserco	11/1/2006-3/31/2007	$10.15 per MMBTU	2,000 MMBTU per day
October 4, 2006	Enserco	12/1/2006-3/31/2007	$7.30 per MMBTU	2,000 MMBTU per day

January 30, 2007	Enserco	4/1/2007-10/31/2007	$7.65 per MMBTU	2,000 MMBTU per day
April 12, 2007	Enserco	11/1/2007-3/31/2008	$9.02 per MMBTU	2,000 MMBTU per day

February 15, 2008	Enserco	4/1/2008-10/31/2008	$8.61 per MMBTU	1,000 MMBTU per day
February 21, 2008	Enserco	4/1/2008-10/31/2008	$8.81 per MMBTU	1,000 MMBTU per day
February 26, 2008	Calpine	4/1/2008-10/31/2008	$8.80 per MMBTU	500 MMBTU per day

We expect to have sufficient gas available for delivery to Enserco and Calpine from anticipated production from our California fields. Aspen s sales of natural gas under the contracts qualify for the Normal Purchases and Normal Sales exception in paragraph 10(b) of FAS 133. The contract is a normal industry sales contract that provides for the sale of gas over a reasonable period of time in the normal course of business.

Present Activities:

We are currently the operator of 67 gas wells, have a non-operated interest in 26 additional gas wells, and have a non-operating working interest in approximately 84 oil wells in Montana, 37 of which are currently producing. During fiscal 2008, we commenced drilling on approximately 11 gas wells in the Sacramento Valley gas province of northern California.

Drilling Commitments:

We have a proposed drilling budget for the period July 2008 through June 2009. The budget includes drilling two gas wells in the Sacramento gas province of northern California. Our share of the estimated costs to complete this program is set forth in the following table:

Area	Wells	Drilling Costs	Completion & Equipping Costs	Total
West Grimes Field				
Colusa County, CA	2	$ 480,000	$ 288,000	$ 768,000
Total	2	$ 480,000	$ 288,000	$ 768,000

The proposed drilling budget only includes the wells that we have already budgeted. It can be expected that we will drill several wells in addition to the two included in our current budget. We have not identified locations for those additional drilling activities, however.

Reserve Information Oil and Gas Reserves:

Cecil Engineering, Inc. evaluated our oil and gas reserves attributable to our properties at June 30, 2008. Reserve calculations by independent petroleum engineers involve the estimation of future net recoverable reserves of oil and gas and the timing and amount of future net revenues to be received therefrom. Those estimates are based on numerous factors, many of which are variable and uncertain. Reserve estimators are required to make numerous judgments based upon professional training, experience and educational background. The extent and significance of the judgments in them are sufficient to render reserve estimates of future events, actual production determinations involve estimates inherently imprecise, since reserve revenues and operating expenses may not occur as estimated. Accordingly, it is common for the actual production and revenues later received to vary from earlier estimates. Estimates made in the first few years of production from a property are generally not as reliable as later estimates based on a longer production history. Reserve estimates based upon volumetric analysis are inherently less reliable than those based on lengthy production history. Also, potentially productive oil and gas wells may not generate revenue immediately due to lack of pipeline connections and potential development wells may have to be abandoned due to unsuccessful completion techniques. Hence, reserve estimates may vary from year to year.

Estimated Proved Reserves/Developed and Undeveloped Reserves: The following tables set forth the estimated proved developed and proved undeveloped oil and gas reserves of Aspen for the years ended June 30, 2008 and 2007. See Note 6 to the Consolidated Financial Statements and the above discussion.

Estimated Proved Reserves

Proved Reserves	Oil (Bbls)	Gas (Mcf)
Estimated quantity, June 30, 2006	1,838	2,750,716
Revisions of previous estimates	(79)	(325,865)
Discoveries	-	874,010
Acquisitions	132,072	-
Production	(3,986)	(597,660)
Estimated quantity, June 30, 2007	129,845	2,701,201
Revisions of previous estimates	71,656	(337,674)
Discoveries	-	382,828
Acquisitions	-	-
Production	(10,166)	(595,621)
Estimated quantity, June 30, 2008	191,335	2,150,734

Developed and Undeveloped Reserves

	Developed	Undeveloped	Total
Oil (Bbls)			
June 30, 2008	191,335	-	191,335
June 30, 2007	129,845	-	129,845
Gas (Mcf)			
June 30, 2008	2,150,734	-	2,150,734
June 30, 2007	2,701,201	-	2,701,201

For information concerning the standardized measure of discounted future net cash flows, estimated future net cash flows and present values of such cash flows attributable to our proved oil and gas reserves as well as other reserve information, see Note 6 to the Consolidated Financial Statements.

Oil and Gas Reserves Reported to Other Agencies: We did not file any estimates of total proved net oil or gas reserves with, or include such information in reports to, any federal authority or agency during the fiscal year ended June 30, 2008, or subsequently thereafter.

Title Examinations: Oil and Gas: As is customary in the oil and gas industry, we perform only a perfunctory title examination at the time of acquisition of undeveloped properties. Prior to the commencement of drilling, in most cases, and in any event where we are the operator, a thorough title examination is typically conducted and significant defects are usually remedied before proceeding with operations. We believe that the title to our properties is generally acceptable to a reasonably prudent operator in the oil and gas industry. As described above, we have identified certain title issues that may affect our Johnson #11, #12 and #13 wells (which are included within the Johnson Unit of the Malton Black Butte Field and the overlapping Elektra unit) and the Merrill #31-1 (which is not included in the Johnson or Electra Units). As a result of these issues, Aspen may be required to make certain economic adjustments, although any requirement to make any economic adjustments and the scope or amount of those possible adjustments have not yet been determined. At the present time, Aspen has not been able to quantify the potential liability, if any, and cannot offer any assessment as to the likelihood that any liability will be recognized or to determine whether the likelihood of an unfavorable outcome on any potential claim regarding its wells in the Johnson Unit or the Merrill #31-1 well is either probable or remote. However, Aspen believes that it has meritorious defenses to any such potential claim. The properties we own are subject to royalty, overriding royalty and other interests customary in the industry, liens incidental to operating agreements, current taxes and other burdens, minor encumbrances, easements and restrictions. We do not believe that any of these burdens materially detract from the value of the properties or will materially interfere with our business.

We have purchased producing properties on which no updated title opinion was prepared. In such cases, we have retained third party certified petroleum landmen to review title.

Office Facilities:

Our principal office is located in Denver, Colorado. We also have an office located in Bakersfield, California. The Denver office consists of approximately 1,108 square feet with an additional 750 square feet of basement storage. We entered into a lease agreement on May 1, 2008 for a period of one year, to continue thereafter on a month-to-month basis for a lease rate of $1,261 per month.

We entered into a lease agreement for our Bakersfield, California office, which consists of approximately 546 square feet. The Bakersfield, California lease payments are $901-$934 per month over the term of the lease, which expired July 31, 2008 and was extended until December 31, 2008.

ITEM 3. LEGAL PROCEEDINGS

We are not subject to any pending or, to our knowledge, threatened, legal proceedings.

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

No matters were presented to security holders for a vote during the year ended June 30, 2008, or any subsequent period.

PART II

ITEM 5. MARKET FOR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS AND SMALL BUSINESS ISSUER PURCHASES OF EQUITY SECURITIES

Market Information:

Our common stock is quoted on the Over-the-Counter Bulletin Board (OTCBB) under the symbol "ASPN". The OTCBB rules provide that companies not current in their reporting requirements under the Securities Exchange Act of 1934 will be removed from the quotation service. At present and at June 30, 2008 and June 30, 2007, we believe that we were in full compliance with these rules.

The table below sets forth the high and low closing prices of the Company s Common Stock during the periods indicated as reported by the Internet source Yahoo Finance (http://finance.yahoo.com). The quotations reflect inter-dealer prices without retail mark-up, mark-down or commission and may not reflect actual transactions. The market data and dividends for 2008 and 2007 are shown below:

	2008			2007		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$ 3.80	$ 2.10	$-	$ 5.45	$ 3.50	$ -
Second Quarter	3.32	2.08	-	4.09	2.85	0.05
Third Quarter	2.50	1.86	-	3.00	2.23	-
Fourth Quarter	3.00	1.82	-	3.95	2.41	-
Total Dividend Paid			$-			$ 0.05

Holders:

As of June 30, 2008, there were approximately 1,020 holders of record of our Common Stock. This does not include an indeterminate number of persons who hold our Common Stock in brokerage accounts and otherwise in street name.

Dividends:

Holders of common stock are entitled to receive such dividends as may be declared by Aspen s Board of Directors. On November 8, 2006, the Company declared a cash dividend in the amount of $0.05 per share. A total of $357,981 was paid to the shareholders on December 6, 2006, as determined by shareholders of record as of November 20, 2006. No dividends were declared or paid during the 2008 fiscal year. Decisions concerning dividend payments in the future will depend on income and cash requirements. There are no contractual restrictions on our ability to pay dividends to our shareholders.

Securities Authorized for Issuance Under Equity Compensation Plans:

The following is provided with respect to compensation plans (including individual compensation arrangements) under which equity securities are authorized for issuance as of the fiscal year ending June 30, 2008.

Equity Compensation Plan Information[1]

Plan Category and Description	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants, and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity Compensation Plans Approved by Security Holders	-	$ -	-
Equity Compensation Plans Not Approved by Security Holders	887,098	2.17	342,902
Total	887,098	$ 2.17	342,902

[1] This does not include options held by management and directors that were not granted as pursuant to a compensation plan or compensation arrangement. In each case, the disclosure refers to options or warrants unless otherwise specifically stated.

Recent Sales of Unregistered Securities Item 701 Disclosure:

There were no sales of unregistered securities during the fiscal year ended June 30, 2008 or subsequently that were not previously disclosed in a quarterly report on Form 10-QSB or a current report on Form 8-K.

ITEM 6. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION OR PLAN OF OPERATION

The management discussion and analysis and other portions of this report contain forward-looking statements (as such term is defined in Section 21E of the Securities Exchange Act of 1934, as amended). These statements reflect our current expectations regarding our possible future results of operations, performance, and achievements. These forward-looking statements are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995.

Wherever possible, we have tried to identify these forward-looking statements by using words such as anticipate, believe, estimate, expect, plan, intend, and similar expressions. These statements reflect our current beliefs and are based on information currently available to us. Accordingly, these statements are subject to certain risks, uncertainties, and contingencies, which could cause our actual results, performance, or achievements to differ materially from those expressed in, or implied by, such statements.

Overview:

Aspen Exploration Corporation was organized in 1980 for the purpose of acquiring, exploring and developing oil and gas properties. Since 1996, we have focused our efforts on the exploration, development and operation of natural gas properties in the Sacramento Valley of northern California, and in 2007 we acquired interests in oil properties in Montana. Our business activities are primarily focused in two separate aspects of the oil and gas industry:

(1) holding and acquiring operating interests in oil and gas properties where we act as the operator of oil and gas wells and properties; and

(2) holding non-operating interests in oil and gas properties.

We are currently the operator of 67 gas wells in the Sacramento Valley of northern California. Additionally, we have a non-operated interest in 26 gas wells in the Sacramento Valley of northern California and non-operating working interest in approximately 37 oil wells in Montana When appropriate we may engage in business activities related to the exploration and development of other minerals and resources.

Where possible, we attempt to be the operator of each property in which we invest. We believe that our knowledge of drilling and operating wells in the Sacramento Valley allows us to maximize the potential return of each property. In addition, the other working interest owners are obligated to pay us fees pursuant to the overhead reimbursement provisions of the COPAS Accounting Procedures which are included as an attachment to the operating agreements. These accounting procedures define the overhead expenses that are charged to the joint accounts and permit us to charge some expenses (such as salaries, wages and Personal Expenses of Technical Employees directly employed on the Joint Property and drilling expenses) directly to the joint interest owners. In almost all cases, Aspen also charges a general monthly producing overhead rate per well. We do not recognize these fees received from the joint interest owners as revenues; rather they are offset against (and are a deduction from) our general and administrative expenses as reflected in our statement of operations. During the fiscal year ended June 30, 2008, these administrative charges to the properties help cover approximately 49% of our selling, general and administrative expenses.

On September 4, 2008, subsequent to our fiscal year end, we announced that we have decided to investigate strategic alternatives, including the possibility of selling Aspen s assets or considering another appropriate merger or acquisition transaction. We have opened a data room where interested persons may review certain information about our properties. As of the date of this Annual Report we have not received any offer from any person for an asset acquisition, merger, or other business combination. We cannot offer any assurance that we will receive an acceptable offer from any person for an asset acquisition, merger, or other business combination. Further, we may later determine that it is in the best interest of its shareholders to investigate other forms of business alternatives or to continue and expand existing business operations with existing or new management. In the meantime, Aspen is carrying on its business operations in the normal course.

Critical Accounting Policies and Estimates:

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

<u>Reserve Estimates</u>:

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

Many factors will affect actual future net cash flows, including:

- the amount and timing of actual production;
- supply and demand for oil and natural gas;
- curtailments or increases in consumption by purchasers; and
- changes in governmental regulations or taxation.

Gas Delivery Commitments:

We have entered into contracts for the sale and purchase of natural gas with Enserco Energy Inc., and Calpine Producer Services, L.P. The original, master contract with Enserco is dated November 1, 2005. The master contract with Calpine is dated June 1, 2007 Aspen has continuously renewed these contracts with Enserco and Calpine since then. Aspen s sales of natural gas under the Enserco and Calpine contracts qualify for the Normal Purchases and Normal Sales exception in paragraph 10(b) of FAS 133. The contracts are normal industry sales contracts that provides for the sale of gas over a reasonable period of time in the normal course of business. The contracts contain net settlement provisions should Aspen fail to deliver natural gas when required. Those provisions are mutual and establish the sole and exclusive remedy of the parties in the event of a breach of a firm obligation to deliver or receive natural gas as agreed.

Property, Equipment and Depreciation:

We follow the full-cost method of accounting for oil and gas properties. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, including salaries, benefits and other internal salary related costs directly attributable to these activities. All capitalized costs are depleted on a composite units-of-production method based on estimated proved reserves attributable to the oil and gas properties owned by Aspen. Costs associated with production and general corporate activities are expensed in the period incurred. When the Company acts as operator of our producing wells, we receive management fees for these services, which serve to offset our selling, general, and administrative expenses. Interest costs related to unproved properties and properties under development are also capitalized to oil and gas properties. If the net investment in oil and gas properties exceeds an amount equal to the sum of:

(1) the standardized measure of discounted future net cash flows from proved reserves, and

(2) the lower of cost or fair market value of properties in process of development and unexplored acreage

The excess is charged to expense as additional depletion. Normal dispositions of oil and gas properties are accounted for as adjustments of capitalized costs, with no gain or loss recognized.

We apply Statement of Financial Accounting Standard (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. Under SFAS No. 144, long-lived assets and certain intangibles are reported at the lower of the carrying amount or their estimated recoverable amounts. Long-lived assets subject to the requirements of SFAS No. 144 are evaluated for possible impairment through review of undiscounted expected future cash flows. If the sum of undiscounted expected future cash flows is less than the carrying amount of the asset or if changes in facts and circumstances indicate, an impairment loss is recognized.

Asset Retirement Obligations:

We recognize the future cost to plug and abandon gas wells over the estimated useful life of the wells in accordance with the provision of SFAS No. 143, Asset Retirement Obligations . SFAS No. 143 requires that we record a liability for the present value of the asset retirement obligation with a corresponding increase to the carrying value of the related long-lived asset. The increase in the asset will be amortized over time and recognize accretion expense in connection with the discounted liability over the remaining life of the respective well. Any asset retirement costs capitalized pursuant to Statement 143 are subject to the full cost ceiling limitation under Rule 4-10(c)(4) of Regulation S-X. Our liability estimate is based on our historical experience in plugging and abandoning gas wells, estimated well lives based on engineering studies, external estimates as to the cost to plug and abandon wells in the future and federal and state regulatory requirements. Revisions to the liability could occur due to changes in well lives, or if federal and state regulators enact new requirements on the plugging and abandonment of gas wells.

Income Taxes

The Company computes income taxes in accordance with SFAS No. 109, Accounting for Income Taxes . SFAS No. 109 requires an assets and liability approach which results in the recognition of deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the Company s financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Additionally, the Company s federal and state income tax returns are generally not filed before the financial statements are prepared; therefore the Company estimates the tax basis of its asset and liabilities at the end of each calendar year as well as the effects of tax rate changes, tax credits, and tax credit carryforwards. A valuation allowance is recognized if it is determined that deferred tax assets may not be fully utilized in future periods. Adjustments related to differences between the estimates used and actual amounts reported are recorded in the period in which income tax returns are filed. These adjustments and changes in estimates of asset recovery could have an impact on results of operations. Due to uncertainties involved with tax matters, the future effective tax rate may vary significantly from the estimated current year effective tax rate.

Equity-Based Compensation

We adopted SFAS No. 123(R) beginning July 1, 2006. Prior to July 1, 2006, the Company accounted for these plans under the recognition and measurement provisions of Accounting Principles Board ("APB") Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, as permitted by Statement of Financial Accounting Standards("SFAS") No. 123, Accounting for Stock-Based Compensation. No stock-based employee compensation expense was recognized in the Company's Consolidated Statement of Operations prior to July 1, 2006, as all options granted under the Company's stock-based compensation plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective July 1, 2006, the Company adopted the fair value recognition provisions of SFAS No. 123 (R), Share Based Payment, using the modified-prospective transition method as described in SFAS No. 148, Accounting for Stock-Based Compensation - Transition and Disclosure. Under this method, compensation cost recognized in the fiscal years ended June 30, 2008 and 2007 is the same as that which would have been recognized had the recognition provisions of Statement 123(R) been applied from its original effective date.

Investments in Debt and Equity Securities

Prior to the beginning of the current fiscal year, the Company classified all investments as Trading Securities in accordance with SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities*. These securities were marked to market each period with the realized and unrealized gain or loss recorded in the statement of operations. During the first quarter of fiscal year 2008, management reassessed the appropriateness of the classification of the securities held, and determined that due to the sufficiency of cash flows to finance current operations and budgeted expenditures, the Company will hold investments until such time it determines there may be a need to sell those securities. As of July 1, 2007, Management determined the securities are more appropriately classified as available for sale, and changes in the fair value of the securities are reported as a separate component of shareholders equity until realized. The securities were transferred from the trading category, and as such, the unrealized holding gain or loss at the date of the transfer has already been recognized in earnings and shall not be reversed. Aspen uses the specific identification method to determine the cost of securities sold.

Although our production of natural gas remained approximately constant between fiscal 2007 (597,660 Mcf) and fiscal 2008 (595,621 Mcf), we believe that our natural gas production is likely to increase during the 2009 fiscal year due to recent drilling successes. However, our projections are subject to many factors and may not ultimately prove to be accurate. Total production for the year will depend on the number of wells successfully completed, the date they are put on line, their initial rate of production, and their production decline rates. During the last fiscal year,

gas sales decreased approximately 8% from 631,557 MMbtu to 581,787 MMbtu;

oil sales increased to 10,166 barrels due to full year results of the acquisition of operating interests in the Poplar fields in Montana; and

reserves have decreased approximately 5% to 3,298,744 net equivalent Mcf (MCFEQ) from 3,480,271 MCFEQ. Natural gas reserves reduced by approximately 20% from 2,701,201 Mcf (at June 30, 2007) to 2,150,734 Mcf (at June 30, 2008). The significant reduction of natural gas reserves resulted primarily from discoveries during our 2008 fiscal year (382,828 Mcf) being less than one-half of the discoveries achieved during our 2007 fiscal year (874,010 Mcf). If we are not successful in replacing our production with discoveries, our reserves will continue to decrease.

During the last fiscal year, the average price received for our gas production increased approximately 8% from $7.00 per MMbtu to $7.58 per MMbtu. The average price received for oil increased almost 66% from $58.30 per barrel to $96.65 per barrel. Costs of production and accretion, depletion, depreciation, and amortization, increased 37%.

Over the past five years we have been able to replace the majority of our produced reserves and maintain our yearly natural gas production through the drilling of new wells and the acquisition of producing properties which have offset the oil and gas we produce although (as noted above) we were not able to do so during our 2008 fiscal year due to significantly less discoveries than our natural gas discoveries during 2007. These 2008 additions resulted primarily from 7 newly drilled gas wells and the reactivation and improvement efforts on properties in which Aspen holds oil interests in Montana. Our oil reserves increased significantly during 2008 because of successful recompilations resulting in revisions of prior estimates, not as a result of any new discoveries. Overall, Aspen s interest in net producing reserves of new wells replaced 64.3% of calculated total net gas sales in 2008. Management uses the measurement of our produced reserves to help measure the success of our exploration and development activity. Where reserves are replaced in an amount greater than production, it is a sign that we are continuing our exploration and development activity successfully. A one-year decline (as occurred during our fiscal 2008) or increase may not be important to investors, but seeing a decline or increase over a several year period is a trend worthy of noting, both internally by management and externally by investors.

At June 30, 2008, our standardized measure of discounted future net cash flows from our oil and gas operations was determined to be $10,269,000 as compared to $8,034,000 as at June 30, 2007. Our standardized measure increased during 2008 notwithstanding the reduction of our reserves of oil (Bbl) and natural gas (Mcf) primarily because of the increased prices that we are receiving for our production, offset in part by an increase in operating costs.

Quantitative and Qualitative Disclosure About Risk:

Our ability to replace reserves, dissipated through production or recalculation, will depend largely on how successful our drilling and acquisition efforts will be in the future. While we cannot predict the future, and past results are not necessarily indicative of future success, our historic success drilling ratio over the past seven years has been 84%. With the use of 3-D seismic and well control data, interpreted by our geological and geophysical consultants, we feel we can manage our dry hole risk adequately.

The prices that we receive for the oil and natural gas (including natural gas liquids) produced are impacted by many factors that are outside of our control. Historically, and as seen during calendar 2008, these commodity prices have been volatile and we expect them to remain volatile. Prices for oil and natural gas are affected by changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, the world political situation, basis differentials and other factors. As a result, we cannot accurately predict future oil, natural gas and NGL (natural gas liquids) prices, and therefore, we cannot determine what effect increases or decreases in production volumes will have on future revenues.

On regulatory and operational matters, we actively manage our exploration and production activities. We value sound stewardship and strong relationships with all stakeholders in conducting our business. We attempt to stay abreast of emerging issues to effectively anticipate and manage potential impacts to our operations.

The average price we received during fiscal 2008 for our natural gas was approximately $7.58 per MMBTU as compared to $6.63 per MMBTU during fiscal 2007. In order to reduce the risk of natural gas price fluctuations, we have entered into a series of gas sales contracts with Enserco and Calpine as described above in Item 2 Properties Gas Delivery Commitments, set forth above.

Liquidity and Capital Resources:

We have historically financed our operations with internally generated funds, limited borrowings from banks and third parties, and farmout arrangements, which permit third parties (including some related parties) to participate in our drilling prospects. During the year ended June 30, 2007, we borrowed $600,000 to purchase an interest in the Poplar Field and became obligated for an additional $375,000 indebtedness as part of that purchase. During our 2008 fiscal year, we have also received approximately $20,000 from the sale of investment securities that we owned, as compared to $600,000 in fiscal 2007.

Our principal uses of cash are for operating expenses, the acquisition, drilling, completion and production of prospects, the acquisition of producing properties, working capital, servicing debt and the payment of income taxes.

During the 2008 fiscal year, we used approximately $2.5 million of cash in our operations, investing activities and financing activities, similar to those activities using $2.4 million during the same period of our 2007 fiscal year.

Our operating activities generated net cash of approximately $1.8 million from operations for the year ended June 30, 2008, as compared to approximately $2.5 million in cash generated from operating activities for the year ended June 30, 2007. This negative change of approximately $788,000 was due to a number of factors, including a reduction of our net income of approximately $122,000 (as discussed below in results of operations), and a use of cash to retire current liabilities (which were about $5.3 million at June 30, 2007 as compared to $3.5 million at June 30, 2008). Our current liabilities decreased by about $1.8 million during the 2008 period as compared to a decrease in current liabilities of approximately $1.4 million during the 2007 period.

Our investing activities used cash to increase capitalized oil and gas costs of $3.9 million during the 2008 fiscal year as compared to $5.5 million in 2007. Investing activities during 2008 were for lease acquisition, seismic work, intangible drilling and well workovers and equipment. These expenditures are net of the sale of interests in wells to be drilled that will be charged to third party investors. In addition, we invested $280,000 in municipal bonds in the current period.

Financing activities in the current year were solely to retire $275,000 of the $867,000 in long-term debt balance at June 30, 2007. The company did not declare or pay dividends in the current year; however, approximately $358,000 was paid in 2007.

Our working capital surplus (current assets less current liabilities) at June 30, 2008, was $1.3 million, which reflects a $722,000 decrease from our working capital at June 30, 2007. As detailed above, this decrease was due primarily to our negative cash flow of approximately $2.5 million for investing and operating activities.

<u>Future Commitments</u>:

We have a proposed drilling, completion and construction budget for the period July 2008 through June 2009. The budget includes drilling 2 gas wells in the Sacramento gas province of northern California. Our share of the estimated costs to complete this program is set forth in the following table.

Area	Wells	Drilling Costs	Completion & Equipping Costs	Total
West Grimes Gas Field				
Colusa County, CA	2	$ 480,000	$ 288,000	$ 768,000
Total Expenditure	2	$ 480,000	$ 288,000	$ 768,000

We anticipate that our working capital and anticipated cash flow from operations and future successful drilling activities will be sufficient to finance our planned drilling and operating expenses and to pay our other obligations. As discussed herein, this is dependent, in part, on maintaining or increasing our level of production and the national and world market maintaining its current prices for our oil and gas production. Furthermore, we expect to drill more than the two wells that are currently budgeted, but to date we have not identified any drilling locations or timing for these anticipated additional wells.

If our drilling efforts are successful, the anticipated increased cash flow from the new gas discoveries, in addition to our existing cash flow, should be sufficient to fund our share of planned future completion and pipeline costs.

Results of Operations:

June 30, 2008 Compared to June 30, 2007:

The following table sets forth certain items from our Consolidated Statements of Operations as expressed as a percentage of total revenues, shown by year for fiscal 2008 and 2007:

	For the Year Ended June 30, 2008	June 30, 2007
Total Revenues	100.0%	100.0%
Oil and Gas Production Costs	27%	18.9%
Gross Profit	73%	81.1%
Cost and Expenses		
Depreciation and depletion	45%	45.7%
Selling, general and administrative	12%	19.3%
Total Cost and Expenses	84%	83.9%
Income from Operations	16%	16.1%
Other Income and Expenses	1%	18.8%
Income Before Income Taxes	17%	34.9%
Provision for Income Taxes	-2%	-13.9%
Net Income	15%	21.0%

To facilitate discussion of our operating results for the years ended June 30, 2008 and 2007, we have included the following selected data from our Consolidated Statements of Operations:

	Comparison of the Fiscal Year Ended June 30, 2008	2007	Increase (Decrease) Amount	Percentage
Revenues:				
Oil and gas sales	$ 5,390,367	$ 4,418,231	$ 972,136	22%
Cost and Expenses:				
Oil and gas production	1,463,415	837,155	626,260	75%
Depreciation and depletion	2,451,417	2,018,550	432,865	21%
Selling, general and administrative	621,463	850,847	(229,384)	-27%
Total Costs and Expenses	4,536,295	3,706,552	829,741	22%
Operating Income	854,074	711,679	142,395	20%
Other Income (Expenses)	58,510	829,580	(771,072)	-93%
Income Tax Benefit (Provision)	(109,779)	(615,990)	506,211	-82%
Net Income (Loss)	$ 802,803	$ 925,269	$ (122,466)	-13%

In general, our operations during fiscal 2008 were adversely affected by significantly increasing costs of production and accretion, depletion, depreciation, and amortization, as well as additional administrative, consulting, legal, and accounting costs incurred as a result of Mr. Cohan s stroke and disability to perform his duties as previously noted. Our income tax provision was significantly lower in the current year due to the carryback of a portion of our Net Operating Losses to prior years. As previously noted, oil and gas prices are subject to national and international pressures, and Aspen has no control over those prices.

For the fiscal year ended June 30, 2008, our operations continued to be focused on the production of oil and gas in California and Montana. Our gas production decreased from 598,000 Mcf during the year ended June 30, 2007, to 596,000 Mcf during the fiscal year ended June 30, 2008 (a decrease of less than 1%). Oil production increased approximately 155% due to recompletion and improvement efforts in the recovery of oil in our Montana properties, and including the oil production from our Montana properties in our financial information for a full year as compared to only six months during our 2007 fiscal year. As a result of the overall increase in production and increased prices during the 2008 fiscal year (14% increase per MMbtu and 57.6% increase per barrel of oil as compared to 2007), our revenues from oil and gas sales increased during 2008 by approximately $972,000 from approximately $4.4 million (2007) to approximately $5.4 million (2008).

For the fiscal year ended June 30, 2008 oil and gas production costs increased approximately 75%, as compared to 2007, from approximately $837,000 to almost $1.5 million. The increase can be attributed to the addition of 7 gross operated gas wells, from 60 wells to 67 wells and our percentage working interests in these wells were somewhat higher than the average of wells owned at June 30, 2007. The increase was also due to the recompletion of oil wells in Montana. Equipment rental and water disposal fees increased due to the addition of compressors and increased water production in our more mature wells. Additionally, all of the costs for the service companies who perform work on Aspen's wells increased dramatically during the past twelve months. Aspen is attempting to address these costs, but these costs are driven by market conditions and Aspen s ability to control these costs is minimal. Generally the costs increase as prices received for oil and natural gas increase, but costs may increase more quickly than the prices received.

Depletion, depreciation and amortization expense increased 21%, from approximately $2 million for the year ended June 30, 2007 as compared to more than $2.4 million during 2008. DD&A expense per net equivalent Mcf produced increased from $3.25 to $3.75. This increase can be attributed to the continued level of investment in oil and gas-producing properties, without an immediate corresponding increase in proved reserves.

When the Company acts as operator for our producing wells, we receive management fees for these services, which serve to offset our SG&A expenses. When comparing SG&A for 2008 and 2007, costs decreased by $135,000, or 10%, due primarily to decreases in accounting and audit fees and promotional, while management fees increased approximately $94,000, or 18%. As a result, management fees as a percentage of SG&A increased 31% for the period ending June 30, 2008 compared to 2007.

	2008 Fiscal Year	2007 Fiscal Year
Management fees	607,269	512,923
Selling, general and administrative (SG&A)	1,228,732	1,363,770
Management fees as a percentage of SG&A	49.4%	37.6%

Central to the issue of success of the twelve months operations ended June 30, 2008 is the discussion of changes in oil and gas sales, volumes of natural gas sold and the price received for those sales. We present them here in tabular form:

	Gas Sales	MMBTU Sold	Price/ MMBTU	Oil & NGL Sales	Bbls Sold	Price/ Bbl
June 30, 2008	$4,407,873	581,787	$ 7.58	$ 982,494	10,166	$ 96.65
June 30, 2007	$4,185,828	631,557	$ 7.00	$ 232,403	3,986	$ 58.30
12 Month Change						
2008 vs 2007						
Amount	$ 222,045	(49,770)	$ 0.6	$ 750,091	6,180	$ 38
Percentage	5.3%	-7.9%	8.2%	322.8%	155.0%	65.8%

Oil and gas revenue and volumes sold of our product showed a general increase during fiscal 2008. As the table above notes, gas revenue increased approximately 5% when comparing the year ended June 30, 2008 and 2007, while oil revenue increased 323% due to the full year results of sales from the Poplar Field, acquired in the third quarter of our 2007 fiscal year. Gas volumes sold decreased approximately 8%, while the price received for our product increased 8%. Oil and NGL volume increased 155%, due to the property acquisition, while the price per barrel increased 66%.

Results of operations and net income (loss) before income taxes are presented in the following table:

Quarterly Financial Information (unaudited)

	Total Revenues	Operating Income [1]	Income (Loss) Before Income Taxes	Income (Loss) Before Income Taxes Per Share Basic	Income (Loss) Before Income Taxes Per Share Diluted
2008					
lst Quarter	$ 1,220,822	$ 128,676	$ 185,377	$ 0.026	$ 0.025
2nd Quarter	1,364,775	190,018	192,876	0.027	0.026
3rd Quarter	1,325,261	271,526	271,853	0.037	0.037
4th Quarter	1,479,509	263,852	262,476	0.036	0.036
Total	5,390,367	854,072	912,582	0.126	0.124
2007					
lst Quarter	$ 962,933	$ (105,987)	$ 185,219	$ 0.026	$ 0.025
2nd Quarter	1,053,839	264,970	507,576	0.071	0.069
3rd Quarter	1,344,790	437,471	629,345	0.088	0.086

4th Quarter		1,056,669		165,225		219,119		0.030		0.029
Total	$	4,418,231	$	761,679	$	1,541,259	$	0.215	$	0.209

1 Operating income is oil and gas sales less oil and gas production costs, depreciation, depletion and amortization, and selling, general and administrative expenses.

Income before taxes decreased from approximately $1.5 million for the year ended June 30, 2007 to $912,000 in 2008 primarily due to a 22% increase in operating expenses, and the reclassification of trading securities to available for sale. As of July 1, 2007, the unrealized gains or losses on securities are no longer included in our results of operations.

Our future success in the oil and gas industry will depend on the cost of finding oil or gas reserves to replace our production, the volume of our production and the prices we receive for sale of our production. These factors are subject to all of the risks associated with operations in the oil and gas industry, many of which are beyond our control.

Risk Factors

Investing in shares of our common stock is highly speculative and involves a high degree of risk. In addition to the other information included in this report, you should carefully consider the risks described below before purchasing shares of our common stock. If any of the following risks actually occur, our business, financial condition and results of operations could materially suffer. As a result, the trading price of our common stock could decline, and you might lose all or part of your investment. These factors include, but are not limited to:

Oil and gas production operations are inherently risky and our ability to succeed in that business depends on a number of factors. Our revenues, profitability and future growth and reserve calculations depend substantially on three different but inter-related factors:

- The prices available for the sale of our oil and natural gas production;
- Our ability to transport our produced oil or natural gas to the market; and
- Our ability to increase our oil and gas reserves at a faster rate than our production.

These factors are interrelated and are dependent in part on world markets for oil and natural gas and other energy fuels. When prices increase for oil or natural gas because of world economic or political factors, our access to drilling rigs and other necessary supplies become more difficult and expensive because of competition from other producers. These are described in more detail in the next several risk factors.

Oil and gas prices are volatile, and a decline in oil and natural gas prices is likely to have a material adverse impact on our business. As is evidenced by the average prices received for our oil and natural gas production over the last two fiscal years, the prices that the market offers for our oil and natural gas production are volatile and are dependent in large part on factors beyond our control, including those described below. Higher prices result in higher revenues for the same level of production; conversely, lower prices result in lower revenues. Price volatility impacts our cash flow and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and gas that we can produce economically. Among the factors that can cause price fluctuations are:

- domestic and foreign supply of and prices for oil and natural gas;
- price and availability of alternative fuels;
- weather conditions;
- level of consumer demand, including seasonal fluctuations;
- world-wide economic conditions;
- political conditions in oil and gas producing regions;
- domestic and foreign governmental regulations;
- technological advances affecting oil and gas consumption;
- price speculation and the issuance and trading of future contracts on oil and natural gas;
- availability and capacity of refineries;
- availability of gathering systems with sufficient capacity to handle local production; and
- interstate pipeline capacity.

Market conditions or operational impediments may hinder our access to crude oil and natural gas markets or delay our production. Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities and refineries owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut-in wells for a lack of a market or because of inadequate or a lack of natural gas pipelines, gathering system capacity, processing facilities or refineries. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market.

Our business model depends on our ability to find, develop and acquire oil and gas reserves. To maintain or increase production levels, we must locate and develop or acquire new oil and gas reserves to replace those depleted by production. Without successful exploration, exploitation or acquisition activities, our reserves, production and revenues will decline. There are a number of factors associated with our ability or inability to replace and increase our oil and natural gas reserves which may adversely impact our operations:

- Lower prices for oil or natural gas will reduce the volume of reserves since as a result of lower prices certain of our reserves may no longer be economically producible;
- We may not be able to locate and acquire on reasonable terms acceptable exploration or development acreage;
- Our drilling operations may not find oil or natural gas in sufficient quantities to be economically extracted, or may result in a dry hole;
- We may not have adequate capital resources to explore or develop the acreage we own or may acquire;
- Weather conditions and natural disasters may impact our ability to engage in exploration or development operations;
- Compliance with governmental regulations may adversely impact the economics of our exploration and development activities;
- Unanticipated geological formations may create mechanical difficulties, adversely affecting our ability to produce oil or natural gas from various formations in which oil or natural gas may be found;
- Higher prices for oil and natural gas increase national and international demand for drilling equipment and supplies, thereby reducing the availability of equipment for our operations, or increasing the cost of that equipment to us; and
- Any failure of the drilling equipment may result in significant costs and delays in our drilling operations.

We may be required to write-down the carrying value of our oil and gas properties when oil or gas prices are low, or there are substantial downward adjustments to our estimated proved reserves, increases in estimates of development costs or deterioration in exploration or production results. We capitalize costs to acquire, find and develop our oil and gas properties under the full cost accounting method. If net capitalized costs of our oil and gas properties exceed fair value, we must charge the amount of the excess to earnings. We review the carrying value of our properties on a quarterly basis, and at any other time when events or circumstances indicate a review is necessary, based on prices in effect as of the end of the reporting period. Once incurred, a write-down of oil and gas properties is not reversible at a later date even if oil or gas prices increase.

Actual quantities of recoverable of oil and gas reserves may be lower than our estimates. Estimating reserves of oil and gas is complex. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, some of which are mandated by the SEC. The accuracy of a reserve estimate is a function of quality and quantity of available data, interpretation of that data, and accuracy of various mandated economic assumptions.

Any significant variance could materially affect the quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of development and exploration and prevailing oil and gas prices.

In accordance with requirements of the Securities and Exchange Commission, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

We have limited control over the activities on properties that we do not operate. Although we operate many of the properties in which we have an interest, other companies operate some of the properties, including all of the wells in Montana where we hold working interests. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

We may incur losses as a result of title deficiencies. We purchase working and revenue interests in the oil and natural gas leasehold interests upon which we will perform our exploration activities from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. Title insurance covering mineral leaseholds is not generally available and often we forego the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled. As is customary in our industry, we rely upon the judgment of oil and natural gas lease brokers or independent landmen who perform field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest. Where, despite our efforts, title deficiencies exist as described above for Johnson #11, #12, and #13 wells in the Johnson Unit of the Malton Black Butte Field or the Merrill #31-1 well, we risk loss of some or all of our interest in the affected properties or possible economic adjustment where we may have overpaid or underpaid one or more economic interest owners.

We sell a significant amount of our production to two customers. We generally sell our oil and gas production to a limited number of companies. In fiscal 2008 and 2007 (as in prior years) we obtained a majority of our revenues from sales to Calpine Corporation and Enserco Energy, Inc., (33% and 61%, respectively). Because we believe that oil and gas sales are primarily market driven and are not dependent on particular purchasers we do not believe the loss of these customers would adversely impact our revenues. However, we cannot guarantee that the loss of either of these major customers would not negatively impact our business operations and revenues.

Hedging transactions may limit our potential gains. We have entered into certain price hedging arrangements with respect to a significant portion of our expected production. Such transactions may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement, or the counterparties to our hedging agreements fail to perform under the contracts.

The oil and gas business involves many operating risks that can cause substantial losses; insurance may not protect us against all of these risks. Among the risks faced by all operators in the oil and gas industry are the risks of fires, explosions, blow-outs, uncontrollable flows of oil, gas, formation water or drilling fluids, natural disasters; pipe or cement failures, casing collapses, embedded oilfield drilling and service tools, abnormally pressured formations, major equipment failures, including cogeneration facilities, and environmental hazards such as oil spills, natural gas leaks, pipeline ruptures and discharges of toxic gases. If any of these events occur, we could incur substantial losses as a result of injury or loss of life, severe damage or destruction of property, natural resources and equipment, pollution and other environmental damage, investigatory and clean-up responsibilities, regulatory investigation and penalties, suspension of operations, and repairs to resume operations.

If we experience any of these problems, our ability to conduct operations could be adversely affected. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect us. In accordance with customary industry practices, we maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. We do not carry business interruption insurance. We may elect not to carry insurance if our management believes that the cost of available insurance is excessive relative to the risks presented. In addition, we cannot insure fully against pollution and environmental risks. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition and results of operations. While we intend to obtain and maintain appropriate insurance coverage for these risks, there can be no assurance that our operations will not expose us to liabilities exceeding such insurance coverage or to liabilities not covered by insurance.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business. Our development, exploration, production and marketing operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations oppose certain drilling projects and/or access to prospective lands.

Our actual results may differ materially from our estimates and projections. In planning drilling programs, we either estimate costs and the likelihood of success, or we review estimates prepared by others. Furthermore, the preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and related disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from these estimates and assumptions used in preparation of its financial statements. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities, the related present value of estimated future net cash flows therefrom, and the costs to develop and abandon oil and gas properties.

Competitive industry conditions may negatively affect our ability to conduct profitable operations. Competition in the oil and gas industry is intense, particularly with respect to the acquisition of producing properties and proved undeveloped acreage. Major and independent oil and gas companies actively bid for desirable oil and gas properties, as well as for the equipment and labor required to operate and develop their properties. Many of our competitors have financial resources that are substantially greater, which may adversely affect our ability to compete within the industry.

We have recently announced that management has decided to investigate strategic alternatives, including the possibility of selling Aspen s assets or considering another appropriate merger or acquisition transaction.

The loss of key personnel could adversely affect our business. We depend to a large extent on the efforts and continued employment of our executive Management team and other key personnel. The loss of the services of these or other key personnel could adversely affect our business. We do maintain key man insurance on Robert A. Cohan, President and former CEO, in the amount of $1,000,000. In January 2008, Mr. Cohan suffered a stroke and was unable to continue to perform his duties as chief executive officer and chief financial officer of Aspen. As a result, these duties were assumed by Messrs. R.V. Bailey and Kevan Hensman. Mr. Cohan retained the title of president, and has been working with Messrs. Bailey and Hensman and Aspen s other employees and consultants as able to ensure that Aspen s oil and gas operations continue. Although Mr. Cohan has provided substantial continuing assistance to Aspen, he has been unable to resume his duties as chief executive officer and chief financial officer. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen and other professionals. Competition for many of these professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

Our common stock has and may continue to experience price volatility. Our common stock is traded on the OTC Bulletin Board. Since July 1, 2006, our stock has traded as high as $5.45 per share, and as low as $1.66 per share. During that period, our trading volume has ranged from as low as 100 shares per day to 118,300 shares per day. Until a larger secondary market for our common stock develops, the price of and trading volume for our common stock will likely continue to fluctuate substantially. The price of and trading volume for our common stock is impacted not only by our performance and announcements, but also by general market conditions and other factors that are beyond our control or influence and which may be unrelated to our performance.

Our common stock is subject to the penny stock rules which limits the market for our common stock. Because our stock is quoted on the NASD-OTC Bulletin Board, if the market price of the common stock is less than

$5.00 per share, the common stock is classified as a penny stock. SEC Rule 15g-9 under the Exchange Act imposes additional sales practice requirements on broker-dealers that recommend the purchase or sale of penny stocks to persons other than those who qualify as an established customer or an accredited investor. This includes the requirement that a broker-dealer must make a determination that investments in penny stocks are suitable for the customer and must make special disclosures to the customers concerning the risk of penny stocks. Many broker-dealers decline to participate in penny stock transactions because of the extra requirements imposed on penny stock transactions. Application of the penny stock rules to our common stock reduces the market liquidity of our shares, which in turn affects the ability of holders of our common stock to resell the shares they purchase, and they may not be able to resell at prices at or above the prices they paid.

Our Board of Directors has no independent directors and we have not instituted corporate governance policies or procedures. Our Board of Directors has no director who may be considered independent. Further, we do not have an audit committee, a nominating committee, or any other corporate governance committee. Thus, our shareholders do not have the benefits or protections associated with corporate governance controls and other corporate oversight mechanisms overseen by independent directors.

We have made, and will need to continue to make substantial financial and man-power investments in order to assess our internal controls over financial reporting and our internal controls over financial reporting may be found to be deficient. Section 404 of the Sarbanes-Oxley Act of 2002 requires management to assess our internal controls over financial reporting and requires auditors to attest to that assessment. We have expanded our use of outside consultants to prepare for the Section 404 requirements. If our independent auditors are unable to provide an unqualified attestation report on such assessment when such report is required, we may be required to change our internal control over financial reporting to remediate deficiencies. In addition, investors may lose confidence in the reliability of our financial statements causing our stock price to decline.

Off Balance Sheet Arrangements:

We do not have any off balance sheet accounting arrangements. We do enter into joint ventures and operating agreements for the ownership and drilling of wells with third parties. Aspen s balance sheet only reflects its own interest in these arrangements, however, and has no interest in any ownership by third parties (some of whom are related parties).

Recently Issued Pronouncements:

In September 2006, Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* was issued by the Financial Accounting Standards Board (FASB). This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 will become effective for the Company s fiscal year beginning after November 15, 2007, and the Company is currently assessing the potential impact of this Statement on its financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity s election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. This statement was effective beginning January 1, 2008 and did not have a material impact on our financial statements.

In December 2007, FASB issued SFAS No. 160, which amends Accounting Research Bulletin (ARB) No. 51 and (1) establishes standards of accounting and reporting on noncontrolling interests in consolidated statements, (2) provides guidance on accounting for changes in the parent's ownership interest in a subsidiary, and (3) establishes standards of accounting of the deconsolidation of a subsidiary due to the loss of control. The amendments to ARB No. 51 made by SFAS No. 160 are effective for fiscal years (and interim period within those years) beginning on or after December 15, 2008. The Company is currently assessing the potential impact this statement on its financial statements.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, which expands the information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement establishes principles and requirements for how the acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply it before that date. We may experience a financial statement impact depending on the nature and extent of any new business combinations entered into after the effective date of SFAS No. 141(R).

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133, which changes the disclosure requirements for derivative instruments and hedging activities. Enhanced disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement will require the additional disclosures described above.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This Statement is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. We do not expect the adoption of SFAS 162 to have a material effect on our financial statements or related disclosures.

Recent Developments

On September 4, 2008, subsequent to our fiscal year end, Aspen issued a press release announcing that Aspen has decided to investigate strategic alternatives, including the possibility of selling Aspen s assets or considering another appropriate merger or acquisition transaction, and plans to open a data room where interested persons may review certain information. Aspen has entered into an agreement with Brian Wolf, a California-licensed mineral, oil and gas broker and consulting geologist, to assemble and operate the data room. Any transaction may require shareholder approval; such approval, if required, will be sought in accordance with the requirements of the Securities Exchange Act of 1934, as amended, and the rules and regulations thereunder.

ITEM 7. FINANCIAL STATEMENTS

The information required by this item begins on page 47 of Part III of this Report on Form 10-KSB and is incorporated into this part by reference.

ITEM 8. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Dismissal of Hein & Associates, LLP. On March 1, 2007, the Board of Directors informed Hein that it had been dismissed as the Company s independent registered public accounting firm effective immediately. On the same date we informed Gordon, Hughes & Banks, LLP that such firm was reappointed as the Company s independent registered accounting firm effective immediately.

During our two most recent fiscal years and subsequently through the date of dismissal, there were no disagreements with Hein on any matter of accounting principles, practices, financial statement disclosure, or auditing scope or procedure which if not resolved to Hein s satisfaction would have caused Hein to make reference to the subject matter of the disagreement in connection with its principal accounting report on the financial statements for our fiscal year ended June 30, 2007, or any subsequent report. However, as discussed in our annual report for the year ended June 30, 2006, Hein advised us that they were concerned about material weaknesses in our disclosure controls based on several factors, including: corrections to our financial statements and related disclosures that they proposed, the dual functions performed by our president who is also our chief financial officer; the lack of an audit committee; and the lack of sufficient professional accounting personnel at Aspen during the 2006 fiscal year. There is no legal requirement prohibiting our president from serving as both principal executive and financial officer, and Aspen is not subject to a requirement to have an audit committee. As a result of the concerns expressed by our auditors, our president reached the conclusion that, in his opinion as of June 30, 2006, disclosure controls and procedures were not effective.

In reaching his conclusion our president considered various mitigating factors, noting that formerly Aspen had one consultant serving us on a part-time basis. During the last quarter of our fiscal 2006, we increased our accounting staff to three part-time consultants, including two certified public accountants. Our newly-enlarged staff worked together with Aspen during the last quarter of, and after the end of our fiscal year. Although the president identified material weaknesses as of June 30, 2006, the president observed the synergies and efficiencies developed by the new accounting team working together and with other Aspen personnel during the first quarter of the 2007 fiscal year in preparing Aspen s financial statements for the 2006 fiscal year-end audit and concluded that the material weaknesses earlier identified had been eliminated during the first quarter of our 2007 fiscal year. The president noted that these material weaknesses were addressed, not as a result of any changes in disclosure controls or procedures, but as a result of greater experience working together and with Aspen s existing personnel. Consequently, our president concluded that as of September 30, 2006 and subsequently (as described in Item 8A, below) our disclosure controls and procedures were effective.

ITEM 8A(T). CONTROLS AND PROCEDURES

Disclosure Controls and Procedures.

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed in our reports filed or submitted under the Securities Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed in our reports filed under the Exchange Act is accumulated and communicated to management, including our principal executive officer and our principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Our management, under the direction of our Chief Executive Officer, and Chief Financial Officer (who is our principal accounting officer) has evaluated the effectiveness of our disclosure controls and procedures as required by Exchange Act Rule 13a-15(b) as of June 30, 2008 (the end of the period covered by this report). Based on that evaluation, our principal executive officer and our principal accounting officer concluded that these disclosure controls and procedures were effective as of such date.

Internal Control Over Financial Reporting

Our management is also responsible for establishing internal control over financial reporting (ICFR) as defined in Rules 13a-I5(f) and 15(d)-15(f) under the 1934 Act. Our ICFR are intended to be designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. Our ICFR are expected to include those policies and procedures that management believes are necessary 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 our directors; 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.

Management recognizes that there are inherent limitations in the effectiveness of any system of internal control, and accordingly, even effective internal control can provide only reasonable assurance with respect of financial statement preparation and may not prevent or detect misstatements. In addition, effective internal control at a point in time may become ineffective in future periods because of changes in conditions or due to deterioration in the degree of compliance with our established policies and procedures.

As of June 30, 2008, management assessed the effectiveness of the Company s ICFR based on the criteria for effective ICFR established in Internal Control--Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and SEC guidance on conducting such assessments by smaller reporting companies and non-accelerated filers. Based on that assessment, management concluded that, during the period covered by this report, such internal controls and procedures were effective as of June 30, 2008.

This Annual Report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our independent registered public accounting firm pursuant to temporary rules of the SEC that permit us to provide only management's report in this Annual Report.

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2008, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 8B. OTHER INFORMATION

Not applicable. All required information has been reported herein.

PART III

ITEM 9. DIRECTORS, EXECUTIVE OFFICERS, PROMOTERS AND CONTROL PERSONS, COMPLIANCE WITH SECTION 16(A) OF THE EXCHANGE ACT

Identification of Directors and Executive Officers:

The following table sets forth the names and ages of all the Directors and Executive Officers of Aspen, and the positions held by each such person as of June 30, 2008. As described below, the Board of Directors is divided into three classes which, under Delaware law, must be as nearly equal in number as possible. The members of each class are elected for three-year terms at each successive meeting of stockholders serve until their successors are duly elected and qualified; officers are appointed by, and serve at the pleasure of, the Board of Directors. Since we have held no annual meeting since February 25, 1994, the terms of each class of director expires at the next annual meeting of stockholders or until their resignation or retirement.

Name	Age	Position	Class	Director Since
R. V. Bailey	76	Chief Executive Officer, Secretary, Director, Vice President, and Board Chairman	III	1980
Robert A. Cohan	52	President and Director	I	1998
Kevan B. Hensman	52	Chief Financial Officer and Director	II	2006

Each of the directors will be up for reelection at the next annual meeting of stockholders and will continue to serve until his successor is elected and qualified or until his or her earlier death, resignation, or removal. We did not hold an annual meeting during fiscal 2007 or 2008, and unless we seek to effect a transaction that requires the approval of our shareholders, we do not expect to hold an annual meeting during fiscal 2009.

Each officer is appointed annually and serves at the discretion of the Board of Directors until his successor is duly elected and qualified. No arrangement exists between any of the above officers and directors pursuant to which any of those persons was elected to such office or position. None of the directors are also directors of other companies filing reports under the Securities Exchange Act of 1934. None of the directors are involved in, or have been involved in, any legal proceedings of the type that must be disclosed pursuant to Item 401(d) of SEC Regulation S-B. None of the directors are considered to be independent .

Robert A. Cohan. Mr. Cohan currently serves as our President and as a director. He served as our chief executive officer and chief financial officer until January 2008 when he suffered a stroke and he has not been able to resume full-time duties since then. Mr. Cohan obtained a Bachelor of Science degree in Geology from the State University College at Oneonta, NY in 1979 and he works for Aspen on a full-time basis. He has approximately 28 years experience in oil and gas exploration and development, including employment in Denver, CO with Western Geophysical, H. K. van Poollen & Assoc., Inc., as a Reservoir Engineer and Geologist, Universal Oil & Gas, and as a principal of Rio Oil Co., Denver, CO. Mr. Cohan served as Manager, Oil & Gas Operations, Aspen Exploration Corporation, Denver, CO from 1989 to 1992. He was employed as Vice President, Oil & Gas Operations, for Tri-Valley Oil & Gas Co., Bakersfield, CA. from 1992 to April 1995, at which time Mr. Cohan rejoined Aspen Exploration Corporation as Vice President West Coast Division (now President & CEO), opening an office in Bakersfield, CA. He is a member of the Society of Petroleum Engineers (SPE) and the American Association of Petroleum Geologists (AAPG).

Kevan B. Hensman became a director of Aspen Exploration Corporation on September 11, 2006. As a result of Mr. Cohan s stroke, Mr. Hensman was appointed as our chief financial officer in January 2008. Since April 2002, except for a one-year position as Manager of Paramount Citrus Association, Mr. Hensman has served as an Analyst for Truxtun Radiology Medical Group, LP with the duties of providing financial analysis; performing special projects; and assisting the Practice Administrator in performing various duties and assignments.

Mr. Hensman was employed by Aera Energy, LLC as its Energy Portfolio Consultant from June 1999 to November 2001. During his tenure, his duties included providing an analysis of gas pricing and supply to upper management and the operation departments; the administration and negotiation of all gas purchase/sales contracts and gas pipeline transportation contracts and agreements; advising business partners on current Governmental regulations and legislation; managing the fuel budget; preparing month-, quarter- and year-end reports; and partnering with department heads to prepare the annual plan and budget forecasts.

Mr. Hensman served as the Planner/Gas Analyst from November 1997 to May 1999 for Texaco Exploration and Production Company. His duties included evaluating the energy markets for gas pricing for the management team and production department; supporting the gas contract administration; negotiating gas contracts for natural gas purchase and sales and pipeline transportation; managing the imbalance account with vendors to minimize the company s penalty fees; scheduling deliveries of supplies to production operations and projects; budgeting for the yearly plan and five year strategic plan for Kern River Business Unit; completing forecasts; economics evaluations; performing variance reports and month-end reports; managing project completion audits; resolving accounting and budget issues; and preparing month-end and year-end reports with accounting.

Mr. Hensman served as the Supervisor of Fuel Supply and Acquisition Analyst from February 1991 to October 1997 for Santa Fe Energy/Monterey Resources. Mr. Hensman was responsible for administration and negotiating gas purchase/sales contracts; tracking fuel use; scheduling and balancing on gas pipelines; evaluating energy markets relating to gas pricing for the recommendation of term purchases; supporting annual planning and budget cyclic; economic evaluation of acquisition candidates; and portfolio evaluation.

Mr. Hensman is not a director of any other public company. In 1999, Mr. Hensman received a Bachelor of Science degree in finance from California State University Bakersfield (CSUB).

R. V. Bailey. Mr. Bailey served as our vice president until January 2008 when he was appointed as our chief executive officer as a result of Mr. Cohan s stroke. Mr. Bailey obtained a Bachelor of Science degree in Geology from the University of Wyoming in 1956. He has approximately 45 years experience in exploration and development of mineral deposits, primarily gold, uranium, coal, and oil and gas. His experience includes basic conception and execution of mineral exploration projects. Mr. Bailey is a member of several professional societies, including the Society for Mining and Exploration, the Society of Economic Geologists and the American Association of Petroleum Geologists, and has written a number of papers concerning mineral deposits in the United States. He is the co-author of a 542-page text, published in 1977, concerning applied exploration for mineral deposits. Mr. Bailey is the founder of Aspen and has been an officer and director since its inception, and currently devotes a substantial portion of his time to Aspen s business.

Meetings of the Board and Committees:

The Board of directors held one formal meeting during the fiscal year ended June 30, 2007 and one formal meeting during the fiscal year ended June 30, 2008. Each director attended all of the formal meetings either in person or by telephone, without exception. In addition, regular communications were maintained throughout the year among all of the officers and directors of the Company and the directors acted by unanimous consent eight times during fiscal 2007, six times during fiscal 2008, and three times subsequently.

No Audit Committee or Code of Ethics:

Aspen does not have an audit committee, compensation committee, nominating committee, or other committee of the board that performs similar functions. Instead, the entire board acts as the Company s audit committee and therefore, Aspen does not have a designated audit committee financial expert.

Aspen s board of directors has not adopted a code of ethics because the board does not believe that, given the small size of Aspen and the limited transactions, a code of ethics is warranted.

No Nominating Committee; Procedures by which Security Holders May Recommend Nominees to the Board of Directors; Communications with Members of the Board of Directors:

As noted above, Aspen does not have a nominating committee. We do not have a nominating committee because our board does not believe that such a committee is necessary given our small size, and because we have not held an annual meeting of shareholders since February 1994, and we have no plans to hold such a meeting. Instead, when a board vacancy occurs, the remaining board members participate in deliberations concerning director nominees.

For the same reasons stated immediately above, the board of directors has not adopted a formal procedure by which security holders may recommend nominees to the board of directors. However, any shareholder desiring to nominate a person to the Board of Directors or communicate directly with any officer or director of Aspen may address correspondence to that person at our offices in Denver, Colorado. Our office staff will forward such communications to the addressee.

Identification of Significant Employees:

There are no significant employees who are not also directors or executive officers as described above. No arrangement exists between any of the above officers and directors pursuant to which any one of those persons was elected to such office or position.

Family Relationships:

As of June 30, 2008, and subsequently, there were no family relationships between any director, executive officer, or person nominated or chosen by the Company to become a director or executive officer.

Section 16(a) Beneficial Ownership Reporting Compliance:

Section 16(a) of the Securities Exchange Act of 1934 (the "Exchange Act") requires Aspen's directors and officers and any persons who own more than ten percent of Aspen's equity securities, to file reports of ownership and changes in ownership with the Securities and Exchange Commission (the "SEC"). All directors, officers and greater than ten-percent shareholders are required by SEC regulation to furnish Aspen with copies of all Section 16(a) reports files. Based solely on our review of the copies of Forms 3, 4 and any amendments thereto furnished to us during the fiscal year completed June 30, 2008 and subsequently, we believe that during the period from July 1, 2007 through August 31, 2008, all filing requirements applicable to our officers, directors and greater-than-ten-percent shareholders were complied with.

ITEM 10. EXECUTIVE COMPENSATION

The following table sets forth information regarding compensation awarded, paid to, or earned by the chief executive officer and the other principal officers of Aspen for the two years ended June 30, 2007 and 2008. No other person who is currently an executive officer of Aspen earned salary and bonus compensation exceeding $100,000 during any of those years. This includes all compensation paid to each by Aspen and any Aspen subsidiary.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Fiscal Year	Salary ($)	Bonus ($)	Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Non-Qualified Deferred Plan Compensation ($)	All Other Compensation ($)	Total ($)
R. A. Cohan,									
President and director	2008	$ 160,000	$ -	$-	$ 71,563	$-	$-	$ 156,123	$ 387,686
	2007	$ 160,000	$ 24,000	$-	$ -	$-	$-	$ 121,340	$ 305,340
R. V. Bailey, CEO									
and Chairman,	2008	$ 60,000	$ -	$-	$ 50,957	$-	$-	$ 135,367	$ 246,324
Executive Vice	2007	$ 55,000	$ -	$-	$ -	$-	$-	$ 76,196	$ 131,196
President									
Kevan Hensman, CFO									
and director,	2008	$ 4,830	$ -	$-	$ 16,435	$-	$-	$ 2,000	$ 23,265

Compensation Discussion and Analysis

The following Compensation Discussion and Analysis describes the material elements of compensation for the executive officers identified in the Summary Compensation Table contained above being our chief executive officer (R.V. Bailey (CEO)), President (Robert Cohan), and our Chief Financial Officer (Kevan Hensman), the named executive officers.

As more fully described below, the board of directors (which includes the named executive officers) acting in lieu of a compensation committee reviews the total direct compensation programs for our CEO, President, and Chief Financial Officer. Notably the salary and other benefits payable to our named executive officers are set forth in employment agreements which are discussed below. The only discretionary portion of the compensation is the options that may (in the discretion of the board) be issued to the named executive officers.

Our CEO reviews the base salary, annual bonus and long-term compensation levels for other employees of the Company. The entire Board of Directors remains responsible for significant changes to or adoption of new employee benefit plans.

A. ***Cash Compensation Payable To Our Named Executive Officers.*** Our named executive officers receive a base salary payable in accordance with our normal payroll practices and pursuant to contracts between each of these officers and Aspen (which contracts are described in more detail below), except for Kevan Hensman, our Chief Financial Officer, who is compensated on an hourly basis for services rendered. Based on our knowledge of the industry and Aspen s performance (including its earnings and stock price performance, and successful well drilling), we believe that their base salaries are less than those that are received by comparable officers with comparable responsibilities in similar companies. Notably our chief executive officer and our president are participants in our amended royalty and working interest plan discussed below. Our chief financial officer does not participate in this plan. As described in more detail below, Mr. Cohan s employment contract will expire December 31, 2008 and Mr. Bailey s contract will expire May 1, 2009. In the notification given to Mr. Cohan that the Board of Directors determined not to renew the contract as written, the Board advised Mr. Cohan that the Board will reconsider continuing employment of all officers later in the year.

In the future, when we reconsider salaries for our executives, we will do so by evaluating their responsibilities, experience and the competitive marketplace. More specifically, we expect to consider the following factors in determining our executive officers base salaries:

1. the executive s leadership and operational performance and potential to enhance long-term value to the Company s shareholders;
2. performance compared to the financial, operational and strategic goals established for the Company;
3. the nature, scope and level of the executive s responsibilities;
4. competitive market compensation paid by other companies for similar positions, experience and performance levels; and
5. the executive s current salary, the appropriate balance between incentives for long-term and short-term performance.

Unless the composition of our board of directors changes before that time, however, the board considering these issues will not be independent. All of our current three directors are either employees or Company consultants and named executive officers. Thus any compensation decisions made in the future are not likely to be at arms -length.

B. ***Stock Option Plan Benefits***. Our officers and directors are eligible to be granted options pursuant to our three stock option plans, Option Plan #2, Option Plan #3, and The 2008 Equity Plan. In fiscal year 2008, our named executive officers were granted options to purchase a total of 600,000, over a three-year period. One-third of the options granted will vest as of September 30, 2008, one-third as of September 30, 2009, and one-third as of September 30, 2010, in each case based on Aspen achieving certain performance goals as reflected in its audited financial statements and reserve report as of the fiscal year end immediately preceding such date:

Factors*	Weight	Actual Results for year ended June 30, 2007	Goals for the Year Ended June 30, 2008	2009	2010
Total Barrels of Oil Equivalent Proved	30%	580,045	600,000	650,000	700,000
Present Value of Reserves 10% Discount	25%	$ 13,400,466	$ 14,200,000	$ 15,140,000	$ 16,030,000
Production (Barrels of Oil Equivalent)	30%	103,653	110,000	120,000	130,000
Net Income	15%	$ 925,269	10% increase over prior year	10% increase over prior year	10% increase over prior year

* No factor may be valued more than 100%. Any factor that is less than the 2007 base year will be weighted at zero.

At June 30, 2008, 108,721 options were earned by the three named executive officers based on performance conditions that were met, and 91,279 options expired due to unmet conditions. The 108,721 options that were earned by the three named executive officers as of June 30, 2008 will vest as of September 30, 2008.

C. ***Elements of All Other Compensation.*** The amounts reflected in the column labeled other compensation in the above Summary Compensation Table predominately consist of compensation paid to the named executive officers from our Amended Royalty and Working Interest Plan and from benefits received from our 401(k) plan.

1. <u>Amended Royalty and Working Interest Plan</u>

Aside from their base salaries, the largest element of the compensation of our executive officers is realized from our Amended Royalty and Working Interest Plan (the Plan) by which we, in our discretion, assign overriding royalty interests or other interests in oil and gas properties or in mineral properties. Since the amended plan was first implemented in 1986, we have only assigned royalty interests under this plan. This plan is intended to provide additional compensation to Aspen s personnel involved in the acquisition, exploration and development of

Aspen s oil or gas or mineral prospects. In addition to our executive officers, all of our employees are eligible to participate in this Plan. In the fiscal years ended June 30, 2008 and 2007, Ms. Shelton, our corporate office manager (and neither an officer nor a director of Aspen), also participated in the Plan.

The allocations for royalty under Aspen s Royalty and Working Interest Plan for employees are based on a determination by management whether there is any room for royalties in a particular transaction. In some specific cases management may believe that an oil or gas property or project is sufficiently burdened with existing royalties so that no additional royalty burden can be allocated to our employees for that property or project. In other situations a determination may be made that there are royalty interests available for assignment to our employees. The determination of whether royalty interests are available and how much to assign to employees (usually less than 3%) is made on a case-by-case basis by Robert A. Cohan, president, and R. V. Bailey, our chief executive officer and vice president, both of whom benefit from royalty interests assigned.

During fiscal years 2007 and 2008, we assigned to employees royalties on certain of our properties pursuant to our Amended Royalty and Working Interest Plan, as set forth in the following table. At the time we assign these overriding royalty interests, we considered the value of the royalties assigned to be nominal since the assignments are made while the properties are undeveloped and unproved, and before any wells or drilled or significant exploratory work has been performed. We have not granted any overriding royalty interests in our Montana oil properties. The overriding royalty interests in these properties granted to our named officers and our one additional (non-executive) employee were as follows:

	R.V. Bailey	**R.A. Cohan**	**J.L. Shelton**
Assigned during the 2008 fiscal year	**percent**	**percent**	**percent**
Johnson Unit 13	1.260000	1.260000	0.480000
SJDD 11-1	1.360000	2.000000	0.640000
Delta Farms 10	0.816000	1.200000	0.384000
Eastby 1-1	0.906661	1.333325	0.426664
Assigned during the 2007 fiscal year:			
Sewald 1-1	0.630000	0.630000	0.240000
Heidrick 11-2	1.360000	2.000000	0.640000
Nelson 1-10	1.317500	1.937500	0.620000

The following table sets forth the payments received during the years stated by our named executive officers.

	Payments Received During Fiscal Year Ended June 30,	
	2008	2007
Mr. Cohan	$ 145,873	$ 88,268
Mr. Bailey	$ 102,927	$ 66,196

These payments derive from royalties assigned to employees as described above and the royalties that were assigned in prior years. Any monies realized by our executive officers under the Amended Royalty and Working Interest Plan are reflected in column labeled All Other Compensation in the Summary Compensation Table.

2. Other Elements of Compensation and Benefits

Our executive officers also receive certain other benefits, although these benefits do not constitute a large portion of their overall compensation. These benefits are summarized below.

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We have a Profit-Sharing 401(k) Plan which we adopted effective July 1, 1990. All employees are eligible to participate in this Plan immediately upon being hired to work at least 1,000 hours per year and attained age 21. Aspen s contribution (if any) to this plan is determined by the Board of Directors each year.

We adopted an Amendment to the Profit-Sharing 401(k) Plan effective July 1, 2005 which states that Aspen will make matching contributions equal to 50% of the participant s elective deferrals. During fiscal 2007, we contributed $30,125 to the plan ($10,000 to R. V. Bailey s plan; $10,125 to Robert A. Cohan s plan; $10,000 to Judith L. Shelton s plan). During fiscal 2008, we contributed $30,250 to the plan ($10,000 to R. V. Bailey s plan; $10,250 to Robert A. Cohan s plan; $10,000 to Judith L. Shelton s plan). When amounts are contributed to Mr. Bailey s and Mr. Cohan s accounts (which amounts are fully vested), these amounts are also included in the column labeled All Other Compensation in the Summary Compensation table, above.

For the fiscal years ended June 30, 2008 and 2007, the Company had a policy of reimbursing employees for medical expenses incurred but not covered by the paid medical insurance plan. Expenses reimbursed for fiscal 2008 and fiscal 2007 were $24,108 and $22,947, respectively. As of June 30, 2008 and 2007 there were no accruals for reimbursement of medical expenses. Under the terms of Mr. Bailey s current employment agreement, he is responsible for his own medical insurance premiums and will no longer be reimbursed excess medical expenses.

We have furnished a vehicle to Mr. Bailey, and the compensation allocable to this vehicle, plus amounts paid for various travel and entertainment paid on behalf of Mr. Bailey and Mr. Bailey's wife when she accompanied him for business purposes, are also included in column (i) of the table. Aspen also purchased a vehicle for Mr. Cohan. This vehicle is used substantially for business purposes; therefore, no vehicle costs have been charged to Mr. Cohan.

3. Expense Reimbursement.

We have agreed to reimburse our officers and directors for out-of-pocket costs and expenses incurred on behalf of Aspen. Since this reimbursement is on a fully-accountable basis, there is no portion treated as compensation.

4. Purchases of Working Interests

As described in Item 1, above, Aspen generally does not incur all of the expense and bear all of the risk in drilling its wells. Aspen generally seeks other participants who are familiar with the oil and gas industry and the wells being drilled and retains a promotional interest. Oftentimes, our named executive officers participate in these wells. When they do, they purchase working interests on the same basis as unaffiliated parties and bear their proportionate share of Aspen s promotional interest. These investments by our named executive officers are not considered to be compensatory since the named executive officers are participating in the wells on the same basis as unaffiliated parties. Messrs. Bailey and Cohan have each participated in the Johnson #11, #12 and #13 wells and in the Merrill #31-1 well which are subject to possible title deficiencies. Depending on the results of our analysis of these deficiencies (which are described in more detail above), we may have overpaid Messrs. Bailey and Cohan some amounts to the same extent (if at all) we may have overpaid other working interest owners in the Johnson Unit of the Malton Black Butte Field with respect to Johnson #11 or #12, and with respect to the Merrill #31-1 which is outside of the Johnson and Elektra units. Because we have not commenced production on Johnson #13, we have not made any payments to working interest or royalty owners of that well. In addition, they may have overpaid their share of the drilling costs of such wells.

D. ***Employment Agreement with our Named Executive Officers.*** We have entered into employment agreements with two of our named executive officers. The material terms of these agreements are summarized as follows:

Mr. Cohan: Aspen and Robert A. Cohan entered into an employment agreement dated January 1, 2003, as amended on April 22, 2005 (the Agreement). The Agreement was for an initial three year term and was amended in April 2005. As amended, the term of the agreement ends on December 31, 2008, but would continue thereafter on a year-to-year basis unless terminated by either party. Currently under the Agreement we pay Mr. Cohan an annual salary of $160,000 (which we will continue to pay through December 31, 2008). We also offer Mr. Cohan health insurance, cost reimbursement, and certain other benefits.

The Agreement provides that Mr. Cohan may terminate the Agreement for cause if Aspen breaches the contract, reduces Mr. Cohan s responsibilities, fails to reappoint Mr. Cohan as president or if the shareholders fail to reelect him as director, or upon a change of control of Aspen. As described in the employment contract, under the Agreement, a change of control would occur if:

- any person (not currently owning at least 15% of the outstanding common stock) acquires 15% or more of Aspen s outstanding common stock;
- a change in the board of directors occurs that results in the existing directors having less than 75% of the board s total vote; or
- a merger, consolidation, or other business combination as a result of which Aspen is not the surviving entity or (if surviving) becomes a subsidiary of another entity.

Upon termination by Mr. Cohan for cause, Aspen must pay him the greater of the amount remaining due for the remaining term of the contract or six months salary.

Aspen may also terminate the contract for cause, upon Mr. Cohan s death or disability, or without cause. If Aspen terminates the Agreement for cause, it only must compensate Mr. Cohan through the date of termination. If Aspen terminates the Agreement upon Mr. Cohan s death or disability, Aspen must pay Mr. Cohan the greater of the amount remaining due for the remaining term of the Agreement or six months salary. If Aspen terminates the Agreement without cause, Aspen must pay Mr. Cohan the greater of the amount remaining due for the remaining term of the contract or nine months salary.

As reported in January 2008, Mr. Cohan suffered a stroke and was unable to continue to perform his duties as chief executive officer and chief financial officer of Aspen. As a result, these duties were assumed by Messrs. R.V. Bailey and Kevan Hensman. Mr. Cohan retained the title of president, and has been working with Messrs. Bailey and Hensman and Aspen s other employees and consultants as he is able to ensure that Aspen s oil and gas operations continue. Although Mr. Cohan has provided substantial continuing assistance to Aspen, he has been unable to resume his duties as chief executive officer and chief financial officer. Inasmuch as Aspen is exploring strategic alternatives the Board of Directors, including Mr. Cohan, concurred that it was appropriate to provide notice to Mr. Cohan that his employment agreement would not be renewed when it expires on December 31, 2008.

Therefore, on September 4, 2008, Aspen notified Mr. Cohan that his employment agreement will not be renewed when it expires on December 31, 2008. This notification does not terminate Mr. Cohan s employment either now or on December 31, 2008, but merely advises him that his employment agreement will not be renewed. Mr. Cohan retains the title of president. The Board of Directors determined that it will consider the continuing employment status of all of its officers later in the year.

Mr. Bailey: Effective May 1, 2003, and as amended September 21, 2004, we entered into an employment agreement with Chairman of the Board, R. V. Bailey. The pertinent provisions of this agreement include an employment period ending May 1, 2009, the title of Vice President (although Mr. Bailey is now serving as our chief executive officer) subject to the general direction of the Board of Directors of Aspen. Mr. Bailey s salary was $45,000 per year through December 31, 2006 and $60,000 per year from January 1, 2007, ending May 1, 2009. Mr. Bailey will also participate in Aspen s stock options and royalty interest programs. During the term of the agreement, and in lieu of health insurance, we have agreed to pay Mr. Bailey a monthly allowance to cover such items as prescriptions, medical and dental coverage for himself and his dependents and other expenses not covered in the agreement. To the extent that Mr. Bailey does not provide documentation accounting for the expenditure of this amount for medical reimbursement purposes, it is treated as compensation to him. The original monthly allowance was $1,700, but the contract provided that it should be adjusted each June for inflation. Currently the monthly allowance is $1,870.

We may terminate this agreement upon Mr. Bailey s death by paying his estate all compensation that had or will accrue to the end of the year of his death plus $75,000. Should Mr. Bailey become totally and permanently disabled, we will pay Mr. Bailey one half of the salary and benefits set forth in our agreement with him for the remainder of the term of the agreement. Aspen may not terminate the employment agreement for other reasons. The original May 1, 2003, agreement also terminated Aspen s obligations under a June 4, 1993 agreement by which it was obligated to repurchase Mr. Bailey s stock upon his death.

Stock Options and Stock Appreciation Rights Granted During the Last Fiscal Year:

On February 27, 2008, the Board of Directors adopted the 2008 Equity Plan (the Plan). 1,000,000 shares of common stock are reserved under the Plan for the grant of stock options or issuance of stock bonuses to compensate new, continuing, and existing employees, officers, consultants, and advisors of the Company. Concurrent with the adoption of the Plan, the board granted options to purchase 775,000 shares of common stock at an exercise price of $2.14 per share. 1/3 of the shares vest on each September 30, of 2008, 2009, and 2010 if certain performance conditions are met. At June 30, 2008, 247,097 shares were earned, based on performance conditions, and 117,902 expired.

The following table sets out the unexercised stock options, stock granted as bonuses that have not vested, and equity incentive plan awards for each Named Executive Officer outstanding at June 30, 2008.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

Name and Principal Position	Number of Securities Underlying Unexercised Options(1)(#) Exercisable	Unexercisable	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested ($)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units, Other Rights That Have Not Vested (#)
R. V. Bailey,	65,000	-	2.67	1/1/2010	$ -	$ -	$ -
CEO and Chairman	36,240	133,333	2.14	2/27/2013	133,333	373,332	133,333
Robert A. Cohan,	50,000	-	0.57	8/15/2008	-	-	-
President and Director	80,000	-	2.67	1/1/2010	-	-	-
	54,360	200,000	2.14	2/27/2013	200,000	560,000	200,000
Kevan Hensman,	10,000	-	3.70	9/11/2011	-	-	-
CFO and Director	18,120	66,667	2.14	2/27/2013	66,667	186,668	66,667

(1) On February 27, 2008, the Board of Directors adopted the 2008 Equity Plan (the Plan). 1,000,000 shares of common stock are reserved under the Plan for the grant of stock options or issuance of stock bonuses to compensate new, continuing, and existing employees, officers, consultants, and advisors of the Company.

(2a) On April 27, 2005, Mr. Bailey was granted an option to purchase 65,000 shares of our common stock at an exercise price of $2.67 per share. These options vested over three years without performance criteria, and are now entirely vested.

(2b) On February 27, 2008, Mr. Bailey was granted an option to purchase 200,000 shares of our common stock at an exercise price of $2.14 per share. 1/3 of the shares vest on each September 30, of 2008, 2009, and 2010 if certain performance criteria are met. At June 30, 2008, 36,240 shares were earned based on the performance criteria and will be vested on September 30, 2008, and 30,427 expired.

(3a) On February 27, 2008, Mr. Cohan was granted an option to purchase 300,000 shares of our common stock at an exercise price of $2.14 per share. 1/3 of the shares vest on each September 30, of 2008, 2009, and 2010 if certain performance criteria are met. At June 30, 2008, 54,360 shares were earned, based on the performance criteria and will be vested on September 30, 3008, and 45,640 expired.

(3b) On April 27, 2005, Mr. Cohan was granted an option to purchase 80,000 shares of our common stock at an exercise price of $2.67 per share. These options vested over three years without performance criteria, and are now entirely vested.

(3c) On March 14, 2002, Mr. Cohan was granted an option to purchase 250,000 shares of our common stock at an exercise price of $0.57 per share. These options vested over five years without performance criteria, and are now entirely vested. Of these, 50,000 remain unexercised

(4a) On February 27, 2008, Mr. Hensman was granted an option to purchase 100,000 shares of our common stock at an exercise price of $2.14 per share. 1/3 of the shares vest on each September 30, of 2008, 2009, and 2010 if certain performance criteria are met. At June 30, 2008, 18,120 shares were earned, based on the performance criteria and will be vested on September 30, 2008, and 15,213 expired.

(4b) On September 11, 2006, Mr. Hensman was granted an option to purchase 10,000 shares of Aspen s common stock exercisable at $3.70. The option vested immediately and is exercisable through September 11, 2011. These options vested when granted.

Long Term Incentive Plans/Awards in Last Fiscal Year:

Except as described in our 401(k) plan, we do not have a long-term incentive plan nor have we made any awards during the fiscal years ended June 30, 2008 or 2007.

Report on Re-pricing of Options/SARs:

We did not reprice any options or stock appreciation rights during the fiscal years ended June 30, 2007, June 30, 2008, or subsequently.

Compensation of Directors

Although we have not formally adopted a plan for the compensation of our directors, in September 2006, upon his appointment as a director we issued Mr. Hensman an option to purchase 10,000 share of our common stock at a price of $3.70 per share, exercisable through September 11, 2011. In addition, we agreed to pay Mr. Hensman $2,000 per meeting of the board of directors that he attends in person or by telephone, and to reimburse him for any expenses that he may incur in performing his duties as a member of the board of directors. The fees earned for attending meetings in fiscal year 2008 is reflected in the Director Compensation Table below. As a result of his appointment as chief financial officer, Mr. Hensman is also receiving consulting fees from Aspen at the rate of $70.00 per hour, which fees are reflected in the Summary Compensation table, above.

Mr. Bailey and Mr. Cohan also served as directors during our fiscal year 2008 but are not reflected in the Director Compensation table below as all compensation received by them is reflected in the Summary Compensation table.

We have no other arrangements pursuant to which any of our directors was compensated during the fiscal year ended June 30, 2007 or 2008 for services as a director.

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash	Stock Nonqualifed Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Non-Qualified Deferred Compensation on Earnings ($)	Total ($)
Kevan Hensman	$ 2,000	$-	$-	$-	$-	$ 2,000

(1) Mr. Hensman was appointed to our board of directors in September 2006 and during our 2007 fiscal year was paid fees for attending board meetings and was also granted an option to purchase 10,000 shares of our common stock upon his appointment to our board of directors. In January 2008 Mr. Hensman was appointed to serve as our chief financial officer. The line item above solely reflects compensation paid to Mr. Hensman during fiscal 2008 in his capacity as a director.

ITEM 11. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

The following table sets forth as of July 31, 2008 the number and percentage of Aspen s shares of $.005 par value common stock owned of record and beneficially owned by each person owning more than five percent of such common stock, and by each Director, and by all Officers and Directors as a group. The percentages set forth in the table below are based on the total number of shares outstanding as set forth on the cover page to this annual report.

Beneficial Owner	Beneficial Ownership Number of Shares		Percent of Total
R. V. Bailey	1,391,336	i	19.17%
Robert A. Cohan	742,737	ii	10.23%
Kevan B. Hensman	28,120	iii	0.39%
All Officers and Directors as a Group (3 persons)	2,162,193		29.78%

The address for all of the above directors and executive officers is:
2050 S. Oneida St., Suite 208, Denver, CO
80224

[i] This number includes 1,241,776 shares of stock held of record in the name of R. V. Bailey, and 16,320 shares of record in the name of Mieko Nakamura Bailey, his spouse. Additionally, the number includes 32,000 shares of common stock Aspen issued to the Aspen Exploration Profit Sharing Plan for the benefit of R. V. Bailey as a corporation contribution to Mr. Bailey s 401(k) account. The number of shares beneficially owned also includes stock options to purchase 101,240 shares of restricted common stock. However, the number of shares does not include stock options to purchase 133,333 shares that have not yet vested and will not vest until on or after September 30, 2009, to the extent earned.

[ii] This number includes 527,644, shares of common stock. Additionally, Aspen issued 30,733 shares of common stock to the Aspen Exploration Profit Sharing Plan for the benefit of Robert A. Cohan as a corporation contribution to Mr. Cohan s 401(k) account. The total number of shares beneficially owned by Mr. Cohan also includes stock options to purchase 184,360 shares of restricted common stock. However, the number of shares does not include stock options to purchase 200,000 shares that have not yet vested and will not vest until on or after September 30, 2009, to the extent earned.

[iii] On September 11, 2006, upon being appointed to our board of directors Mr. Hensman was granted an option to purchase 10,000 shares of our common stock at $3.70 per share. These options vested immediately upon grant and are exercisable through September 11, 2011. Mr. Hensman also owns options exercisable to acquire 18,120 shares included in the above table. The table does not include options to acquire 66,667 shares, which will not vest until on or after September 30, 2009, to the extent earned.

Except with respect to the employment agreements between Aspen and R. V. Bailey and between Aspen and Robert Cohan, we know of no arrangement, the operation of which may, at a subsequent date, result in change in control of Aspen.

See Item 5, above, for information regarding securities authorized for issuance under equity compensation plans in the form required by Item 201(d) of Regulation S-B.

ITEM 12. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The following sets out information regarding transactions between officers, directors and significant shareholders of Aspen during the most recent two fiscal years and during the subsequent fiscal year.

Working Interest Participation:

Some of the directors and officers of Aspen are engaged in various aspects of oil and gas and mineral exploration and development for their own account. Aspen has no policy prohibiting, nor does its Certificate of Incorporation prohibit, transactions between Aspen and its officers and directors. We plan to enter into cost-sharing arrangements with respect to the drilling of its oil and gas properties. Directors and officers (and other employees) may participate (and from time to time have participated) in these arrangements. All directors and executive officers participating in these drilling opportunities must do so on the same basis as non-affiliated participants, and consequently must share a proportional amount of Aspen s promotional interest.

R. V. Bailey, chief financial officer, vice president and director of Aspen and Robert A. Cohan, president and director of Aspen, each have working and royalty interests in certain of the California oil and gas properties operated by Aspen including Johnson #11, #12 and #13 in the Johnson Unit of the Malton Black Butte field and the Merrill #31-1 which are subject to possible title deficiencies. Depending on the results of our analysis of these deficiencies (which are described in more detail above), we may have overpaid Messrs. Bailey and Cohan some amounts to the same extent (if at all) we may have overpaid other working interest owners in the Johnson Unit of the Malton Black Butte Field with respect to Johnson #11 and #12, and the Merrill #31-1 well. Because we have not commenced production on Johnson #13, we have not made any payments to working interest or royalty owners of that well. In addition, they may have overpaid their share of the drilling costs of such wells.

As of June 30, 2007 and 2008, working interests of the Company and its affiliates in certain producing California properties are set forth below, as compared to Aspen s interests in all of its wells:

	Gross Wells Gas	Net Wells Gas
As of June 30, 2008		
Aspen Exploration	88	19.17
R. V. Bailey	67	2.14
R. A. Cohan	67	1.2
As of June 30, 2007		
Aspen Exploration	82	17.4
R. V. Bailey	64	1.98
R. A. Cohan	64	1.15

We have not granted any participatory rights in our Montana oil properties.

Amended Royalty and Working Interest Plan:

A discussion of Aspen s Amended Royalty and Working Interest Plant and the specific royalties assigned to our executive officers is included in Item 10 Executive Compensation above.

Employment Agreements:

See Item 10, Executive Compensation -- Employment contracts and termination of employment and change in control arrangements, for a discussion of the current employment contracts between Aspen and Messrs. Cohan and Bailey.

Other Arrangements:

During the fiscal years 2008 and 2007, Aspen paid for various hospitality functions and for travel, lodging and hospitality expenses for spouses who occasionally accompanied directors when they were traveling on company business. Management believes that the expenditures were to Aspen s benefit. During the 2008 fiscal year and during the year ended June 30, 2007, Aspen provided one vehicle each to Aspen s president and vice president.

Certain Business Relationships:

None.

(1)-(5) Indebtedness of Management:

None.

Transactions with Promoters:

Not applicable.

Director Independence

Our board of directors consists of Messrs. Bailey, Cohan and Hensman. No board member is considered to be independent as defined by Section 803A of the American Stock Exchange Listing Standards. The board considers all relevant facts and circumstances in its determination of independence of all members of the board (including any relationships set forth in this Form 10-KSB under the heading Certain Related Person Transactions).

ITEM 13. EXHIBITS

Exhibits Pursuant to Item 601 of Regulation S-B:

3.01	Restated Certificate of Incorporation (without) amendments. (8)
3.02	Registrant s Amended and Restated Bylaws(1)
10.01	Royalty and Working Interest Plan. (2)
10.02	Amended Royalty and Working Interest Plan. (8)
10.03	Employment Agreement between Aspen Exploration Corporation and Robert A. Cohan dated January 1, 2003. (1)
10.04	Amendment to Employment Agreement between Aspen Exploration Corporation and Robert A Cohan dated April 22, 2005. (8)
10.05	Employment Agreement between Aspen Exploration Corporation and R.V. Bailey, as amended. (3)
10.06	Option Plan #2
10.07	Option Plan #3
10.09	Participation Agreement dated January 31, 2007, between Aspen Exploration Corporation and Nautilus Poplar, LLC. (5)
10.10	Aspen Exploration Corporation 2008 Equity Plan (6)
16.1	Letter of Hein & Associates LLP dated March 9, 2007, regarding change in certifying accountant. (8)
21.1	Subsidiaries of Aspen Exploration Corporation . (8)
31.1	Certification pursuant to Rule 13a-14. *
31.2	Certification pursuant to Rule 13a-14. *
32	Certification pursuant to 18 U.S.C. §1350. *

* Filed herewith.

(1) Incorporated by reference from Aspen s Annual Report on Form 10-KSB dated June 30, 2003 (filed on September 26, 2003).

(2) Incorporated by reference from Commission File No. 2-69324.

(3) Incorporated by reference from Aspen s Annual Report on Form 10-KSB dated June 30, 2004 (filed on September 28, 2004).

(4) Incorporated by reference from Aspen s Annual Report on Form 10-KSB dated June 30, 2006 (filed on October 12, 2006).

(5) Incorporated by reference from Aspen s Current Report on Form 8-K dated February 13, 2007 (filed on February 16, 2007).

(6) Incorporated by reference from Aspen s Current Report on Form 8-K dated February 27, 2008 (filed on March 10, 2008).

(7) Incorporated by reference from Aspen s Current Report on Form 8-K/A dated March 1, 2007 (filed on March 12, 2007).

(8) Incorporated by reference from Aspen's Annual Report on Form 10-KSB dated June 30, 2007 (filed on September 28, 2007).

ITEM 15. PRINCIPAL ACCOUNTANT S FEES AND SERVICES.

(a) **Audit Fees.**

We reappointed Gordon, Hughes & Banks, LLP as our principal accountant effective March 1, 2007. They billed us aggregate fees for audit and tax services in the amount of approximately $22,285 for the fiscal year ended June 30, 2007 and $46,336 for the fiscal year ended June 30, 2008. These amounts were billed for professional services that Gordon, Hughes & Banks, LLP provided for the audit of our annual financial statements, review of the financial statements included in our report on 10-QSB and other services typically provided by an accountant in connection with statutory and regulatory filings or engagements for those fiscal years.

On February 21, 2006, the Company s Board of Directors informed Hein & Associates LLP, certified public accountants, that such firm was appointed as the Company s independent registered accounting firm effective immediately. We dismissed Hein & Associates LLP as our principal accountant effective March 1, 2007. Hein & Associates LLP s aggregate fees were approximately $22,248 for audit services for the fiscal year ended June 30, 2007.

(b) **Audit-Related Fees.**

Gordon, Hughes & Banks, LLP billed us aggregate fees in the amount of $515 and $7,640 for the fiscal years ended June 30, 2008 and 2007 for assurance and related services that were reasonably related to the performance of the audit or review of our financial statements.

(c) **Tax Fees.**

Gordon, Hughes & Banks, LLP billed us aggregate fees in the amount of approximately $7,395 for the fiscal year ended June 30, 2008, and $14,645 for the fiscal year ended June 30, 2007, for tax compliance, and tax planning.

(d) **All Other Fees.**

Gordon, Hughes & Banks, LLP billed us aggregate fees in the amount of $0 for the fiscal years ended June 30, 2008 and 2007 for other fees.

(e) **Audit Committee s Pre-Approval Practice.**

Inasmuch as Aspen does not have an audit committee, Aspen s board of directors performs the functions of its audit committee. Section 10A(i) of the Securities Exchange Act of 1934 prohibits our auditors from performing audit services for us as well as any services not considered to be audit services unless such services are pre-approved by the board of directors (in lieu of the audit committee) or unless the services meet certain *de minimis* standards.

The board of directors has adopted resolutions that provide that the board must:

Preapprove all audit services that the auditor may provide to us or any subsidiary (including, without limitation, providing comfort letters in connection with securities underwritings or statutory audits) as required by §10A(i)(1)(A) of the Securities Exchange Act of 1934 (as amended by the Sarbanes-Oxley Act of 2002).

Preapprove all non-audit services (other than certain *de minimis* services described in §10A(i)(1)(B) of the Securities Exchange Act of 1934 (as amended by the Sarbanes-Oxley Act of 2002) that the auditors propose to provide to us or any of its subsidiaries.

The board of directors considers at each of its meetings whether to approve any audit services or non-audit services. In some cases, management may present the request; in other cases, the auditors may present the request. The board of directors has approved Gordon, Hughes & Banks, LLP performing our audit and tax services for the 2007 and 2008 fiscal years.

The percentage of the fees for audit, audit-related, tax and other services were as set forth in the following table:

	Hein & Associates Fiscal Year Ended June 30,		Gordon Hughes & Banks LLP Fiscal Year Ended June 30,	
	2008	2007	2008	2007
Audit fees	100%	100%	86%	28%
Audit-related fees	0%	0%	1%	25%
Tax fees	0%	0%	13%	47%
All other fees	0%	0%	0%	0%

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

September 29, 2008

ASPEN EXPLORATION CORPORATION,
a Delaware Corporation

By: /s/ R. V. Bailey
R. V. Bailey
Chief Executive Officer, Chairman of the Board, Director

Pursuant to the requirement of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated:

Date	Name and Title	Signature
September 29, 2008	R. V. Bailey Chief Executive Officer Chairman of the Board, Director	/s/ R. V. Bailey
September 29, 2008	Kevan B. Hensman Chief Financial Officer Director	/s/ Kevan B. Hensman
September 29, 2008	Robert A. Cohan President Director	/s/ Robert A. Cohan

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors
Aspen Exploration Corporation and Subsidiary
Denver, Colorado

We have audited the accompanying consolidated balance sheets of Aspen Exploration Corporation and Subsidiary (the Company) as of June 30, 2008 and 2007, and the related statements of operations, stockholders equity and comprehensive income, and cash flows 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 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Aspen Exploration Corporation and Subsidiary as of June 30, 2008 and 2007, and the results of its consolidated operations and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ Gordon, Hughes & Banks, LLP

Greenwood Village, Colorado
September 16, 2008

ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY CONSOLIDATED BALANCE SHEETS

JUNE 30, 2008 AND 2007

	June 30, 2008	June 30, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,595,150	$ 4,057,279
Marketable securities	930,818	1,120,485
Accounts and trade receivables	2,287,519	2,136,609
Other current assets	39,474	33,609
Total current assets	4,852,961	7,347,982
Property and equipment		
Oil and gas property	23,677,355	19,802,843
Support equipment	183,374	184,514
	23,860,729	19,987,357
Accumulated depletion and impairment - full cost pool	(10,479,466)	(8,083,383)
Accumulated depreciation - support equipment	(70,570)	(49,304)
Net property and equipment	13,310,693	11,854,670
Other assets:		
Deposits	263,650	263,650
Deferred income taxes	1,573,500	1,673,000
Total other assets	1,837,150	1,936,650
Total assets	$ 20,000,804	$ 21,139,302

(Statement Continues)

See accompanying notes to these consolidated financial statements.

ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS (Continued)
JUNE 30, 2008 AND 2007

	June 30, 2008	June 30, 2007
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 2,260,611	$ 2,961,100
Other current liabilities and accrued expenses	620,875	1,690,709
Notes payable - current portion	475,000	275,000
Asset retirement obligation, current portion	56,400	39,400
Deferred income taxes, current	122,000	342,000
Total current liabilities	3,534,886	5,308,209
Long-term liabilities		
Notes payable, net of current portion	116,667	591,667
Asset retirement obligation, net of current portion	675,955	447,253
Deferred income taxes	3,971,500	3,786,000
Total long-term liabilities	4,764,122	4,824,920
Stockholders' equity:		
Common stock, $.005 par value:		
Authorized: 50,000,000 shares		
Issued and outstanding: At June 30, 2008,		
and June 30, 2007, 7,259,622 shares	36,298	36,298
Capital in excess of par value	7,676,458	7,501,789
Accumulated other comprehensive loss	(281,849)	-
Retained earnings	4,270,889	3,468,086
Total stockholders' equity	11,701,796	11,006,173
Total liabilities and stockholders' equity	$ 20,000,804	$ 21,139,302

See accompanying notes to these consolidated financial statements.

ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED JUNE 30, 2008 AND 2007

	Year Ended June 30, 2008	Year Ended June 30, 2007
Revenues:		
Oil and gas sales	$ 5,390,367	$ 4,418,231
Operating expenses:		
Oil and gas production	1,463,415	837,155
Accretion, and depreciation, depletion and amortization	2,451,417	2,018,550
Selling, general and administrative	621,463	850,847
Total operating expenses	4,536,295	3,706,552
Income from operations	854,072	711,679
Other income (expenses)		
Interest and other income	117,354	136,411
Interest and other (expenses)	(63,678)	(36,709)
Gain (loss) on investments	4,834	717,878
Gain on sale of equipment	-	12,000
Total other income (expenses)	58,510	829,580
Income before income taxes	912,582	1,541,259
Provision for income taxes	(109,779)	(615,990)
Net income	$ 802,803	$ 925,269
Basic net income per share	$ 0.11	$ 0.13
Diluted net income per share	$ 0.11	$ 0.13
Weighted average number of common shares outstanding used to calculate basic net income per share :	7,259,622	7,213,992
Effect of dilutive securities:		
Equity based compensation	113,455	166,778
Weighted average number of common shares outstanding used to calculate diluted net income per share :	7,373,077	7,380,770

See accompanying notes to these consolidated financial statements.

ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
FOR THE YEARS ENDED JUNE 30, 2008 AND 2007

	Common Stock			Accumulated (Deficit)	Accumulated Other		
	Shares	Par Value	APIC	Retained Earnings	Comprehensive Income (Loss)	Deferred Compensation	T Eq
Balances at July 1, 2006	7,094,641	$ 35,473	$ 7,283,914	$ 2,900,798	$ -	$ (119,233)	$ 10,1
Options exercised by employees	167,000	835	94,355	-	-	-	9
Stock forfeited by employees	(2,019)	(10)	(9,680)	-	-	-	
Compensation expense per FAS 123R	-	-	133,200	-	-	-	1
Amortization of deferred compensation	-	-	-	-	-	119,233	1
Payment of cash dividends	-	-	-	(357,981)	-	-	(3
Net income	-	-	-	925,269	-	-	9
Balances at June 30, 2007	7,259,622	$ 36,298	$ 7,501,789	$ 3,468,086	$ -	$ -	$ 11,0
Compensation expense per FAS 123R	-	-	174,669	-	-	-	1
Unrealized loss on marketable securities	-	-	-	-	(281,849)	-	(2
Net income	-	-	-	802,803	-	-	8
Balances at June 30, 2008	7,259,622	$ 36,298	$ 7,676,458	$ 4,270,889	$ (281,849)	$ -	$ 11,7

See accompanying notes to these consolidated financial statements.

ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED JUNE 30, 2008 AND 2007

	Year Ended June 30, 2008	Year Ended June 30, 2007
Cash Flows from Operating Activities:		
Net income	$ 802,803	$ 925,269
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion and depreciation, depletion, and amortization	2,451,417	2,018,550
Deferred income taxes	252,888	615,990
Amortization of deferred compensation	-	119,233
Compensation expense related to stock options granted	174,669	133,200
Realized (gain) on marketable securities	-	(559,949)
Unrealized (gain) on marketable securities	-	(157,930)
Proceeds from sale of marketable securities	-	599,921
(Gain) on sale of vehicle	-	(12,000)
Changes in assets and liabilities:		
(Increase) decrease in current assets other than cash, cash equivalents, and short-term marketable securities	(156,775)	218,996
Increase (decrease) in current liabilities other than notes payable and asset retirement obligation	(1,770,323)	(1,358,636)
Net Cash Provided by Operating Activities	1,754,679	2,542,644
Cash Flows from Investing Activities:		
Additions to oil and gas properties	(3,662,878)	(4,018,136)
Sales of securities	19,930	-
(Purchases) of securities	(300,000)	-
Producing oil and gas properties purchased	-	(1,450,000)
Additions to property and equipment	-	(89,425)
Sale of property and equipment	1,140	12,000
Net Cash (Used in) Investing Activities	(3,941,808)	(5,545,561)
Cash Flows from Financing Activities:		
Proceeds from exercise of stock options	-	85,500
Proceeds from issuance of long-term debt	-	975,000
Payment of long-term debt	(275,000)	(108,333)
Payment of cash dividends	-	(357,981)
Net Cash Provided by (Used in) Financing Activities	(275,000)	594,186
Net Increase (Decrease) in Cash and Cash Equivalents	(2,462,129)	(2,408,731)
Cash and Cash Equivalents, beginning of year	4,057,279	6,466,010
Cash and Cash Equivalents, end of year	$ 1,595,150	$ 4,057,279

Supplemental disclosures of cash flow information:				
Interest paid	$	63,678	$	30,093
Income taxes paid	$	800	$	800
Supplemental non-cash activity				
Increase in asset retirement obligation	$	223,782	$	116,602
Notes payable assumed	$	-	$	375,000

See accompanying notes to these consolidated financial statements.

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Aspen Exploration Corporation (the Company or Aspen) was incorporated under the laws of the State of Delaware on February 28, 1980 for the primary purpose of acquiring, exploring and developing oil and gas properties. The Company is currently engaged primarily in the exploration and development of oil and gas properties in California and has a significant working interest in oil wells in the Poplar Field of northern Montana.

Oil and Gas Exploration and Development. The major emphasis has been participation in the oil and gas segment acquiring interests in producing oil or gas properties and participating in drilling operations. The Company engages in a broad range of activities associated with the oil and gas business in an effort to develop oil and gas reserves. With the assistance of management, independent contractors retained from time to time by Aspen, and, to a lesser extent, unsolicited submissions, the Company has identified and will continue to identify prospects believed to be suitable for drilling and acquisition. The Company s primary area of interest is in the state of California where the Company has acquired a number of interests in oil and gas properties; in 2008, we acquired a working interest in 84 oil wells in the State of Montana, all as described below in more detail. In addition, the Company also acts as operator for a number of our producing wells and receives management fees for these services, which serve to offset our selling, general, and administrative expenses.

A summary of the Company's significant accounting policies follows:

Consolidated Financial Statements

The consolidated financial statements include the Company and its wholly-owned subsidiary, Aspen Gold Mining Company. Significant intercompany accounts and transactions, if any, have been eliminated. The subsidiary is currently inactive.

Cash and Cash Equivalents

For statement of cash flows purposes, short-term investments with original maturities of three months or less are considered to be cash equivalents. Cash restricted from use in operations beyond three months is not considered cash equivalents.

Management's Use of Estimates

Accounting principles generally accepted in the United States of America require certain estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent liabilities at the date of the financial statements and reported amounts of revenues and expenses to be made. Actual results could differ from those estimates. The Company s significant estimates include estimated life of long-lived assets, use of reserves in the estimation of depletion of oil and gas properties, impairment of oil and gas properties, asset retirement obligation abilities, and income taxes.

The mining and oil and gas industries are subject, by their nature, to environmental hazards and cleanup costs for which the Company carries catastrophe insurance. At this time, there is no known substantial costs from environmental accidents or events for which the Company may be currently liable. In addition, the oil and gas business makes it vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future. By definition, proved reserves are based on current oil and gas prices and estimated reserves. Price declines reduce the estimated quantity of proved reserves and increase annual depletion expense (which is based on proved reserves).

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Impairment of Long-Lived Assets

Long-lived assets and identifiable intangibles are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the expected undiscounted future cash flow from the use of the assets and their eventual disposition is less than the carrying amount of the assets, an impairment loss is recognized and measured using the asset s fair value or discounted cash flows.

Financial Instruments

The carrying value of current assets and liabilities reasonably approximates their fair value due to their short maturity periods.

Investments in Debt and Equity Securities

Prior to the beginning of the current fiscal year, the Company classified all investments as Trading Securities in accordance with SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities. These securities were marked to market each period with the realized and unrealized gain or loss recorded in the statement of operations. The unrealized holding gain or loss at the date of the transfer (July 1, 2007), to the classification as available for sale, as described below, has already been recognized in earnings and shall not be reversed.

During the first quarter, management reassessed the appropriateness of the classification of the securities held, and determined that due to the sufficiency of the Company s cash flows to finance current operations and budgeted expenditures, the Company will hold investments until such time it determines there may be a need to sell those securities, or the company determines a sale to be in its best interest. Consequently, as of July 1, 2007, Management determined the securities are more appropriately classified as available for sale, and changes in the fair value of the securities are reported as a separate component of shareholders equity until realized. Gains and losses are no longer a component of the Company s Statement of Operations. Aspen uses the specific identification method to determine the cost of securities sold.

At June 30, 2008, the fair value of securities available for sale was $930,818. The net unrealized holding (loss) reported as a separate component of shareholders equity during the twelve months ended June 30, 2008, on securities still held as of June 30, 2008, was ($281,849), net of income tax of ($187,888).

Oil and Gas Properties

The Company follows the "full-cost" method of accounting for our oil and gas properties. Under this method, all costs associated with property acquisition, exploration and development activities, are capitalized within one cost center. No gains or losses are recognized on the receipt of prospect fees or on the sale or abandonment of oil and gas properties, unless the disposition of significant reserves is involved.

Depletion and amortization of our full-cost pool is computed using the units-of-production method based on proved reserves as determined annually by the Company and independent petroleum engineer. Capitalized costs related to unproved and developmental properties are immaterial as of June 30, 2008 and 2007, and are included in the amortization computation. An additional depletion provision in the form of a valuation allowance is made if the costs incurred on oil and gas properties, or revisions in reserve estimates, cause the total capitalized costs of oil and gas properties in the cost center to exceed the capitalization ceiling. The capitalization ceiling is the sum of (1) the present value of our future net revenues from estimated production of proved oil and gas reserves applicable to the cost center (using a 10% discount factor) plus (2) the lower of cost or estimated fair value of our cost center's unproved properties less (3) applicable income tax effects. The valuation allowance was $281,720 at June 30, 2008 and 2007 (Note 6). The Company has adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. Prior to adopting Statement 143, in calculating the full cost ceiling, we reduced the expected future revenues from proved oil and gas reserves by the estimated future expenditures to be incurred in developing and producing such reserves discounted using a specified factor. While expected future cash flows related to the asset retirement obligation (ARO) were included in the calculation of the ceiling test, no associated asset was recorded. Under Statement 143, we must recognize a liability for an asset retirement obligation at fair value in the period in which the obligation is incurred. The company also must initially capitalize the associated asset retirement costs by increasing long-lived oil and gas assets by the same amount as the liability. Any asset retirement costs capitalized pursuant to Statement 143 are subject to the full cost ceiling limitation under Rule 4-10(c)(4) of Regulation S-X.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Oil and Gas Properties (Continued)

All capitalized costs are depleted on a composite units-of-production method based on estimated proved reserves attributable to the oil and gas properties owned by Aspen. Depletion and amortization expense was $2,396,083 and $1,964,504 for the years ended June 30, 2008 and 2007, respectively. Depletion expense per equivalent unit of production (MCFe) was $3.65 and $3.25 for 2008 and 2007, respectively.

Property and Equipment

Depreciation and amortization of property and equipment are expensed in amounts sufficient to relate the expiring costs of depreciable assets to operations over estimated service lives, principally using the straight-line method. Estimated service lives range from three to eight years. When assets are sold or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is reflected in operations in the period realized. Depreciation expense was $21,266 and $54,046 for the years ended June 30, 2008 and 2007, respectively.

Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount. We do not have any off-balance-sheet credit exposure related to our customers. We assess credit risk and allowance for doubtful accounts on a customer specific basis. Aspen s policy is not to grant long-term credit to customers, and to deal only with customers well-known in the oil and gas industry and with sufficient financial capability to meet its obligations. At June 30, 2008, except for immaterial amounts, all of our production was sold to 3 customers. Each of these customers is well known in the industry and to management and management believes each customer to have sufficient financial capability. As of June 30, 2008 and 2007, we do not have an allowance for doubtful accounts.

Revenue Recognition

Sales of oil and gas production are recognized at the time of delivery of the product to the purchaser.

Earnings Per Share

The Company follows Statement of Financial Accounting Standards (SFAS) No. 128, addressing earnings per share. SFAS No. 128 established the methodology of calculating basic earnings per share and diluted earnings per share. The calculations differ by adding any instruments convertible to common stock (such as stock options, warrants, and convertible preferred stock) to weighted average shares outstanding when computing diluted earnings per share.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Earnings Per Share (Continued)

The following is a reconciliation of the numerators and denominators used in the calculations of basic and diluted earnings per share.

	Year Ended June 30,					
	2008			2007		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic Earnings Per Share:						
Net income and share amounts	$ 802,803	7,259,622	$ 0.11	$ 925,269	7,213,992	$ 0.13
Effect of Dilutive Securities:						
Stock Options	-	113,455	-	-	166,778	-
Diluted Earnings Per Share:						
Net income and assumed share conversion	$ 802,803	7,373,077	$ 0.11	$ 925,269	7,380,770	$ 0.13

Income Taxes

The Company uses the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities. Deferred tax assets or liabilities at the end of each period are determined using the tax rate in effect at that time. The Company adopted FASB interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes, effective July 1, 2007*. Fin 48 requires that amounts recognized in the Balance Sheet related to uncertain tax positions be classified as a current or noncurrent liability, based upon the expected timing of the payment to a taxing authority. The Company had no material uncertain tax positions as of June 30, 2008 or 2007.

The total future deferred income tax liability is extremely complicated for any energy company to estimate due in part to the long-lived nature of depleting oil and gas reserves and variables such as product prices. Accordingly, the liability is subject to continual recalculation, revision of the numerous estimates is required, and may change significantly in the event of such things as major acquisitions, divestitures, product price changes, changes in reserve estimates, changes in reserve lives, and changes in tax rates or tax laws.

See Note 3 below.

Equity-Based Compensation

We adopted SFAS No. 123(R) beginning July 1, 2006. Prior to July 1, 2006, the Company accounted for these plans under the recognition and measurement provisions of Accounting Principles Board ("APB") Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, as permitted by Statement of Financial Accounting Standards("SFAS") No. 123, Accounting for Stock-Based Compensation. No stock-based employee compensation expense was recognized in the Company's Consolidated Statement of Operations prior to July 1, 2006, as all options granted under the Company's stock-based compensation plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective July 1, 2006, the Company adopted the fair value recognition provisions of SFAS No. 123 (R), Share Based Payment, using the modified-prospective transition method as described in SFAS No. 148, Accounting for Stock-Based Compensation - Transition and Disclosure. Under this method, compensation cost recognized in fiscal 2007 is the same as that which would have been recognized had the recognition provisions of Statement 123(R) been applied from its original effective date. See Note 2 below.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Equity-Based Compensation (Continued)

The adoption of SFAS 123(R) resulted in stock compensation expense for the years ended June 30, 2008 and 2007 of $174,669 and $133,200, respectively, to income from continuing operations and income before income taxes. This expense reduced our basic and diluted earnings per share by approximately $0.24 and $0.18 for the year ended June 30, 2008.

Recently Issued Pronouncements

In September 2006, Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* was issued by the Financial Accounting Standards Board (FASB). This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 will become effective for the Company s fiscal year beginning after November 15, 2007, and the Company is currently assessing the potential impact of this Statement on its financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity s election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. This statement was effective beginning January 1, 2008 and did not have a material effect on the Company s financial statements of this pronouncement.

In December 2007, FASB issued SFAS No. 160, *Noncontrollnig Interests in Consolidated Financial Statements*, which amends Accounting Research Bulletin (ARB) No. 51 and (1) establishes standards of accounting and reporting on noncontrolling interests in consolidated statements, (2) provides guidance on accounting for changes in the parent's ownership interest in a subsidiary, and (3) establishes standards of accounting of the deconsolidation of a subsidiary due to the loss of control. The amendments to ARB No. 51 made by SFAS No. 160 are effective for fiscal years (and interim period within those years) beginning on or after December 15, 2008. The Company is currently assessing the potential impact this statement on its financial statements.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, which expands the information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement establishes principles and requirements for how the acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply it before that date. We may experience a financial statement impact depending on the nature and extent of any new business combinations entered into after the effective date of SFAS No. 141(R).

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Recently Issued Pronouncements (Continued)

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* an amendment of FASB Statement No. 133, which changes the disclosure requirements for derivative instruments and hedging activities. Enhanced disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement will require the additional disclosures described above.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This Statement is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. We do not expect the adoption of SFAS 162 to have a material effect on our financial statements or related disclosures.

NOTE 2 EQUITY COMPENSATION PLANS

Stock Options

Effective July 1, 2006, the Company adopted the fair value recognition provisions of Statement of Financial Accounting Standard 123(R) Share-Based Payment (SFAS 123(R)) using the modified prospective transition method. In addition, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 107 Share-Based Payment (SAB 107) in March, 2005, which provides supplemental SFAS 123(R) application guidance based on the views of the SEC. Under the modified prospective transition method, compensation cost recognized for the year ended June 30, 2008 include: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of July 1, 2007, 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 July 1, 2007, based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R). In accordance with the modified prospective transition method, results for prior periods have not been restated.

We have three stock option plans as of June 30, 2008, Option Plan #2, effective March 14, 2002, Option Plan #3, effective April 27, 2005, and The 2008 Equity Plan . There were an aggregate of 1,936,000 common shares reserved for issuance under our stock option plans. These plans provided for the issuance of 676,000, 260,000, and 1,000,000 common shares, respectively, pursuant to stock option exercises. The fair value of each option grant, as opposed to its exercise price, is estimated on the date of grant using the Black-Scholes option-pricing model. The options issued under the 2008 Option Plan were valued using with the following weighted average assumptions: no dividend yield, expected volatility of 58%, risk free interest rates of 2.25% and expected lives of 3.3 years. Expected volatility was calculated based upon actual historical stock price movements over the most recent periods through the date of issuance, equal to the expected option term. Expected pre-vesting forfeitures were assumed to be zero. The expected option term was calculated using the simplified method permitted by SAB 107.

Additionally, 10,000 options were granted to a non-employee director on September 11, 2006. The fair value of those options was estimated using the Black-Scholes option-pricing model with the following assumptions: no dividend yield, expected volatility of 73%, risk free interest rates of 4.97% and expected life of 5 years.

NOTE 2 EQUITY COMPENSATION PLANS (Continued)

Stock Options (Continued)

The following information summarizes information with respect to options granted under equity plans:

	Number of Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at July 1, 2006	502,000	$ 1.55		
Granted	10,000	3.70		
Exercised	(167,000)	0.57		
Forfeited or expired	(115,000)	1.76		
Outstanding at June 30, 2007	230,000	$ 2.26	2.28	$ 333,500
Granted	775,000	2.14		
Exercised	-	-		
Forfeited or expired	(117,902)	2.14		
Outstanding at June 30, 2008	887,098	$ 2.17	3.79	$ 558,872
Exercisable at June 30, 2007	123,334	$ 2.75	2.65	$ 118,401
Exercisable at June 30, 2008	370,431	$ 2.21	2.56	$ 218,554

The grant-date fair value of options granted during the period was $702,929. No options were exercised during the period ending June 30, 2008.

A summary of the status of the Company s nonvested shares underlying the options outstanding as of June 30, 2008 and 2007, and changes during the years then ended are presented below:

	Number of Shares	Weighted-Average Grant-Date Fair Value
Nonvested at July 1, 2006	256,666	$ 1.85
Granted	-	-
Vested	(106,667)	1.69
Forfeited	(43,333)	2.67
Nonvested at June 30, 2007	106,666	$ 1.69
Granted	775,000	0.91

Vested	(247,097)		1.00
Forfeited	(117,902)		0.91
Nonvested at June 30, 2008	516,667	$	0.91

NOTE 2 EQUITY COMPENSATION PLANS (Continued)

The total compensation cost related to nonvested awards not yet recognized on June 30, 2008 is approximately $291,000, net of tax, and the weighted average period over which this cost is expected to be recognized is 2 years. The total fair value of options vested during the period was $691,872.

Stock Options (Continued)

The following table summarizes information concerning outstanding and exercisable options as of June 30, 2008:

	Outstanding			Exercisable	
Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life in Years (1)	Weighted Average Exercisable Price	Number Exercisable	Weighted Average Exercisable Price
$ 0.57	50,000	0.13	$ 0.57	50,000	$ 0.57
2.67	170,000	1.51	2.67	170,000	2.67
3.70	10,000	3.20	3.70	10,000	3.70
2.14	657,098	4.67	2.14	140,431	2.14
	887,098	3.79	$ 2.17	370,431	$ 2.21

(1) The term of the option will be the earlier of the contractual life of the options or 90 days after the date the optionee is no longer an employee, consultant or director of the Company.

No options were exercised during the current fiscal year.

NOTE 3 INCOME TAXES

The Company recorded deferred income tax assets of $1,573,500 and $1,673,000, and deferred income tax liabilities of approximately $4,093,500 and $4,128,000 as of June 30, 2008 and 2007, respectively. The Company paid $800 in California state income taxes in fiscal 2008.

The deferred tax consequences of temporary differences in reporting items for financial statement and income tax purposes are recognized, if appropriate. Realization of future tax benefits related to the deferred tax assets is dependent on many factors, including the ability to generate taxable income within the carryforward period. The Company had approximately $219,500 in net operating loss carryforwards at June 30, 2007 expiring June 30, 2027, and an additional $494,500 at June 30, 2008, which will expire June 30, 2028. The Company has considered these factors in reaching our conclusion as to the valuation allowance for financial reporting purposes and believe it more likely than not that the benefit will be realized.

NOTE 3 INCOME TAXES (Continued)

The income tax effect of temporary differences comprising the deferred tax assets and deferred tax liabilities on the accompanying balance sheets is the result of the following:

	2008	2007
Deferred tax assets:		
NOL and percentage depletion carryforward	$ 896,500	$ 1,129,000
State income tax expense	341,000	292,000
Equity based compensation	99,500	54,000
Asset retirement obligation	236,500	198,000
	1,573,500	1,673,000
Deferred tax (liabilities):		
Oil and gas properties	(3,959,500)	(3,774,000)
Property, plant, and equipment	(12,000)	(12,000)
Gain on Investments	(122,000)	(342,000)
	(4,093,500)	(4,128,000)
	$ (2,520,000)	$ (2,455,000)

A reconciliation between the statutory federal income tax rate and the effective rate of income tax expense for the two years ended June 30 is as follows:

	2008	2007
Statutory federal income tax rate	35%	35%
Statutory state income tax rate, net of federal benefit	5%	6%
Recognition of tax basis of properties	-27%	-2%
Blended State Rate Change/Other	-1%	1%
Effective rate	12%	40%

The provision for income taxes consists of the following components:

	2008	2007
Current tax expense/(benefit)	$ 44,779	$ 342,000
Deferred tax expense	65,000	273,990
Total income tax provision	$ 109,779	$ 615,990

NOTE 4 RELATED PARTY TRANSACTIONS

During fiscal 2008, the Company assigned the following overrides to employees:

	R.V. Bailey percent	**R.A. Cohan percent**	**J.L. Shelton percent**
Johnson unit 13	1.260000	1.260000	0.480000
SJDD 11-1	1.360000	2.000000	0.640000
Delta Farms 10	0.816000	1.200000	0.384000
Eastby 1-1	0.906661	1.333325	0.426664

The Company has an "Amended Royalty and Working Interest Plan" by which the Company, in our discretion, is able to assign overriding royalty interests or working interests in oil and gas properties or in mineral properties. This plan is intended to provide additional compensation to Aspen's personnel involved in the acquisition, exploration and development of Aspen's oil or gas or mineral prospects. Since the Company only assigns interests under the Amended Royalty and Working Interest Plan from properties that are unproven or exploratory, those interests are deemed to have no value and consequently Aspen recognizes no compensation expense and the employees recognize no income from the assignment. If drilling on such property occurs in the future and results in a well capable of production, the employees holding royalty interests will recognize income as royalty income is received.

R. V. Bailey, Chief Executive Officer and director of the Company, Robert A. Cohan, President and director of the Company, have working and royalty interests in certain of the California oil and gas properties operated by us. Mr. Bailey and Mr. Cohan purchased working interests from the Company amounts totaling $220,490 and $109,790, respectively, for the year ended June 30, 2008, and $263,690 and $131,250, respectively, for the year ended June 30, 2007. The related parties paid for their proportionate working interest share of all costs to acquire, develop and operate these properties on the same terms as other unaffiliated participants. Mr. Bailey and Mr. Cohan also received royalty interest payments totaling $102,927 and $145,873, respectively, for the year ended June 30, 2008, and $66,196 and $88,268, respectively, for the year ended June 30, 2007. These royalties relate to the royalties assigned to employees as described above, and the royalties that were assigned in prior years. As of June 30, 2008, working interests of Aspen and related parties in certain producing California properties are as set forth below (unaudited):

	Gross Wells Gas	Net Wells Gas
Aspen Exploration	88	19.17
R. V. Bailey	67	2.14
R. A. Cohan	67	1.20
J.L. Shelton	52	0.12

The Company has remaining advances from Messrs. Bailey and Cohan for working interests of $5,600 and $10,307, respectively, as of June 30, 2008 and $79,799 and $33,267 as of June 30, 2007, respectively, and are recorded in other current liabilities and accrued expenses in the accompanying balance sheets.

NOTE 5 DIVIDENDS

We paid a special dividend of $.05 per share on December 6, 2006 totaling $357,981 to shareholders of records as of November 20, 2006. No dividends were declared or paid during the fiscal year ended June 30, 2008.

NOTE 6 OIL AND GAS ACTIVITIES

Capitalized Costs

Capitalized costs associated with oil and gas producing activities are as follows:

	June 30, 2008	June 30, 2007
Proved properties	$ 23,677,355	$ 19,802,843
Accumulated depreciation, depletion, and amortization	(10,197,746)	(7,801,663)
Valuation allowance	(281,720)	(281,720)
	(10,479,466)	(8,083,383)
Net capitalized costs	$ 13,197,889	$ 11,719,460

At the date of acquisition of the properties, certain undeveloped properties were also acquired. The value assigned to these properties was nominal as it was determined the fair value of the properties was immaterial at the time of acquisition.

Results of Operations

Results of operations for oil and gas producing activities are as follows:

	Year Ended June 30, 2008	Year Ended June 30, 2007
Revenues	$ 5,390,367	$ 4,418,231
Production costs	(1,463,415)	(837,155)
Depreciation, depletion and accretion	(2,451,415)	(2,018,550)
Results of operations (excluding corporate overhead)	$ 1,475,537	$ 1,562,526

Acquisition, Exploration and Development Costs

	2008	2007
Property acquisition costs net of divestiture proceeds	$ 30,000	$ 1,450,000
Exploration	3,632,878	4,018,136
Development	-	-
Total before asset retirement obligation	$ 3,662,878	$ 5,468,136
Total including asset retirement obligation:		
Acquisitions	$ 30,000	$ 109,250
Exploration	3,844,512	5,418,951
Development	-	-
Total	$ 3,874,512	$ 5,528,201

Fees charged by Aspen to operate the properties totaled approximately $607,000 and $513,000 for the years ended 2008 and 2007, respectively, and are recorded as reductions to SG&A in the accompanying Statement of Operations.

NOTE 6 OIL AND GAS ACTIVITIES (Continued)

Unaudited Oil and Gas Reserve Quantities

The following unaudited reserve estimates presented as of June 30, 2008 and 2007 were prepared by an independent petroleum engineer. There are many uncertainties inherent in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. In addition, reserve estimates of new discoveries that have little production history are more imprecise than those of properties with more production history. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and gas reserves are the estimated quantities of crude oil, condensate, 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, i.e., process and costs as of the date the estimate is made.

Proved developed oil and gas reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods.

Unaudited net quantities of proved developed reserves of crude oil (including condensate) and natural gas (all located within the United States) are as follows:

	(Bbls)	(MCF)
	(in thousands)	
Estimated quantity, July 1, 2006	2	2,751
Revisions of previous estimates	-	(326)
Acquisitions	132	-
Discoveries	-	874
Production	(4)	(598)
Estimated quantity, June 30, 2007	130	2,701
Revisions of previous estimates	72	(337)
Discoveries	-	383
Production and Sales	(11)	(596)
Estimated quantity, June 30, 2008	191	2,151

Changes in Proved Reserves

Proved Reserves at Year End	Developed Producing	Developed Non-Producing	Total
		(in thousands)	
Oil (Bbls)			
June 30, 2008	158	33	191
June 30, 2007	99	31	130
Gas (MCF)			
June 30, 2008	889	1,262	2,151
June 30, 2007	959	1,742	2,701

NOTE 6 OIL AND GAS ACTIVITIES (Continued)

Unaudited Standardized Measure

The following information has been developed utilizing procedures prescribed by SFAS 69 Disclosures About Oil and Gas Producing Activities and based on crude oil and natural gas reserves and production volumes estimated by the Company. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative or realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

Future cash inflows were computed by applying year-end prices of oil and gas to the estimated future production of proved oil and gas reserves. The future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved oil and gas reserves and the tax basis of proved oil and gas properties and available net operating loss carryforwards. Discounting the future net cash inflows at 10% is a method to measure the impact of the time value of money.

	June 30, 2008	June 30, 2007
	(in thousands)	
Future cash inflows	$ 46,843	$ 26,015
Future production costs	(22,108)	(4,534)
Future development costs	(229)	(306)
Future income tax expense	(8,658)	(8,628)
Future cash flows	15,848	12,547
10% annual discount for estimated timing of cash flows	(5,579)	(4,513)
Standardized measure of discounted future net cash	$ 10,269	$ 8,034

NOTE 6 OIL AND GAS ACTIVITIES (Continued)

Unaudited Standardized Measure (Continued)

The following presents the principal sources of the changes in the standardized measure of discounted future net cash flows:

	Years Ended June 30, 2008	2007
	(in thousands)	
Standardized measure of discounted future net cash flows, beginning of year	$ 8,034	$ 5,104
Sales and transfers of oil and gas produced, net of production costs	(3,927)	(3,581)
Net changes in prices and production costs and other	2,246	1,846
Net change due to discoveries	1,773	2,625
Acquisition of reserves	-	3,129
Revisions of previous quantity estimates	71	(269)
Development costs incurred	889	306
Accretion of discount	803	1,306
Net change in income taxes	539	(2,130)
Other	(159)	(302)
	2,235	2,930
Standardized measure of discounted future net cash flows, end of year	$ 10,269	$ 8,034

Net changes in prices and production costs of $2.2 million were the result of an increase in the price received for gas at year end which was offset slightly by an increase in operating costs associated with more producing gas wells in 2008 than in 2007. The revision of previous estimates of $71,000 was the result of reducing recoverable reserves of gas by approximately 337,000 MCF, and an increase in oil reserves of 72,000 barrels. All adjustments were based on performance reviews of individual wells.

NOTE 7 PROPERTY ACQUISITIONS

In February 2007, the Company purchased from Nautilus Poplar, LLC, a non-operating working interest in certain oil producing assets encompassing 22,600 acres in the East Poplar Unit and the Northwest Poplar Field in Roosevelt County, Montana located in the Williston Basin. These properties contain a total of 33 producing oil wells, and 7 salt-water disposal wells. Current production is 230 gross BOPD from the Charles B reservoir. Through December 2007, Aspen was obligated to pay 12.5% of the expenses of operations for a 10% working interest. Since Aspen s investment did not reach payout as of January 1, 2008, Aspen s expense obligation was reduced to 10%. At payout, Aspen s working interest will proportionately be reduced also. As of June 30, 2008, there remains $1,315,211 until Aspen reaches payout, based on total revenues received through June 30, 2008 of $984,590. Commencing February 2008, Aspen (and the other working interest participants) agreed that the operator could retain 60% of the cash flow from the producing wells (after deduction of royalties, taxes, expenses and loan payment) for capital projects, geology and engineering (amounting to a total of $96,250 to Aspen s account as of June 30, 2008). The operator has used these funds for capital expenses, workovers and recompletions. Additionally, in May 2008 Aspen amended its participation agreement in the Poplar Unit to separately market and deal with the deeper rights, oil and gas rights below the base of the Mission Canyon Formation and to grant one of the participants the right to seek to farmout the deeper rights. To the extent that Aspen has available capital and has identified other appropriate drilling or exploration opportunities, Aspen may participate in the drilling of additional wells.

NOTE 8 ASSET RETIREMENT OBLIGATION

The Company has adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires the Company to recognize an estimated liability for the plugging and abandonment of all oil and gas wells. A liability for the fair value of an asset retirement obligation with a corresponding increase in the carrying value of the related long-lived asset is recorded at the time a well is completed and ready for production. The increase in the asset will be amortized over time and the Company will recognize accretion expense in connection with the discounted liability over the remaining life of the respective well. Any asset retirement costs capitalized pursuant to Statement 143 are subject to the full cost ceiling limitation under Rule 4-10(c)(4) of Regulation S-X. Inherent in the fair value calculation of ARO are numerous assumptions and judgments including: the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. In 2008, we reassessed our estimate as costs have increased due to demand for these services, resulting in an increase in the ARO balance at year end.

Under SFAS 143, the following table summarizes the change in abandonment obligation for the years ended June 30:

	2008	2007
Beginning balance at July 1	$ 486,653	$ 394,623
Liabilities incurred	80,073	189,256
Liabilities settled	(9,225)	(30,416)
Accretion expense	34,068	31,965
Revision to estimate	140,786	(98,775)
Ending balance at June 30	$ 732,355	$ 486,653

NOTE 9 LONG-TERM DEBT

In January 2007, we borrowed $600,000 from Wells Fargo Bank, NA pursuant to a promissory note payable over thirty-six months to partially finance the acquisition of the Poplar Field discussed in Note 7. Interest on the note is charged at LIBOR plus 2.25% . We subsequently entered into an interest rate swap agreement with Wells Fargo Bank, which fixes the interest rate on the note at 8.10% . Principal of $16,667 plus interest payments are due monthly beginning February 15, 2007 and continuing to January 15, 2010. Collateral consists of a blanket filing on Accounts Receivables. At June 30, 2008 the outstanding balance on the note was $316,667, of which $200,000 is classified as current.

The Wells Fargo note contains restrictive covenants which, among other things, require us to maintain a certain Net Worth defined as total stockholder s equity of not less that $9,000,000 at any time, net income after taxes not less than $1,000 on an annual basis and an EBITDA ratio, as defined. We are currently in compliance with our covenants to Wells Fargo. At June 30, 2008, the outstanding balance was $316,667, of which $200,000 is classified as current.

In February 2007, as part of the Poplar acquisition, Aspen agreed to be responsible for 12.5% of a $3,000,000 loan obtained by Nautilus in connection with the purchase of the Poplar Field assets. Nautilus Poplar, LLC obtained the loan from the Jonah Bank of Wyoming, as lender. Aspen s share of this loan is $375,000 plus interest at a rate of 9.0%, and Aspen is subject to the repayment schedule that Nautilus Poplar negotiated and to the other terms and conditions of the loan agreement as fully as if Aspen were a party to the loan agreement. Aspen s share of principal payments of $6,250 plus interest is due monthly through February 25, 2009. At June 30, 2008, the outstanding balance was $275,000, all of which is classified as current.

NOTE 9 LONG-TERM DEBT (Continued)

Required principle payments on all long-term debt through maturity are as follows:

Year Ended June 30,	Total
2009	$ 475,000
2010	116,667
	$ 591,667

NOTE 10 MAJOR CUSTOMERS

Aspen derived in excess of 10% of revenue from our major customers as follows:

	Company	
Year Ended	A	B
June 30, 2008	33%	61%
June 30, 2007	15%	77%

NOTE 11 CONCENTRATION OF CREDIT RISK

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist principally of cash and cash equivalents, accounts receivable and short-term investments. While as of June 30, 2008 the Company has approximately $3 million in excess of the Federal Deposit Insurance Corporation $100,000 limit at one bank, the Company places cash and cash equivalents with high quality financial institutions in order to limit credit risk. Concentrations of credit risk with respect to accounts receivable are distributed across unrelated businesses and individuals, with the exception of two major gas purchasers and one investor in our wells, who normally settle within 25 days of the previous month s gas purchases. The Company believes its exposure to credit risk is minimal.

Cash equivalents are invested through a quality national brokerage firm and a major regional bank. The cash equivalents consist of liquid short-term investments. The Securities Investor Protection Corporation insures the Fund s accounts at this brokerage firm and a commercial insurer up to the total amount held in the account.

NOTE 12 COMMITMENTS AND CONTINGENCIES

In January 2007 Aspen entered into a venture to explore for gold in Alaska with Hemis Corporation, with offices in Las Vegas, Nevada, whereby Hemis will provide all funding and be the operator of a venture to carry out permit acquisition and exploration for commercial quantities of gold. If such deposits are found, Hemis intends to produce and sell the gold as well as any other commercially valuable minerals that may occur with the gold. Hemis has commenced work to obtain permits for the project.

NOTE 12 COMMITMENTS AND CONTINGENCIES (Continued)

Hemis paid us $50,000 in January 2007 and another $50,000 in August 2007. Hemis was obligated to pay us another $50,000 on or before September 1, 2008 and on each anniversary date until production of gold begins. Hemis did not make the 2008 payment to us, and we have provided notification to Hemis of our intention to terminate that agreement. The agreement will be terminated unless Hemis cures the payment default and certain other defaults within the 30 day notice period. We do not know if Hemis will cure the payment default or contest the existence of the other defaults that Aspen alleged.

In the agreement with Hemis, we retained a 5% gross royalty on production. In June 2007, Hemis announced that it had begun a preliminary oceanographic survey of the gold project and was optimistic regarding the project s potential. Hemis has provided information to us from the 2007 survey.

The Company has entered into a series of gas sales contracts with Enserco and Calpine Producer Services, L.P. In each of the contracts, the purchasers were required to purchase the stated quantities at stated prices, less transportation and other expenses. The contracts contain monetary penalties for non-delivery of the gas. The following table sets forth some additional information about those contracts:

Date of Contract	Purchaser	Term	Fixed Price	Quantity
July 31, 2006	Enserco	11/1/2006-3/31/2007	$10.15 per MMBTU	2,000 MMBTU per day
October 4, 2006	Enserco	12/1/2006-3/31/2007	$7.30 per MMBTU	2,000 MMBTU per day
January 30, 2007	Enserco	4/1/2007-10/31/2007	$7.65 per MMBTU	2,000 MMBTU per day
April 12, 2007	Enserco	11/1/2007-3/31/2008	$9.02 per MMBTU	2,000 MMBTU per day
February 15, 2008	Enserco	4/1/2008-10/31/2008	$8.61 per MMBTU	1,000 MMBTU per day
February 21, 2008	Enserco	4/1/2008-10/31/2008	$8.81 per MMBTU	1,000 MMBTU per day
February 26, 2008	Calpine	4/1/2008-10/31/2008	$8.80 per MMBTU	500 MMBTU per day

We expect to have sufficient gas available for delivery to Enserco and Calpine from anticipated production from our California fields.

Aspen s sales of natural gas under the Enserco and Calpine Contracts qualify for the Normal Purchases and Normal Sales exception in paragraph 10(b) of FAS 133. The contracts contain net settlement provisions should the Company fail to deliver natural gas when required. Those provisions are mutual and establish the sole and exclusive remedy of the parties in the event of a breach of a firm obligation to deliver or receive natural gas. The provisions are summarized as follows:

(i) In the event of a breach by Aspen on any day, Aspen would be required to pay Enserco or Calpine an amount equal to the positive difference, if any, between the purchase price and transportation costs paid by Enserco purchasing replacement natural gas and the amount of Aspen s default; or

(ii) In the event of a breach by Enserco or Calpine on any day, they must pay to Aspen any losses incurred by Aspen after attempting the resale of the natural gas; or

(iii) In the event that Enserco or Calpine have used commercially reasonable efforts to replace the natural gas not delivered by Aspen, or Aspen has used commercially reasonable efforts to sell the undelivered natural gas to a third party and no such replacement or sale is available, the sole and exclusive remedy of the performing party shall be any unfavorable difference between the contract price and the spot price, adjusted for transportation.

The natures of the penalties are based on the current market prices and therefore are variable. Aspen has met its obligations under the contracts since the inception of the contracts, and expects to continue to have sufficient gas available for delivery to fulfill current contractual delivery quantity obligations from anticipated production from the Company s California fields.

NOTE 12 COMMITMENTS AND CONTINGENCIES (Continued)

The Company has the following commitments for exploration in the next fiscal year:

Area	Wells	Drilling Costs	Completion & Equipping Costs	Total
West Grimes Gas Field Colusa County, CA	2	$ 480,000	$ 288,000	$ 768,000
Total Expenditure	2	$ 480,000	$ 288,000	$ 768,000

The proposed drilling budget only includes the wells that we have already budgeted. It can be expected that we will drill several wells in addition to the two included in our current budget. We have not identified locations for those additional drilling activities, however.

Employment Contracts and Termination of Employment and Change in Control Arrangements

Mr. Bailey: Effective May 1, 2003 the Company entered into an employment agreement with Chairman of the Board, R. V. Bailey. Some of the pertinent provisions include an employment period ending May 1, 2009, the title of Vice President subject to the general direction of the President, Robert A. Cohan, and the Board of Directors of Aspen. Mr. Bailey s salary will be $45,000 per year from May 1, 2003 to December 31, 2006 and $60,000 per year from January 1, 2007, ending May 1, 2009. Mr. Bailey will also participate in Aspen s stock options and royalty interest programs. During the term of the agreement, the Company has agreed to pay Mr. Bailey a monthly $1,700 allowance to cover such items as prescriptions, medical and dental coverage for himself and his dependents and other expenses not covered in the agreement.

Mr. Bailey will continue to use the Company vehicle and may trade the current vehicle for a similar vehicle of his choice prior to June 30, 2007. A vehicle was purchased for Mr. Bailey in 2006. During 2007 or thereafter, Mr. Bailey may purchase the vehicle for $500.

The Company may terminate this agreement upon Mr. Bailey s death by paying his estate all compensation that had or will accrue to the end of the year of his death plus $75,000. Should Mr. Bailey become totally and permanently disabled, the Company will pay Mr. Bailey one half of the salary and benefits set forth in our agreement with him for the remainder of the term of the agreement.

Mr. Cohan: Aspen and Robert A. Cohan entered into an employment agreement dated January 1, 2003, as amended on April 22, 2005 (the Agreement). The Agreement was for an initial three-year term and was amended in April 2005. As amended, the term of the agreement ends on December 31, 2008, but would continue thereafter on a year-to-year basis unless terminated by either party. Currently under the Agreement we pay Mr. Cohan an annual salary of $160,000 (which we will continue to pay through December 31, 2008). We also offer Mr. Cohan health insurance, cost reimbursement, and certain other benefits.

As reported in January 2008, Mr. Cohan suffered a stroke and was unable to continue to perform his duties as chief executive officer and chief financial officer of Aspen. As a result, Messrs. R.V. Bailey and Kevan Hensman assumed these duties. Mr. Cohan retained the title of president, and has been working with Messrs. Bailey and Hensman and Aspen s other employees and consultants as able to ensure that Aspen s oil and gas operations continue. Although Mr. Cohan has provided substantial continuing assistance to Aspen, he has been unable to resume his duties as chief executive officer and chief financial officer. Inasmuch as Aspen is exploring strategic alternatives as described above, the board of directors, including Mr. Cohan, concurred that it was appropriate to provide notice to Mr. Cohan that his employment agreement would not be renewed when it expires on December 31, 2008.

Therefore, on September 4, 2008, Aspen notified Mr. Cohan that his employment agreement would not be renewed when it expires on December 31, 2008. This notification does not terminate Mr. Cohan s employment either now or on December 31, 2008, but merely advises him that his employment agreement will not be renewed. Mr. Cohan retains the title of president. The Board of Directors determined that it would consider the continuing employment status of all of its officers later in the year. Aspen will not be obligated to pay any penalties for not renewing the Agreement.

NOTE 12 COMMITMENTS AND CONTINGENCIES (Continued)

Operating Leases

The Company maintains office space in Denver, Colorado, our principal office, and Bakersfield, California. The Denver office consists of approximately 1,108 square feet with an additional 750 square feet of basement storage. We entered into a one year lease May 1, 2008 and will continue thereafter on a month-to-month basis for $1,261 per month. The Bakersfield, California office has 546 square feet and lease payments are $901 to $934 over the term of the lease, which expired July 31, 2008 and was extended to December 31, 2008. Rent expense for the years ended June 30, 2008 and 2007 were $26,581 and $26,264, respectively.

NOTE 13 EMPLOYEE BENEFIT PLANS

Defined Contribution Plan

The Company has adopted a Profit-Sharing 401(k) Plan, which took effect July 1, 1990. All employees are eligible to participate in this Plan immediately upon being hired to work at least 1,000 hours per year and attained age 21. Aspen makes matching contributions equal to 50% of the participant s elective deferrals. Those contributions totaled $30,250 and $30,125 for the years ended 2008 and 2007, respectively.

Medical Benefit Plan

For the fiscal years ended June 30, 2008 and 2007, the Company had a policy of reimbursing employees for medical expenses incurred but not covered by the paid medical insurance plan. Expenses reimbursed for fiscal 2008 and fiscal 2007 were $24,108 and $22,947, respectively. As of June 30, 2008 and 2007 there were no accruals for reimbursement of medical expenses. Under the terms of a revised employment agreement with Mr. Bailey, effective May 1, 2003 he will be responsible for his own medical insurance premiums and will no longer be reimbursed excess medical expenses.

NOTE 14 SUBSEQUENT EVENTS

At June 30, 2008, the Company held investments in securities totaling $930,818. Subsequent to our fiscal year end, the fair market value of our trading portfolio has decreased approximately $350,000 as of September 15, 2008, due to unfavorable market conditions. The Company does not have enough information available to ascertain whether this decline in fair value is an other than temporary impairment.

On September 4, 2008, Aspen issued a press release announcing that Aspen has decided to investigate strategic alternatives, including the possibility of selling Aspen s assets or considering another appropriate merger or acquisition transaction, and plans to open a data room where interested persons may review certain information. Aspen has entered into an agreement with Brian Wolf, a California-licensed mineral, oil and gas broker and consulting geologist, to assemble and operate the data room. Any transaction may require shareholder approval; such approval, if required, will be sought in accordance with the requirements of the Securities Exchange Act of 1934, as amended, and the rules and regulations thereunder.

As of the date of this Annual Report we have not received any offer from any person for an asset acquisition, merger, or other business combination. We cannot offer any assurance that we will receive an acceptable offer from any person for an asset acquisition, merger, or other business combination. Further, we may later determine that it is in the best interest of its shareholders to investigate other forms of business alternatives or to continue and expand existing business operations with existing or new management. In the meantime, Aspen will continue to carry on its business operations in the normal course.