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]

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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 40º 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

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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.

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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.

Reserve Estimates:

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					