ASPEN EXPLORATION CORP
Form 10KSB
October 12, 2006

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-KSB

(Mark One)

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

For the fiscal year ended June 30, 2006

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 X 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. [ ]

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

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Aspen's revenues for the fiscal year ended June 30, 2006 were $5,979,462.

At September 25, 2006, the aggregate market value of the shares held by non-affiliates was approximately $16,449,458. The aggregate market value was calculated by multiplying the mean of the closing bid and asked prices ($3.5833) 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 (4,590,589).

At September 25, 2006, there were 7,161,641 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 and our email address is aecorp2@qwest.net. We are currently engaged primarily in the exploration and development of oil and gas properties in California. 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. 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 area of interest is in the state of California. We have acquired a number of interests in oil and gas properties in California, as described below in more detail. In addition, we also act as operator for most of our producing wells and receive management fees for these services.

Company Strategy:

At the present time, we do not plan to finance our oil and gas acquisitions and drilling activities solely through our own resources. Consequently, we identify prospects or production to acquire and drill prospects, and seek other industry investors who are willing to participate in these activities with us. We frequently retain a promotional interest in these prospects, but generally we finance a portion (and sometimes a significant portion) of the acquisition and drilling costs.

Where we acquire an interest in 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 more 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. In such cases, we may retain a carried working interest, a reversionary interest, or may be 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.

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"). As of this writing, we have participated in the drilling of two farm-in wells.

Principal Products Produced and Services Rendered. Our principal products during fiscal 2006 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, 2006, crude oil and natural gas sales and revenues from operating oil and gas properties accounted for $5,911,656, or 84% of our total revenues; while $1,086,577 or 16%, was from interest and other income.

Distribution Methods of the Products or Services. We are not involved in the distribution aspect of the oil and gas industry.

Status of any Publicly Announced New Products or Services. We do 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, we have not made 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 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) the 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.

In addition, the availability of a ready market for oil and gas will depend upon numerous factors beyond our control, including the extent of domestic production and imports of oil and gas, proximity and capacity of pipelines, and the effect of federal and state regulation of oil and gas sales, as well as environmental restrictions on exploration 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. We have a minimal competitive position in the oil and gas industry.

Sources and Availability of Raw Materials. To conduct business, we depend on such items as drilling rigs and other equipment, casing pipe, drilling mud and other supplies and equipment necessary for our operations. Such items have been commonly available from a number of sources. Although we foresee no short supply or difficulty in acquiring any equipment relevant to the conduct of business, we cannot offer any assurances that these items 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 2006 and 2005 we obtained more than 10% of our revenues from sales to Calpine Corporation and Enserco Energy, Inc., (27% and 73%, 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. On July 31, 2006, we entered into a gas sales contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $10.15 per MMBTU less transportation and other expenses. The contract is for the term November 1, 2006 through March 31, 2007, requires Enserco to purchase the stated quantities at the stated prices, and contains monetary penalties for non-delivery of the gas. On October 4, 2006, we entered into a contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $7.30 per MMBTU less transportation and other expenses; for the term December 1, 2006 through March 31, 2007.

Patents, Trademarks, Licenses, Franchises, Concessions, Royalty Agreements or Labor Contracts (Including Duration). We do not own any patents, licenses, franchises, or concessions except oil, gas and other mineral interests granted by governmental authorities and private landowners. We received a trademark registration (serial no. 74-396,919 registered on March 1, 1994; serial no. 78-508,628 registered December 13, 2005) for our corporate logo. The registration is for a term of ten years. To maintain the registration for its entire term we must file an affidavit of commercial use by December 13, 2010.

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. 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.

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:

At June 30, 2006, we employed 2 full-time and 1 part-time person. We also employ independent contractors and other consultants, as needed.

ITEM 2. 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, 2006, we participated in the drilling of 14 gross (3.335 net) operated wells, 13 of which were completed as gas wells, for a 93% success ratio. Of the 13 wells drilled, 6 gas wells were drilled in the West Grimes Field, 1 gas well was drilled in the Rice Creek Field, 1 gas well was drilled in the Winters Field, 3 gas wells were drilled in the Malton Black Butte Field, and 2 gas wells were drilled in the Kirk Buckeye Field.

West Grimes Field, Colusa County, California

The first 12 wells drilled in the West Grimes Gas Field were successful with 10 wells currently producing and 2 wells waiting on completion. These wells were drilled based on a recently acquired 10.5 square mile 3-D seismic program located over Aspen's 5,000 plus leased acres in this field. 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 million cubic feet per day or "MCFPD"), have yielded excellent per well reserves (3 to 4 BCF per well), and have long productive well lives. Several of the 10

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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 has a 21% operated working interest in this field.

The Morris #1-13 well was drilled to a depth of 7,262 feet and encountered approximately 80 feet of potential net gas pay in the Forbes formation. Production casing was run based on favorable mud log and excellent electric log responses. After the casing was run to protect the upper potential gas horizon, Aspen moved in a completion rig and drilled approximately 30 feet deeper with an underbalanced drilling system and encountered additional gas pay in another Forbes horizon. This deeper Forbes zone tested gas at a prolific stabilized flow rate of 3,300 MCFPD. Aspen will produce the lower zone first and then perforate the upper zone in the future. Gas sales commenced in late June 2006.

The WGU #14-8 well was drilled to an undisclosed depth and encountered approximately 100 feet of potential gas pay in several Forbes intervals. Production casing was run based on favorable mud log and electric log responses. Aspen tested one of the Forbes intervals at a stabilized flow rate of approximately 400 MCFPD. Gas sales commenced in July 2006.

Malton Black Butte

Aspen has drilled 8 gas wells out of 10 attempts in this field during the last 4 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 31%.

The Johnson Unit #11 well was drilled to a depth of 4,800 feet and encountered approximately 80 feet of potential gas pay in various intervals in the Forbes formation. One of the Forbes intervals was perforated and tested gas at a stabilized rate of approximately 700 MCFPD. Gas sales commenced in August 2005.

The Merrill #31-1 well was drilled to a depth of 4,875 feet and encountered approximately 200 feet of potential net gas pay in various intervals in the Forbes and Kione formations. One of the Forbes intervals was perforated and tested gas at a stabilized rate of approximately 700 MCFPD. Gas sales commenced in August 2005. We believe numerous potential gas zones remain behind-pipe in this well.

Aspen has a 31% operated working interest in the Merrill #31-1 and the Johnson Unit #11 wells.

The Merrill #31-2 was drilled to a depth of approximately 3,300 feet, produced gas at very low rates for a few months, and was plugged and abandoned.

Rice Creek Field, Tehama County, California

The Sour Grass prospect area is a 2,000 acre play located in southern Tehama County. In this project, for which a 7.5 square mile area 3-D seismic survey has been acquired, Aspen has a 23.33% operated working interest in the majority of the wells in this field. There is also abundant well data for the area in addition to 2-D seismic survey information. Several prospective locations have been identified through an analysis of the data, with numerous pay zones from 2,000 to 6,000 feet in depth. Aspen has drilled eight successful gas wells out of nine attempts by in this field.

The Zimmerman #22-2 well was drilled to a depth of 5,600 feet and encountered approximately 75 feet of potential net gas pay in several intervals in the Forbes formation. One of these Forbes intervals was perforated and tested gas on a 3/16 inch choke at a stabilized rate of 1,434 MCFPD with a flowing tubing pressure of 1,760 psig and a flowing casing pressure of 1,800 psig. This represents only a 9% pressure drawdown from the shut in pressure of 1,940 psig, and is indicative that this well is capable of flowing at higher gas rates. Gas sales commenced in June 2006.

Drilling Activity:

The following table sets forth the results of our drilling activities during the fiscal years ended June 30, 2004, 2005 and 2006:

	Drilling Activity				
	Gross Wells			Net Wel	
Year	Total	Producing	Dry	Total	Produc
2004 Exploratory	7	5	2	1.38	1.05
2005 Exploratory	7	7	0	1.56	1.56
2006 Exploratory	14	13	1	3.69	3.34

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, 2006, 2005, and 2004, and the average sales prices, average production costs and direct lifting costs per unit of production.

	Years Ended June 30, 2006	2005	2004
Net Production			
Oil (Bbls)	176	219	357
Gas (MMcf)	696	617	305
Average Sales Prices			
Oil (per Bbl)	$81.12	$43.79	$31.65
Gas (per Mcf)	$7.74	$6.23	$5.17
Average Production Cost(1)			
Per equivalent Bbl of oil	$17.81	$16.50	$15.73
Average Lifting Costs(2)			
Per equivalent Bbl of oil	$4.63	$3.36	$4.73

(1) Production costs include all operating expenses, 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 sets forth Aspen's leasehold interests in productive and shut-in gas wells, and in developed acres, at June 30, 2006:

Producing and Shut-In Wells

Prospect	Gross Gas	Net(1) Gas
California:		
Anderson Unit 1-2	1	0.90000
Armstrong 17-4	1	0.36000
Balsdon 3-21	1	0.05983
Balsdon 6-21	1	0.04134
Chickohominy 1-12	1	0.24438
Church 1	1	0.10000
Cygnus 2	1	0.05583

Deane 1	1	0.12938
Dragon 1	1	0.05565
Eastby 36-2	1	0.07000
Elektra 1	1	0.07560
Emigh 34-1	1	0.44954
Emigh 35-2	1	0.32800
Emigh 35-6	1	0.05514
Ettl 1-10	1	0.24438
Farnsworth 3-35	1	0.21000
Firestone 1-10	1	0.05519
Gay Unit	1	0.21000
Grey Wolf 1	1	0.18000
Griffin 1-1	1	0.24438
Heidrick 11-1	1	0.38667
Houghton 25-1	1	0.07770
Houghton 25-2	1	0.11470
Johnson Unit	4	0.84000
Johnson Unit 11	1	0.31000
Johnston 1	1	0.21000
Kalfsbeek 1-13	1	0.30625
Kuppenbender 20-2	1	0.27075
Kuppenbender 20-3	1	0.15200
Leal 22-1	1	0.23334
McCullough 36-1	1	0.17725
Malton Arbuckle 1	1	0.51667
Mapco-Kylling 1	1	0.37800
Meckfessel 1-24	1	0.24438
Merrill 31-1	1	0.31000
Merrill 31-2	1	0.31000
Morris 1-13	1	0.21000
Morris 12-2	1	0.21000
Morris 12-3	1	0.21000
Noseco 1	1	0.67900
Pinheiro 1-10	1	0.01890
Pinheiro 2-10	1	0.01890
Pinheiro 3-10	1	0.04187
Pope Bypass 1-5	1	0.25400
Porter 26-2	1	0.23334
Sanborn 3-3	1	0.12762
Sanborn 4-10	1	0.02979
Sciortino 1-7	1	0.03000
South Sycamore 7	1	0.21000
South Sycamore 20	1	0.21000
Street 1-3	1	0.21875
Swanson 22-1	1	0.23334
Tank 18-3	1	0.03938
Tiahrt 1-4	1	0.13617
Trinity 18-2	1	0.03938
Verona Farms 1	1	0.30000
West Grimes Unit 14	2	0.42000
West Grimes Unit 15	6	1.26000
West Grimes Unit 16	3	0.63000
Strain Ranch 10-2	1	0.21000
Strain Ranches 16-3	1	0.21000
Strain Ranches 17-1	1	0.21000
Walter Trust 1	1	0.07291
Zimmerman 22-2	1	0.23334
TOTAL	75	15.60304

(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

Prospect	Aspen's Developed Acres(1) Gross(2)	Net(3)
California:		
Denverton Creek	1,431	216
Firestone 1-10	160	6
Grey Wolf 1	120	22
Kirk Buckeye/Orion	972	307
Malton Black Butte Field	1,432	333
McCullough 36-1	583	103
Momentum	936	234
Phillips Acquisition	1,120	79
Pope Bypass 1-5	120	30
Sac Valley Acquisition	1,324	555
Sour Grass	1,084	277
West Grimes	3,313	695
TOTAL	12,595	2,857

(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, 2006:

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.

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Undeveloped Acreage:

Leasehold Interests Undeveloped Acreage: The following table sets forth Aspen's leasehold interest in undeveloped acreage at June 30, 2006:

	Undeveloped Acreage	
	Gross	Net
California:		
Andromeda	342	342
Denverton Creek	514	69
Denverton Horizontal Underbalanced	2,080	260
Dunkirk 3-D	873	788
Orion	510	197
West Grimes	5,510	3,705
TOTAL	9,829	5,361

Gas Delivery Commitments:

On July 31, 2006, we entered into a gas sales contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $10.15 per MMBTU less transportation and other expenses. The contract is for the term November 1, 2006 through March 31, 2007, and requires Enserco to purchase the stated quantities at the stated prices, and contains monetary penalties for non-delivery of the gas. On October 4, 2006, we entered into a gas sales contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $7.30 per MMBTU less transportation and other expenses; for the term December 1, 2006 through March 31, 2007. We expect to have sufficient gas available for delivery to Enserco from anticipated production from our California fields.

Drilling Commitments:

We have a proposed drilling budget for the period July 2006 through June 2007. The budget includes drilling ten 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	Tota

Denverton Creek Fld. Solano County, CA	1	$170,000	$75,000	$2
West Grimes Field Colusa County, CA	4	546,000	378,000	9
Malton Black Butte Tehama County, CA	2	191,000	106,000	2
Rice Creek Field Tehama County, CA	2	223,000	198,000	4
San Emidio Field Kern County, CA	1	140,000	-	1
Total Expenditure	10	$1,270,000	$757,000	$2,0

Reserve Information - Oil and Gas Reserves:

Cecil Engineering, Inc. evaluated our oil and gas reserves attributable to our properties at June 30, 2006. 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 in 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 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, 2006 and 2005. 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, 2004	2,000	2,534,000
Revisions of previous estimates	-	(306,000)
Discoveries	-	667,000

Production	-	(617,000)
Estimated quantity, June 30, 2005	2,000	2,278,000
Revisions of previous estimates	14	(319,983)
Discoveries	-	1,488,804
Production	(176)	(696,105)
Estimated quantity, June 30, 2006	1,838	2,750,716

Developed and Undeveloped Reserves

	Developed	Undeveloped	Total
Oil (Bbls)			
June 30, 2006	1,838	-	1,838
June 30, 2005	-	2,000	2,000
Gas (Mcf)			
June 30, 2006	2,750,716	-	2,750,716
June 30, 2005	1,327,000	951,000	2,278,000

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 since the beginning of the fiscal year ended June 30, 2006.

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 conducted and significant defects 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. 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 month-to-month lease agreement on January 1, 2005 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 over the term of the lease, which expires July 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, 2006, or any subsequent period.

PART II

ITEM 5. MARKET FOR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information:

Our common stock is quoted on the Over-the-Counter Bulletin Board ("OTCBB") under the symbol "ASPN". The quotations reflect inter-dealer prices without retail mark-up, mark-down or commission and may not reflect actual transactions.

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 June 30, 2006 and 2005, we believe that we were in full compliance with these rules.

	Quarter Ended		
	September 30, 2005	December 31, 2005	March 31, 2006
Common Stock ("ASPN")			
High	$9.95	$8.10	$6.15
Low	$3.50	$5.09	$4.17

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	Quarter Ended		
	September 30, 2004	December 31, 2004	March 31, 2005

Common Stock ("ASPN")			
High	$1.37	$2.42	$3.34
Low	$0.95	$1.09	$1.95

Holders:

As of June 30, 2006, there were approximately 1,075 holders of record of our Common Stock, respectively. 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. There were no dividends declared by the Board of Directors during the fiscal year ended June 30, 2006, or subsequently, and we have paid no cash dividends on its common stock since inception. 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, 2006.

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)	(Re
Equity Compensation Plans Approved by Security Holders	-	$ -	
Equity Compensation Plans Not Approved by Security Holders	484,000	1.59	
Total	484,000	$1.59	

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

Recent Sales of Unregistered Securities - Item 701 Disclosure:

The following sets forth information regarding sales of unregistered securities during the June 30, 2006 fiscal year and subsequently as required by Item 701 of Regulation S-B.

On August 15, 2005, a consultant, R. K. Davis, at the time a ss.16(a) reporting person, exercised options for 25,000 shares of our common stock granted March 14, 2002, at an average price of $0.57 per share. The consultant paid us $14,250 to exercise his options on the 25,000 shares.

(a) The options were exercised on August 15, 2005, for 25,000 shares of our common stock.

(b) No underwriter, placement agent, or finder was involved in the transaction. The consultant is an accredited investor.

(c) The total exercise price for the options was $14,250, which was paid in cash. No underwriting discounts or commissions were paid.

(d) We relied on the exemption from registration provided by Sections 4(2) and 4(6) under the Securities Act of 1933 for this transaction and Regulation D for the issuance. We did not engage in any public advertising or general solicitation in connection with this transaction, and we provided the accredited investor with disclosure of all aspects of our business, including providing the accredited investor with our reports filed with the Securities and Exchange Commission, our press releases, access to our auditors, and other financial, business, and corporate information. Based on our investigation, we believe that the accredited investor obtained all information regarding Aspen Exploration it requested, received answers to all questions it (and its advisors) posed, and otherwise understood the risks of accepting our securities for investment purposes.

(e) The common stock issued in this transaction is not convertible or exchangeable.

(f) We will use the proceeds for working capital, as well as expenses of drilling and (if warranted) completing oil and gas wells.

On October 13, 2005, the board of directors approved the issuance of 10,000 shares of restricted common stock to CEOcast, Inc. as partial consideration for consulting services to be provided over a six month term being performed pursuant to a consulting agreement dated October 13, 2005.

(a) The issuance was completed on November 29, 2005 for 10,000 shares of our restricted common stock.

(b) There was no placement agent or underwriter for the transaction.

(c) The shares were not sold for cash. The shares of common stock were issued in exchange for services pursuant to a consulting agreement.

(d) We relied on the exemption from registration provided by Sections 4(2) and 4(6) under the Securities Act of 1933 and Regulation D for the issuance of the shares. In addition, we did not engage in any public advertising or general solicitation in connection with this transaction; and we provided the investor with disclosure of all aspects of our business, including providing the investor with our reports filed with the Securities and Exchange Commission, our press releases, access to our auditors, and other financial, business, and corporate information. Based on our investigation, we believe that the investor obtained all information regarding Aspen Exploration it requested, received answers to all questions it posed, and otherwise understood the risks of accepting our securities for investment purposes.

(e) The common stock issued in this transaction is not convertible or exchangeable. Aspen Exploration granted piggyback registration rights to CEOcast, Inc.

(f) We received no cash proceeds from the issuance of the shares of common stock.

On January 10, 2006, a consultant, R. K. Davis, at the time a ss.16(a) reporting person, exercised options for 8,333 shares of our common stock granted April 27, 2005, at an average price of $2.67 per share. The consultant paid us $22,249 to exercise his options on the 8,333 shares.

(a) The options were exercised on January 10, 2006, for 8,333 shares of our common stock.

(b) No underwriter, placement agent, or finder was involved in the transaction. The consultant is an accredited investor.

(c) The total exercise price for the options was $22,249, which was paid in cash. No underwriting discounts or commissions were paid.

(d) We relied on the exemption from registration provided by Sections 4(2) and 4(6) under the Securities Act of 1933 for this transaction and Regulation D for the issuance. We did not engage in any public advertising or general solicitation in connection with this transaction, and we provided the accredited investor with disclosure of all aspects of our business, including providing the accredited investor with our reports filed with the Securities and Exchange Commission, our press releases, access to our auditors, and other financial, business, and corporate information. Based on our investigation, we believe that the accredited investor obtained all information regarding Aspen Exploration it requested, received answers to all questions it (and its advisors) posed, and otherwise understood the risks of accepting our securities for investment purposes.

(e) The common stock issued in this transaction is not convertible or exchangeable.

(f) We will use the proceeds for working capital, as well as expenses of drilling and (if warranted) completing oil and gas wells.

On April 21, 2006 warrant s were exercised for 300,000 shares of our common stock.

(a) On April 21, 2006, two accredited investors, John and Susan Gibbs, exercised warrants (the "Warrants") for the purchase of 300,000 shares of our common stock at an exercise price of $1.25 per share for a total offering price of $375,000. The Warrants were issued on March 8, 2005 as a result of an accredited investor, Tripower Resources, Inc., exercising a warrant issued in June 2004 (the "Initial Warrants"). The Initial Warrants provided that if the Initial Warrants were exercised by March 31, 2005, we would issue to Tripower Resources, Inc. additional warrants for the purchase of 300,000 shares of common stock at the exercise price of $1.25 per share that would expire on June 30, 2006. The exercise price of the Warrants was set in June 2004, when our stock was trading at approximately $0.93 per share and, therefore, we considered the transaction to be "above market." Tripower assigned the Warrants to John and Susan Gibbs.

(b) No underwriter, placement agent, or finder was involved in the transaction. There were only the two accredited investors named in paragraph (a), above.

(c) The total offering price was $375,000 which was paid in cash. No underwriting discounts or commissions were paid. There was no placement agent or underwriter for the current transaction or the prior transactions related to the Initial Warrants, and we did not publicly offer any securities.

(d) We relied on the exemption from registration provided by Sections 4(2) and 4(6) under the Securities Act of 1933 for this transaction and Regulation D for the issuances. We did not engage in any public advertising or general solicitation in connection with this transaction, and we provided the accredited investors with disclosure of all aspects of our business, including providing the accredited investors with our reports filed with the Securities and Exchange Commission, our press releases, access to our auditors, and other financial, business, and corporate information. Based on our investigation, we believe that the accredited investors obtained all information regarding Aspen Exploration they requested, received answers to all questions they (and their advisors) posed, and otherwise understood the risks of accepting our securities for investment purposes.

(e) The common stock issued to the accredited investors is not convertible or exchangeable for other securities. There are no registration rights associated with the securities issued to the accredited investor.

(f) We will use the proceeds for working capital, as well as expenses of drilling and (if warranted) completing oil and gas wells.

On April 13, 2006, the board of directors approved the issuance of 18,000 shares of restricted common stock to CEOcast, Inc. as partial consideration for consulting services to be provided over a six month term being performed pursuant to a consulting agreement dated April 13, 2006.

(a) The issuance was completed on May 8, 2006 for 18,000 shares of our restricted common stock.

(b) There was no placement agent or underwriter for the transaction.

(c) The shares were not sold for cash. The shares of common stock were issued in exchange for services pursuant to a consulting agreement.

(d) We relied on the exemption from registration provided by Sections 4(2) and 4(6) under the Securities Act of 1933 and Regulation D for the issuance of the shares. In addition, we did not engage in any public advertising or general solicitation in connection with this transaction; and we provided the investor with disclosure of all aspects of our business, including providing the investor with our reports filed with the Securities and Exchange Commission, our press releases, access to our auditors, and other financial, business, and corporate information. Based on our investigation, we believe that the investor obtained all information regarding Aspen Exploration it requested, received answers to all questions it posed, and otherwise understood the risks of accepting our securities for investment purposes.

(e) The common stock issued in this transaction is not convertible or exchangeable. Aspen Exploration granted piggyback registration rights to CEOcast, Inc.

(f) We received no cash proceeds from the issuance of the shares of common stock.

On August 11, 2006 (after the end of 2006 fiscal year), our chairman, R. V. Bailey, exercised options for 50,000 shares of our common stock granted March 14, 2002, at an average price of $0.57 per share. Mr. Bailey paid us $28,500 to exercise his options on the 25,000 shares.

(a) The options were exercised on August 11, 2006, to purchase 50,000 shares of our common stock.

(b) No underwriter, placement agent, or finder was involved in the transaction. The consultant is an accredited investor.

(c) The total exercise price for the options was $28,500, which was paid in cash. No underwriting discounts or commission were paid.

(d) We relied on the exemption from registration provided by Section 4(2) and 4(6) under the Securities Act of 1933 for this transaction and Regulation D for the issuance. We did not engage in any public advertising or general solicitation in connection with this transaction, and we provided the accredited investor with disclosure of all aspects of our business, including providing the accredited investor with our reports filed with the Securities and Exchange Commission, our press releases, access to our auditors, and other financial, business, and corporate information. Based on our investigation, we believe that the accredited investor obtained all information regarding Aspen Exploration it requested, received answers to all questions it (and its advisors) posed, and otherwise understood the risks of accepting our securities for investment purposes.

(e) The common stock issued in this transaction is not convertible or exchangeable.

(f) We will use the proceeds for working capital, as well as expenses of drilling and (if warranted) completing oil and gas wells.

On August 14, 2006 (after the end of the 2006 fiscal year), an employee performed a cashless exercise options or an option which resulted in an acquisition of 17,000 shares of our common stock. The option to acquire 17,000 shares was originally granted March 14, 2002, at an exercise price of $0.57 per share.

(a) The options were exercised on August 14, 2006, to purchase 17,000 shares of our common stock. The option holder exercised options to acquire 17,000 shares in the cashless exercise which had a value of $9,690 by surrendering 2,019 shares of Aspen's common stock with a fair value based on a ten-day average bid price immediately prior to the exercise date of $4.80.

(b) No underwriter, placement agent, or finder was involved in the transaction. The consultant is an accredited investor.

(c) The total exercise price for the options was $9,690, which was paid by surrendering 2,019 shares to purchase 17,000 shares. No underwriting discounts or commission were paid.

(d) We relied on the exemption from registration provided by Section 4(2) under the Securities Act of 1933 for this transaction and Regulation D for the issuance. We did not engage in any public advertising or general solicitation in connection with this transaction, and we provided the accredited investor with disclosure of all aspects of our business, including providing the accredited investor with our reports filed with the Securities and Exchange Commission, our press releases, access to our auditors, and other financial, business, and corporate information. Based on our investigation, we believe that the accredited investor obtained all information regarding Aspen Exploration it requested, received answers to all questions it (and its advisors) posed, and otherwise understood the risks of accepting our securities for investment purposes.

(e) The common stock issued in this transaction is not convertible or exchangeable.

(f) We received no proceeds from the exercise of this transaction.

Option to Director

Aspen appointed Kevan B. Hensman a director of Aspen effective September 11, 2006. In connection with that appointment, Aspen granted Mr. Hensman an option to purchase 10,000 shares of Aspen common stock.

(a) On September 11, 2006, we issued an option to purchase 10,000 shares of Aspen's common stock to Kevan B. Hensman. The options are exercisable at $3.70, expire September 11, 2011 and vested immediately.

(b) No underwriters were involved in this transaction.

(c) The stock options were issued in consideration of Mr. Hensman joining the board of directors and Aspen received no cash therefore.

(d) The transaction was exempt from registration under the Securities Act of 1933, as amended by reason of Section 4(2) and 4(6) of the Securities Act of 1933.

(e) The options are exercisable to purchase shares of common stock as described above.

(f) No proceeds were received.

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. These risks, uncertainties and contingencies include, without limitation, the factors set forth in our Form 10-KSB under "Item 6. Management's Discussion and Analysis of Financial Conditions or Plan of Operation - Factors that may affect future operating results."

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. We are currently the operator of 55 gas wells and have a non-operated interest in 20 additional gas wells.

We currently have offices in Bakersfield, California and Denver, Colorado and have 2 full time and 1 part-time employee. We also make extensive use of consultants for the conduct of our business, ranging from financial, engineering, land, legal, and geological and geophysical specialists.

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. Administrative charges to the properties help cover approximately 44% of our selling, general and administrative expenses.

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 natural gas;
- curtailments or increases in consumption by natural gas purchasers; and
- changes in governmental regulations or taxation.

Property, Equipment and Depreciation:

We follow the full-cost method 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. Costs associated with production and general corporate activities are expensed in the period incurred. 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 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. 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. We amortize the amount added to the oil and gas properties and recognize accretion expense in connection with the discounted liability over the remaining lives of the respective gas wells. 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. The liability is discounted using a risk-free rate of 4.97%. 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.

Outlook and Trends:

We expect our natural gas production to increase substantially during fiscal 2007 due to recent drilling successes. 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. We also anticipate that the average price for our product will be in the range of $5.00 to $10.00 per MMBTU for the fiscal year ended June 30, 2007.

Over the past five years we have been able to replace our produced reserves and increase our yearly natural gas production. During fiscal 2006, we managed to replace 121% of our proved reserves. We have also benefited from an increase in average gas sales price of 24%, from $6.23 per MCF to $7.74 per MCF.

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, our historic success ratio over the past 6 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, 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 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.

To manage commercial risk, we have used financial tools to hedge the price we receive for our product. The primary purpose of hedging is to provide adequate return on our investments, grow our reserves while leaving as much commodity price upside as possible. During the period November 1, 2005 through March 31, 2006, we were contractually obligated to deliver 3,750 MMBTU per day to two of our natural gas purchasers as follows:

1,000 MMBTU/Day @ $8.43 per MMBTU
1,000 MMBTU/Day @ $8.40 per MMBTU
500 MMBTU/Day @ $9.49 per MMBTU
500 MMBTU/Day @ $9.48 per MMBTU
750 MMBTU/Day @ $11.02 per MMBTU

The average price received during fiscal 2006 for our natural gas was approximately $7.74 per MMBTU as compared to $6.23 per MMBTU during fiscal 2005. On July 31, 2006, the Company entered into an additional forward contract to deliver gas to Enserco beginning November 1, 2006. This contract, which expires on March 31, 2007, requires that we deliver and that Enserco purchase 2,000 MMBTU of gas per day at a fixed price of $10.15 per MMBTU less transportation and other expenses. On October 4, 2006, the Company entered into a contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $7.30 per MMBTU less transportation and other expenses; for the term December 1, 2006 through March 31, 2007.

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

Cash of $6,942,588 and $2,861,494 was provided by our operations for the twelve months ended June 30, 2006 and 2005. The cash flow from operations increase of $4,081,094 or 143%, was because of:

Increased oil and gas sales ($5,400,950 in 2006 as compared to $3,853,000 in 2005) due to increasing prices and production volume;

A decrease in accounts receivable and prepaid expenses during 2005 which provided cash of $44,100 compared to an increase in accounts receivable, prepaids, and deposits during 2006 which had a negative affect on cash of $2,065,889; and

A decrease in accounts payable, accrued expenses, and advances from joint owners in 2005 which used cash of $155,703 compared to an increase in accounts payable, accrued expenses, and advances from joint owners in 2006 which provided cash of $4,541,545.

Investing activities used cash to increase capitalized oil and gas costs of $4,305,846 and $1,465,427 in the twelve months ended June 30, 2006 and 2005. Cash in the current twelve month period ended June 30, 2006 was used for lease acquisition and seismic work ($207,300), intangible drilling and well workovers ($3,201,118), and the purchase of oil and gas well equipment ($765,100). These expenditures were offset by the sale of interests in wells to be drilled charged to third party investors.

Contractual Obligations:

We had two contractual obligations as of June 30, 2006. The following table lists our significant liabilities at June 30, 2006:

	Payments Due By Period			
Contractual Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
Employment Obligations	$233,464	$418,410	$-	$-
Operating Leases	9,900	12,104	-	-
Total Contractual Cash Obligations	$243,364	$430,514	$-	$-

Future Commitments:

We have a proposed drilling, completion and construction budget for the period July 2006 through June 2007. The budget includes drilling ten 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
Denverton Creek Fld. Solano County, CA	1	$170,000	$75,000
West Grimes Field Colusa County, CA	4	546,000	378,000
Malton Black Butte Tehama County, CA	2	191,000	106,000
Rice Creek Field Tehama County, CA	2	223,000	198,000

San Emidio Field Kern County, CA	1	140,000	-
Total Expenditure	10	$1,270,000	$757,000

We maintain 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 month-to-month lease agreement beginning January 1, 2005 for a lease rate of $1,261 per month. The Bakersfield, California office has 546 square feet and a monthly rental fee of $901 to $934 over the term of the lease. The two-year lease expires July 31, 2008. Rent expense for the years ended June 30, 2006 and 2005 was $22,817 and $24,370, respectively.

Our working capital surplus (current assets less current liabilities) at June 30, 2006, was $3,873,146. We anticipate that our working capital and anticipated cash flow from operations and future successful drilling will be sufficient to pay our current liabilities as long as our gas production continues to provide us with sufficient cash flow. As discussed below, 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 gas production.

Our capital requirements can fluctuate over a twelve month period because our drilling program is usually carried out in California's dry season, from late April until November, after which wet weather either precludes further activity or makes it cost prohibitive.

Results of Operations:

June 30, 2006 Compared to June 30, 2005:

For the twelve months ended June 30, 2006, our operations continued to be focused on the production of oil and gas, and the investigation for possible acquisition of producing oil and gas properties in California. During the 2006 fiscal year, our revenues increased by more than $1.85 million as compared to the comparable period of our 2005 fiscal year because of:

Increased production (672,643 MMBTU sold as compared to 622,000 MMBTU sold during our 2005 fiscal year, an 8.14% increase); and

Increased price received for our production (an average of $7.74 per MMBTU during our 2006 fiscal year as compared to $6.23 per MMBTU received during that period in 2005).

The foregoing increases were reinforced in part by an increase in management fees received (which were $510,706 during 2006) as compared to $266,127 during 2005. We were operators of more wells during 2006 (55 wells compared to 49 wells in 2005), and our management fees were positively impacted by the increased number of wells we operate.

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 2006, 2005 and 2004:

	For the Year Ended	
	June 30, 2006	June 30, 2005
Total Revenues	100.0%	100.0%
Oil and Gas Production Costs	9.0	8.4
Income from Operations	91.0	91.6
Costs and Expenses		
Depreciation and depletion	26.0	33.2
Selling, general and administrative	14.9	18.5
Interest expense	0.1	0.1
Total Costs and Expenses	41.0	51.8
Gain on Sale of Investment	17.0	13.7
Income Before Income Taxes	67.0	53.5
Provision for Income Taxes	(17.9)	(18.9)
Net Income	49.7	34.6

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To facilitate discussion of our operating results for the years ended June 30, 2006 and 2005, we have included the following selected data from our Consolidated Statements of Operations:

	Comparison of the Fiscal Twelve Months Ended June 30,		Increas
	2006	2005	Amount
Revenues:			
Oil and gas sales	$5,400,950	$3,853,177	$1,547,773
Management fees	510,706	266,127	244,579
Interest and other	67,806	8,140	59,666
Total Revenues	5,979,462	4,127,444	1,852,018
Cost and Expenses:			
Oil and gas production	537,508	346,451	191,057

Depreciation and depletion	1,557,076	1,372,265	184,811
Selling, general and administrative	890,255	763,236	126,599
Interest expense	6,427	6,180	247
Total Costs and Expenses	2,991,266	2,488,132	502,714
Net Operating Income	$2,988,196	$1,639,312	$1,349,304

Central to the issue of success of the twelve months operations ended June 30, 2006 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:

	Oil & Gas Sales	MMBTU Sold	Price/MM
2006			
1st Quarter	$1,062,543	146,445	
2nd Quarter	2,018,233	201,371	
3rd Quarter	1,496,427	182,987	
4th Quarter	823,747	141,840	
Year to Date	5,400,950	672,643	
2005			
1st Quarter	$697,553	130,000	
2nd Quarter	1,132,359	177,350	
3rd Quarter	1,103,687	169,150	
4th Quarter	919,578	145,500	
Year to Date	3,853,177	622,000	
2004			
1st Quarter	$341,926	72,600	
2nd Quarter	362,942	79,900	
3rd Quarter	401,941	71,900	
4th Quarter	481,441	80,600	
Year to Date	$1,588,250	305,000	

12 Month Change		
2006		
Amount	$1,547,773	50,643
Percentage	40.2%	8.1%

2005

Amount	$2,264,927	317,000
Percentage	142.6%	103.9%

(1) Price per MMBTU may not agree with oil and gas sales because of the inclusion of oil and NGL sales.

Oil and gas revenue, volumes sold and price received for our product have shown a steady improvement over the past twelve months of fiscal 2006 and the twelve months of fiscal 2005. As the table above notes, revenue has increased approximately 40% when comparing the two twelve month periods ended June 30, 2006 and 2005. Volumes sold increased approximately 8%, while the price received for our product increased approximately 29%.

Total revenue increased $1,852,018, or 45% when comparing the two periods, while operating and production costs increased $191,057, or 55%. As set out in the previous paragraph, revenue from gas sales increased because the volumes sold from new and existing wells increased and natural gas prices increased substantially. Production costs increased due to the addition of newly productive wells.

Depletion and depreciation increased $202,811, or 15% due largely to increased drilling activity in the current year.

A significant ratio presented is the percentage of management fees charged to operated wells versus our general and administrative costs. This coverage of general and administrative costs increased from approximately 35% for the twelve months ended June 30, 2005 to approximately 57% at June 30, 2006.

When comparing general and administrative expense for 2006 and 2005, costs increased by $127,019, or 17%, due primarily to increases in accounting and audit fees, promotional expense and corporate reporting expense and the issuance of common stock as compensation for services.

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	Incom Before I Per
				Basic
2006				
1st Quarter	$1,194,168	$1,112,448	$641,697	$0.095
2nd Quarter	2,108,723	1,978,244	1,496,922	0.222
3rd Quarter	1,512,721	1,424,313	992,311	0.147
4th Quarter	1,163,850	859,179	876,457	0.128
Total	5,979,462	5,374,184	4,007,387	0.592
2005				
1st Quarter	784,299	715,249	389,781	0.063
2nd Quarter	1,190,333	1,092,632	729,748	0.074
3rd Quarter	1,163,746	1,056,268	703,738	0.109
4th Quarter	980,926	908,704	382,957	0.094
Total	4,119,304	3,772,853	2,206,224	0.340

2004				
1st Quarter	388,337	348,739	50,197	0.010
2nd Quarter	433,317	365,761	93,022	0.010
3rd Quarter	440,127	354,642	76,762	0.010
4th Quarter	558,899	509,066	145,664	0.020
Total	$1,820,680	$1,578,208	$365,645	$ 0.050

(1) Operating income is oil and gas sales plus management fees less oil and gas production costs.

As can be seen in the table, revenues and operating income have improved significantly when comparing the twelve month periods ended June 30, 2006 and 2005. We believe this is due to the steady increase in production volumes sold in each subsequent quarter and the fact that we have enjoyed an appreciating price received for our product. Operating income has increased because production costs have increased at a lesser rate than production and prices.

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.

Factors That May Affect Future Operating Results:

In evaluating our business, readers of this report should carefully consider the following factors in addition to the other information presented in this report and in our other reports filed with the SEC that attempt to advise interested parties of the risks and factors that may affect our business. As noted elsewhere herein, the future conduct of Aspen's business, non-oil and gas exploration activities, and discussions of possible future activities is dependent upon a number of factors, and there can be no assurance that Aspen will be able to conduct its operations as contemplated herein. These risks include, but are not limited to:

Oil and gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business. Our revenues, profitability and future growth and reserve calculations depend substantially on reasonable prices for oil and gas. These prices also affect the amount of our cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our credit facility is subject to periodic asset redeterminations based in part on changing expectations of future crude oil and natural gas prices. Lower prices may also reduce the amount of oil and gas that we can produce economically.

- Among the factors that can cause fluctuations are:
- domestic and foreign supply of oil and natural gas;
- price and availability of alternative fuels;
- weather conditions;

- o level of consumer demand;
- o price of foreign imports;
- o world-wide economic conditions;
- o political conditions in oil and gas producing regions; and
- o domestic and foreign governmental regulations.

A widening of commodity differentials may adversely impact our revenues and per barrel economics. 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 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. 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, etc. We may be adversely impacted by a widening differential on the products sold.

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 inadequacy or unavailability of natural gas pipeline, 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.

Factors that can cause price volatility for crude oil and natural gas include:

- o availability and capacity of refineries;
- o availability of gathering systems with sufficient capacity to handle local production;
- o seasonal fluctuations in local demand for production;
- o local and national gas storage capacity;
- o interstate pipeline capacity; and

Our future success depends on our ability to find, develop and acquire oil and gas reserves. To maintain 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. We may not be able to find and develop or acquire additional reserves at an acceptable cost. In addition, substantial capital is required to replace and grow reserves. If lower oil and gas prices or operating difficulties result in our cash flow from operations being less than expected or limit our ability to borrow under credit arrangements, we may be unable to expend the capital necessary to locate and develop or acquire new oil and gas reserves.

Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves, future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from estimates. Estimating accumulations 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 SEC requirements, 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.

If oil or gas prices decrease, we may be required to take write-downs. 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 annually and at any 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.

Competitive industry conditions may negatively affect our ability to conduct 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.

Drilling is a high-risk activity. Our future success will partly depend on the success of our drilling program. In addition to the numerous operating risks described in more detail below, these drilling activities involve the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, we are often uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including obtaining government required permits, unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, compliance with governmental or landowner requirements, and shortages or delays in the availability of drilling rigs and the delivery of equipment and/or services.

The oil and gas business involves many operating risks that can cause substantial losses; insurance may not protect us against all of these risks. These risks include 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.

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. 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.

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 Mr. Robert A. Cohan, President and CEO, in the amount of $1,000,000. 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.

We have limited control over the activities on properties that we do not operate. Although we operate most of the properties in which we have an interest, other companies operate some of the properties. 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 not adhere to our proposed drilling schedule. Our final determination of whether to drill any scheduled or budgeted wells will depend on a number of factors, including results of our exploration efforts and the acquisition, review and analysis of our seismic data, if any; availability of sufficient capital resources to us and any other participants for the drilling of the prospects, approval of the prospects by other participants after additional data has been compiled, economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and natural gas and the availability and prices of drilling rigs and crews, and availability of leases, license options, farm-outs, other rights to explore and permits on reasonable terms for the prospects.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame, or at all. In addition, our drilling schedule may vary from our expectations because of future uncertainties and rig availability and access to our drilling locations utilizing available roads.

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 the 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. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. The work might include obtaining affidavits of heirship or causing an estate to be administered. In cases involving more serious title problems, the amount paid for affected oil and natural gas leases can be generally lost, and the target area can become undrillable.

Estimates may differ from actual. 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.

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:

FASB 123(R) (revised 2004) - Share-Based Payments

In December 2004, the FASB issued a revision to FASB Statement No. 123, "Accounting for Stock Based Compensation", SFAF 123(R), "Share Based Payment". This Statement supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees", and its related implementation guidance. This Statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments.

The Company will initially measure the cost of employee services received in exchange for an award of liability instruments based on its current fair value; the fair value of that award will be re-measured subsequently at each reporting date through the settlement date. Changes in fair value during the requisite service period will be recognized as compensation cost over that period. A nonpublic entity may elect to measure its liability awards at their intrinsic value through the date of settlement.

The grant-date fair value of employee share options and similar instruments will be estimated using the option-pricing models adjusted for the unique characteristics of those instruments (unless observable market prices for the same or similar instruments are available).

The effective date for public entities that do not file as small business issuers will be as of the beginning of the first interim or annual reporting period of the registrant's first fiscal year that begins after June 15, 2005. For public entities that file as small business issuers and nonpublic entities the effective date will be as of the beginning of the first interim or annual reporting period of the registrant's first fiscal year that begins after December 15, 2005. The impact of the adoption of this statement will be to recognize in compensation expense approximately $115,000 during fiscal years ending June 30, 2007 and 2008 related to unvested option grants issued prior to July 1, 2006. However, the actual expense recognized will depend on a number of factors including the fair value of awards issued during those periods.

In February 2006, SFAS No. 155, Accounting for Certain Hybrid Financial Instruments--an amendment of FASB Statements No. 133 and 140 was issued. SFAS No. 155 will become effective for the Company's fiscal year after September 15, 2006. Adoption of this statement is expected to have no impact on the Company's financial position or results of operations.

In March 2006, SFAS No. 156, Accounting for Servicing of Financial Assets--an amendment of FASB Statement No. 140 was issued. This Statement amends FASB Statement No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, with respect to the accounting for separately recognized servicing assets and servicing liabilities. SFAS No. 156 will become effective for the Company's fiscal year beginning after September 15, 2006. Adoption of this statement is expected to have no impact on the Company's financial position or results of operations.

ITEM 7. FINANCIAL STATEMENTS

The information required by this item begins on page 44 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

On February 21, 2006, our Board of Directors informed Gordon, Hughes, & Banks, LLP ("Gordon Hughes") that it had dismissed Gordon Hughes as the Company's independent registered public accounting firm effective immediately.

On February 21, 2006, the Board of Directors informed Hein & Associates LLP, certified public accountants, that such firm was appointed as the Company's registered accounting firm effective immediately.

Gordon Hughes' principal accountant report on the financial statements for either of the previous two fiscal years (ending June 30, 2005 and 2004, including interim periods), or any subsequent period up to the dismissal of Gordon Hughes as the Company's independent registered public accounting firm, did not contain an adverse opinion or disclaimer of opinion, or was modified as to uncertainty, audit scope, or accounting principles.

There were no disagreements with Gordon Hughes on any matters of accounting principles, practices, financial statement disclosure, or auditing scope or procedure.

The Company has provided Gordon Hughes with a copy of the disclosures set for in its Form 8-K reporting an event of February 21, 2006 (filed February 22, 2006) and requested Gordon Hughes to furnish to the Company with a letter addressed to the Securities and Exchange Commission stating whether Gordon Hughes agrees with the statements by the Company in this report. Gordon Hughes' letter was attached as Exhibit 16.1 to that Form 8-K.

ITEM 8A. CONTROLS AND PROCEDURES

(a) Evaluation of 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.

As required by Rule 13a-15 under the Securities Exchange Act of 1934, within the 90 days prior to the filing date of this report, we carried out an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures. This evaluation was carried out under the supervision and with the participation of our president who serves as our principal executive officer and as our principal financial officer. Our president considered advice from our auditors, Hein & Associates, LLP, that, based on several corrections to our financial statements and related disclosures that they proposed, there is a material weakness in our internal controls over financial reporting. In reaching its conclusion, our auditors also discussed the fact that our president acts as both our principal executive officer and our principal financial officer and that we do not have an audit committee (both factors discussed elsewhere in this report). 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, disclosure controls and procedures were not effective. In reaching his conclusion, our president also considered various mitigating factors, noting that formerly Aspen had one consultant serving us on a part-time basis, and during fiscal 2006 we had increased our accounting staff to three consultants, including two certified public accountants.

(b) Changes in Internal Controls.

There were no changes in our internal controls or in other factors that could significantly affect these internal controls subsequent to the date of their evaluation. Our president also noted that Aspen is still evaluating and implementing additional controls to meet the requirements of Sarbanes-Oxley ss.

404, and will continue to implement appropriate changes as they are identified, and will implement changes in fiscal year 2007 to remediate the material weaknesses that our auditors identified. Aspen is not subject to the requirement that it provide a management's report on internal control over financial reporting or the requirement that the report be attested to by its auditors until its first fiscal year ending after July 15, 2007.

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 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. We have held no annual meetings since February 25, 1994. Therefore the terms of each class of director expires at the next annual meeting of stockholders.

Name	Age	Position	Class	Dir
Robert A. Cohan	50	President, Chief Executive Officer, Chief Financial Officer, Treasurer and Director	I	
Kevan B. Hensman	50	Director	II	
R. V. Bailey	74	Vice President, Secretary, Director, and Board Chairman	III	

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 do not expect to hold an annual meeting during fiscal 2007.

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(c) of SEC Regulation S-B.

Robert A. Cohan. 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 27 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. Since June 2006, Mr. Hensman has been the Manager of Paramount Citrus Association with current duties including the preparation of an annual plan; quarterly budget updates; management reporting; and analysis. From April 2002 to June 2006, Mr. Hensman 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

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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. R. V. Bailey obtained a Bachelor of Science degree in Geology from the University of Wyoming in 1956. He has approximately 44 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, but currently devotes only a small portion of his time to Aspen's business.

Meetings of the Board and Committees:

The Board of directors held 2 formal meetings during the fiscal year ended June 30, 2006 and one subsequently. 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 six times during fiscal 2005, 8 times during fiscal 2006, and has not acted by consent 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. Consequently Aspen has not designated an 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.

Procedures by which Security Holders May Recommend Nominees to the Board of Directors; Communications with Members of the Board of Directors:

The board of directors has not adopted procedures by which security holders may recommend nominees to the board of directors.

Any shareholder desiring to 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, 2006, 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 the reports it received from persons required to file, we believe that during the period from July 1, 1995 through September 25, 2006, all filing requirements applicable to its officers, directors and greater-than-ten-percent shareholders were complied with except as set forth in the following paragraph.

1. Robert F. Sheldon, then a director, filed one Form 4 late. The Form 4 reported a single transaction.

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 three years ended June 30, 2004, 2005 and 2006. 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 subsidiary.

		Annual Compensation			Long-Term Compensatio	
					Awards	
(a)	(b)	(c)	(d)	(e)	(f)	(g)
Name and Principal Position	Fiscal Year	($) Salary	($) Bonus	($) Other(1)	($) Restricted Awards	Securities Underlying Options and SARs (#)
R. A. Cohan,						

President and CEO	2004	137,100	0	54,800	0	0
	2005	145,000	0	128,100	0	0
	2006	152,500	0	191,023	0	0
R. V. Bailey, Vice President and Chairman	2004	45,000	0	59,100	0	0
	2005	45,000	0	96,200	0	0
	2006	45,000	0	140,671	0	0

(1.) We have an "Amended Royalty and Working Interest Plan" by which we, in our discretion, are 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.

No additional compensation has been recognized as reimbursement to the vice president for income taxes for the years ended June 30, 2006, 2005, and 2004. Mr. Bailey's taxable amount was $0 for fiscal 2006, 2005, and 2004, equal to the "economic benefit" attributed to the vice president as defined by the Internal Revenue Code. The Company paid no premiums during fiscal 2006, 2005, and 2004.

We 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's contribution (if any) to this plan is determined by the Board of Directors each year. At June 30, 2004, we contributed $8,550 to the plan; during fiscal 2005 we contributed $7,350 to the plan ($1,350 to R. V. Bailey's plan; $4,350 to Robert A. Cohan's plan; $1,650 to Judith L. Shelton's plan). An Amendment to the Profit-Sharing 401(k) Plan was adopted effective July 1, 2005 which states that Aspen will make matching contributions equal to 50% of the participant's elective deferrals. During fiscal 2006, we contributed $30,250 to the plan ($9,000 to R. V. Bailey's plan; $8,750 to Robert A. Cohan's plan; $12,500 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 column (e) of the tables, above.

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 were charged to Mr. Cohan.

We have agreed to reimburse our officers and directors for out-of-pocket costs and expenses incurred on behalf of Aspen.

During fiscal 2006, we assigned to employees royalties on certain of our properties pursuant to our Amended Royalty and Working Interest plan, as follows. The value attributed to these overrides is considered nominal, since the assignments were made while the properties were undeveloped and unproved. The overriding royalty interests in these properties granted to our named officers and all employees were as follows:

R. V. Bailey	R. A. Cohan	J. L. Shelton

Johnson Unit 11	1.260000	1.260000	0.480000
Merrill 31-1	1.360000	2.000000	0.640000
Heidrick 11-1	1.133333	1.666667	0.533333
Kalfsbeek 1-13	1.360000	2.000000	0.640000
Denverton Horizontal	1.066750	1.568750	0.502000
Houghton 25-2	0.377400	0.555000	0.177600
Merrill 31-2	1.360000	2.000000	0.640000
Street 1-3	1.241743	1.826088	0.584349

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

We did not grant any stock options or stock appreciation rights to any person during the fiscal year ended June 30, 2006. As described above, we did grant an option to purchase 10,000 shares to a person who became a director of Aspen on September 11, 2006.

The following table sets forth information regarding options exercised by the named executive officers and the value of in the money options at June 30, 2006. This does not include options that Mr. Bailey exercised subsequent to the end of the fiscal year.

Name and Principal Position	Shares Acquired on Exercise (#)	Value Realized	Number of Securities Underlying Unexercised Options/SARs at June 30, 2006 Exercisable/ Unexercisable
R. V. Bailey, Vice President and Chairman	0	$-	71,667 /43,333
Robert A. Cohan, President and CEO	0	$-	119,667 /110,333
Robert F. Sheldon, Director	0	$-	53,667 /43,333

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 year ended June 30, 2006.

Employment Contracts and Termination of Employment and Change in Control Arrangements:

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.

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 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 $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.

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.

Mr. Cohan: On January 1, 2003 we entered into an employment contract with Mr. Cohan which has been extended through December 31, 2008. This currently provides for a salary of $160,000, plus health insurance, cost reimbursement, and certain other benefits. The employment contract also provides for standard confidentiality provisions.

The employment contract 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, 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.

By approving Mr. Hensman's election to the board of directors, Mr. Cohan waived the change in the board of directors which might have resulted in his right to terminate his employment agreement for cause. He has the right to waive other potential events of default, as well. Were Mr. Cohan to terminate the employment agreement for cause, Aspen would be obligated to pay Mr. Cohan, within 30 days, an amount equal to the greater of the amount due for the remaining term of the employment contract or six months of his then current monthly salary. Aspen's liability is the same were it to terminate the contract because of Mr. Cohan's death or disability.

Aspen may also terminate the employment contract with cause, and if it does so it will owe Mr. Cohan his salary only through the date of termination. Were Aspen to terminate the employment contract without cause, Aspen would be obligated to pay Mr. Cohan, within 30 days, an amount equal to the greater of the amount due for the remaining term of the employment contract or nine months of his then current monthly salary.

See also Item 12, Certain Relationships and Related Party Transactions.

Report on Repricing of Options/SARs:

We did not reprice any options or stock appreciation rights during the fiscal year ended June 30, 2006, or subsequently.

Compensation of Directors

Although we have not formally adopted a plan for the compensation of our directors, we issued to 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.

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

The following table sets forth as of September 25, 2006 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.

Beneficial Owner	Beneficial Ownership Number of Shares		Percent of Total
R. V. Bailey	1,355,096	i	18.92%
Robert A. Cohan	688,377	ii	9.61%
Robert F. Sheldon	198,656	iii	2.77%
All Officers and Directors as a Group (3 persons)	2,242,129		31.31%

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 1,191,776 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 wife. In addition, the number of shares owned includes 100,000 shares of common stock granted in a property exchange; stock options to purchase 65,000 shares of restricted common stock; stock options to purchase 150,000 shares of restricted common stock, which includes 50,000 shares of restricted common stock that were exercised on May 14, 2004, 50,000 shares of restricted common stock that were exercised on March 9, 2005, and 50,000 shares of common stock that were exercised on August 11, 2006; and 200,000 shares of restricted common stock that were exercised on June 11, 2001. Additionally, Aspen issued 32,000 shares of common stock 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.

ii This number includes 300,000 shares of common stock granted; stock options to purchase 80,000 shares of restricted common stock; stock options to purchase 250,000 shares of restricted common stock, which includes 50,000 shares of restricted common stock that were exercised on May 14, 2004 and 50,000 shares of restricted common stock that were exercised on August 16, 2004; and stock options to purchase 200,000 shares of restricted common stock that were exercised on February 27, 2001. 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.

iii This number includes 20,000 shares of common stock granted December 13, 1996; 20,000 shares of common stock granted November 1, 1997; all of the stock options to purchase 65,000 shares of restricted common stock expired upon his death; stock options to purchase 150,000 shares of restricted common stock, which includes 50,000 shares of restricted common stock that were exercised on May 14, 2004 and 50,000 shares of restricted common stock that were exercised on March 9, 2005 and 50,000 shares of restricted common stock which expired upon his death; and stock options granted for 80,000 shares of common stock that were exercised on December 17, 2001.

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

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 may participate, from time to time, in these arrangements and such transactions may be on a non-promoted basis (actual costs), although they have participated mainly on a promoted basis, but must be approved by a majority of the disinterested directors of our Board of Directors.

R. V. Bailey, vice president and director of Aspen, Robert A. Cohan, president and director of Aspen, and Ray K. Davis, former consultant to Aspen, each have working and royalty interests in certain of the California oil and gas properties operated by Aspen. The affiliates paid for their proportionate share of all costs to acquire, develop and operate these properties. As of June 30, 2006, working interests of the Company and its affiliates in certain producing California properties are set forth below:

	Gross Wells Gas	Net Wells Gas
Aspen Exploration	74	14.99
R. V. Bailey	54	1.63
R. A. Cohan	54	0.94
R. K. Davis	64	1.34
J. L. Shelton	45	0.10

Amended Royalty and Working Interest Plan:

The allocations for royalty under Aspen's "Royalty and Working Interest Plan" for employees are based on a determination of whether there is any "room" for royalties in a particular transaction. In some specific cases 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, vice president, both of whom may benefit from royalty interests assigned. During fiscal 2002, assignments to Mr. Cohan and Mr. Bailey have been on an equal basis, while Ms. Judy Shelton, the corporate office manager, was assigned a lesser amount. For fiscal 2003 Mr. Bailey and Ms. Shelton shared a proportionately lesser amount. A discussion of specific royalties assigned 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 2006 and 2005, 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 years ended June 30, 2006 and 2005, 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.

ITEM 13. EXHIBITS AND REPORTS ON FORM 8-K.

Exhibits Pursuant to Item 601 of Regulation S-B:

Exhibit No.	Title
3.01*	Certificate of Incorporation
3.03*	Bylaws - Subsidiary
3.20*	Registrant's Amended and Restated Bylaws
4.01*	Specimen Common Stock Certificate
10.01*	Royalty and Working Interest Plan
10.02	Employment Agreement between Aspen Exploration Corporation and Robert A. Cohan dated April 1, 2005, as amended
10.03*	Employment Agreement between Aspen Exploration Corporation and R.V. Bailey dated September 21, 2004, as amended
10.08*	Stock Purchase Agreement between Aspen Exploration Corporation and R.V. Bailey dated January, 1983
10.13*	Split-Dollar Life Insurance Plan for R.V. Bailey
10.16	Option Grant to Director Kevan B. Hensman
22.1*	Subsidiaries of Aspen Exploration Corporation Aspen Gold Mining Company, a Colorado corporation Aspen Power Systems, LLC, a Colorado limited liability company
31	Certification pursuant to Rule 13a-14
32	Certification pursuant to 18 U.S.C.ss.1350

* Incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT'S FEES AND SERVICES.

(a) Audit Fees.

Our principal accountant, Gordon Hughes & Banks LLP, billed us aggregate fees in the amount of approximately $42,810 for the fiscal year ended June 30, 2006 and $26,700 for the fiscal year ended June 30, 2005. 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 Board of Directors of Aspen Exploration Corporation (the "Company" or "we") informed Gordon, Hughes, & Banks, LLP ("Gordon Hughes") that it has dismissed Gordon Hughes as the Company's independent registered public accounting firm effective immediately.

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. Hein & Associates LLP's aggregate fees are expected to be approximately $58,500 for the fiscal year ended June 30, 2006.

(b) Audit-Related Fees.

Gordon Hughes & Banks LLP billed us aggregate fees in the amount of $3,850 and $3,750 for the fiscal years ended June 30, 2006 and 2005 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 $7,740 for the fiscal year ended June 30, 2006 and approximately $5,400 for the fiscal year ended June 30, 2005, for tax compliance, tax advice, 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, 2005 and 2004 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 ss.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 ss.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 for the 2005 fiscal year, as well as tax services for the 2004 and 2005 fiscal years, and has approved Hein & Associates LLP to perform our audit for the 2006 fiscal year.

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

Percentage of Total Fees Paid to:

	Hein & Associates	Gordon Hughes & Banks LLP	Gordon Hughes & Banks LLP
	Fiscal Year 2006	Fiscal Year 2006	Fiscal Year 2005
Audit fees	100%	73%	66%
Audit-related fees	0%	9%	14%
Tax fees	0%	18%	20%
All other fees	0%	0%	0%

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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.

October 11, 2006

ASPEN EXPLORATION CORPORATION,
a Delaware Corporation

By: /s/ Robert A. Cohan

Robert A. Cohan
President, Chief Executive Officer, and
Chief Financial Officer

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
October 11, 2006	Robert A. Cohan Principal Executive Officer, Principal Financial Officer Director	/s/ Robert A. Cohan
October 11, 2006	R. V. Bailey Chairman of the Board Director	/s/ R. V. Bailey
October 11, 2006	Kevan B. Hensman	/s/ Kevan B. Hensman

Director ----------------------

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED
PUBLIC ACCOUNTING FIRM

Board of Directors
Aspen Exploration Corporation and Subsidiary
Denver, Colorado

We have audited the consolidated balance sheet of Aspen Exploration Corporation and Subsidiary as of June 30, 2006 and the related consolidated statements of income, stockholders' equity, and cash flows for the year ended June 30, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management as well as evaluating the overall financial statement presentation. We believe that our audit provides 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, 2006, and the results of their consolidated operations and cash flows for the year ended June 30, 2006 in conformity with U.S. generally accepted accounting principles.

Hein & Associates LLP
Denver, Colorado
August 18, 2006

REPORT OF INDEPENDENT REGISTERED
PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated balance sheet of Aspen Exploration Corporation and Subsidiary as of June 30, 2005 and the related consolidated statements of operations, stockholders' equity and cash flows for the year ended June 30, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides 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, 2005, and the results of their consolidated operations and cash flows for the year ended June 30, 2005 in conformity with accounting principles generally accepted in the United States of America.

/s/Gordon, Hughes & Banks, LLP
Greenwood Village, Colorado
August 19, 2005

ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

	June 30, 2006
ASSETS	
Current Assets:	
Cash and cash equivalents	$ 6,466,010
Investments	1,002,527
Accounts and trade receivables	2,119,758
Accounts receivable - related party	1,273
Prepaid expenses	338,000
Precious metals	18,823
Total Current Assets	9,946,391
Investment in oil and gas properties, at cost (full cost method of accounting)	14,274,642
Less accumulated depletion and impairment	(6,118,879)
	8,155,763
Property and Equipment, at cost:	
Furniture, fixtures, and vehicles	122,576
Less accumulated depreciation	(54,710)
	67,866
Other Assets:	
Deposits	250,000
Deferred tax asset	771,000

	1,021,000	
Total Assets	$ 19,191,020	$

(Statement

See accompanying notes to these financial statements.

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ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS (Continued)

	June 30,	
	2006	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued expenses	$ 3,823,298	$
Accounts payable - related party	--	
Advances from joint interest owners	2,187,147	
Asset retirement obligation, current portion	62,800	
Total Current Liabilities	6,073,245	
Asset Retirement Obligation, net of current portion	331,823	
Deferred Income Taxes	2,685,000	
Total Long Term Liabilities	3,016,823	
Total Liabilities	9,090,068	
Commitments and Contingencies (Notes 3, 5, 7, 10, and 11)		
Stockholders' Equity:		
Common stock, $.005 par value:		
Authorized: 50,000,000 shares		
Issued and outstanding: At June 30, 2006, 7,094,641shares and June 30, 2005, 6,733,308 shares	35,473	
Capital in excess of par value	7,283,914	
Retained earnings (deficit)	2,900,798	
Deferred compensation	(119,233)	

Total Stockholders' Equity	10,100,952	
Total Liabilities and Stockholders' Equity	$ 19,191,020	$

See accompanying notes to these financial statements.

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ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended June 30	
	2006	
Revenues:		
Oil and gas	$ 5,400,950	$
Management fees	510,706	
Interest and other income	67,806	
Total Revenues	5,979,462	
Costs and Expenses:		
Oil and gas production	537,508	
Depreciation, depletion and amortization	1,557,076	
Interest expense	6,427	
Selling, general and administrative	890,255	
Total Costs and Expenses	2,991,266	
Operating Income	2,988,196	
Gain on Investments	1,018,771	
Gain on Sale of Equipment	--	
Income Before Income Tax Provision	4,006,967	
Provision for Income Taxes	(1,037,000)	
Net Income	$ 2,969,967	$

Basic Earnings Per Common Share	$ 0.44	$
Diluted Earnings Per Common Share	$ 0.40	$
Basic Weighted Average Number of Common Shares Outstanding	6,826,333	
Diluted Weighted Average Number of Common Shares Outstanding	7,456,495	

See accompanying notes to these financial statements.

ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

	Common Stock			Accumulated (Deficit) Retained Earnings
	Shares	Par Value	APIC	
Balances at June 30, 2004	5,958,979	$ 29,796	$ 6,064,602	$(1,556,225)
Stock issued for debt and interest	300,500	1,503	259,717	--
Options exercised by directors and officers	109,167	545	(545)	--
Options exercised by employee	9,173	46	(46)	--
Options exercised by consultant	13,489	67	(67)	--
Stock issued for consulting services	28,000	140	34,860	--
Stock warrants exercised	300,000	1,500	328,500	--
Stock issued for consulting services	14,000	70	41,300	--
Amortization of deferred compensation	--	--	--	--
Net income	--	--	--	1,487,056
Balances at June 30, 2005	6,733,308	33,666	6,728,321	(69,169)
Options exercised by consultant	25,000	125	14,125	--
Stock issued for consulting services	10,000	50	63,950	--
Options exercised				

by consultant	8,333	42	22,208	--
Stock warrants exercised	300,000	1,500	373,500	--
Stock issued for consulting services	18,000	90	81,810	--
Amortization of deferred compensation	--	--	--	--
Net income	--	--	--	2,969,967
Balances at June 30, 2006	7,094,641	$ 35,473	$ 7,283,914	$ 2,900,798

See accompanying notes to these financial statements.

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ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended J
	2006
Cash Flows from Operating Activities:	
Net income	$ 2,969,967
Adjustments to reconcile net income to net cash provided by operating activities:	
Amortization of deferred compensation	43,904
Depreciation, depletion, and amortization	1,557,076
Deferred income tax provision	898,512
Realized gain on investments	--
Unrealized gain on investments	(1,018,210)
Purchase of investments	(100,356)
Proceeds from sale of investments	116,039
Gain on sale of equipment	--
Changes in assets and liabilities:	
Decrease (increase) in receivable, prepaid expenses, and deposits	(2,065,889)
Increase (decrease) in accounts payable, accrued expenses and advances from joint owners	4,541,545
Net Cash Provided by Operating Activities	6,942,588
Cash Flows from Investing Activities:	
Additions to oil and gas properties	(4,305,846)
Producing oil and gas properties purchased	--
Additions to property and equipment	(12,378)
Proceeds from sale of investments	--
Sale of property and equipment	--

Net Cash Used by Investing Activities	(4,318,224)
Cash Flows from Financing Activities:	
Proceeds from exercise of stock options	411,500
Payment of notes payable	--
Net Cash Provided by Financing Activities	411,500
Net Increase in Cash and Cash Equivalents	3,035,864
Cash and Cash Equivalents, beginning of year	3,430,146
Cash and Cash Equivalents, end of year	$ 6,466,010
Other Information:	
Interest paid	$ 6,427
Income taxes paid	$ 476,908
Non-Cash Investing and Financing Activities:	
Asset retirement obligation	$ 298,413
Conversion of debt for equity	--
Stock issued for deferred consulting services	145,900

See accompanying notes to these financial statements.

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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.

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. Currently, the Company's primary area of interest is in the state of California. The Company has acquired a number of interests in oil and gas properties in California, as described below in more detail. In addition, the Company also acts as operator for a number of our producing wells and receive management fee revenues for these services.

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.

Statement of Cash Flows

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 a cash equivalent.

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).

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 Trading Securities

The Company has classified all investments as Trading Securities in accordance with SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities. These securities are marked to market each period with the realized and unrealized gain or loss recorded in the statement of operations. The Company recognized gains of $1,018,771 on trading securities still held as of June 30, 2006.

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, including internal costs that can be directly identified with those 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 engineers. 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 $281,719 at June 30, 2006 and 2005 (Note 9). Depletion and amortization expense was $1,531,788 and $1,354,055 for the years ended June 30, 2006 and 2005, 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 $25,288 and $18,210 for the years ended June 30, 2006 and 2005, respectively.

Deferred Compensation Costs

The Company records the fair value of stock bonuses to employees and consultants as an expense and an increase to paid-in capital in the year of grant unless the bonus vests over future years. Bonuses that vest are deferred and expensed ratably over the vesting period. During the fiscal years ended June 30, 2006 and 2005, $43,904 and $62,725, respectively, was expensed for stock bonuses.

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NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Allowance for Bad Debts

The Company extends credit to participants of drilling prospects and operated wells. The Company bears the risks inherent in granting credit to these customers. Management reviews accounts receivable on a regular basis to determine if any receivables will potentially be uncollectible. Any accounts receivable that are determined to be uncollectible, along with a general reserve, are included in the overall allowance for doubtful accounts. After all attempts to collect the receivable have failed, the receivable is written off against the allowance. As of June 30, 2006 and 2005, based on information available, management considers accounts receivable to be fully collectible as recorded, accordingly, no allowance for doubtful accounts is required.

Revenue Recognition

Sales of oil and gas production are recognized at the time of delivery of the product to the purchaser. Management fees from outside parties are recognized at the time the services are rendered.

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.

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

	2006			
	Net Income	Shares	Per Share Amount	Net Income
Basic Earnings Per Share:				

Net income and share amounts	$2,969,967	6,826,333	$0.44	$1,487,056
Effect of Dilutive Securities:				
Stock Options	-	397,487	(0.03)	-
Stock Warrants	-	232,675	(0.01)	-
Diluted Earnings Per Share:				
Net income and assumed share conversion	$2,969,967	7,456,495	$0.40	$1,487,056

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Income Taxes

Income taxes are accounted for under SFAS No. 109, "Accounting for Income Taxes", which requires the use of the "liability method". Accordingly, temporary differences are differences between the tax basis of assets and liabilities and their reported amounts in the financial statements that will result in taxable or deductible amounts in future years using enacted tax rates in effect for the year in which the differences are expected to reverse. See Note 3 below.

Stock Award and Stock Option Plans

The Company accounts for stock options using the intrinsic value recognition and measurement principles prescribed in APB No. 25, "Accounting for Stock Issued to Employees" (APB 25), and related interpretations in accounting for options issued to directors and employees. Under APB 25, no compensation cost was recognized for stock options granted to employees and directors as the option price equaled or exceeded the market price of the underlying common stock on the date of the grant. The alternative fair market value accounting provided for under Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" (SFAS 123) and related statements, require use of grant valuation models that were not developed for use in valuing employee stock options and grants.

SFAS No. 123, "Accounting for Stock-Based Compensation", requires pro forma information regarding net income as if compensation cost for the Company's stock option plans had been determined in accordance with the fair value based method prescribed in SFAS No. 123. To provide the required pro forma information, the Company estimated the fair value of each stock option at the grant date by using the Black-Scholes option-pricing model.

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 with the following weighted average assumptions: no dividend yield, expected volatility of 76%, risk free interest rates of 3.92% and expected lives of 4.5 years. The fair value of these options is estimated to be approximately $737,000, and vest over a period of 3 to 5 years. Upon adoption of SFAS 123(R), the fair value of all unvested options will be recognized as compensation expense over the remaining vesting period.

A summary of the pro forma effects to reported net income and earning per share, as if the company had elected to recognize compensation cost based on the fair value of the options granted at grant date as prescribed by SFAS No. 123:

	2006
Net income, as reported	$2,969,967
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	(115,000)
Net income, pro forma	$2,854,967
Basic Earnings Per Share	
As Reported	0.44
Pro Forma	0.42
Diluted Earnings Per Share	
As Reported	0.40
Pro Forma	0.38

Reclassification

Certain 2005 amounts have been reclassified to conform to 2006 presentation. Such reclassifications had no effect on net income.

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NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Recently Issued Pronouncements

FASB 123(R) (revised 2004) - Share-Based Payments

In December 2004, the FASB issued a revision to FASB Statement No. 123, "Accounting for Stock Based Compensation", SFAS 123(R), "Share Based Payment". This Statement supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees", and its related implementation guidance. This Statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments.

The Company will initially measure the cost of employee services received in exchange for an award of liability instruments based on its current fair value; the fair value of that award will be re-measured subsequently at each reporting date through the settlement date. Changes in fair value during the requisite service period will be recognized as compensation cost over that period. A nonpublic entity may elect to measure its liability awards at their intrinsic value through the date of settlement.

The grant-date fair value of employee share options and similar instruments will be estimated using the option-pricing models adjusted for the unique characteristics of those instruments (unless observable market prices for the same or similar instruments are available).

The effective date for public entities that do not file as small business issuers will be as of the beginning of the first interim or annual reporting period of the registrant's first fiscal year that begins after June 15, 2005. For public entities that file as small business issuers and nonpublic entities the effective date will be as of the beginning of the first interim or annual reporting period of the registrant's first fiscal year that begins after December 15, 2005. The impact of the adoption of this statement will be to recognize in compensation expense approximately $115,000 during fiscal years ending June 30, 2007 and 2008 related to unvested option grants issued prior to July 1, 2006. However, the actual expense recognized will depend on a number of factors including the fair value of awards issued during those periods.

In February 2006, SFAS No. 155, Accounting for Certain Hybrid Financial Instruments--an amendment of FASB Statements No. 133 and 140 was issued. SFAS No. 155 will become effective for the Company's fiscal year after September 15, 2006. The Company is still analyzing the potential impact of adopting this statement.

In March 2006, SFAS No. 156, Accounting for Servicing of Financial Assets--an amendment of FASB Statement No. 140 was issued. This Statement amends FASB Statement No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, with respect to the accounting for separately recognized servicing assets and servicing liabilities. SFAS No. 156 will become effective for the Company's fiscal year beginning after September 15, 2006. Adoption of this statement is expected to have no impact on the Company's financial position or results of operations.

NOTE 2 - STOCKHOLDERS' EQUITY

Common Stock

During 2004, the Company issued a convertible debenture and detachable warrants to one accredited investor in exchange for the investor's payment of $300,000. The warrants were valued using the Black-Scholes valuation method at $39,281 and have been recorded as a discount to the debt. The discount was amortized until the debt was converted to common stock in July 2004 at which time the unamortized balance was expensed. In July 2004, the debt was converted to 300,500 share of common stock as consideration for payment of principal and interest.

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NOTE 2 - STOCKHOLDERS' EQUITY (Continued)

Common Stock (Continued)

The convertible debenture included a potential 600,000 common stock warrants exercisable as follows:

If the holder exercised the first warrant before June 30, 2005, the Company would receive $330,000 ($1.10 per share) and issue 300,000 shares of stock; if the holder exercises the warrant before June 30, 2006 but after June 30, 2005, the Company receives an additional $360,000 ($1.20 per share) instead of $330,000.

The holder exercised the warrant before March 31, 2005 and received an additional warrant exercisable to purchase another 300,000 shares at $1.25 per share, which were exercised on April 21, 2006.

On April 12, 2005 the Company entered a contract with CEOcast, Inc., for consulting services to be provided over a six-month period. The Board of Directors approved the issuance of 18,000 shares of restricted common stock and agreed to pay CEOcast, Inc. $5,000 per month. The contract has been renewed twice. On October 13, 2005 and April, 13, 2006 the Board of Directors approved the issuance of 10,000 and 14,000 shares of restricted common stock for each six month period, respectively. The payment of $5,000 per month has continued during each contract period. The Company valued the stock at the estimated fair market value at the date of issuance using the quoted price for the Company's stock.

During fiscal 2006, a consultant exercised his options for 33,333 shares of our common stock, 25,000 of which were granted March 14, 2002 at a price of $0.57 per share, and 8,333 granted April 27, 2005 at a price of $2.67. As consideration for the option shares purchased, the consultant exercised the options with cash payments of $14,250 and $22,249, respectively.

Stock Options

We have two stock option plans as of June 30, 2006, "Option Plan #2," and "Option Plan #3." We had an aggregate of 484,000 common shares reserved for issuance under our stock option plans effective March 14, 2002 and April 22, 2005. These plans provided for the issuance of 676,000 and 260,000 common shares, respectively, pursuant to stock option exercises.

During fiscal 2005, there were 260,000 options granted. Directors and employees were granted 235,000 options and consultants were granted 25,000. The director and employee options have a life of 4.5 years and vest one-third in each January 2006, 2007 and 2008. The consultant options were valued using the fair value approach method of SFAS 123 using the Black-Scholes option pricing model. The fair value of the consultants' options was $58,492 and was fully expensed in fiscal 2005.

Total compensation expense in the statement of operations includes amortization of prior stock awards of $43,904 and $62,725 for the years ended June 30, 2006 and 2005, respectively.

NOTE 2 - STOCKHOLDERS' EQUITY (Continued)

Stock Options (Continued)

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

	Number of Shares	Weighte Exercis Shares
Outstanding Balance, June 30, 2004	484,000	
Granted	260,000	
Exercised	(192,000)	
Outstanding Balance, June 30, 2005	552,000	
Granted	-	
Exercised	(33,333)	
Forfeited or expired	(34,667)	
Outstanding Balance, June 30, 2006	484,000	

The following table summarizes information concerning outstanding and exercisable options as of June 30, 2006:

	Outstanding			Exerc
Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life in Years (1)	Weighted Average Exercisable Price	Number Exercisable
$0.57	99,000	0.12	$0.57	99,000
0.57	150,000	2.12	0.57	85,500
2.67	235,000	3.50	2.67	86,667
	484,000	2.38	$1.59	271,167

(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.

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 with the following weighted average assumptions for fiscal year end 2005: no dividend yield, expected volatility of 76%, risk free interest rates of 3.92% and expected lives of 4.5 years. The fair value of these options is estimated to be approximately $737,000, and vest over a period of 3-5 years. Upon adoption of SFAS 123r, the fair value of all unvested options will be recognized as compensation expense over the remaining vesting period. No options were issued during fiscal 2006.

NOTE 3 - INCOME TAXES

The Company recorded deferred income tax assets of $771,000 and $7,904, and deferred income tax liabilities of approximately $2,685,000 and $1,023,392 as of June 30, 2006 and 2005, respectively. The Company paid $40,885 in California state income taxes in fiscal 2006.

NOTE 3 - INCOME TAXES (Continued)

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 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.

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

	2006	2005
Deferred Tax Assets:		
Percentage depletion carryforward	$ 581,000	$ --
Federal tax loss carryforward	--	2,189
Asset retirement obligation	190,000	5,715
	771,000	7,904
Deferred Tax (Liabilities):		
Property, plant, and equipment	--	(2,365)
Oil and gas properties	(2,685,000)	(1,021,027)
	(2,685,000)	(1,023,392)
	$(1,914,000)	$(1,015,488)

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:

	2006	2005

Statutory federal income tax rate	35%	34%
Statutory state income tax rate, net of federal benefit	6%	9%
Oil and gas percentage depletion permanent difference	-13%	0%
Other	-2%	-10%
Effective Rate	26%	33%

The provision for income taxes consists of the following components:

	2006	2005
Current tax expense	$ 139,000	$ --
Deferred tax expense	898,000	719,168
Total income tax provision	$1,037,000	$ 719,168

NOTE 4 - RELATED PARTY TRANSACTIONS

During fiscal 2006, the Company assigned the following overrides at no cost to employees:

	R. V. Bailey	R. A. Cohan	J. L. Shelton
Johnson Unit 11	1.260000	1.260000	0.480000
Merrill 31-1	1.360000	2.000000	0.640000
Heidrick 11-1	1.133333	1.666667	0.533333
Kalfsbeek 1-13	1.360000	2.000000	0.640000
Denverton Horizontal	1.066750	1.568750	0.502000
Houghton 25-2	0.377400	0.555000	0.177600
Merrill 31-2	1.360000	2.000000	0.640000
Street 1-3	1.241743	1.826088	0.584349

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. The Company's drilling activities are classified as exploratory, and as such the assignment of overriding royalty interests or working interests is not considered to have significant value.

R. V. Bailey, Vice President and former President 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 $481,189 and $240,582, respectively, for the year ended June 30, 2006, and $195,800 and $82,800, respectively, for the year ended June 30, 2005. 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 $117,922 and $157,816, respectively, for the year ended June 30, 2006, and $96,224 and $128,055, respectively, for the year ended June 30, 2005. 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, 2006, 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	74	14.99
R. V. Bailey	54	1.63
R. A. Cohan	54	0.94
R. K. Davis	64	1.34
J. L. Shelton	45	0.10

The Company has remaining advances from Messrs. Bailey and Cohan for working interests of $21,051 and $20,442, respectively, as of June 30, 2006 and $37,640 and $21,400 as of June 30, 2005, respectively, and are recorded in advances from joint interest owners in the accompanying balance sheet.

NOTE 5 - 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 the cash surrender value of life insurance. While as of June 30, 2006 the Company has approximately $8,509,000 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.

NOTE 5 - CONCENTRATION OF CREDIT RISK (Continued)

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 6 - OIL AND GAS ACTIVITIES

Capitalized Costs

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

	June 30, 2006	June 30, 2005
Proved properties	$ 14,274,642	$ 9,670,383
Accumulated depreciation, depletion, and amortization	(5,837,160)	(4,305,371)
Impairment	(281,719)	(281,719)
	(6,118,879)	(4,587,090)
Net capitalized costs	$ 8,155,763	$ 5,083,293

At the date of acquisition of the properties, certain undeveloped properties were also acquired. The Company did not assign any value to these properties as it believed 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, 2006	Year Ended June 30, 2005
Revenues*	$ 5,911,656	$ 4,119,304
Production costs	(537,508)	(346,452)
Depreciation, depletion and accretion	(1,531,788)	(1,354,055)
Interest expense	(6,427)	(6,180)
Results of operations (excluding corporate overhead)	$ 3,835,933	$ 2,412,617

* Includes oil and gas related fees and management fees.

NOTE 6 - OIL AND GAS ACTIVITIES (Continued)

Acquisition, Exploration and Development Costs

	2006	2005

Property acquisitions costs net of divestiture proceeds	$ 47,366	$ 36,129
Exploration	4,316,422	2,231,864
Development	--	--
Total before asset retirement obligation	$4,363,788	$2,267,993
Total including asset retirement obligation	$4,662,201	$2,284,621

Fees charged by Aspen to operate the properties totaled approximately $40,365 per month in 2006 and $22,177 per month in 2005.

Unaudited Oil and Gas Reserve Quantities

The following unaudited reserve estimates presented as of June 30, 2006 and 2005 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.

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, June 30, 2004	2	2,534
Revisions of previous estimates	-	(306)
Discoveries	-	667
Production	-	(617)
Estimated quantity, June 30, 2005	2	2,278
Revisions of previous estimates	-	(320)
Discoveries	-	1,489
Production	-	(696)
Estimated quantity, June 30, 2006	2	2,751

NOTE 6 - OIL AND GAS ACTIVITIES (Continued)

Changes in Proved Reserves

Proved Reserves at Year End	Developed	Developed Non-Producing	Total
		(in thousands)	
Oil (Bbls)			
June 30, 2006	-	2	2
June 30, 2005	-	2	2
Gas (MCF)			
June 30, 2006	1,514	1,237	2,751
June 30, 2005	1,327	951	2,278

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, 2006	June 30, 2005
	(in thousands)	
Future cash inflows	$ 14,765	$ 13,837
Future production costs	(2,024)	(1,433)
Future development costs	(114)	(50)
Future income tax expense	(5,043)	(4,119)

Future cash flows	7,584	8,235
10% annual discount for estimated timing of cash flows	(2,480)	(2,510)
Standardized measure of discounted future net cash	$ 5,104	$ 5,725

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 Jun
	2006
	(in thousan
Standardized measure of discounted future net cash flows, beginning of year	$ 5,725
Sales and transfers of oil and gas produced, net of production costs	(4,863)
Net changes in prices and production costs and other	(422)
Net change due to discoveries	4,690
Acquisition of reserves	--
Revisions of previous quantity estimates	33
Development costs incurred	114
Accretion of discount	848
Net change in income taxes	(914)
Other	(107)
	(621)
Standardized measure of discounted future net cash flows, end of year	$ 5,104

Net changes in prices and production costs of $1.25 million were the result of an increase in the price received for oil and gas at year end which was offset slightly by an increase in operating costs associated with more producing gas wells in 2006 than in 2005. The revision of previous estimates of $97,000 was the result of assigning approximately 62 more barrels of recoverable oil and reducing recoverable reserves of gas by approximately 317,886 MCF. All adjustments were based on performance reviews of individual wells. These additions represent approximately 1,776,014 MCF of recoverable reserves.

NOTE 7 - COMMITMENTS AND CONTINGENCIES

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

Area	Wells	Drilling Costs	Completion and Equipment Costs
Denverton Creek Fld. Solano County, CA	1	$170,000	$75,000
West Grimes Field Colusa County, CA	4	546,000	378,000
Malton Black Butte Tehama County, CA	2	191,000	106,000
Rice Creek Field Tehama County, CA	2	223,000	198,000
San Emidio Field Kern County, CA	1	140,000	-
Total Expenditures	10	$1,270,000	$757,000

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, 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: In April 2005 Mr. Cohan's employment agreement was renewed to December 31, 2008 with a salary increase to $160,000 per year. Other benefits and duties will remain the same as the previous employment contract.

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NOTE 7 - COMMITMENTS AND CONTINGENCIES (Continued)

Gas Sales Contract

On December 20, 2005 Calpine Corporation, one of our major purchasers of natural gas (currently purchases about 10% of our gas), filed for Chapter 11 bankruptcy protection in New York. At the time of the filing, Calpine Corporation owed the Company, exclusive of outside owner participation, approximately $193,000. The Company believes that the amount due to Aspen at the time of this filing will be collectible, but because of issues associated with all bankruptcies, there are no assurances that it will be collected. The Company will continue to monitor the situation with respect to collectibility and take further actions as determined to be appropriate.

Effective July 31, 2006, the Company entered into a gas sales contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $10.15 less transportation and other expenses; the contract is for the term November 1, 2006 - March 31, 2007, requires Enserco to purchase the stated quantities at the stated prices, and contains monetary penalties for non-delivery of the gas. On October 4, 2006, the Company entered into a contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $7.30 per MMBTU less transportation and other expenses for the term December 1, 2006 through March 31, 2007.

NOTE 8 - GAIN ON SALE OF INVESTMENT

In 1998, the Company sold certain geological data to ISL Resources Corporation (ISL) for $250,000 in cash and 2 million shares of ISL common stock. Because there was no viable market to sell or value the shares, and based on the Company's internal evaluation of financial condition, prospects, and estimated fair value of ISL at the time of the initial transaction, the Company recorded the 2 million shares of common stock with a zero cost basis.

On October 18, 2004, the Company entered into an agreement with UR-Energy Inc., a privately held Canadian corporation, which stipulated, among other things, that Aspen would exchange 2,000,000 shares it held in ISL Resources Corporation for 2,000,000 shares of UR-Energy Inc. restricted common shares. The Company also received warrants for an additional 1,000,000 shares of UR-Energy Inc. exercisable at $.75 Cdn per share. This was a non-monetary transaction, and based on the substance of the transaction no gain or loss was recorded at the time of the exchange.

On April 25, 2005, the Company entered into a transaction with UR-Energy Inc. exchanging the 2,000,000 shares of their common stock and the warrants referenced above for $560,090 (U.S.) and 500,000 shares of newly issued UR-Energy Inc. common stock. The Company recorded the entire $560,090 as a gain in the period ended June 30, 2005, and continued to carry the newly issued shares at a zero cost basis (due to the nature of the exchange being a like-kind exchange, that is, UR-Energy Stock and warrants for UR-Energy Stock.) Additionally, there was no viable market to sell or value the shares.

In November 2005, UR-Energy went public via an initial public offering in Canada. At that time the Securities met the definition of a marketable security under Financial Accounting Standards Board Statement Number 115 Accounting for Certain Investment in Debt and Equity Securities (SFAS 115). Irrespective of the fact that the securities met the technical definition of a marketable security, the Company initially did not record any gain in the second or third quarters, as it was uncertain if a viable market for the stock had, in fact been established. In the fourth quarter the Company made an assessment that a viable market had been established and the fair value of the shares is readily determinable as of June 30, 2006. Additionally, the Company changed the classification of the securities to "trading securities", as defined under FAS 115, and began to liquidate its investment in the fourth quarter and subsequently in the first quarter of fiscal 2007. Based on these factors the Company has recognized a gain in the amount of $1,018,771 to record the current market value of the trading securities in its earnings. The securities are recorded on the balance sheet as Investments.

Had the Company applied the provision of FAS 115 in its second and third quarters it would have considered the securities "available for sale" and as a result there would not have been any impact on the Company's reported earnings. The assets and stockholders equity of the Company would have been higher by approximately $484,000 and $886,000 in the second and third quarters, respectively.

NOTE 9 - CONTRACTUAL OBLIGATIONS

The Company has two contractual obligations as of June 30, 2006. The following table lists the significant liabilities at June 30, 2006:

	Payments Due by Period			
Contractual Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
Employment Obligations	$233,464	$418,410	$-	
Operating Leases	9,900	12,104	-	
Total Contractual Cash Obligations	$243,364	$430,514	$-	

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. Rent is 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 expires July 31, 2008. Rent expense for the years ended June 30, 2006 and 2005 were $22,817 and $24,370, respectively.

NOTE 10 - 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 recognize accretion expense in connection with the discounted liability over the remaining life of the respective well. The estimated liability is based on historical experience in plugging and abandoning wells, estimated useful 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. The liability is a discounted liability using a credit-adjusted risk-free rate of 8%. Revisions to the liability could occur due to changes in plugging and abandonment costs, well useful lives or if federal or state regulators enact new guidance on the plugging and abandonment of wells.

A reconciliation of the liability is as follows:

	2006	2005
Beginning balance at July 1	$ 96,210	$ 79,582
Liabilities incurred	292,534	28,977
Liabilities settled	--	(7,881)
Accretion expense	5,879	2,136
Revision to estimate	--	(6,604)
Ending balance at June 30	$394,623	$ 96,210

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NOTE 11 - 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. A total of $7,350 was contributed to the plan for fiscal 2005. An Amendment to the Profit-Sharing 401(k) Plan was adopted effective July 1, 2005 which states that Aspen will make matching contributions equal to 50% of the participant's elective deferrals. During fiscal 2006, $30,250 was contributed to the plan.

Medical Benefit Plan

For the fiscal years ended June 30, 2006 and 2005, 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 2006 and fiscal 2005 were $38,174 and $8,437, respectively. As of June 30, 2006 and 2005 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 12 - MAJOR CUSTOMERS

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

	Company	
Year Ended	A	B
June 30, 2006	27%	73%
June 30, 2005	36%	51%

NOTE 13 - SUBSEQUENT EVENTS (UNAUDITED)

On August 11, 2006, the Board Chairman exercised his option for 50,000 shares of our common stock granted March 14, 2002 at a price of $0.57 per share. As consideration for the option shares purchased, the Mr. Bailey paid cash consideration of $28,500.

On August 14, 2006, an employee exercised her option for 17,000 shares of our common stock granted March 14, 2002 at a price of $0.57 per share. As consideration for the option shares purchased, the employee surrendered shares equal to the exercise price.

On July 31, 2006, the Company entered into a gas sales contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $10.15 per MMBTU less transportation and other expenses. The contract is for the term November 1, 2006 through March 31, 2007, requires Enserco to purchase the stated quantities at the stated prices, and contains monetary penalties for non-delivery of the gas. On October 4, 2006, the Company entered into a contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $7.30 per MMBTU less transportation and other expenses for the term December 1, 2006 through March 31, 2007.

WEST GRIMES FIELD, COLUSA COUNTY, CA

The Stoddard-Johnston #1-1 well was drilled to a depth of 8,700 feet and production casing was run based on mud log and electric log responses.

The WGU #15-12 well was conventionally drilled to a depth of 6,070 feet. Production casing was run, the drilling rig was released, and a completion rig will move in to complete another approximate 130 feet deeper.

NOTE 13 - SUBSEQUENT EVENTS (UNAUDITED) (Continued)

RICE CREEK FIELD, TEHAMA COUNTY, CA

The Ridge #1-15 well was drilled to a depth of 5,755 feet. Production casing was run based on mud log and electric log responses.

The Patterson #27-1 well, located in the Rice Creek Gas Field, Tehama County, California, was drilled to a depth of 5,250 feet. Production casing was run based on mud log and electric log responses.

The Alston #23-2 well, located in the Rice Creek Gas Field, Tehama County, California, was drilled to a depth of 5,700 feet. Production casing was run based on mud log and electric log responses. This was the ninth successful gas well out of ten attempts by Aspen in this field. Aspen has a 38.75% operated working interest in this well and a 23.33% operated working interest in the other wells in this field.

SAN EMIDIO FIELD, KERN COUNTY, CA

Aspen also recently drilled and plugged and abandoned a deep well in Kern County, California after encountering excessive borehole problems. The target objective was never reached. Aspen has a 7% operated working interest in this well.

APPOINTMENT OF DIRECTORS

On August 6, 2006, a Board member, Robert F. Sheldon passed away. The Board appointed Kevan B. Hensman to fill the vacancy created by Mr. Sheldon's death. In connection with that appointment, Aspen granted Mr. Hensman an option to purchase 10,000 shares of Aspen common stock at $3.70 per share.

Since June 2006, Mr. Hensman has been the Manager of Paramount Citrus Association with current duties including the preparation of an annual plan; quarterly budget updates; management reporting; and analysis. From April 2002 to June 2006, Mr. Hensman 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).

NOTE 13 - SUBSEQUENT EVENTS (UNAUDITED) (Continued)

Mr. Hensman was not appointed to any committees of the board of directors, and has no prior relationship with Aspen. Mr. Hensman was not appointed pursuant to any arrangement or understanding between him and any other person except for the grant of stock options as described above.