ASPEN EXPLORATION CORP
Form 10QSB
November 14, 2007

FORM 10-QSB

SECURITIES AND EXCHANGE COMMISSION

Washington D.C. 20549

MARK ONE [**X**] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2007

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ________ to ________

Commission File Number 0-9494

ASPEN EXPLORATION CORPORATION

(Exact Name of Aspen as Specified in its Charter)

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

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

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

Yes [**X**] No [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [**X**]

Indicate the number of shares outstanding of each of the Issuer's classes of common stock as of the latest practicable date.

Class	**Outstanding at November 12, 2007**
Common stock, $.005 par value	7,259,622

Transitional small business disclosure format: [ ] YES [X] No

Part One. FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY

CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2007 (unaudited)	June 30, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,149,795	$ 4,057,279
Short-term investments	1,138,867	1,120,485
Accounts and trade receivables	2,623,226	2,136,609
Other current assets	2,285	33,609
Total current assets	6,914,173	7,347,982
Property and equipment		
Oil and gas property (full cost method)	21,445,108	19,802,843
Support equipment	210,371	184,514
	21,655,479	19,987,357
Accumulated depletion and impairment - full cost pool	(8,730,867)	(8,083,383)
Accumulated depreciation - support equipment	(54,613)	(49,304)
Net property and equipment	12,869,999	11,854,670
Other assets:		
Deposits	263,650	263,650
Deferred income taxes	1,990,000	1,673,000
Total other assets	2,253,650	1,936,650
Total assets	$ 22,037,822	$ 21,139,302

(Statement Continues)

The accompanying notes are an integral part of these condensed consolidated financial statements.

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

	September 30, 2007 (unaudited)	June 30, 2007
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 3,432,991	$ 2,961,100
Other current liabilities and accrued expenses	1,881,425	1,690,709
Notes payable - current portion	275,000	275,000
Asset retirement obligation, current portion	43,000	39,400
Deferred income taxes, current	203,000	342,000
Total current liabilities	5,835,416	5,308,209
Long-term liabilities		
Notes payable, net of current portion	529,167	591,667
Asset retirement obligation, net of current portion	497,681	447,253
Deferred income taxes	4,163,000	3,786,000
Total long-term liabilities	5,189,848	4,824,920
Stockholders' equity:		
Common stock, $.005 par value:		
Authorized: 50,000,000 shares		
Issued and outstanding: At September 30, 2007, and June 30, 2007, 7,259,622 shares	36,298	36,298
Capital in excess of par value	7,525,438	7,501,789
Accumulated other comprehensive loss	(166,870)	-
Retained earnings	3,617,692	3,468,086
Total stockholders' equity	11,012,558	11,006,173
Total liabilities and stockholders' equity	$ 22,037,822	$ 21,139,302

The accompanying notes are an integral part of these condensed consolidated financial statements.

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006
Revenues:		
Oil and gas sales	$ 1,220,822	$ 962,933
Operating expenses:		
Oil and gas production	264,916	191,178
Accretion, and depreciation, depletion and amortization	662,648	480,277
Selling, general and administrative	164,582	397,465
Total operating expenses	1,092,146	1,068,920
Income from operations	128,676	(105,987)
Other income (expenses)		
Interest and other income	75,036	21,415
Interest and other expenses	(18,335)	(4,745)
Gain (loss) on investments	-	262,536
Gain on sale of equipment	-	12,000
Total other income (expenses)	56,701	291,206
Income before income taxes	185,377	185,219
Provision for income taxes	(35,771)	86,000
Net income	$ 149,606	$ 271,219
Basic net income per share	$ 0.02	$ 0.04
Diluted net income per share	$ 0.02	$ 0.04
Weighted average number of common shares outstanding used to calculated basic net income per share :	7,259,622	7,130,175
Effect of dilutive securities:		
Equity based compensation	70,185	242,249
Weighted average number of common shares outstanding used to calculated diluted net income per share :	7,329,807	7,372,424

Unaudited Condensed Statements of Comprehensive Income
Three Month Periods Ended September 30, 2007 and 2006

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006

Net income	$	149,606	$	271,219
Unrealized losses on available-for-sale securities, net of income taxes of $114,748		(166,870)		-
Comprehensive income (loss)	$	(17,264)	$	271,219

The accompanying notes are an integral part of these condensed consolidated financial statements.

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(UNAUDITED)

	Three Months Ended September 30, 2007	2006
Cash Flows from Operating Activities:		
Net income	$ 149,606	$ 271,219
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion and depreciation, depletion, and amortization	662,648	480,277
Deferred income taxes	35,748	(86,000)
Amortization of deferred compensation	-	113,415
Compensation expense related to stock options granted	23,649	54,508
Realized (gain) on investments	-	(129,638)
Unrealized (gain) on investments	-	(130,414)
Proceeds from sale of investments	-	268,230
Gain on sale of vehicle	-	(12,000)
Changes in assets and liabilities:		
Increase in current assets other than cash, cash equivalents, and short-term investments	(455,293)	(1,313,670)
Increase (decrease) in current liabilities other than notes payable and asset retirement obligation	662,607	(1,338,687)
Net Cash Provided (Used) by Operating Activities	1,078,965	(1,822,760)
Cash Flows from Investing Activities:		
Additions to oil and gas properties	(1,623,949)	(1,317,931)
Purchase of securities	(300,000)	-
Producing oil and gas properties purchased	-	(89,062)
Sale of property and equipment	-	12,000
Net Cash (Used) in Investing Activities	(1,923,949)	(1,394,993)
Cash Flows from Financing Activities:		
Proceeds from exercise of stock options	-	28,500
Payment of long-term debt	(62,500)	-
Net Cash Provided (Used) by Financing Activities	(62,500)	28,500
Net (Decrease) in Cash and Cash Equivalents	(907,484)	(3,189,253)
Cash and Cash Equivalents, beginning of year	4,057,279	6,466,010
Cash and Cash Equivalents, end of year	$ 3,149,795	$ 3,276,757
Supplemental disclosures of cash flow information:		
Interest paid	$ 18,335	$ 4,745

Supplemental non-cash activity

Decrease in fair value of investments (net of income taxes of $114,748)	$	166,870	$	-
Increase in asset retirement obligation	$	44,173	$	-

The accompanying notes are an integral part of these condensed consolidated financial statements.

ASPEN EXPLORATION CORPORATION

Notes to Condensed Consolidated Financial Statements
(Unaudited)
September 30, 2007

NOTE 1 BASIS OF PRESENTATION

The accompanying condensed consolidated financial statements of Aspen Exploration Corporation (the Company) are unaudited. However, in the opinion of management, the accompanying condensed consolidated financial statements reflect all adjustments, consisting of only normal recurring adjustments, necessary for fair presentation for the interim period.

The consolidated financial statements included herein have been prepared by the Company pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in consolidated financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to such rules and regulations. Management believes the disclosures made are adequate to make the information not misleading and suggests that these condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes hereto included in the Company s Form 10-KSB for the year ended June 30, 2007.

This Form 10-QSB includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included in this Form 10-QSB, including, without limitation, the statements under both Notes to Consolidated Financial Statements and Item 2. Management s Discussion and Analysis located elsewhere herein regarding the Company s financial position and liquidity, its strategies, financial instruments, and other matters, are forward-looking statements. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from the Company s ex pectations are disclosed in this Form 10-QSB in conjunction with the forward-looking statements.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

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.

Investments in Debt and Equity Securities

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

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

At September 30, 2007, the fair value of securities available for sale was $1,138,867. The gross unrealized holding loss during the three months ended September 30, 2007, on securities still held as of September 30, 2007, was $281,618.

Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, and provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. This Interpretation is effective for fiscal years beginning after December 15, 2006. The Company has evaluated the effects of adopting this interpretation and determined there are no material uncertain tax positions.

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

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

NOTE 3 EQUITY COMPENSATION PLANS

Stock Options

Effective July 1, 2006, the Company adopted the fair value recognition provisions of Statement of Financial Accounting Standard 123(R) Share-Based Payment (SFAS 123(R)) using the modified prospective transition method. In addition, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 107 Share-Based Payment (SAB 107) in March, 2005, which provides supplemental SFAS 123(R) application guidance based on the views of the SEC. Under the modified prospective transition method, compensation cost recognized in the quarterly and year-to-date periods ended March 31, 2007 include: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of July 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all share-based payments granted beginning July 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R). In accordance with the modified prospective transition method, results for prior periods have not been restated.

NOTE 3 EQUITY COMPENSATION PLANS (Continued)

The Company currently has two share-based employee compensation plans, which are described in the Notes to Consolidated Financial Statements in the Company s Annual Report on Form 10-KSB for the year ended June 30, 2007.

The adoption of SFAS 123(R) resulted in stock compensation expense for the three months ended September 30, 2007 and 2006 of $23,649 and $54,508, respectively, to income from continuing operations and income before income taxes. This expense did not have a significant effect on diluted earnings per share for the quarter, or year-to-date periods ended September 30, 2007 and 2006.

NOTE 4 INCOME TAXES

The Company uses the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities. Deferred tax assets or liabilities at the end of each period are determined using the tax rate in effect at that time.

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

NOTE 5 CONTINGENCIES AND DRILLING COMMITMENTS

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

Aspen is paid $50,000 on each anniversary of the agreement so long as Hemis continues work in the area. The payment ceases when and if production begins. Aspen retained a 5% production royalty, which may be taken in kind or in cash as Aspen prefers. Aspen provided to Hemis exploration data assembled and gathered by Aspen over a period of several years in the 1980 s. Permits will be required before Hemis may commence work and there is no assurance such needed permits will be issued by the State of Alaska or by the Federal government.

The Company and Enserco Energy, Inc. entered into a Contract for Sale and Purchase of Natural Gas dated November 1, 2005. Aspen and Enserco have continuously renewed this contract since then. On January 30, 2007 Aspen agreed to sell and Enserco agreed to purchase 2,000 MMBTU (million BTUs or British Thermal Units) of gas per day at a fixed price of $7.65 per MMBTU less transportation and other expenses during the period April 1, 2007 through October 31, 2007. On April 12, 2007, the Company entered into a subsequent renewal of the gas sales contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $9.02 per MMBTU less transportation and other expenses during the period from November 1, 2007 through March 31, 2008.

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

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

NOTE 5 CONTINGENCIES AND DRILLING COMMITMENTS (Continued)

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

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

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

The Company has the following commitments for drilling and completion for the period October 2007 through December 2007:

Area	Wells	Drilling Costs	Completion & Equipping Costs	Total
West Grimes Field				
Colusa County, CA	1	$ -	$ 160,000	$ 160,000
Grimes Gas Field				
Colusa County, CA	1	-	130,000	130,000
Butte Sink Field				
Colusa County, CA	1	315,000	140,000	455,000
Total Expenditure	3	$ 315,000	$ 430,000	$ 745,000

NOTE 6 LONG-TERM DEBT

In January 2007, we borrowed $600,000 from Wells Fargo Bank, NA pursuant to a promissory note payable over thirty-six months to partially finance the acquisition of the Poplar Field in northern Montana. Interest on the note is charged at LIBOR plus 2.25% . We subsequently entered into an interest rate swap agreement with Wells Fargo Bank, which fixes the interest rate on the note at 5.85% . Principal of $16,667 plus interest payments are due monthly through January 15, 2010. Collateral consists of a blanket filing on Accounts Receivables. At September 30, 2007 the outstanding balance on the note was $466,667, of which $200,000 is classified as current.

The Wells Fargo note contains restrictive covenants which, among other things, require us to maintain a certain Net Worth defined as total stockholder s equity of not less that $9,000,000 at any time, net income after taxes not less than $1,000 on an annual basis and an EBITDA ratio, as defined.

In February 2007, as part of the Poplar acquisition, Aspen agreed to be responsible for 12.5% of a $3,000,000 loan obtained by Nautilus in connection with the purchase of the Poplar Field assets. Nautilus Poplar, LLC obtained the loan from the Jonah Bank of Wyoming, as lender. Aspen s share of this loan is $375,000 plus interest at a rate of 9.0%, and Aspen is subject to the repayment schedule that Nautilus Poplar negotiated and to the other terms and conditions of the loan agreement as fully as if Aspen were a party to the loan agreement. Aspen s share of principal payments of $6,250 plus interest is due monthly through February 25, 2009. At September 30, 2007, the outstanding balance was $337,500, of which $75,000 is classified as current.

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

General

The following discussion provides information on the results of operations for the periods ended September 30, 2007 and 2006 and our financial condition, liquidity and capital resources as of September 30, 2007 and June 30, 2007. The financial statements and the notes thereto contain detailed information that should be referred to in conjunction with this discussion.

The profitability of our operations in any particular accounting period will be directly related to the realized prices of oil and gas sold, the type and volume of oil and gas produced and the results of development, exploitation, acquisition, and exploration activities, and the other factors set forth in this report and in our report on Form 10-KSB for the year ended June 30, 2007. The realized prices for natural gas will fluctuate from one period to another due to regional market conditions and other factors, while oil prices will be predominantly influenced by world supply and demand. The aggregate amount of oil and gas produced may fluctuate based on the success of development and exploitation of oil and gas reserves pursuant to current reservoir management. Accordingly, our results of operations may fluctuate from period to period based on the foregoing principal factors, among others.

Overview

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

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

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

We are currently the operator of 63 gas wells in the Sacramento Valley of northern California. Additionally, we have a non-operated interest in 21 gas wells in the Sacramento Valley of northern California and non-operating working interest in approximately 27 oil wells in Montana. When appropriate we may engage in business activities related to the exploration and development of other minerals and resources.

Where possible, we attempt to be the operator of each property in which we invest. We believe that our knowledge of drilling and operating wells in the Sacramento Valley allows us to maximize the potential return of each property. In addition, the other working interest owners are obligated to pay us fees pursuant to the overhead reimbursement provisions of the COPAS Accounting Procedures which are included as an attachment to the operating agreements. These accounting procedures define the overhead expenses that are charged to the joint accounts and permit us to charge some expenses (such as salaries, wages and Personal Expenses of Technical Employees directly employed on the Joint Property and drilling expenses) directly to the joint interest owners. In almost all cases, Aspen also charges a general monthly producing overhead rate per well. We do not recognize these fees received from the joint interest owners as revenues; rather they are offset against (and are a deduction from) our general and administrative expenses as reflected in our statement of operations. During the three months ended September 30, 2007, these administrative charges to the properties helped cover approximately 47% of our selling, general and administrative expenses as compared to 19.5% for the same period of the 2006 fiscal year due primarily to decreases in the issuance of equity instruments as compensation for services, while management fees increased 54%. Management fees as a percentage of SG&A increased 143% for the period ending September 30, 2007 compared to 2006 because the company operated 7 more wells than in the prior period.

Outlook and Trends

Total production for the year depends on a variety of factors set forth herein and in our Form 10-KSB for the year ended June 30, 2007. Over the past five years, through our exploration and development activities and property acquisitions, the Company has been able to increase our oil and gas reserves notwithstanding our production. Since our 2003 fiscal year, only at June 30, 2005, were our reserves at year-end less than our reserves at the previous year-end. Management uses the measurement of our produced reserves to help measure the success of our exploration and development activity. Where reserves are replaced in an amount greater than production, it is a sign that we are continuing our exploration and development activity successfully. A one-year decline or increase may not be important to investors, but seeing a decline or increase over a several year period is a trend worthy of noting, both internally by management and externally by investors.

We have entered into contracts with Enserco Energy, Inc. to sell about 30% of our production from April 1, 2007 through March 31, 2008. We expect to have sufficient gas available for delivery to Enserco from anticipated production from our California fields.

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 drilling 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 may use financial tools to hedge the price we will 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. We have done so through a contract with Enserco Energy, Inc., since November 1, 2005. Under the current renewal of that contract, we are contractually obligated to deliver 2,000 MMBTU per day at $7.65 per MMBTU through October 31, 2007, and then $9.02 per MMBTU through March 31, 2008. These contracts were designated as normal sales contracts.

Liquidity and Capital Resources

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

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

During the first three months of our 2008 fiscal year, we used approximately $907,000 of cash in our operations, investing activities and financing activities as compared to $3.2 million during the same period of our 2007 fiscal year.

We generated cash of $1.08 million from operations for the three months ended September 30, 2007, as compared to $(1.8 million) cash used in operating activities for the three months ended September 30, 2006. This positive change of approximately $2.9 million was primarily due to an increase in income from operations of approximately $235,000 (as discussed below in results of operations), and a use of cash to retire current liabilities which decreased $1.3 million during the period ending September 30, 2006 compared to an increase of $663,000 in the current period. The increase in current liabilities during the period impacts cash flows immediately in that less cash was used in the period to satisfy those liabilities; however, the increase is due to the timing of payments, and cash will be used to satisfy those liabilities in the near term. In addition, there was less of an increase in accounts receivable ($486,000 in 2007 compared to $1.3 million in 2006).

Investing activities used cash to increase capitalized oil and gas costs of $1.6 million during the first three months of FY 2008 as compared to $1.3 million in the three months ended September 30, 2006. These expenditures are net of the sale of interests in wells to be drilled charged to third party investors. In addition, we invested $300,000 in municipal bonds in the current period.

Our working capital surplus (current assets less current liabilities) at September 30, 2007, was $1.08 million, which reflects a $961,000 decrease from our working capital at June 30, 2007. As detailed above, this decrease was due primarily to our negative cash flow of more than $1.6 million for investing activities. Aspen has just finished a large drilling program (which is typical for the period for April - November), which required large expenditures classified as investing activities. This program resulted in increased production, which together with Aspen s existing production is generating about $400,000 per month net to Aspen. As Aspen will not be engaging in significant drilling operations during the November - March period and Aspen expects that it will continue to receive production revenues at rates at least similar to prior quarters, Aspen expects that its cash position and working capital will increase. This has historically been the pattern of Aspen's available cash resources. Another factor contributing to the change in working capital was the increase in accounts payable of $472,000.

Future Commitments

We have a proposed drilling budget for the period October 2007 through December 2007. The budget includes drilling of one well, completing one well, and re-perforating and possibly fracture stimulating one well in the Sacramento gas province of northern California. Our share of the estimated costs to complete this program is set forth in the following table:

Area	Wells	Drilling Costs	Completion & Equipping Costs	Total
West Grimes Field Colusa County, CA	1	$ -	$ 160,000	$ 160,000
Grimes Gas Field Colusa County, CA	1	-	130,000	130,000
Butte Sink Field Colusa County, CA	1	315,000	140,000	455,000
Total Expenditure	3	$ 315,000	$ 430,000	$ 745,000

We anticipate that our working capital and anticipated cash flow from operations and future successful drilling activities will be sufficient to finance our drilling and operating expenses for the next twelve months and to pay our other obligations. Based on national and international concerns, we anticipate that our gas production will continue to provide us with sufficient cash flow through our current fiscal year and beyond. As discussed herein, this is dependent, in part, on maintaining or increasing our level of production and the national and world market maintaining its current prices for our gas production.

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

Results of Operations

September 30, 2007 Compared to September 30, 2006

The following table sets forth certain items from our Condensed Consolidated Statements of Operations as expressed as a percentage of total revenues, shown for the three months of fiscal 2007 and 2006:

	For the Three Months Ended	
	September 30, 2007	September 30, 2006
Total Revenues	100.0%	100.0%
Oil and Gas Production Costs	21.7%	19.9%
Gross Profit	78.3%	80.1%
Cost and Expenses		
Depreciation and depletion	54.3%	49.8%
Selling, general and administrative	13.5%	41.3%
Total Cost and Expenses	67.8%	91.1%
Income from Operations	10.5%	-11.0%
Other Income and Expenses	4.7%	30.2%
Income Before Income Taxes	15.2%	19.2%
Provision for Income Taxes	-2.9%	8.9%
Net Income	12.3%	28.1%

To facilitate discussion of our operating results for the three months ended September 30, 2007 and 2006, we have included the following selected data from our Condensed Consolidated Statements of Operations:

	Comparison of the Fiscal Three Months Ended September 30,		Increase (Decrease)	
	2007	2006	Amount	Percentage
Revenues:				
Oil and gas sales	$ 1,220,822	$ 962,933	$ 257,889	27%
Cost and Expenses:				
Oil and gas production	264,916	191,178	73,738	39%
Depreciation and depletion	662,648	480,277	182,371	38%
Selling, general and administrative	164,582	397,465	(232,883)	-59%
Total Costs and Expenses	1,092,146	1,068,920	23,226	2%
Net Operating Income	$ 128,676	$ (105,987)	$ 234,663	221%

In general, our operations have been adversely affected by increasing costs of production and accretion, depletion, depreciation, and amortization; however, the recent increase in oil and gas prices and production have produced positive results for the three months ended September 30, 2007. As noted, oil and gas prices are subject to national and international pressures, and Aspen has no control over those prices.

For the three months ended September 30, 2007, our operations continued to be focused on the production of oil and gas, in California and Montana. Our gas production increased from 158,391 MMBTU sold during the first three months of September 30, 2006, to 170,058 MMBTU sold this quarter (an increase of approximately 7.4%) . Prices received also increased approximately 2.8% over the same period last fiscal year. As a result of our increased production and prices during the first three months of our 2008 fiscal year, and the acquisition of oil properties in Montana, our revenues from oil and gas sales increased during the 2008 period by approximately $258,000 from approximately $963,000 to approximately $1.2 million.

Oil and gas production costs increased approximately 39% in the three months ended September 30, 2007, as compared to the same period in 2006, from approximately $191,000 to almost $265,000. The increase can be attributed to the addition of gas wells, and our percentage working interests in these wells were somewhat higher than the average of wells owned at September 30, 2006. Additionally, all of the costs for the service companies who perform work on Aspen's wells have increased dramatically.

Depletion, depreciation and amortization expense increased 38%, from approximately $481,000 for the three months ended September 30, 2006 as compared to more than $662,000 during the 2007 period. This increase was the result of increased investments in oil and gas activities, which resulted in the higher total depletion taken. Depletion expense per equivalent unit of production (MCFe) was $3.53 and $3.02 for the three months ending September 30, 2007 and 2006, respectively.

When the Company acts as operator for our producing wells, we receive management fees for these services, which serve to offset our SG&A expenses. When comparing SG&A for the first quarter of 2007 and 2006, costs decreased by $180,662, or 37%, due primarily to decreases in the issuance of equity instruments as compensation for services, while management fees increased 54%. Management fees as a percentage of SG&A increased 143% for the period ending September 30, 2007 compared to 2006.

A significant ratio presented is the percentage of management fees charged to operated wells versus our general and administrative costs. This ratio coverage of general and administrative costs increased from approximately 19.5% during the three months ended September 30, 2006 to approximately 47.4% at September 30, 2007.

	September 30, 2007	September 30, 2006
Management fees	$ 148,324	$ 96,103
Selling, general and administrative (SG&A)	312,906	493,568
Management fees as a percentage of SG&A	47.4%	19.5%

Central to the issue of success of the three months operations ended September 30, 2007 is the discussion of changes in oil and gas sales, volumes of natural gas sold and the price received for those sales. We present them here in tabular form:

	Gas Sales	MMBTU Sold	Price/ MMBTU	Oil & NGL Sales	Bbls Sold	Price/ Bbl
2008						
lst Quarter	$ 1,057,907	170,058	$ 6.22	$ 162,915	2,256	$ 72.21
Year to date	1,057,907	170,058	6.22	162,915	2,256	72.21
June 30, 2007						
lst Quarter	958,171	158,391	6.05	4,762	67	$ 71.07
2nd Quarter	1,051,640	156,003	6.74	2,198	31	70.90
3rd Quarter	1,239,895	173,623	7.14	104,896	1,831	57.29
4th Quarter	936,122	143,540	6.52	120,547	2,155	55.94
June 30, 2007	$ 4,185,828	597,660	$ 7.00	$ 232,403	3,986	$ 58.30

First Quarter Change										
2007										
Amount	$	99,736	11,667	$	0.17	$	158,153	2,189	$	1.14
Percentage		10.4%	7.4%		2.8%		3321.1%	3267.2%		1.6%

(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 and volumes sold of our product have shown an increase over the three months of fiscal 2008. As the table above notes, gas revenue has increased approximately 10.4% when comparing the three-month periods ended September 30, 2007 and 2006. Volumes sold increased approximately 7.4%, while the price received for our gas product increased 2.8% . The significant increase in oil revenue is due to the acquisition of working interests in approximately 33 wells in Montana in the third quarter of fiscal 2007.

Contractual Obligations

The Company and Enserco Energy, Inc. entered into a Contract for Sale and Purchase of Natural Gas dated November 1, 2005. Aspen and Enserco have continuously renewed this contract since then. On January 30, 2007 Aspen agreed to sell and Enserco agreed to purchase 2,000 MMBTU (million BTUs or British Thermal Units) of gas per day at a fixed price of $7.65 per MMBTU less transportation and other expenses during the period April 1, 2007 through October 31, 2007. On April 12, 2007, the Company entered into a subsequent renewal of the gas sales contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $9.02 per MMBTU less transportation and other expenses during the period from November 1, 2007 through March 31, 2008.

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

Critical Accounting Policies and Estimates

The Company believes the following accounting policies and estimates are critical in the preparation of its consolidated financial statements: the carrying value of its oil and natural gas properties, the accounting for oil and gas reserves, and the estimate of its asset retirement obligations.

Oil and Gas Properties

The Company uses the full cost method of accounting for costs related to its oil and natural gas properties. Capitalized costs included in the full cost pool are depleted on an aggregate basis using the units-of-production method. Depreciation, depletion and amortization is a significant component of oil and natural gas properties, but does not impact cash flow. A change in proved reserves without a corresponding change in capitalized costs will cause the depletion rate to increase or decrease.

Both the volume of proved reserves and any estimated future expenditures used for the depletion calculation are based on estimates such as those described under Reserve Estimates below.

The capitalized costs in the full cost pool are subject to a quarterly ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves discounted at 10 percent plus the lower of cost or market value of unproved properties less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and result in lower depreciation and depletion in future periods. A write-down may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the ceiling. Aspen has not recognized any write-downs of the full cost pool during the first three months of 2008 or the comparable period in 2007.

Changes in oil and natural gas prices have historically had the most significant impact on the Company s ceiling test.

In general, the ceiling is lower when prices are lower. Even though oil and natural gas prices can be highly volatile over weeks and even days, the ceiling calculation dictates that prices in effect as of the last day of the test period be used and held constant. The resulting valuation is a snapshot as of that day and, thus, is generally not indicative of a true fair value that would be placed on the Company s reserves by the Company or by an independent third party. Therefore, the future net revenues associated with the estimated proved reserves are not based on the Company s assessment of future prices or costs, but rather are based on prices and costs in effect as of the end of the test period.

Reserve Estimates

Our estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas pr ices, 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.

Accounts Receivable

Accounts receivable balances are evaluated on a continual basis and allowances are provided for potentially uncollectible accounts based on management s estimate of the collectibility of customer accounts. If the financial condition of a customer were to deteriorate, resulting in an impairment of its ability to make payments, an allowance may be required. Allowance adjustments are charged to operations in the period in which the facts that give rise to the adjustments become known; however, no allowance is recorded for the period ending September 30, 2007, as all receivables are expected to be collected in full.

Investments in Debt and Equity Securities

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

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 credit-adjusted risk-free rate of 8%. Revisions to the liability could occur due to changes in well liv es, or if federal and state regulators enact new requirements on the plugging and abandonment of gas wells.

Deferred Taxes

Deferred income taxes have been determined in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. For the period ended September 30, 2007 the Company recorded income tax provision of $35,771. Projections of future income taxes and their timing require significant estimates with respect to future operating results. Accordingly, the net deferred tax liability is continually re-evaluated and numerous estimates are revised over time. As such, the net deferred tax liability may change significantly as more information and data is gathered with respect to such events as changes in commodity prices, their effect on the estimate of oil and gas reserves, and the depletion of these long-lived reserves.

Off Balance Sheet Arrangements

We have no off balance sheet arrangements and thus no disclosure is required.

Other Developments

Subsequent to the quarter ending September 30, 2007 the Harlan #1-24 well, located in the West Grimes Gas Field, Colusa County, California, was drilled to a depth of 8,250 feet and encountered approximately 70 feet of potential gross gas pay in several intervals in the Forbes formation. One of these intervals was perforated and tested gas on a 3/16 inch choke at a stabilized flow rate of 1,700 MCFPD. The shut in tubing and shut in casing pressures were 3,740 psig. Aspen has a 34% operated working interest in this well.

During early November 2007 (subsequent to the quarter end), the Delta Farms #10 well, located in the Butte Sink Gas Field, Colusa County, California, was directionally drilled to a depth of 5,600 feet and encountered over 100 feet of potential gross gas pay in several intervals in the Forbes and Kione formations. Production casing was run based on favorable mud log and electric log responses. If the Forbes intervals prove to be productive in this well, it will be a new pool discovery for this field, which has produced over 7.5 BCF, primarily from the shallower Kione formation. Aspen has additional potential locations based on 3-D seismic data and well control on its 1,000 acre leasehold in this field. Aspen owns a 38% operated working interest before payout and a 44.3% working interest after payout in this well. The well is currently waiting on a completion rig.

Forward Looking Statements

The management discussion and analysis portion 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 items are discussed at length in Aspen s Form 10-KSB filed with the Securities and Exchange Commission, under the heading Risk Factors in the section titled Management s Discussion and Analysis of Financial Condition or Plan of Operation. No material changes are have been noted as of the filing of this 10-QSB.

Item 3. CONTROLS AND PROCEDURES

As of September 30, 2007, we have carried out an evaluation under the supervision of, and with the participation of the Chief Executive Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities and Exchange Act of 1934, as amended.

Based on the evaluation as of September 30, 2007, the Chief Executive Officer (who is also our principal financial officer) has concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e)) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There was no change in our internal control over financial reporting during the most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II

Item 1. LEGAL PROCEEDINGS

There are no material pending legal or regulatory proceedings against Aspen Exploration Corporation, and it is not aware of any that are known to be contemplated.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

No matter was submitted during the first quarter of the fiscal year covered by this report to a vote of security holders, through the solicitation of proxies or otherwise.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

Exhibit No.	Document
31	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Robert A. Cohan, Chief Executive Officer).
32	Certification Pursuant to 18 U.S.C. §1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Robert A. Cohan, Chief Executive Officer).

Other exhibits and schedules are omitted because they are not applicable, not required or the information is included in the financial statements or notes thereto.

In accordance with the requirements of the Securities Exchange Act of 1934, we have duly caused this report to be signed on our behalf by the undersigned, thereunto duly authorized.

ASPEN EXPLORATION CORPORATION

Date: November 12, 2007

/s/ Robert A. Cohan
Robert A. Cohan, Chief Executive Officer and
Chief Financial Officer
(principal executive and financial officer)