ASPEN EXPLORATION CORP
Form 10QSB/A
June 19, 2006

FORM 10-Q-SB/A-2

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 March 31, 2006

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)	(I.R.S. 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 June 19, 2006
Common stock, $.005 par value	7,094,641
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

ASSETS

	March 31, 2006	**June 30, 2005**
	(unaudited)	
Current Assets:		
Cash and cash equivalents	$ 7,116,151	$ 3,430,146
Accounts receivables	4,065,006	614,720
Receivable, related party	1,273	13,000
Prepaid expenses	10,283	15,422
Precious metals	18,823	18,823
Total Current Assets	11,211,536	4,092,111
Investment in oil and gas properties, at cost (full cost method of accounting)	12,931,202	9,670,383
Less: accumulated depletion and valuation allowance	(5,737,090)	(4,587,090)
	7,194,112	5,083,293
Property and equipment, at cost:		
Furniture, fixtures and vehicles	122,576	154,819
Less: accumulated depreciation	(44,341)	(74,044)
	78,235	80,775
TOTAL ASSETS	$ 18,483,883	$ 9,256,179

	March 31, 2006	June 30, 2005

(Statement Continues)
See notes to Consolidated Financial Statements

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

LIABILITIES AND STOCKHOLDERS' EQUITY

	March 31, 2006	June 30, 2005
	(unaudited)	
Current Liabilities:		
Accounts payable and accrued expenses	$ 2,720,824	$ 655,190
Accounts payable - related party (Note 2)		103,233
Income taxes payable (Note 6)	223,259	
Advances from joint interest owners	5,510,855	710,477
Asset retirement obligation (Note 3)	13,826	13,826
Total Current Liabilities	8,468,764	1,482,726
Asset retirement obligation, net of current portion (Note 3)	108,384	82,384
Deferred income taxes (Note 6)	1,353,830	1,015,488
Total long term liabilities	1,462,214	1,097,872
Total Liabilities	9,930,978	2,580,598
Stockholders' Equity: (Notes 1 and 5): Common stock, $.005 par value: Authorized: 50,000,000 shares Issued and outstanding: At March 31, 2006, 6,777,641 shares and June 30, 2005, 6,733,308	33,883	33,666
Capital in excess of par value	6,828,603	6,728,321
Retained earnings (deficit)	1,727,752	(69,169)
Deferred compensation and consulting fees	(37,333)	(17,237)
Total Stockholders' Equity	8,552,905	6,675,581

	March 31, 2006	June 30, 2005
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 18,483,883	$ 9,256,179

See Notes to Consolidated Financial Statements

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31,		Nine Months Ended March 31,	
	2006	**2005**	**2006**	**2005**
Revenues:				
Oil and gas	$ 1,496,427	$ 1,103,687	$ 4,576,203	$ 2,933,599
Management fees	92,682	59,616	295,768	201,441
Total Revenues	1,589,109	1,163,303	4,871,971	3,135,040
Costs and Expenses:				
Oil and gas production	164,796	107,035	356,966	270,891
Depreciation, depletion and amortization	450,000	159,895	1,159,040	469,896
Selling, general and administrative	205,592	192,025	668,654	568,493
Total Costs and Expenses	820,388	458,955	2,184,660	1,309,280
Operating Income	768,721	704,348	2,687,311	1,825,760
Other Income (Expense)				
Interest and other, net	23,612	443	43,641	3,338
Interest (expense)	(22)	(1,053)	(22)	(5,831)
Income Before Taxes	792,311	703,738	2,730,930	1,823,267
Provision for Income Taxes	361,955	1,273	934,009	437,110
Net Income	$ 430,356	$ 702,465	$ 1,796,921	$ 1,386,157
Basic Income per Common Share	0.06	0.11	0.27	0.22
Diluted Income per Common Share	0.06	0.11	0.24	0.21

	Three Months Ended March 31,		Nine Months Ended March 31,	
Basic Weighted Average Number of Common Shares Outstanding	6,775,715	6,406,510	6,762,712	6,406,510
Diluted Weighted Average Number of Common Shares Outstanding	7,360,966	6,640,818	7,347,290	6,640,818

See notes to these consolidated financial statements

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ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Nine Months Ended March 31,	
	2006	**2005**
Cash Flows from Operating Activities:		
Net income	$ 1,796,921	$ 1,386,157
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,159,040	469,896
Stock issued for interest expense and consulting fees	43,904	39,091
Deferred income tax provision	338,342	437,110
Changes in assets and liabilities:		
Increase in receivable	(3,438,559)	(87,116)
(Increase) Decrease in prepaid expense	5,139	(596)
Increase (Decrease) in accounts payable and accrued expense	6,986,038	(1,411,291)
Net cash provided by operating activities	6,890,825	833,251
Cash Flows from Investing Activities:		
Equipment inventory sale	2,000	
Additions to oil and gas properties	(3,234,819)	(1,229,772)
Purchase of producing properties		(19,248)
Purchase of furniture and fixtures	(8,500)	(21,479)
Net cash used by investing activities	(3,241,319)	(1,270,499)
Cash Flows from Financing Activities		
Proceeds from the issuance of common stock	36,499	330,000
Payment of notes payable		(112,500)
Net cash provided by financing activities	36,499	217,500
Net increase (decrease) in cash and cash equivalents	3,686,005	(219,748)
Cash and cash equivalents, beginning of year	3,430,146	1,329,376

	Nine Months Ended March 31,	
Cash and cash equivalents, end of year	$ 7,116,151	$ 1,109,628
Other information:		
Interest paid	$	$ 5,831
Income taxes paid	$ 372,408	
Non-cash investing and financing activities Asset retirement obligation additions	$ 26,000	$ 8,000
Stock issued for deferred consulting services	$ 64,000	

The accompanying notes are an integral part of these statements.

ASPEN EXPLORATION CORPORATION

Notes to Condensed Consolidated Financial Statements

(Unaudited)

March 31, 2006

Note 1 BASIS OF PRESENTATION

The accompanying financial statements are unaudited. However, in our opinion, the accompanying financial statements reflect all adjustments, consisting of only normal recurring adjustments, necessary for fair presentation. Interim results of operations are not necessarily indicative of results for subsequent interim periods or the remainder of the year. These financial statements should be read in conjunction with our Annual Report on Form 10-KSB for the year ended June 30, 2005.

Except for the historical information contained in this Form 10-QSB/A-2, this Form contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those discussed in this Report. Factors that could cause or contribute to such differences include, but are not limited to, those discussed in this Report and any documents incorporated herein by reference, as well as the Annual Report on Form 10-KSB for the year ended June 30, 2005.

Note 2 RECEIVABLE RELATED PARTIES, PAYABLE RELATED PARTIES

The receivable from related parties constitutes amounts due from officers and consultants for joint operating costs of wells operated by us. The transactions are in the normal course of business with the same terms as other joint owners and are repaid in a normal business cycle. The payable to related parties at June 30, 2006, represents unexpended prepayments made by officers and consultants on wells operated by us as well as unpaid business expenses due officers. There is no payable to related parties as of March 31, 2006. These transactions are in the normal course of business.

Note 3 ASSET RETIREMENT OBLIGATION

We have adopted the provisions of Statement of Financial Accounting Standards (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 us to recognize an estimated liability for the plugging and abandonment of our gas wells. We have recognized the future cost to plug and abandon the gas wells over the estimated useful lives of the wells in accordance with SFAS No. 143. 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 producing well is purchased or a drilled well is completed and ready for production. We will amortize the amount added to the oil and gas properties 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 6%. Revisions to the liability could occur due to changes in plugging and abandonment costs, useful well lives or if federal or state regulators enact new regulations on the plugging and abandonment of wells.

A reconciliation of our liability for the three months ended March 31, 2006 is as follows:

Asset retirement obligations as of June 30, 2005	$ 96,210
ARO additions	26,000
Liabilities settled	
Accretion expense	*
Revision of estimate	
Asset retirement obligation as of March 31, 2006	$ 122,210

* Accretion not material

Note 4 EARNINGS PER SHARE

We follow 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.

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Note 4 EARNINGS PER SHARE (CONTINUED)

The following is a reconciliation of the numerators and denominators used in the calculations of basic and diluted earnings per share. We had a net income of $1,796,921 and $1,386,157 for the nine months ended March 31, 2006 and 2005, respectively.

	Nine Months Ended March 31, 2006	2005
	Net Income	Net Income
Basic earning per share:		
Net income	$ 1,796,921	$ 1,386,157
Weighted average common shares outstanding	6,762,712	6,406,510
Basic Earnings per share	$ 0.27	$ 0.22
Diluted earnings per share		
Net Income:	$ 1,796,921	$ 1,386,157
Weighted average common shares outstanding	6,762,712	6,406,510
Dilutive effect of outstanding options	584,578	234,308
Weighted average common shares outstanding - Diluted	7,347,290	6,640,818
Diluted earnings per share	$ 0.24	$ 0.21

Note 5 STOCKHOLDERS EQUITY

Stock Options

On January 10, 2006, a consultant 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.

As of March 31, 2006, we had an aggregate of 502,000 common shares reserved for issuance under our stock option plans. These plans provide for the issuance of common shares pursuant to stock option exercises, restricted stock awards and other equity based awards.

We account for stock options using APB No. 25 for directors and employees and SFAS No. 123 for consultants.

Note 5 STOCKHOLDERS' EQUITY (CONTINUED)

We have adopted SFAS Standards No. 148, Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123. SFAS No. 148 amends No. SFAS 123, Accounting for Stock-Based Compensation to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. We will continue to account for stock based compensation using SFAS 123 detailed in the stock-based compensation accounting standard.

There were 260,000 options granted in 2005. Directors and employees were granted 235,000 and consultants were granted 25,000. The consultant options were valued using the fair value method of SFAS No. 123 as calculated by 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 159.54%, risk free interest rates of 3.92% and expected lives of 4.5 years. The options vest one-third in each of January 2006, 2007 and 2008.

SFAS No. 123, Accounting for Stock-Based Compensation , requires us to provide 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, we estimate the fair value of each stock option at the grant date by using the Black-Scholes option-pricing model.

Note 5 STOCKHOLDERS' EQUITY (CONTINUED)

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:

	3 Months Ended March 31,		9 Months Ended March 31,	
	2006	**2005**	**2006**	**2005**
Net income, as reported	$ 430,356	$ 702,465	$ 1,796,921	$ 1,386,157
Add: Stock based employee compensation expense included in reported net income, net of related tax effects				
Deduct: Total stock based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(81,532)	(27,857)	(244,595)	(83,571)
Proforma net income	348,824	674,608	1,552,326	1,302,586
Earnings per share:				
Basic - as reported	$ 0.06	$ 0.11	$ 0.27	$ 0.22
Basic - pro forma	$ 0.05	$ 0.11	$ 0.23	$ 0.20
Diluted - as reported	$ 0.06	$ 0.11	$ 0.24	$ 0.21
Diluted - pro forma	$ 0.05	$ 0.11	$ 0.21	$ 0.20

Note 6 INCOME TAXES

We have recorded a deferred income tax liability of $1,353,830 and an estimated current income tax liability of $223,259. During the first six months of fiscal 2006, we used all of our net operating loss carryforwards.

Note 6 INCOME TAXES (CONTINUED)

A reconciliation between the statutory federal income tax rate (34%) and the effective rate of income tax expense for the two nine month periods ended March 31 is as follows:

	2006	2005
Statutory federal income tax rate	34%	34%
Other	-6%	-20%
Net federal income tax rate	28%	14%
Statutory state income tax rate, net of federal benefit	2%	9%
Effective rate	30%	23%

	2006	2005
Current tax expense	$595,667	$
Deferred tax expense	338,342	437,110
Total income tax provision	$934,009	$437,110

Note 7 CONTINGENCIES AND DRILLING COMMITMENTS

On December 20, 2005 Calpine Corporation, one of our major purchasers of natural gas (currently purchases about 25% of our gas), filed for Chapter 11 bankruptcy protection in New York. At the time of the filing, Calpine Corporation owed us, exclusive of outside owner participation, approximately $193,000. We believe that the amount due to us at the filing will be collectible, but because of issues associated with all bankruptcies, we cannot offer any assurance that it will be collected. We will continue to monitor the situation with respect to collectibility and take further actions as we determine to be appropriate.

We have a proposed drilling budget for the period April through June 2006. The budget includes drilling three wells in the Sacramento gas province of northern California and one well in Kern County, 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	3	$ 393,000	$ 221,000	$ 614,000
San Emidio Field, Kern County, CA	1	203,000	56,000	259,000
Total Expenditure	4	$ 596,000	$ 277,000	$ 873,000

Note 8 NEW ACCOUNTING PRONOUNCEMENTS

FASB 123 (revised 2004) Share-Based Payments

In December 2004, the FASB issued a revision to FASB Statement No. 123, Accounting for Stock Based Compensation . 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. This Statement focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. This Statement does not change the accounting guidance for share-based payment transactions with parties other than employees provided in Statement 123 as originally issued and EITF Issue No. 96-18, Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling, Goods or Services. This Statement does not address the accounting for employee share ownership plans, which are subject to AICPA Statement of Position 93-6, Employers Accounting for Employee Stock Ownership Plans.

Note 8 NEW ACCOUNTING PRONOUNCEMENTS (CONTINUED)

A nonpublic entity will measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of those instruments, except in certain circumstances.

A public entity 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).

Excess tax benefits, as defined by this Statement, will be recognized as an addition to paid-in-capital. Cash retained as a result of those excess tax benefits will be presented in the statement of cash flows as financing cash inflows. The write-off of deferred tax assets relating to unrealized tax benefits associated with recognized compensation cost will be recognized as income tax expense unless there are excess tax benefits from previous awards remaining in paid-in capital to which it can be offset.

The notes to the financial statements of both public and nonpublic entities will disclose information to assist users of financial information to understand the nature of share-based payment transactions and the effects of those transactions on the financial statements.

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.

In February 2006, SFAS No. 155, Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140 was issued. This Statement resolves issues addressed in Statement 133 Implementation Issue No. D1, Application of Statement 133 to Beneficial Interests in Securitized Financial Assets. 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.

Note 8 NEW ACCOUNTING PRONOUNCEMENTS (CONTINUED)

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 9 THIRD QUARTER ADJUSTMENT

During the quarter ended March 31, 2006, the Company adjusted the depreciation, depletion and amortization expense for the quarters ending September 30, 2005 and December 31, 2005. The adjustment resulted in an increase in depreciation, depletion and amortization of approximately $100,000 per quarter, and is recorded in the nine month results of operations ended March 31, 2006. The adjustment was due to the Company revising its depletion rate using production and its estimated reserves at each quarter end.

Note 10 SUBSEQUENT EVENTS

Aspen re-entered the previously abandoned Cygnus #1RD well located in the Denverton Creek Field, Solano County, California. An attempt was made to re-establish production from the partially depleted Petersen Formation at a depth of approximately 11,000 feet, through the application of underbalanced drilling techniques. The data gathered to date indicates that commercial production will probably not be obtained from this well. Aspen is operator and has a 19.775% working interest in this well.

Aspen also attempted to increase production from the Merrill #31-2 well located in the Malton Black Butte Field, Tehama County, California through the application of underbalanced drilling techniques. The well was returned to production at essentially the same flow rate as prior to the workover. Aspen is operator and has a 31% working interest in this well.

Aspen also participated in the drilling of four gas wells which are operated by other companies. One of these wells is located in the Malton Black Butte Field, Tehama County, California, two are located in the Grimes Gas Field, Colusa County, California, and one is located in the Lindsey Slough Field, Solano County, California. All four of these wells were successful; one is currently producing, two have been tested and are awaiting a pipeline connection, and the other has been logged and is waiting on a completion rig. Aspen operates numerous producing gas wells in the Grimes and Malton Black Butte Fields.

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

This segment should be read in conjunction with the management s discussion and analysis of financial condition and results of operations contained in our Annual Report on Form 10-KSB for the year ended June 30, 2005, which has been filed with the Securities and Exchange Commission. 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. 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-QSB/A-2.

Overview

Aspen Exploration Corporation was organized in 1980 for the purpose of acquiring, exploring and developing oil and gas and other mineral 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 52 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 employees as well as the Chairman of the Board who allocates a portion of his time to the Company. 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 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.

Outlook and Trends

We expect our natural gas production to increase during fiscal 2006 due to recent drilling successes. Total production for the year will depend on the number of wells successfully completed, the date they commence gas sales, 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 $9.00 per MMBTU for the fiscal year ended June 30, 2006 as compared to the average gas price of $6.20 received during our 2005 fiscal year.

Over the past five years we have been able to replace the majority of our produced reserves and increase our yearly natural gas production. We have also benefited from a general increase in natural gas prices over the past three years, from a low of $3.76 per MMBTU average during the second quarter of fiscal 2003 to $10.14 per MMBTU during the second quarter of fiscal 2006 (with an average of $8.62 per MMBTU for the nine months ended March 31, 2006).

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 five years has been 89%. 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 as well as anyone in the industry.

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. 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 the first nine months of fiscal 2006 for our natural gas was approximately $8.62 per MMBTU as compared to $6.12 per MMBTU during the first nine months of fiscal 2005. All contractual obligations expired on March 31, 2006.

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

Cash of $6,890,825 and $833,251 was provided by our operations for the nine months ended March 31, 2006 and 2005. The 2006 period generated net income of $1,796,921, and we were able to generate increased positive cash flow from operations during the first nine months of fiscal 2006 as compared to the 2005 period (when we generated net income of $1,386,157) because of:

For the nine months ended March 31, 2006, the increase in cash flow from operations of $6,890,825, or 727%, was due primarily to:

An increase in net income of approximately $410,764 ($1,796,921 in 2006 as compared to $1,386,157 in 2005); and

A $6,390,371 increase in accounts payable and accrued expenses in 2006 (which conserved cash during the 2006 period) compared to an decrease in accounts payable and accrued expenses in 2005 of $1,411,291; and

An increase in receivables of $3,438,559 in 2006 (which reduced cash flow from operations) compared to an increase in receivables of $87,116 during 2005.

Investing activities used cash to increase capitalized oil and gas costs and office equipment of $3,241,319 and $1,270,499 in the nine months ended March 31, 2006 and 2005. Cash in the current nine month period ended March 31, 2006 was used for lease acquisition, seismic work, intangible drilling and well workovers ($3,234,819), and office equipment of ($8,500). These expenditures are net of the sale of interests in wells to be drilled charged to third party investors.

We have a proposed drilling budget for the period April through June 2006. The budget includes drilling three wells in the Sacramento gas province of northern California and one well in Kern County, 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	3	$ 393,000	$ 221,000	$ 614,000
San Emidio Field, Kern County, CA	1	203,000	56,000	259,000
Total Expenditure	4	$ 596,000	$ 277,000	$ 873,000

Our working capital (current assets less current liabilities) at March 31, 2006, was $2,742,772, which reflects an approximate $133,387 increase from our working capital at June 30, 2005. Our working capital increased by 5% during the first nine months of our 2006 fiscal year because of

an increase in accounts receivable ($4,065,006 at March 31, 2006 as compared to $614,720 at June 30, 2005) due to larger production volumes and greater prices received during the period and the Calpine Corporation bankruptcy (leaving a receivable of approximately $193,000 net of etal participation that (at this time) we believe is collectible);

an increase in advances from joint owners of $4,800,378 that were not expended for drilling projects at March 31, 2006,

which were partially offset by an increase in accounts payable of $2,065,634, an increase in taxes payable of $223,259 and an increase during the period in cash of approximately $3,686,005.

We anticipate that our working capital and anticipated cash flow from operations and future successful drilling will be sufficient to pay our 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.

We believe that internally generated funds will be sufficient to finance our drilling and operating expenses for the next twelve months. 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

March 31, 2006 Compared to March 31, 2005

For the nine months ended March 31, 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 nine months ended March 31, 2006, our revenues increased by approximately $1,736,931 as compared to the comparable period of our 2005 fiscal year because of:

Increased production (530,803 MMBTU sold as compared to 476,500 MMBTU sold during the first nine months of our 2005 fiscal year);

Increased price received for our production (an average of $8.62 per MMBTU during the first nine months of our 2006 fiscal year as compared to $6.16 per MMBTU received during that period in 2005); and

Increased management fees received ($295,768 during fiscal 2006 as compared to $201,441 during fiscal 2005) because we were operators of more wells during 2006 (52 wells compared to 47 wells in 2005).

For the three months ended March 31, 2006, our revenues increased by approximately $425,806 as compared to the comparable period of 2005 because of:

Increased production (182,987 MMBTU sold as compared to 169,150 during the three months ended March 31, 2005);

Increased price received for our production (an average of $8.18 per MMBTU during the three months ended March 31, 2006 compared to $6.52 per MMBTU received for the three months ended March 31, 2005); and

Our revenues during the nine months ended March 31, 2006 include revenues accrued from (but not paid by) Calpine Corporation because of its bankruptcy proceeding. We believe that such revenues are collectible and will be collected. If those revenues are ultimately not collected, then our revenues for the nine months ended March 31, 2006, will decrease by approximately $193,000 of pre-petition receivables and any unpaid post-petition receivables. (See further discussion in Note 8 to the financial statements and Accounts Receivable, below.)

Oil and gas production costs increased $86,075, or 32%, for the nine months ended March 31, 2006 and increased $57,761, or 54%, for the three months ended March 31, 2006. The increase in operating costs can be attributed to the addition of 10 gross wells, from 62 wells to 72 wells and our percentage working interests in these wells were somewhat higher than the average of wells owned at March 31, 2005. Equipment rental and water disposal fees increased due to the addition of compressors and increased water production in our more mature wells.

Depletion, depreciation and amortization expense increased $689,144 and $290,105 for the nine and three months ended March 31, 2006. These increases of 147% and 181%, respectively, were the result of using the approximate same depletion rate as fiscal 2005, but applying it to a larger full cost pool which resulted in the higher total depletion taken.

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 nine months of fiscal 2006, 2005 and 2004:

	For the Nine Months Ended		
	03/31/06	**03/31/05**	**03/31/04**
Total revenues	100.0%	100.0%	100.0%
Oil & gas production costs	7.3%	8.6%	15.0%
Income from operations	92.7%	91.4%	85.0%
Cost and expenses			
Depreciation and depletion	23.8%	15.0%	30.7%
Selling, general and administrative	13.7%	18.1%	36.9%
Interest Expense	0.0%	0.0%	0.0%
Total costs and expenses	32.5%	33.1%	67.6%
Income before income taxes	55.2%	58.3%	17.4%
Other income	-0.9%	0.0%	0.0%
Provision for income taxes	22.8%	13.9%	0.0%
Net income	31.5%	44.4%	17.4%

To facilitate discussion of our operating results for the nine months ended March 31, 2006 and 2005, we have included the following selected data from our Condensed Consolidated Statements of Operations:

	Comparison of the Fiscal Nine Months Ended March 31,		**Increase (Decrease)**	
	2006	**2005**	**Amount**	**Percentage**
Revenues:				
Oil and gas sales	$4,576,203	$2,933,599	$ 1,642,604	56%
Management fees	295,768	201,441	94,327	47%
Interest and other	43,641	3,338	40,303	1207%
Total revenues	4,915,612	3,138,378	1,777,234	57%
Cost and expenses:				
Oil and gas production	356,966	270,891	86,075	32%
Depreciation and depletion	1,159,040	469,896	689,144	147%
General and administrative	668,654	568,493	100,161	18%
Interest expense	22	5,831	(5,809)	-100%
Total costs and expenses	2,184,682	1,315,111	869,571	66%
Income before taxes	3,130,930	1,823,267	1,307,663	50%
Provision for income taxes	934,009	437,110	496,899	114%
Net income	$1,796,921	$1,386,157	$ 410,764	30%

Total revenue increased $1,777,234, or 57% when comparing the two periods, while operating and production costs increased $86,075, or 32%. Our results during the current period were favorable in part because we were able to keep increases in our production costs significantly less than the increases in prices received for natural gas.

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 improved from approximately 35% for the nine months ended March 31, 2005 to approximately 44% at March 31, 2006.

When comparing general and administrative expense for 2006 and 2005, costs increased by $100,161, or 18% due to increased audit and accounting fees, officers salaries and the initiation of an investor relations service.

Central to the issue of success of the nine months operations ended March 31, 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	(1) Price/MMBTU
2006			
1st Quarter	$1,062,543	146,445	$ 7.26
2nd Quarter	2,017,233	201,371	10.14
3rd Quarter	1,496,427	182,987	8.18
Year to date	4,576,203	530,803	8.62
2005			
1st Quarter	697,553	130,000	5.31
2nd Quarter	1,132,359	177,350	6.37
3rd Quarter	1,103,687	169,150	6.52
4th Quarter	919,578	145,500	6.30
Year to date	3,853,177	622,000	6.20
2004			
1st Quarter	341,926	72,600	4.75
2nd Quarter	362,942	79,900	4.64
3rd Quarter	401,941	71,900	5.28
4th Quarter	481,441	80,600	5.97
Year to date	1,588,250	305,000	5.17
Third Quarter Change **2006**			
Amount	$ 392,740	13,837	$ 1.66
Percentage	36%	8%	25%
2005			

	Oil & Gas Sales	MMBTU Sold	(1) Price/MMBTU
Amount	$ 701,746	97,250	$ 1.24
Percentage	175%	135%	23%

(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 first nine months of fiscal 2006 and the twelve months of fiscal 2005. As the table above notes, revenue has increased approximately 36% when comparing the two three month periods ended March 31, 2006 and 2005. Volumes sold increased approximately 8%, while the price received for our product increased 25%.

Contractual Obligations:

We had five contractual obligations as of March 31, 2006. The following table lists our significant liabilities at March 31, 2006:

	Payments Due By Period				
Contractual Obligations	**Less than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Employment Obligations	$226,000	$512,000	$27,000	$	$765,000
Contract Services Obligations	15,000				15,000
Total Contractual Cash Obligations	$241,000	$512,000	$27,000	$	$780,000

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 one-year lease agreement on the Denver office through December 31, 2004 at a lease rate of $1,261 per month. We are currently leasing this space on a month to month basis. The Bakersfield, California office has 546 square feet and had a monthly rental fee of $730 to $770 over the term of the lease. The three year lease expired February 8, 2006 and is currently on a month to month basis. Rent expense for the nine months ended March 31, 2006 and 2005 was $24,372 and $18,921, respectively.

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 Condensed Consolidated Financial Statements.

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 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.

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 additional 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. At the present time, we believe that we will collect the full amount of the pre-petition and post-petition receivables from Calpine Corporation (notwithstanding its bankruptcy petition). We will continue to monitor this situation and revise our estimates as appropriate.

Property, Equipment, Depreciation and Depletion:

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 credit-adjusted risk-free rate of 6%. 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.

Off Balance Sheet Arrangements:

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

Item 3. CONTROLS AND PROCEDURES

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934, as of the filing date of this report, we carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures. This evaluation was carried out under the supervision and with the participation of our principal executive officer (who is also our principal financial officer), who concluded that our disclosure controls and procedures are effective. There have been no significant changes in our internal controls or in other factors, which could significantly affect internal controls subsequent to the date we carried out our evaluation.

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.

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.

The following sets forth the information required by Item 701 of Regulation S-B with respect to the unregistered sale of equity securities:

On January 10, 2006, a consultant 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.

(a) The Warrants were exercised on April 21, 2006, and the transaction was completed 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 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 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. The following sets forth the information required by Item 701 in connection with that transaction:

(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.

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.

31. Rule 13a-14(a) Certification
32. Section 1350 Certification

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.

June 19, 2006

ASPEN EXPLORATION CORPORATION

/s/ Robert A. Cohan
By: Robert A. Cohan,
Chief Executive Officer,
Principal Financial Officer