ASPEN EXPLORATION CORP
Form 10QSB
May 10, 2002

FORM 10-Q-SB

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, 2002

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

Class	Outstanding at May 10, 2002
Common stock, $.005 par value	5,863,828

Part One. FINANCIAL INFORMATION

Item 1. Financial Statements

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

ASSETS

	March 31, 2002 (Unaudited)	June 30, 2001 (Audited)
Current Assets:		
Cash and cash equivalents, including $1,210,075 and $2,636,342 of invested cash at March 31, 2002 and June 30, 2001 respectively	$ 1,265,013	$ 2,695,583
Precious metals	18,823	18,823
Accounts receivable, trade	244,838	554,159
Accounts receivable - related party (Note 7)	-0-	20,000
Prepaid expenses	51,001	14,898
Total current assets	1,579,675	3,303,463
Investment in oil and gas properties, at cost (full cost method of accounting)	4,899,510	4,297,306
Less accumulated depletion and valuation allowance	(2,256,413)	(1,921,413)
	2,643,097	2,375,893
Property and equipment, at cost:		
Furniture, fixtures and vehicles	109,653	104,368
Less accumulated depreciation	(41,154)	(28,133)
	68,499	76,235
Cash surrender value, life insurance	239,095	239,095
TOTAL ASSETS	$ 4,530,366	$ 5,994,686

(Statement Continues)
See notes to Consolidated Financial Statements

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS (Continued)

LIABILITIES AND STOCKHOLDERS' EQUITY

	March 31, 2002 (Unaudited)	June 30, 2001 (Audited)
Current liabilities:		
Accounts payable and accrued expenses	$ 73,157	$ 1,036,715
Advances from joint owners	156,838	444,232
Total current liabilities	229,995	1,480,947
Deferred income tax payable	179,200	179,200
Total liabilities	409,195	1,660,147
Stockholders' equity:		
Common stock, $.005 par value: Authorized: 50,000,000 shares Issued: At March 31, 2002: 5,863,828 and June 30, 2001: 5,812,205	29,320	29,060
Capital in excess of par value	6,024,513	6,015,279
Accumulated deficit	(1,919,161)	(1,692,592)
Deferred compensation	(13,501)	(17,208)
Total stockholders' equity	4,121,171	4,334,539
Total liabilities and stockholders' equity	$ 4,530,366	$ 5,994,686

See Notes to Consolidated Financial Statements

3

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

	Three Months Ended March 31,		Nine Mont Marc	
	2002	2001	2002	

Revenues:			
Oil and gas	$ 124,257	$ 1,109,992	$ 513,444
Management fees	23,632	26,135	91,269
Interest and other, net	10,395	43,387	46,600
Total Revenues	158,284	1,179,514	651,313
Costs and expenses:			
Oil and gas production	34,415	27,058	102,688
Depreciation, depletion and amortization	121,741	77,000	348,020
Aspen Power Systems expense	0	0	25,500
Selling, general and administrative	164,246	146,322	471,725
Interest expense	479	70	479
Total Costs and Expenses	320,881	250,450	948,412
Net income (loss) before taxes	$ (162,597)	$ 929,064	$ (297,099)
Provision for (recovery of) income taxes Notes 2 and 6	(70,530)	82,165	(70,530)
Net income (loss)	$ (92,067)	$ 846,899	$ (226,569)
Basic earnings (loss) per common share	$ (.02)	$ .16	$ (.04)
Diluted earnings (loss) per common share	$ (.02)	$ .15	$ (.04)
Basic weighted average number of common shares outstanding	5,831,800	5,401,678	5,831,800
Diluted weighted average number of common shares outstanding	6,022,414	5,661,678	6,022,414

The accompanying notes are an integral part of these statements.

4

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

	Nine months ended March 31, 2002	2001
Cash flows from operating activities:		
Net income (loss)	$ (226,569)	$ 1,907,567
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion & amortization	348,020	220,000
Amortization of deferred compensation	13,200	13,203

Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	329,321	(36,018)
(Increase) decrease in prepaid expense	(36,103)	3,616
Increase (decrease) in accounts payable and accrued expense	(1,250,950)	279,272
Net cash provided (used) by operating activities ...	(823,081)	2,387,640
Cash flows from investing activities:		
Additions to oil & gas properties	(628,244)	(420,138)
Purchase of office equipment & vehicle	(5,285)	(21,133)
Sale of idle equipment at cost	0	6,000
Sale of oil and gas properties	26,040	0
Net cash (used) by investing activities	(607,489)	(435,271)
Cash flows from financing activities:		
Repayment of notes payable	0	(236,746)
Net cash used in financing activities	0	(236,746)
Net increase (decrease) in cash and cash equivalents	(1,430,570)	1,715,623
Cash and cash equivalents, beginning of year	2,695,583	507,382
Cash and cash equivalents, end of period	$ 1,265,013	$ 2,223,005
Interest paid	$ 479	$ 7,949
Income taxes paid (refund)	$ (70,530)	$ 83,000

The accompanying notes are an integral part of these statements.

ASPEN EXPLORATION CORPORATION

Notes to Consolidated Financial Statements
(Unaudited)

March 31, 2002

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 the full year. These financial statements should be read in conjunction with our Annual Report on Form 10-KSB for the year ended June 30, 2001.

Except for the historical information contained in this Form 10-QSB, 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, 2001.

Note 2 EARNINGS PER SHARE

In February 1997, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 128 ("SFAS No. 128"), addressing earnings per share. SFAS No. 128 changed the methodology of calculating earnings per share and renamed the two calculations basic earnings per share and diluted earnings per share. The calculations differ by eliminating any common stock equivalents (such as stock options, warrants, and convertible preferred stock) from basic earnings per share and changes certain calculations when computing diluted earnings per share. We adopted SFAS No. 128 in fiscal year 1998.

Note 2 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 for the six months ended March 31, 2002 and 2001:

	March 31, 2002			March 31, 2001		
	Net Income	Shares	Per Share Amount	Net Income	Shares	P Sh Am
Basic earnings per share:						
Net income and share amounts	$ (226,569)	5,831,800	$ (.04)	$1,907,568	5,401,678	$
Dilutive securities stock options		776,000			380,000	
Repurchased shares		(585,386)			(120,000)	
Diluted earnings per share:						
Net income and assumed						

share conversion	$ (226,569)	6,022,414	$ (.04)	$1,907,568	5,661,678	$
	==========	==========	=======	==========	==========	==

On December 17, 2001 a director exercised his stock options for 80,000 shares of our common stock at an average exercise price of $0.26 per share. As consideration for the option shares purchased, the director surrendered common stock with a fair value equal to the exercise price of the option shares. The fair value of the shares surrendered was based on a ten-day average bid price immediately prior to the exercise date. Total shares surrendered were 28,377. The effect of this transaction is a net increase to the common stock par value of $260 and a corresponding decrease to additional paid in capital of $260. The filing of this stock option exercise with the Securities and Exchange Commission by Form 4 was not timely filed.

On March 14, 2002 we issued options to purchase 676,000 shares of our common stock at $0.57 per share to our officers, directors, employees and consulting accountant as follows:

R. V. Bailey	150,000
Robert A. Cohan	250,000
Robert F. Sheldon	150,000
Ray K. Davis	75,000
Judith L. Shelton	51,000

Total Shares	676,000
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Bailey, Sheldon, Davis and Shelton options will vest one-third each on August 15, 2003, 2004 and 2005. The Cohan options will vest one-fifth each on August 15, 2003 through 2007.

Note 2 EARNINGS PER SHARE (CONTINUED)

The options to the consultant were valued using the fair value method of SFAS No. 123 as calculated by the Black-Scholes option-pricing model with the following weighted average assumptions: no dividend yield, expected volatility of 13.88%, a risk free interest rate of 8.50% and an expected life of 4.5 years. The resulting compensation of $12,936 will be included in operating expense as the options vest.

The options to officers, directors and employees were valued using the intrinsic method of APB No. 25, resulting in no compensation expense recorded in connection with these options. The adjustment to net income for compensation expense would be recorded under SFAS No. 123 as the options vest. Therefore, there is no proforma effect relating to these options required to be disclosed under SFAS No. 123.

Note 3 SEGMENT INFORMATION

We operate in one industry segment within the United States, oil and gas exploration and development.

Identified assets by industry are those assets that are used in our operations in that industry. Corporate assets are principally cash, cash surrender value of life insurance, furniture, fixtures and vehicles.

During the fourth quarter of 1998, we adopted Statement of Financial Accounting Standards No. 131, "Disclosures about Segments of an Enterprise and Related Information" (SFAS No. 131). The adoption of SFAS No. 131 requires the presentation of descriptive information about reportable segments which is consistent with that made available to the management of the Company to assess performance.

Our oil and gas segment derives its revenues from the sale of oil and gas and prospect generation and administrative overhead fees charged to participants in our oil and gas ventures. Corporate income is primarily derived from interest income on funds held in money market accounts.

During the nine months ended March 31, 2002 there were no intersegment revenues. The accounting policies applied by each segment are the same as those used by us in general.

There have been no differences from the last annual report in the basis of measuring segment profit or loss, with the exception of the elimination of the mineral and power plant segments which we are no longer active in and are not material. There have been no material changes in the amount of assets for any operating segment since the last annual report except for the oil and gas segment which sold oil and gas properties for $26,040 and capitalized $628,244 for the development and acquisition of oil and gas properties, and the corporate segment which purchased $5,285 of computer equipment during the period.

Note 3 SEGMENT INFORMATION (CONTINUED)

Segment information consists of the following for the nine months ended March 31:

	Oil and Gas	Power Plant	Corporate	Consolidated
Revenues:				
2002	$ 604,713	$ -0-	$ 46,600	$ 651,313
2001	2,826,539	-0-	72,533	2,899,072
Income (loss) from operations:				
2002	$ 167,025	$(25,500)	$ (368,094)	$ (226,569)
2001	2,304,789	-0-	(397,221)	1,907,568
Identifiable assets:				
2002	$ 2,887,935	$ -0-	$ 1,642,431	$ 4,530,366
2001	2,010,456	-0-	2,562,664	4,573,120
Depreciation, depletion and valuation charged to identifiable assets:				
2002	$ (2,256,413)	$ -0-	$ (41,154)	$(2,297,567)
2001	(1,728,589)	-0-	(140,689)	(1,869,278)
Capital expenditures:				

2002	$ 628,244	$ -0-	$ 5,285	$ 633,529
2001	420,138	-0-	21,133	441,271

Note 4 MAJOR CUSTOMERS

We derived in excess of 10% of our revenue from various sources (oil and gas sales) as follows:

	The Company			
	A	B	C	D
Year ended:				
March 31, 2002	36%	--	32%	12%
March 31, 2001	35%	12%	49%	--

Note 5 COMMITMENTS AND CONTINGENCIES

At March 31, 2002 the Company was committed to the following drilling and development projects in California:

Note 5 COMMITMENTS AND CONTINGENCIES (CONTINUED)

1. Two Tehama County, California wells. The average total costs for each well is estimated at $520,000 with our share of the average net costs per well approximately $121,000.

2. One Colusa County, California well that is estimated to cost $755,000 with our share of the net costs approximately $70,000, net of prospect fees.

Note 6 INCOME TAXES

The Company has made no provision for income taxes for the nine month period ended March 31, 2002 since it utilizes net operating loss carryforwards. The Company had $583,321 of such carryforwards at June 30, 2001.

On March 26, 2002 we received a refund of overpaid income taxes of $70,530 from the State of California for our fiscal year ended June 30, 2001.

Note 7 SUBSEQUENT EVENTS

On October 4, 2001 the California Power Authority notified our affiliate, Aspen Power Systems ("APS") that no further action would be taken on APS' proposal to build and operate a 323 MW natural gas fired electrical generating plant for the State of California. Consequently, we have written off a $20,000 advance we provided APS, as well as an additional $5,500 payment made to APS in the quarter ended December 31, 2001. The additional $5,500 payment along with a like amount from each of the other three participants in APS was applied to the outstanding obligations of APS at December 31, 2001. At December 31, 2001 we received approximately $10,000 from APS for the services of our president R. V. Bailey. These services were administrative in nature and were mainly for negotiations with third parties for the construction of power plants in California. Future power plant construction opportunities in California appear remote, given current economic conditions, and APS has scaled back its efforts and is seeking other approaches to contracts and financing for power generation facilities in Solano County, California. There is no assurance these efforts will be successful.

On April 22, 2002 we closed on the purchase and sales agreement with an affiliated company to acquire all of its interest in 8 producing gas wells in Northern California. The purchase is effective January 1, 2002. The purchase price of these properties was approximately $118,000. We acquired 60% of the working interest in these properties for $66,075. The balance of 40% was acquired by affiliated investors for $51,925.

On April 27, 2002 we commenced drilling operations on the Porter 26-2, a 6800 foot exploratory gas well in Tehama County, California. We have committed to drill the Porter 26-2 and two additional wells in Tehama and Colusa Counties as follows:

Note 7 SUBSEQUENT EVENTS (CONTINUED)

Well	Estimated Spud Date	Total Depth	Our Estimated Dry Hole Cost
Porter 26-2	4-27-02	6800 feet	$ 80,000
Leal 22-1	5-15-02	5600 feet	57,000
Kuppenbender 20-3	5-15-02	9000 feet	25,000
			$ 162,000

Results of these proposed drilling operations will be disclosed in future reports.

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

This 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, 2001, which has been filed with the Securities and Exchange Commission. This management's 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.

Liquidity and Capital Resources

March 31, 2002 as compared to March 31, 2001

At March 31, 2002 current assets were $1,579,675 and current liabilities were $229,995 and we had positive working capital of $1,349,680 compared to current assets of $3,303,463 at June 30, 2001 and current liabilities of $1,480,947 at the same date, resulting in working capital at June 30, 2001 of $1,822,516. Our current assets decreased by 52%, while current liabilities decreased by 84% from June 30, 2001 to March 31, 2002 for several reasons.

Our current assets decreased primarily because cash and cash equivalents decreased from approximately $2.7 million to approximately $1.3 million. Accounts receivable - trade decreased by about 56% because of the lower prices received for oil and gas production, and decreased production volumes experienced during the nine months ended March 31, 2002.

Our current liabilities decreased to $230,000 at March 31, 2002, from approximately $1.5 million at June 30, 2001. This reduction was due to a number of factors, including a decrease in accounts payable of $963,000 due to a decrease in drilling activity caused by the completion of planned drilling projects, a decrease of $287,000 in advance payments received from joint owners also caused by project completions at March 31, 2002.

We anticipate that our current assets will be sufficient to pay our current liabilities as long as our oil and gas production continues to provide us with sufficient cash flow. As discussed below, this is dependent, in part, on maintaining or increasing our level of production and the national and world market maintaining its current prices for our oil and gas production.

12

During the nine month period ending March 31, 2002, we experienced a sharp decline in production and prices received for the natural gas we produced during that period. At June 30, 2001, we received an average of $10.16 per MMBTU. At March 31, 2002 our price per MMBTU had been reduced to approximately $2.38 per MMBTU, a 77% decline. During the month of April 2002 we will receive an average price of $3.30 per MMBTU, a 39% improvement, but substantially below year ago prices which averaged $8.87 per MMBTU.

In conjunction with a decline in prices we have also experienced a decline in production volumes for the period. For the nine months ended March 31, 2002 we produced approximately 293,000 MMBTU of gas compared to approximately 171,000

MMBTU for the nine months ended March 31, 2002, a 41% decline.

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

Although our drilling and development plans have not been finalized for the coming year, at March 31, 2002 we have spudded one well and are committed to drill 2 additional wells at an estimated dry hole cost to us of approximately $162,000, with the balance (approximately $850,000) to be paid by joint owners in the properties, including certain affiliated investors. For the nine months ended March 31, 2002 we invested $600,000 in our oil and gas properties compared to approximately $420,000 for the nine month period in the preceding fiscal year. We anticipate additional drilling will occur in fiscal 2002.

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Reserve Estimates: Our estimates of oil and natural gas reserves, by necessity, are projections based on 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 there from may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

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

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

Property, Equipment and Depreciation: We follow the full-cost method of accounting for oil and gas properties. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, including salaries, benefits and other internal salary related costs directly attributable to these activities. Costs associated with production and general corporate activities are expensed in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and gas properties. If the net investment in oil and gas properties exceeds an amount equal to the sum of (1) the standardized measure of discounted future net cash flows from proved reserves, and (2) the lower of cost or fair market value of properties in process of development and unexplored acreage, the excess is charged to expense as additional depletion. Normal dispositions of oil and gas properties are accounted for as adjustments of capitalized costs, with no gain or loss recognized.

We apply SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of." Under SFAS No. 121, 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. 121 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.

CONTRACTUAL OBLIGATIONS

We had contractual obligations as of March 31, 2002. The following table lists our significant liabilities at March 31, 2002:

	Payments Due By Period				
Contractual Obligations	Less than 1 year	2-3 years	4-5 years	After 5 years	Total
Operating leases	$26,300	$52,600	$52,600	$ -0-	$131,500
Total contractual cash obligations	$26,300	$52,600	$52,600	$ -0-	$131,500

We lease corporate offices in Denver, Colorado with support offices in Castle Rock, Colorado and Bakersfield, California. The Denver office lease expires December 31, 2002, the Bakersfield office lease expires February 28, 2003 and the Castle Rock office is leased on a month to month basis. Combined yearly lease payments are approximately $26,300.

In addition to office leases, we are responsible for various compressor rentals located on our California producing properties. These leases are on a month to month basis and total approximately $21,500 per year.

Results of Operations

March 31, 2002 Compared to March 31, 2001

For the nine months ended March 31, 2002 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.

Oil and gas revenues, which includes income from management fees, for the nine months ended March 31, 2002 decreased approximately $2,195,000 from $2,800,000 to $605,000, a 78% decrease. This decrease reflects an erosion of prices and reduced production volumes in California. Our share of sales of oil and gas for the nine month period ended March 31, 2002 were 2410 barrels of oil and approximately 171,000 MMBTU of gas with the price received for oil at $19.32 per barrel and $2.70 per MMBTU for gas. This is a decrease in total oil production compared to the 4028 barrels of oil produced in the nine months ended March 31, 2001, and a decrease in natural gas production of 122,000 MMBTU when compared to the approximately 293,000 MMBTU of gas production achieved during the nine months ended March 31, 2001. As discussed in Liquidity and Capital Revenues, a significant factor resulting in the substantial decrease in revenues during the last nine months of fiscal 2002 was a decrease in the prices received for our production when compared to prices of $26.90 and $8.87 received for oil and gas respectively during the first nine months of fiscal 2002.

Oil and gas production costs decreased $48,897 when compared to the last nine month period, from $151,585 to $102,688. Production costs decreased approximately $62,000 due to the elimination of non-recurring workover costs for recompleting wells in upper producing zones. Production costs increased approximately $13,000 because of the addition of new wells and compression costs associated with older producing wells, as well as increased water production and workover costs associated with two oil wells which were sold during the third quarter of 2002.

Depletion, depreciation and amortization increased $128,000 or 58% for the nine month period, which is our best estimate of what the full year cost will be.

Selling, general and administrative expense increased approximately 5% from $449,800 to $471,725 for the nine months ended March 31, 2002. This increase is primarily due to salary and office rental increases, and was offset by the receipt of approximately $10,000 from Aspen Power Systems for the services of our president R. V. Bailey.

As a result of our operations for the nine months ended March 31, 2002, we ended the period with a net loss of $226,600 after taxes compared to net income of $1,908,000 for the year earlier. This loss of approximately $226,600 is due to a decrease in production and the price received for our oil and gas as discussed earlier as well as the fact that our depletion costs rose substantially during the nine month period ending March 31, 2002.

Interest and other income decreased approximately $26,000 to $46,600 and is due to our maintaining a lower average balance of funds in our invested cash accounts, thereby reducing our interest income by $11,900, and a decrease in funds received from Aspen Power Systems of $12,800 from $23,200 to $10,400.

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

/s/ R. V. Bailey

By: R. V. Bailey,
Chief Executive Officer,
Principal Financial Officer

May 10, 2002

16