PRIMA ENERGY CORP
Form 10-Q
November 14, 2001

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

[X] QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES AND EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2001

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 0-9408

PRIMA ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

DELAWARE (State or other jurisdiction of incorporation or organization)	84-1097578 (I.R.S. Employer Identification No.)
1099 18TH STREET, SUITE 400, DENVER CO (Address of principal executive offices)	80202 (Zip Code)

(303) 297-2100
(Registrant's telephone number, including area code)

NO CHANGE
(Former name, former address and former fiscal year, if changed from last report)

Indicate by check mark whether the Registrant (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 the Registrant was require to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

As of October 31, 2001, the Registrant had 12,720,709 shares of Common Stock, $0.015 Par Value, outstanding.

PRIMA ENERGY CORPORATION

INDEX

2

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PRIMA ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

ASSETS

	September 30, 2001 (Unaudited)	December 2000
CURRENT ASSETS		
Cash and cash equivalents	$ 23,347,000	$ 20,382
Available for sale securities, at market	2,400,000	2,311
Receivables (net of allowance for doubtful accounts: $45,000 and $44,000)	6,127,000	8,902
Derivatives, at fair market	5,762,000	

Tubular goods inventory	1,161,000	1,409
Other	669,000	1,042
Total current assets	39,466,000	34,046
OIL AND GAS PROPERTIES, at cost, accounted for using the full cost method	135,026,000	108,272
Less accumulated depreciation, depletion and amortization	(50,334,000)	(43,935
Oil and gas properties - net	84,692,000	64,337
PROPERTY AND EQUIPMENT, at cost		
Oilfield service	13,052,000	9,044
Office furniture and equipment	820,000	729
Field office, shop and land	473,000	473
	14,345,000	10,246
Less accumulated depreciation	(4,839,000)	(3,986
Property and equipment - net	9,506,000	6,260
OTHER ASSETS	1,257,000	257
	$ 134,921,000	$ 104,900

See accompanying notes to unaudited consolidated financial statements.

PRIMA ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS (CONT'D.)

LIABILITIES AND STOCKHOLDERS' EQUITY

	September 30, 2001 (Unaudited)	December 31, 2000
CURRENT LIABILITIES		
Accounts payable	$ 3,180,000	$ 3,207,000
Amounts payable to oil and gas property owners	2,193,000	2,501,000
Ad valorem and production taxes payable	3,862,000	1,857,000
Accrued and other liabilities	621,000	803,000
Deferred tax liability	1,445,000	--
Total current liabilities	11,301,000	8,368,000
AD VALOREM TAXES, non-current	2,776,000	3,213,000
DEFERRED TAX LIABILITY	21,030,000	13,021,000
Total liabilities	35,107,000	24,602,000

STOCKHOLDERS' EQUITY		
Preferred stock, $0.001 par value, 2,000,000 shares authorized; no shares issued or outstanding	--	--
Common stock, $0.015 par value, 35,000,000 shares authorized; 12,860,998 and 12,793,373 shares issued	193,000	192,000
Additional paid-in capital	2,806,000	1,760,000
Retained earnings	99,886,000	78,472,000
Accumulated other comprehensive income (loss)	471,000	(126,000
Treasury stock, 140,289 and no shares, at cost	(3,542,000)	--
Total stockholders' equity	99,814,000	80,298,000
	$ 134,921,000	$ 104,900,000

See accompanying notes to unaudited consolidated financial statements.

PRIMA ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three Months Ended September 30,		Nin
	2001	2000	2001
REVENUES			
Oil and gas sales	$ 9,163,000	$11,428,000	$37,429
Gains on derivative instruments, net	5,552,000	--	5,552
Oilfield services	2,223,000	1,526,000	6,005
Interest, dividend and other income	237,000	310,000	847
	17,175,000	13,264,000	49,833
EXPENSES			
Depreciation, depletion and amortization:			
Depletion of oil and gas properties	2,779,000	1,443,000	6,399
Depreciation of other property	462,000	295,000	1,040
Lease operating expense	869,000	655,000	2,319
Ad valorem and production tax	635,000	950,000	2,928
Cost of oilfield services	1,373,000	1,215,000	3,886
General and administrative	815,000	787,000	2,823
	6,933,000	5,345,000	19,395
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	10,242,000	7,919,000	30,438
Provision for Income Taxes	3,175,000	2,350,000	9,635
Net Income Before Cumulative			

Effect of Change in Accounting Principle	7,067,000	5,569,000	20,803
Cumulative Effect of Change in Accounting Principle	--	--	611
NET INCOME	$ 7,067,000	$ 5,569,000	$21,414
Basic Net Income per Share Before Cumulative Effect of Change in Accounting Principle	$ 0.56	$ 0.44	$
Cumulative Effect of Change in Accounting Principle	--	--	
BASIC NET INCOME PER SHARE	$ 0.56	$ 0.44	$
Diluted Net Income per Share Before Cumulative Effect of Change in Accounting Principle	$ 0.54	$ 0.42	$
Cumulative Effect of Change in Accounting Principle	--	--	
DILUTED NET INCOME PER SHARE	$ 0.54	$ 0.42	$
Weighted Average Common Shares Outstanding	12,704,951	12,751,284	12,731
Weighted Average Common Shares Outstanding Assuming Dilution	13,192,611	13,341,946	13,240

See accompanying notes to unaudited consolidated financial statements.

PRIMA ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(UNAUDITED)

	Three Months Ended September 30,		Ni
	2001	2000	200
Net income	$ 7,067,000	$ 5,569,000	$ 21,41
Other comprehensive income:			
Unrealized gain on hedges	592,000	--	3,61
Deferred income tax expense related to			

unrealized gain (loss) on hedges	363,000	--	(29
Reclassification adjustment for (gains) losses included in net income	(1,575,000)	--	(2,82
Unrealized gain(loss) on available-for-sale securities	1,000	85,000	16
Deferred income tax expense related to unrealized gain on available-for-sale securities	--	(31,000)	(6
Reclassification adjustment for losses included in other income	(1,000)	--	
	(620,000)	54,000	59
COMPREHENSIVE INCOME	$ 6,447,000	$ 5,623,000	$ 22,01

See accompanying notes to unaudited consolidated financial statements.

PRIMA ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Nine Months Ended September 30,	
	2001	2000
OPERATING ACTIVITIES		
Net income	$ 21,414,000	$ 14,564,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	7,439,000	5,232,000
Deferred income taxes	9,193,000	3,891,000
Unrealized gains from derivative instruments	(4,975,000)	--
Other	452,000	556,000
Changes in operating assets and liabilities:		
Receivables	2,775,000	(3,119,000
Inventory	248,000	(1,113,000
Other current assets	282,000	95,000
Accounts payable and payables to owners	(335,000)	623,000
Production taxes payable	1,568,000	1,623,000
Accrued and other liabilities	(182,000)	(735,000
Net cash provided by operating activities	37,879,000	21,617,000
INVESTING ACTIVITIES		
Additions to oil and gas properties	(27,811,000)	(19,406,000
Additions to other property	(4,468,000)	(2,486,000

Purchases of available for sale securities	(92,000)	(216,000
Proceeds from sales of oil and gas and other property	431,000	170,000
Net cash used in investing activities	(31,940,000)	(21,938,000
FINANCING ACTIVITIES		
Treasury stock purchased	(3,542,000)	(1,778,000
Proceeds from issuance of common stock	361,000	455,000
Other	207,000	--
Net cash used in financing activities	(2,974,000)	(1,323,000
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,965,000	(1,644,000
CASH AND CASH EQUIVALENTS, beginning of period	20,382,000	18,883,000
CASH AND CASH EQUIVALENTS, end of period	$ 23,347,000	$ 17,239,000

See accompanying notes to unaudited consolidated financial statements.

PRIMA ENERGY CORPORATION

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL

Prima Energy Corporation ("Prima") is an independent oil and gas company primarily engaged in the exploration for, acquisition, development and production of, natural gas and crude oil. Through its wholly owned subsidiaries, Prima is also engaged in oil and gas property operations, oilfield services and natural gas gathering, marketing and trading. Prima's current activities are principally conducted in the Rocky Mountain region of the United States.

The financial information contained herein is unaudited but includes all adjustments (consisting of only normal recurring accruals) which, in the opinion of management, are necessary to present fairly the information set forth. The unaudited consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with generally accepted accounting principles. These consolidated financial statements should be read in conjunction with the Annual Report on Form 10-K of Prima Energy Corporation for the year ended December 31, 2000, including the financial statements and notes thereto.

The results for interim periods are not necessarily indicative of results to be expected for the fiscal year of the Company ending December 31, 2001. The Company believes that the nine month report filed on Form 10-Q is representative of its financial position, its results of operations and its cash flows for the periods ended September 30, 2001 and 2000.

2. BASIS OF PRESENTATION

The accompanying unaudited consolidated financial statements include the accounts of Prima Energy Corporation ("Prima") and its subsidiaries, herein collectively referred to as "the Company." All significant intercompany transactions have been eliminated. Certain amounts in prior years have been reclassified to conform to the classifications at September 30, 2001.

On a quarterly basis, the Company is required to review the carrying value of its oil and gas properties under the full cost accounting rules of the Securities and Exchange Commission. Under these rules, capitalized costs of proved oil and gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires calculating future revenue using unescalated prices in effect as of the last day of the quarter and requires a write-down for accounting purposes if the ceiling is exceeded. At September 30, 2001, "spot" prices applicable to the Company's natural gas sales were temporarily depressed to a level whereby the Company's capitalized costs exceeded the present value of future net revenues discounted at 10% by approximately $25 million. This calculation was based on a spot price for gas delivered into the Colorado Interstate Gas ("CIG") System of $1.05 per MMBtu. Subsequent to September 30, 2001 and prior to the release of these interim financial statements, the CIG spot price increased substantially, to levels above $2.00 per MMBtu. As a result, the calculated present value of the Company's future net revenues, discounted at 10%, once again exceeded the Company's capitalized costs, and a write-down as of September 30, 2001 was not necessary.

3. RECENT ACCOUNTING PRONOUNCEMENTS

In July 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") No. 141, "Business Combinations." SFAS No. 141 is intended to improve the transparency of the accounting and reporting for business combinations by requiring that all business combinations be accounted for under a single method, the purchase method. This statement is effective for all business combinations initiated after June 30, 2001.

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This statement applies to intangibles and goodwill acquired after June 30, 2001, as well as goodwill and intangibles previously acquired. Under this statement, goodwill as well as other intangibles determined to have an infinite life will no longer be amortized. These assets will be reviewed for impairment on a periodic basis. This statement is effective for the Company in the first quarter of 2002. Management does not believe the adoption of this statement will have a material effect on the Company's financial position or results of operations.

In August 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations." SFAS No. 143 provides the accounting requirements for retirement obligations associated with long-lived assets and requires the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying costs of the asset. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002, and early adoption is permitted. The Company is currently assessing, but has not yet determined, the impact of SFAS No. 143 on its consolidated results of operations, cash flows or financial position.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the

Impairment or Disposal of Long-Lived Assets." SFAS No. 144 requires that long-lived assets be measured at the lower of carrying amount or fair value less costs to sell, whether reported in continuing operations or in discontinued operations. Therefore, discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS No. 144 is effective for financial statements issued for fiscal years beginning after December 15, 2001 and generally is to be applied prospectively.

4. DERIVATIVE ACTIVITIES

Crude oil and natural gas futures, options and swaps, and basis swaps, are used from time to time in order to hedge the price of a portion of the Company's production and to lock in the basis from NYMEX to the Rocky Mountains. These cash flow hedging derivatives are entered into to mitigate the risk of fluctuating oil and natural gas prices and fluctuating basis differentials, which can adversely affect operating results. While such hedges can reduce the adverse effects of oil and gas price declines, they may also limit the benefits of price increases. The Company's derivatives transactions have been entered into with major financial institutions, thereby minimizing credit risk.

Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), as amended, was adopted by the Company effective January 1, 2001. SFAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities. SFAS 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. SFAS 133 prescribes requirements for designation and documentation of hedging relationships, and ongoing assessments of effectiveness, in order to qualify for hedge accounting. Hedge effectiveness is measured based on the relative changes over time in the fair values of the derivative and the hedged item. If a cash flow hedge qualifies for hedge accounting under SFAS 133, and is so designated by the Company, changes in the fair value of the derivative are recorded initially in other comprehensive income and then recognized in the income statement when the hedged item affects earnings. If a cash flow hedge does not qualify for hedge accounting under SFAS 133, or if the Company so elects, changes in the fair value of the derivative are immediately recognized in earnings.

All derivatives within the Company have been evaluated in accordance with SFAS 133. Pursuant to SFAS 133 requirements, the Company has determined that swaps, collars, puts or floors that are based on NYMEX oil prices or CIG gas prices qualify as cash flow hedges, but derivatives based on NYMEX gas prices do not so qualify unless the Company has entered into corresponding transactions to hedge basis

differentials between NYMEX and CIG indices. In addition, sales of call options do not qualify for hedge accounting.

The adoption of SFAS 133 as of January 1, 2001 resulted in the recognition of a current asset of $1,241,000, a current liability of $549,000, and net-of-tax cumulative effect adjustments reducing other comprehensive income by $129,000 and increasing net income by $611,000. The $611,000 is reflected as the cumulative effect of a change in accounting principle in the September 30, 2001 financial statements.

The Company has entered into various cash flow hedges related to its oil and gas production. Some of these derivatives qualify for hedge accounting, while others are non-qualifying. The following table summarizes the income statement effects of these transactions in 2001, through the end of the third quarter (the Company did not hedge any of its natural gas or oil production during the first nine months of 2000):

	Three Months Ended September 30, 2001	Nine Months September 30
Realized gains on derivatives qualifying for hedge accounting, included in oil and gas sales	$ 1,575,000	$ 2,8
Realized gains on non-qualifying hedges	577,000	5
Unrealized gains on non-qualifying hedges	4,975,000	4,9
Aggregate amounts reported on consolidated statements of income	$ 7,127,000	$ 8,3

In addition, as of September 30, 2001, net unrealized gains on derivatives qualifying for hedge accounting, aggregating $786,000 ($495,000 net of related income taxes), were included in accumulated other comprehensive income.

As of September 30, 2001, the Company had recorded a current asset of $5,762,000, representing the aggregate unrealized mark-to-market gains for its open derivative positions (both qualifying and non-qualifying), which are summarized below:

Time Period	Market Index	Total Volumes (MMBtu or Bbls)	Contrac Price
Natural gas			
October 1 - November 30, 2001	CIG	480,000	3.041
October 1 - December 31, 2001	NYMEX	1,320,000	3.611
January 1 - March 31, 2002	NYMEX	1,900,000	3.620
April 1 - June 30, 2002	NYMEX	1,400,000	3.344
July 1 - September 30, 2002	NYMEX	1,200,000	3.450
October 1 - October 31, 2002	NYMEX	400,000	3.491
Crude Oil Calls			
November 1 - December 31, 2001	NYMEX	15,000	29.00
Total Unrealized Gains			

Oil and gas prices are volatile and the market value of these derivatives will change as the underlying commodity futures prices change. Mark-to-market adjustments could result in significant earnings volatility. The actual gains or losses realized will depend on the applicable futures prices in effect at the time such positions expire or are closed.

5. COMMON STOCK

Pursuant to the provisions of the Prima Energy Corporation 1993 Stock Incentive Plan and the Non-Employee Directors' Stock Option Plan, during the second and third quarters of 2001, 67,625 shares of Prima's common stock were issued upon the exercise of stock options, for total proceeds of $361,000.

During the nine months ended September 30, 2001, the Company repurchased 140,289 shares of its common stock as treasury stock for $3,542,000 pursuant to a stock repurchase program. The Board of Directors has authorized the repurchase of up to 5% of the Company's common stock, depending upon market conditions, the Company's financial condition, anticipated capital requirements and liquidity, among other factors. At September 30, 2001, the Company had repurchased approximately 1.1% of the shares that were outstanding when the authorization was approved.

During 2001, the shareholders of Prima approved an increase in the number of authorized shares of common stock from 18,000,000 shares to 35,000,000 shares.

6. EARNINGS PER SHARE

Basic net income per share is computed by dividing net income by the weighted average common shares outstanding during the period. Diluted net income per share includes the potential dilution that could occur upon exercise of options to acquire common stock, computed using the treasury stock method. The treasury stock method assumes the increase in the number of shares issued is reduced by the number of shares which could have been repurchased by the Company with the proceeds from the exercise of the options (which were assumed to have been at the average market price of the common shares during the reporting period).

The following table reconciles the numerator and denominator used in the calculation of basic and diluted net income per share.

	Income (Numerator)	Shares (Denominator)	Per Share Amount
Quarter Ended September 30, 2001:			
Basic Net Income per Share	$ 7,067,000	12,704,951	$ 0.56
Effect of Stock Options	--	487,660	
Diluted Net Income per Share ...	$ 7,067,000	13,192,611	$ 0.54
Quarter Ended September 30, 2000:			
Basic Net Income per Share	$ 5,569,000	12,751,284	$ 0.44

Effect of Stock Options	--	590,662	
Diluted Net Income per Share ...	$ 5,569,000	13,341,946	$ 0.42
Nine Months Ended September 30, 2001:			
Basic Net Income per Share	$21,414,000	12,731,488	$ 1.68
Effect of Stock Options	--	508,767	
Diluted Net Income per Share ...	$21,414,000	13,240,255	$ 1.62
Nine Months Ended September 30, 2000:			
Basic Net Income per Share	$14,564,000	12,737,148	$ 1.14
Effect of Stock Options	--	541,764	
Diluted Net Income per Share ...	$14,564,000	13,278,912	$ 1.10

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

Liquidity and Capital Resources

The Company's principal internal sources of liquidity are cash flows generated from operating activities and existing net working capital. Net cash provided by operating activities for the nine months ended September 30, 2001 was $37,879,000 compared to $21,617,000 for the same nine-month period of 2000, representing a 75% increase. Net working capital at September 30, 2001 was $28,165,000 compared to $25,678,000 at December 31, 2000. Prima's cash equivalents and short-term investments totaled $25,747,000 at September 30, 2001, compared to $22,693,000 at the end of 2000. The Company was free of long-term debt at both dates. Prima expects to fund its exploration, development, and exploitation operations, expansion of its service companies, and stock re-purchases using cash provided by operating activities, working capital, various cost-sharing arrangements, or other financing alternatives. The Company also regularly reviews opportunities for acquisition of assets or companies related to the oil and gas industry that could expand or enhance its existing business. If a sufficiently large transaction is consummated, it could involve the incurrance of debt or issuance of equity securities.

The Company's revenues and cash flows are substantially derived from oil and gas sales, which are dependent on oil and gas production volumes and sales prices. Prima's aggregate net production volumes have increased from 2,765,000 Mcfe in the first quarter of 2001, to 2,892,000 Mcfe in the second quarter, and 3,088,000 Mcfe in the most recent quarter, but gas prices have declined more significantly during the same period. As a consequence, the Company's oil and gas sales revenue, including derivatives qualifying for hedge accounting, declined from $16,357,000 in the first quarter, to $11,909,000 in the following quarter, and $9,163,000 in the latest quarter. Prima's future revenues will continue to be significantly affected by volatility in oil and gas prices.

During the first nine months of 2001, the Company invested $32,279,000 in property and equipment, compared to $21,892,000 invested in the nine months ended September 30, 2000. The Company expended $25,850,000 during the 2001 period for its proportionate share of the costs of drilling, completing, equipping and refracturing wells, $1,884,000 for undeveloped acreage, $77,000 for developed properties and $4,468,000 for gathering and compression facilities and other property and equipment. These expenditures compare to $17,550,000 for well costs, $1,651,000 for undeveloped acreage, $205,000 for developed properties and $2,486,000 for other equipment in the 2000 period. The Company also expended $3,542,000 for the purchase of 140,289 shares of treasury stock during the first nine months of 2001 and $1,778,000 for 103,317 treasury shares purchased during the 2000 period.

The Board of Directors of Prima approved a $45 million capital expenditures budget for 2001 earlier in the year. However, the Company has recently decided to defer certain investments to obtain the benefit of anticipated improvements in service costs or gas prices (as reflected in recent futures markets quotations), and to re-schedule some operations in the Powder River Basin coal bed methane ("CBM") play to occur closer to expected in-service dates of related infrastructure projects. Prima's investments in property and equipment in 2001 are now expected to total approximately $38 million.

Significant investment activities and related operations are updated below.

Denver Basin Operations

During the first nine months of 2001, the Company participated in the drilling of 19 gross (18.8 net) wells and the refracturing or recompleting of 59 gross (55.1 net) wells in the Denver Basin. All of these operations have been successfully completed and all but one of the wells have already been placed on or returned to production. New wells and recompletion operations in the Denver Basin are characterized by flush production at relatively high rates for a few months, after which lower production levels are established at relatively shallow decline rates. The Company generally accelerates these operations when

oil and gas prices are high and defers them when prices are low, to enhance the impact on investment returns from the flush production. Because of oil and gas price declines, and high line pressure attributable to limited processing capacity in the area, Prima elected to postpone certain drilling and recompletion operations that had been scheduled for the third and fourth quarters of 2001. Following a recent recovery in gas prices, and in anticipation of scheduled expansion of third-party owned plant capacity by the end of this year, the Company has resumed recompletion operations, but is still deferring new wells until costs decline or prices increase further. Current plans are to refrac or recomplete approximately seven wells in the Denver Basin during the current quarter.

Powder River Basin Coal Bed Methane Operations

Prima owns leaseholds covering 150,000 gross, 140,000 net, acres in the Powder River Basin CBM play, most of which are still undeveloped. At the end of 2000, Prima's independent engineering consultants identified over 2000 well locations with estimated proved or probable gas reserves on the Company's lands. Approximately 80% of this acreage is comprised of federal leases that are currently subject to stringent limitations on drilling, pending completion of an ongoing environmental impact statement ("EIS") for CBM drilling in the Powder River Basin. This EIS is currently expected to be finalized in the summer of 2002.

Prima has drilled 114 gross (111.5 net) wells in the CBM development area year to-date, including 103 (101.5 net) wells drilled during the first nine months of the year. Since initiating its CBM activities in 1998, the Company has drilled a total of 280 gross (277.6 net) wells in the play, and plans to drill approximately ten additional CBM wells during the balance of 2001. Approximately 140 CBM wells have been tied-in to sales lines and are in various stages of production or de-watering. This number is expected to increase to approximately 156 by year-end.

The Company has organized its CBM acreage into 28 defined project areas. Of the 280 CBM wells drilled by Prima to-date, 272 are located within six of these project areas, each of which is briefly described below. Concentration of Prima's development activities to-date within these project areas, and on the specific coals targeted so far, reflect a number of considerations other than estimated recoverable reserves and projected production rates. The Company's CBM activities have been limited to fee lands, state lands, and certain coals underlying federal lands for which drilling permits have been attainable. These activities have largely been focused on relatively shallow coals, near development activities of other operators. Generally, the higher-potential coals identified on the Company's lands have not yet been developed. These deeper, thicker coal sequences are also not yet proven through development by other operators, and once developed, are expected to take longer to de-water than coals that have already been under development and production in the region for a period of time. The Company recently reduced the pace of its development activities in the CBM play due to lower gas prices, regulatory constraints, and delays in infrastructure development required to tie-in new wells. The Company plans to aggressively develop its CBM acreage as infrastructure development proceeds and regulatory constraints are addressed. Current plans call for focusing near-term activities within the project areas discussed below where existing infrastructure and available drilling permits facilitate cost-effective development, and on commencing limited pilot projects to begin to test some of the deeper, higher-potential coals underlying Prima's acreage. The following is a brief update on activities in the six project areas where most of Prima's CBM operations have been conducted to-date.

Stones Throw - The 9,900-acre Stones Throw project area was the first selected by the Company for CBM development, due primarily to its proximity to an existing CBM field and related infrastructure. Prima has now drilled 153 wells at Stones Throw, of which 114 are currently de-watering or producing. Each well drilled has targeted either the Canyon, Cook, or Wall coal, at depths between approximately 500 and 850 feet. Prima has installed compression at Stones Throw with current capacity to produce up to 10 million cubic feet of gas per day, and gross production from the field has recently been averaging approximately 8 million cubic feet of gas per day. Current plans call for connecting most of the remaining wells drilled in this field into a sales line by the first quarter of next year, but deferring further drilling pending additional production history or improved gas markets. Production results to-date have been less than expected from 29 wells drilled in the southeast portion of the project area (Section 16) and from 20 other wells completed in the Wall coal, which is thinner and shallower in this area than in some other portions of the CBM play. However, Cook and Canyon coal results outside of Section 16 have been more encouraging and production has been continuing to incline.

Kingsbury - Prima has drilled 28 wells in the 8,900-acre Kingsbury project area, of which 26 are producing or de-watering after having been tied into third-party gathering and compression facilities. All but two wells drilled at Kingsbury to-date have been completed in the Lower Anderson coal, but several developable coals are present in this project area. Production has continued to incline as de-watering progresses, and gross production at Kingsbury has recently been averaging approximately 950 Mcf of gas per day. The Company plans to submit applications for permits to drill additional wells on both private and federal lands in this area., but permits for locations on federal lands may be subject to delays due to the on-going EIS. Current plans are to drill and test approximately ten wells in the Kingsbury area during the current quarter, and to formulate 2002 drilling plans for the project after additional monitoring of production performance.

North Shell Draw - Prima has drilled 35 wells targeting the Lower Anderson coal in this 7,400-acre project area. Other developable coals are also present. Access to this area for drilling and pipeline construction is limited during winter months, and no additional drilling is planned until spring 2002. The Company plans to install, or arrange for a third party to install, a gathering system and compression at North Shell Draw by mid-2002. Encouraging results were obtained from production testing of seven North Shell Draw wells during the third quarter. These data will be used to design facilities, structure gas gathering arrangements and plan 2002 drilling activities for this area.

Porcupine-Tuit - The Company has drilled 23 Wyodak-coal wells in this 5,500-acre project area, which exhibits favorable coal quality and thickness at relatively shallow depths. Other operators in the area have already reported encouraging results from completions in the same coal. After an air quality permit to operate compression facilities is obtained, Prima plans to install or arrange for installation of gathering and compression facilities. Initial production is expected to be established by spring 2002. Drilling in the area will likely resume at that time, but is expected to initially be limited by availability of drilling permits on federal lands. Prima's acreage position in the Porcupine-Tuit area was recently enhanced by an acquisition closed in the current quarter that added approximately 1,800 gross (800 net) undeveloped acres.

Hensley - Prima has drilled and completed 18 wells in the 4,800-acre Hensley area, including eight that targeted the Lower Canyon coal, seven that were drilled to the Wall coal, and three that were drilled to the Upper Anderson coal. The Company is finalizing a gathering agreement with a third party for this project area, and 16 of the existing wells at Hensley could be placed on-line by year-end if compression facilities can be installed within that time frame. The Company plans to apply for additional drilling permits on federal lands within the Hensley project area over the next several months, but issuance of such permits may be delayed due to the pending EIS.

Cedar Draw - The Company recently drilled 15 wells, including nine unit obligation wells, on the 3,800-acre Echeta federal unit within the 6,000-acre Cedar Draw project area. Three different coals were targeted by these 15 wells, which will provide test data useful for formulating further development plans. Cedar Draw is in close proximity to the North Shell Draw area, and the Company anticipates coordinating development of the two projects, including infrastructure installation and the scheduling of additional drilling during 2002.

As noted above, all CBM wells hooked-up by Prima to-date are at Stones Throw or Kingsbury. The following table shows year-to-date well status and production for Prima's CBM operations through October 2001. Production volumes for the latest month shown are estimates. The term "hooked-up" means the well is completed and connected to a gas sales line and water handling facilities as of the end of the month. The number of producing wells shown represents all wells that produced any gas during the month. The columns labeled "top quartile production" show the gross production of the top-producing quarter of the producing well count. The increasing trend of production rate per well reflects the early stage in the production profile of a typical CBM well. Individual well production rates during the reported period

varied from less than one Mcf per day to over 350 Mcf per day. Top quartile production rates provide an indication of the variability in production rates within the total group of producing wells.

			Gross Production (Mcf)			
			All Producing Wells		Top Qu We	
	Total Wells Hooked-up	Total Wells Producing	Total	Avg/Well/Day	Total	Avg/We
January 2001	49	40	30,600	25	25,500	
February 2001	64	38	37,200	35	21,700	
March 2001	72	55	58,900	35	36,100	
April 2001	86	69	78,600	38	51,300	
May 2001	103	73	89,700	40	61,100	
June 2001	123	81	109,500	45	63,600	
July 2001	124	110	179,200	53	117.000	
August 2001	138	129	214,100	54	144,500	
September 2001	140	138	243,800	59	153,100	
October 2001	140	138	273,000	64	164,700	

Other Operations

Prima has continued to expand its acreage position in east-central Utah, on the Wasatch Plateau, to approximately 95,000 gross (90,000 net) undeveloped acres, covering several different prospects. Approximately 75,000 gross (71,000 net) acres are included in the Company's Coyote Flats prospect. The Coyote Flats prospect is located 15 to 25 miles northwest of Price, Utah. Significant hydrocarbon production exists in the area, which is characterized by considerable structural complexity. Prima's objective at Coyote Flats is to test the hydrocarbon potential of sandstone and coal bed reservoirs in the Blackhawk, Emery, Ferron and Dakota members of the middle to lower Cretaceous section. The Company has elected to postpone drilling the initial test well on Coyote Flats until the summer of 2002, when test wells on two other prospects in the area are also planned. These are higher-risk exploration projects with no assurance that commercial production will ever be established.

Prima owns approximately 17,500 gross (5,300 net) undeveloped acres in the Hells Half Acre prospect located in Natrona County, Wyoming. This prospect is a seismically-defined structure located approximately 10 miles southeast of the Cave Gulch Field, five miles east of the Cooper Reservoir Field, and five miles southeast of Waltman Field. The Company is participating in the #11-9 Miller Ranch well, which is currently drilling. This 12,700-foot test is designed to evaluate the Lance-Mesaverde section, which produces at the Cave Gulch and Cooper Reservoir Fields. The Company has approximately a 7% working interest in this well, but retains more significant exposure in surrounding lands. Hells Half Acre is also prospective at depths ranging to approximately 20,000 feet for large-potential reserve accumulations. Prima anticipates that the operator will propose a test well to evaluate deeper horizons sometime during the first half of 2002.

Prima owns approximately 72,000 gross (28,000 net) undeveloped acres on its Merna prospect, which is located in Sublette County, Wyoming, 10 to 30 miles north of the Pinedale Anticline. The Company has entered into an agreement with a third party to support that party's effort to re-enter and complete one well and drill a second well on offsetting acreage. In exchange for information obtained from these operations, Prima agreed to allow the third party to participate in the drilling of a test well on Prima's acreage within the next nine months. Operations are currently being conducted on the initial well re-entry to test the over-pressured Lance interval.

Results of Operations

The Company's primary source of revenues is the sale of oil and natural gas production. Because of fluctuations in oil and natural gas prices and production volumes, the Company's operating results for any period are not necessarily indicative of future operating results.

Historically, oil and natural gas prices have been volatile and are likely to continue to be volatile. Prices are affected by, among other things, market supply and demand factors, market uncertainty, and actions of the United States and foreign governments and international cartels. These factors are beyond the control of the Company. Prima's revenues, cash flows, earnings and operations are adversely affected when oil and gas prices decline. Gas prices have declined significantly since reaching record high levels early in 2001, and oil prices have also declined in 2001, albeit more modestly. These price declines have unfavorably impacted the Company's operating results, as more fully described below. The Company cannot accurately predict future oil and natural gas prices, but, historically, oil and gas supply and demand have responded to changes in price levels to correct from short-lived extreme levels of high or low prices.

Quarters Ended September 30, 2001 and 2000

For the quarter ended September 30, 2001, the Company earned net income of $7,067,000, or $0.54 per diluted share, on revenues of $17,175,000. These results compare to net income of $5,569,000, or $0.42 per diluted share, on revenues of $13,264,000 for the comparable quarter of 2000. Expenses totaled $6,933,000 in the 2001 third quarter, compared to $5,345,000 for the 2000 third quarter. Revenues increased $3,911,000, or 29%, expenses increased $1,588,000, or 30%, and net income increased $1,498,000, or 27%.

Revenues for the 2001 period included $7,127,000 of gains related to oil and gas derivatives (see Note 4). This total was comprised of hedging gains, which are discussed below, plus realized and unrealized gains on derivative instruments that did not qualify for hedge accounting, in the amounts of $577,000 and $4,975,000, respectively. No comparable amounts were reported in 2000.

Excluding gains from derivative instruments, oil and gas sales reported for the quarter ended September 30, 2001 were $7,588,000, compared to $11,428,000 for the same quarter of 2000, a decrease of $3,840,000 or 34%. The decrease was attributable to lower natural gas and oil prices, partially offset by increased production volumes.

The following information is provided excluding effects of derivatives. The average sales price received by the Company for natural gas production was $1.96 per Mcf for the 2001 quarter, compared to $3.73 per Mcf for the 2000 quarter, a decrease of $1.77 per Mcf, or 47%. The average price received for oil in the third quarter of 2001 was $26.39 per barrel compared to $30.80 per barrel for the second quarter of 2000, a decrease of $4.41 per barrel or 14%. On an Mcf equivalent basis, the average price received was $2.46 per Mcfe for the quarter ended September 30, 2001 compared to $4.06 per Mcfe for the quarter ended September 30, 2000, representing an overall 39% decline in average prices. The Company's oil and gas revenues were 63% derived from natural gas sales during the 2001 quarter compared to 71% in the 2000 quarter.

Hedging gains of $1,575,000 are included in oil and gas revenues for the third quarter of 2001. Such gains had the effect of increasing average price realizations by $0.63 per Mcf of natural gas, $0.59 per barrel of oil, and $0.51 per Mcfe. Cumulative gains realized on derivatives relating to production months in the third quarter of 2001 aggregated $2,515,000, including gains from derivatives that qualify for hedge accounting and gains from non-qualifying derivatives, and including both gains reported in the current period and gains previously reported. The Company did not hedge any of its production during the third quarter of 2000.

The Company's net natural gas production totaled 2,456,000 Mcf and 2,165,000 Mcf for the third quarters of 2001 and 2000, respectively, an increase of 291,000 Mcf, or 13%, in the current year. Prima's net oil production totaled 105,000 barrels and 109,000 barrels in the third quarters of 2001 and 2000, respectively, a decrease of 4,000 barrels, or 4%. On an equivalent unit basis, the Company's production increased approximately 10%, to 3,088,000 Mcfe in the recent quarter from 2,817,000 Mcfe last year. Total production was 80% natural gas and 20% oil in the third quarter of 2001, compared to 77% gas and 23% oil in the same period last year. Net production from the Company's CBM operations, which totaled 518,000 Mcf in the recent quarter, compared to none last year, more than offset net decreases from the Company's other producing properties attributable to natural declines and limited new activity.

The Company's depletion expense for oil and gas properties was $2,779,000, or $0.90 per Mcfe, in the third quarter of 2001, compared to $1,443,000, or $0.51 per Mcfe, in the third quarter of 2000. The substantial increase in the depletion rate reflects a number of factors, including: significant declines in oil and gas prices, which, under the methodology prescribed, affects estimates of oil and gas reserves that can be economically recovered through future production; increases in oilfield service costs, which impacted actual costs incurred during the past year and the assumptions required to be used in estimating future development costs; and use of more conservative assumptions for estimating undeveloped CBM reserves, pending additional performance-related data. The Company's depletion rate will next be re-evaluated in conjunction with preparation of reserve reports at the end of the year.

Depreciation of other fixed assets, which includes service equipment, gathering, transportation and compression equipment, office furniture and equipment, and buildings, was $462,000 and $295,000 for the quarters ended September 30, 2001 and 2000, respectively. The increase is related to asset additions, primarily for service and gas transportation related equipment.

Lease operating expenses ("LOE") totaled $869,000 for the quarter ended September 30, 2001 compared to $655,000 for the quarter ended September 30, 2000. The increase was primarily attributable to new production from CBM wells. Ad valorem and production taxes were $635,000 and $950,000 for the same periods. Production taxes decreased with revenues, as the result of lower product prices. Total lifting costs (LOE plus ad valorem and production taxes) were 16% of oil and gas revenues and $0.49 per Mcfe for the 2001 quarter, compared to 14% and $0.57 per Mcfe for the 2000 quarter.

Oilfield services include the operations of Action Oilfield Services, Inc. (Colorado), Action Energy Services (Wyoming), and Arete Gathering Company, wholly-owned subsidiaries. Related revenues include well servicing fees from completion and swab rigs, CBM drilling rigs, trucking, water hauling, equipment rentals, and gas gathering, compression and transportation fees. Revenues were $2,223,000 for the quarter ended September 30, 2001 compared to $1,526,000 for the comparable quarter of 2000, an increase of $697,000, or 46%. Costs of oilfield services were $1,373,000 for the quarter ended September 30, 2001 compared to $1,215,000 for the same period of 2000, an increase of $158,000 or 13%. Higher revenues were attributable to rate increases, more equipment placed in service, and an increased portion of services that were provided to third parties. For the quarter ended September 30, 2001, 34% of the fees billed by the service companies were for Company-owned wells, compared to 40% for the quarter ended September 30, 2000. Intercompany billings are eliminated in consolidation.

General and administrative expenses ("G&A"), net of third party reimbursements and amounts capitalized, were $815,000 for the quarter ended September 30, 2001 compared to $787,000 for the quarter ended September 30, 2000, an increase of $28,000 or 4%. Third party reimbursement of management and operator fees were $79,000 and $77,000 during the quarters ended September 30, 2001 and 2000, respectively. The Company's G&A costs have otherwise increased due to expansion of the Company's activities and operations, offset by increased amounts capitalized.

The provision for income taxes was $3,175,000 for the quarter ended September 30, 2001 compared to $2,350,000 for the quarter ended September 30, 2000, an increase of $825,000 or 35%. The Company's effective tax rate increased to 31.0% from 29.7%. The Company's effective tax rates are less than statutory rates due to permanent differences between financial and taxable income, which consist primarily of statutory depletion deductions and Section 29 tax credits. The Company's effective tax rate

increased primarily because income before income taxes increased $2,323,000 or 29% for 2001, while the permanent differences did not increase proportionately.

Nine Months Ended September 30, 2001 and 2000

For the nine months ended September 30, 2001, the Company earned net income of $21,414,000, or $1.62 per diluted share, on revenues of $49,833,000, compared to net income of $14,564,000, or $1.10 per diluted share, on revenues of $36,022,000 for the nine months ended September 30, 2000. Expenses were $19,395,000 for the 2001 nine-month period compared to $15,538,000 for the 2000 nine-month period. Revenues increased $13,811,000, or 38%, expenses increased $3,857,000, or 25%, and net income increased $6,850,000, or 47%.

Revenues for the 2001 period included $8,377,000 of gains related to oil and gas derivatives (see Note 4). This total was comprised of hedging gains, which are discussed below, plus realized and unrealized gains on derivative instruments that did not qualify for hedge accounting, in the amounts of $577,000 and $4,975,000, respectively. No comparable amounts were reported in 2000.

Excluding gains from derivative instruments, oil and gas sales for the nine months ended September 30, 2001 were $34,604,000 compared to $30,390,000 for the nine months ended September 30, 2000, an increase of $4,214,000 or 14%. The increase was due to the combined effects of a 12% rise in average price realizations and a 2% growth in production volumes.

The following information is provided excluding effects of derivatives. The average price received by the Company for its natural gas production was $3.78 per Mcf for the nine months ended September 30, 2001, compared to $3.18 per Mcf for the nine months ended September 30, 2000, an increase of $0.60 per Mcf or 19%. The average price received for oil for the first nine months of 2001 was $27.43 per barrel compared to $28.51 per barrel for the same period of 2000, a decrease of $1.08 per barrel or 4%. On an Mcf equivalent basis, the average price received for the Company's production was $3.96 per Mcfe for the nine months ended September 30, 2001 compared to $3.55 per Mcfe for the nine months ended September 30, 2000, representing an overall 12% increase in average prices. The Company's oil and gas revenues were 74% derived from the sales of natural gas during the first nine months of 2001 compared to 69% during the first nine months of 2000.

Hedging gains of $2,825,000 are included in oil and gas revenues for the first nine months of 2001. Such gains had the effect of increasing average price realizations by $0.41 per Mcf of natural gas, $0.26 per barrel of oil, and $0.32 per Mcfe. Cumulative gains realized on derivatives relating to production months in the first three quarters of 2001 aggregated $4,278,000, including gains from derivatives that qualify for hedge accounting and gains from non-qualifying derivatives, and including both gains reported for the current nine-month period and amounts recorded as the cumulative effect of a change in accounting principle at the beginning of the year. The Company did not hedge any of its production during the nine months ended September 30, 2000.

The Company's net natural gas production was 6,775,000 Mcf and 6,574,000 Mcf for the first nine months of 2001 and 2000, respectively, an increase of 201,000 Mcf, or 3%. Net oil production was 328,000 barrels and 333,000 barrels for the same nine-month periods, representing a decrease of 5,000 barrels or 2%. On an equivalent unit basis, the Company's production increased approximately 2%, to 8,745,000 Mcfe during the first nine months of 2001, from 8,571,000 Mcfe in the same period last year. Total production for the nine months ended September 30, 2001 was 78% natural gas and 22% oil, compared to 77% natural gas and 23% oil for the same period of 2000. Net production from the Company's CBM operations, which totaled 809,000 Mcf in the current year, compared to none last year, more than offset net decreases from the Company's other producing properties attributable to natural declines and limited new activity.

The Company's depletion expense for oil and gas properties was $6,399,000, or $0.73 per Mcfe, during the first nine months of 2001, compared to $4,386,000, or $0.51 per Mcfe produced during the first nine months of 2000. Depreciation of other fixed assets was $1,040,000 and $846,000 for the nine months ended September 30, 2001 and 2000, respectively, an increase of $194,000, or 23%. The increases were attributable to the same factors as noted above in the discussion of third quarter results.

LOE was $2,319,000 for the nine months ended September 30, 2001 compared to $1,910,000 for the nine months ended September 30, 2000, primarily reflecting incremental costs associated with new CBM production. Ad valorem and production taxes were $2,928,000 and $2,434,000 for the same periods, reflecting increased revenue. Total lifting costs were 14% of oil and gas revenues and $0.60 per Mcfe for the first nine months of 2001, compared to 14% and $0.51 per Mcfe for the same 2000 period.

Reflecting higher rates and increased utilization, oilfield service revenues grew by 27%, to $6,005,000 in the nine months ended September 30, 2001, from $4,710,000 during the comparable nine-month period of 2000. Costs of oilfield services were $3,886,000 for the nine months ended September 30, 2001, compared to $3,833,000 for the same period of 2000, an increase of $53,000 or 1%. For the nine months ended September 30, 2001, 37% of the fees billed by the service companies were for Company-owned wells, compared to 35% for the nine months ended September 30, 2000.

G&A was $2,823,000 for the nine months ended September 30, 2001 compared to $2,129,000 for the nine months ended September 30, 2000, an increase of $694,000 or 33%. Third-party reimbursements were $292,000 and $318,000 during the nine months ended September 30, 2001 and 2000, respectively. Management fees received from third parties have decreased as the Company has acquired additional working interests in operated wells and sold interests in properties it previously operated. In addition, the Company has increased its staff in the current year to manage expanded operations.

The provision for income taxes, including the tax effect of a change in accounting principle, was $9,900,000 for the nine months ended September 30, 2001 compared to $5,920,000 for the same nine-month period of 2000. Income before income taxes increased $9,954,000 for the 2001 nine-month period and the effective tax rate increased to 31.7% from 28.9%. The Company's provision for income taxes was 93% deferred in 2001 compared to 66% in 2000.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company's primary market risks relate to changes in the prices received from sales of oil and natural gas. The Company periodically hedges a portion of the price risk associated with the sale of its oil and natural gas production through the use of derivative commodity instruments, which consist of commodity futures contracts, price swaps, options and basis swaps. These instruments reduce the Company's exposure to decreases in oil and natural gas prices and/or increases in basis differential between NYMEX and Rocky Mountain prices on the hedged portion of its production, by enabling it to effectively receive a fixed price for the hedged oil and gas production volumes. Such instruments also generally limit the benefits realized by the Company from increases in oil and natural gas prices on the hedged portion of its production. By hedging only a portion of its market risk exposures, the Company is able to participate in the increased earnings and cash flows associated with increases in oil and natural gas prices; however, it is exposed to risk on the unhedged portion of its oil and natural gas production, and the ineffective portion of its derivatives instruments.

The Company has derivative positions which are designed to hedge the Company's oil and natural gas prices from downward price movements and basis swaps to protect the Company from increases in the basis differential. The Company's derivatives transactions are generally cash flow hedges determined to be qualifying or non-qualifying for hedge accounting treatment in accordance with the provisions of SFAS 133. Note 4 to the unaudited consolidated financial statements provides further information with respect to derivatives and related accounting policies.

All derivative activity is carried out by personnel who have appropriate skills, experience and supervision. The personnel involved in derivative activity must follow prescribed trading limits and parameters that are regularly reviewed by the Company's Chief Executive Officer. All hedging transactions are approved by the Chief Executive Officer before they are entered into and significant transactions are reviewed by the Company's Board of Directors. The Company uses only conventional derivative instruments and attempts to manage its credit risk by entering into derivative contracts with reputable financial institutions.

Following are disclosures regarding the Company's market risk instruments. Investors and other users are cautioned to avoid simplistic use of these disclosures. Users should realize that the actual impact of future commodity price movements will likely differ from the amounts disclosed below due to ongoing changes in risk exposure levels and concurrent adjustments to hedging positions. It is not possible to accurately predict future movements in oil and natural gas prices.

During the first nine months of 2001, the Company sold 328,000 barrels of oil. A hypothetical decrease of $2.74 per barrel (10% of average prices for the period exclusive of hedging transactions) would have decreased the Company's production revenues by $899,000 for the period. The Company sold 6,775,000 Mcf of natural gas during the same period. A hypothetical decrease of $ 0.38 per Mcf (10% of average prices for the period exclusive of hedging transactions) would have decreased the Company's production revenues by $2,574,000 for the period.

The Company closed certain derivative instruments between September 30, 2001 and November 6, 2001, for net realized gains totaling $1,209,000. As of November 6, 2001, open oil and gas derivative instruments showed net unrealized gains of $2,430,000, as follows:

Time Period	Market Index	Total Volumes (MMBtu or Bbls)	Contract Price	Unre Ga
Natural gas				
December 2001	NYMEX	500,000	3.8380	$ 4
January - March, 2002	NYMEX	1,900,000	3.6201	1,0
April - June, 2002	NYMEX	2,000,000	3.2716	4
July - September, 2002	NYMEX	1,800,000	3.3342	3
October 2002	NYMEX	600,000	3.3615	1
Crude Oil Calls				
December 2001	NYMEX	5,000	29.00	

Total Unrealized Gains	$ 2,4

CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

"Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Item 2 of this Report contains "forward-looking statements" and are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. These statements include, without limitation, statements relating to liquidity, financing of operations, capital expenditures budget (both the amount and the source of funds), continued volatility of oil and natural gas prices, future drilling plans and other such matters. The words "anticipate," "expect," "plan," "believe," or "intend" and similar expressions identify forward-looking statements. Such statements are based on certain assumptions and analyses made by the Company in light of its experience and its perception of historical trends, current conditions, expected future developments and other factors it believes are appropriate in the circumstances. Prima does not undertake to update, revise or correct any of the forward-looking information. Factors that could cause actual results to differ materially from the Company's expectations expressed in the forward-looking statements include, but are not limited to, the following: industry conditions; volatility of oil and natural gas prices; hedging activities; operational risks (such as blowouts, fires and loss of production); insurance coverage limitations; potential liabilities, delays and associated costs imposed by government regulation (including environmental regulation); the need to develop and replace its oil and natural gas reserves; the substantial capital expenditures required to fund its operations; risks related to exploration and developmental drilling; and uncertainties about oil and natural gas reserve estimates. For a more complete explanation of these various factors, see "Cautionary Statement for the Purposes of the 'Safe Harbor' Provisions of the Private Securities Litigation Reform Act of 1995" included in the Company's Annual Report on Form 10-K for the year ended December 31, 2000, beginning on page 19.

PART II. FINANCIAL INFORMATION

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

None.

(b) Reports on Form 8-K

The Company filed a Report on Form 8-K dated August 14, 2001, reporting its earnings for the quarter and six months ended June 30, 2001 and providing an operations update.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PRIMA ENERGY CORPORATION
(Registrant)

Date: November 13, 2001	By /s/ Richard H. Lewis
	Richard H. Lewis, President and Chief Executive Officer
Date: November 13, 2001	By /s/ Neil L. Stenbuck
	Neil L. Stenbuck, Executive Vice President and Chief Financial Officer

pt; DISPLAY: block; MARGIN-LEFT: 0pt; MARGIN-RIGHT: 0pt" align="justify">(b) The Reporting Persons have has sole power to vote or direct the vote and the power to dispose or to direct the disposition of the 9,509,023 shares of the Company's Common Stock owned or to be acquired through the exercise of Warrants. (See Rows 7-10 of page 2 herein.)

(c) Please see Item 3 above for the description of the transaction relative to the shares and derivative securities acquired by the Reporting Persons.

(d) The Reporting Persons know of no other person who has the right to receive or the power to direct the receipt of dividends from, or the proceeds from the sale of, such shares or derivative securities.

(e) Not applicable.

Item 6. Contracts, Arrangements, Understandings or Relationships With Respect to Securities of Issuer

Except for the Warrants and Note outlined herein, the Reporting Persons have no contracts, arrangements, understandings or relationships (legal or otherwise) with any person with respect to any securities of the issuer, including but not limited to transfer or voting of any of the securities, finder's fees, joint ventures, loan or option arrangements, puts or calls, guarantees of profits, division of profits or loss, or the giving or withholding of proxies.

7

Item 7. Material to be Filed as Exhibits.

None.

SIGNATURE

After reasonable inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement is true, complete and correct.

Dated:	March 8, 2012	By:	/s/ Robert J. Smith Robert J. Smith, an individual, and as Sole Owner and Member of Plato & Associates, LLC and Energy Capital, LLC

8