POGO PRODUCING CO
Form 10-Q
August 02, 2001

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

FORM 10-Q

[X] Quarterly report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended June 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 1-7792

Pogo Producing Company
(Exact Name of Registrant as Specified in its Charter)

Delaware	74-1659398
[State or Other Jurisdiction of Incorporation or Organization]	[I.R.S. Employer Identification No.]

5 Greenway Plaza, Suite 2700 Houston, Texas	77046-0504
[Address of principal executive offices]	[Zip Code]

(713) 297-5000

(Registrant's Telephone Number, Including Area Code)

Not Applicable

(Former Name, Former Address and Former Fiscal Year, if Changed Since 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 required to file such reports], and [2] has been subject to such filing requirement for the past 90 days: Yes X No ___

Registrant's number of common shares outstanding as of June 30, 2001 53,578,961

Part I. Financial Information

Item 1. Financial Statements

Pogo Producing Company and Subsidiaries

Consolidated Statements of Income (Unaudited)

	Three Mo Jun
	2001
	(Expressed in thousands
Revenues:	
Oil and gas	$ 164,412
Pipeline sales and other	4,982
Gains (losses) on sales	-
Total	169,394
Operating Costs and Expenses:	
Lease operating	29,696
Pipeline operating and natural gas purchases	4,400
General and administrative	9,650
Exploration	5,486
Dry hole and impairment	12,277
Depreciation, depletion and amortization	53,464
Total	114,973
Operating Income	54,421
Interest:	
Charges	(14,988)
Income	694
Capitalized	10,303
Minority Interest - Dividends and costs associated with preferred securities of a subsidiary trust	(2,501)
Foreign Currency Transaction Loss	(421)
Income Before Taxes and Cumulative Effect of Change in Accounting Principle	47,508
Income Tax Expense	(16,529)
Income Before Cumulative Effect of Change in Accounting Principle	30,979

Cumulative Effect of Change in Accounting Principle	-
Net income	$ 30,979
Earnings Per Common Share	
Basic	
Income before cumulative effect of change in accounting principle	$ 0.58
Cumulative effect of change in accounting principle	-
Net income	$ 0.58
Diluted	
Income before cumulative effect of change in accounting principle	$ 0.53
Cumulative effect of change in accounting principle	-
Net income	$ 0.53
Dividends Per Common Share	$ 0.03
Weighted Average Number of Common Shares and Potential Common Shares Outstanding:	
Basic	53,575
Diluted	63,494

See accompanying notes to consolidated financial statements.

(Expressed in thousands, except per share amounts)	Six 2001
Revenues:	
Oil and gas	$ 328,325
Pipeline sales and other	8,259
Gains (losses) on sales	2,672
Total	339,256
Operating Costs and Expenses:	
Lease operating	55,523
Pipeline operating and natural gas purchases	8,420
General and administrative	17,858
Exploration	12,434
Dry hole and impairment	23,044
Depreciation, depletion and amortization	90,532
Total	207,811
Operating Income	131,445
Interest:	

Charges	(26,292
Income	1,996
Capitalized	14,829
Minority Interest - Dividends and costs associated with preferred securities of a subsidiary trust	(4,998
Foreign Currency Transaction Loss	(1,006
Income Before Taxes and Cumulative Effect of Change in Accounting Principle	115,974
Income Tax Expense	(45,049
Income Before Cumulative Effect of Change in Accounting Principle	70,925
Cumulative Effect of Change in Accounting Principle	-
Net income	$ 70,925
Earnings Per Common Share	
Basic	
Income before cumulative effect of change in accounting principle	$ 1.46
Cumulative effect of change in accounting principle	-
Net income	$ 1.46
Diluted	
Income before cumulative effect of change in accounting principle	$ 1.31
Cumulative effect of change in accounting principle	-
Net income	$ 1.31
Dividends Per Common Share	$ 0.06
Weighted Average Number of Common Shares and Potential Common Shares Outstanding:	
Basic	48,425
Diluted	58,373

See accompanying notes to consolidated financial statements.

Pogo Producing Company and Subsidiaries

Consolidated Balance Sheets

	June 30, 2001	
	(Unaudited)	
	(Expressed in tho	

except share amo

Assets		
Current Assets:		
Cash and cash equivalents	$ 79,943	$
Accounts receivable	67,410	
Other receivables	39,675	
Federal income tax receivable	4,301	
Inventory - Product	7,188	
Inventories - Tubulars	9,575	
Price hedge contracts	24,675	
Other	4,675	
Total current assets	237,442	
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties being amortized	2,739,460	
Unevaluated properties and properties under development, not being amortized	401,347	
Pipelines, at cost	6,524	
Other, at cost	17,766	
	3,165,097	
Accumulated depreciation, depletion and amortization		
Oil and gas	(1,146,426)	
Pipelines	(1,406)	
Other	(9,887)	
	(1,157,719)	
Property and equipment, net	2,007,378	
Other Assets:		
Debt issue expenses	16,590	
Price hedge contracts	13,102	
Foreign value added taxes receivable	9,391	
Deferred income tax	9,007	
Other	21,312	
	69,402	
	$ 2,314,222	$

See accompanying notes to consolidated financial statements.

Pogo Producing Company and Subsidiaries

Consolidated Balance Sheets

	June 30, 2001	
	(Unaudited)	
		(Expressed except sh
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable - operating activities	$ 58,694	
Accounts payable - investing activities	50,474	
Federal income taxes payable	11,000	
Accrued interest payable	11,804	
Accrued dividends associated with preferred securities of a subsidiary trust	813	
Accrued payroll and related benefits	2,829	
Other	3,268	
Total current liabilities	138,882	
Long-Term Debt	714,997	
Deferred Income Tax	491,373	
Deferred Credits	15,431	
Total liabilities	1,360,683	
Minority Interest:		
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust, net of unamortized issue expenses	144,959	
Shareholders' Equity:		
Preferred stock, $1 par; 4,000,000 and 2,000,000 shares authorized, respectively	-	
Common stock, $1 par; 200,000,000 and 100,000,000 shares authorized; 53,594,536 and 40,659,591 shares issued, respectively	53,594	
Additional capital	657,231	
Retained earnings	88,207	
Accumulated other comprehensive income (loss)	9,872	
Treasury stock (15,575 shares), at cost	(324)	
Total shareholders' equity	808,580	
	$ 2,314,222	

See accompanying notes to consolidated financial statements.

Pogo Producing Company and Subsidiaries

Condensed Consolidated Statements of Cash Flows (Unaudited)

	Si
	2001
	(Express
Cash Flows from Operating Activities:	
Cash received from customers	$ 365,015
Operating, exploration, and general and administrative expenses paid	(91,077)
Interest paid	(19,255)
Federal income taxes paid	(14,807)
Federal income taxes received	-
Value added taxes (paid) received	(2,129)
Other	2,051
Net cash provided by operating activities	239,798
Cash Flows from Investing Activities:	
Capital expenditures	(179,114)
Acquisition of NORIC, net of $21,235 cash acquired	(323,476)
Purchase of proved reserves	(2,714)
Proceeds from the sale of properties	4,348
Net cash used in investing activities	(500,956)
Cash Flows from Financing Activities:	
Proceeds from issuance of new debt	200,000
Borrowings under senior debt agreements	833,997
Payments under senior debt agreements	(684,000)
Payment of North Central senior debt acquired	(78,600)
Payments of cash dividends on common stock	(2,830)
Payments of preferred dividends of a subsidiary trust	(4,875)
Payments of financing issue expenses	(8,625)
Proceeds from exercise of stock options and other	5,472
Net cash provided by (used in) financing activities	260,539
Effect of Exchange Rate Changes on Cash	(948)
Net Change in Cash and Cash Equivalents	(1,567)
Cash and Cash Equivalents at the Beginning of the Year	81,510
Cash and Cash Equivalents at the End of the Period	$ 79,943
Reconciliation of Net Income to Net Cash Provided by Operating Activities:	
Net income	$ 70,925
Adjustments to reconcile net income to net cash provided by operating activities -	
Cumulative effect of change in accounting principle	-
Minority interest	4,998
Foreign currency transaction losses	1,006

(Gains) losses from the sales of properties	(2,672)
Depreciation, depletion and amortization	90,532
Dry hole and impairment	23,044
Interest capitalized	(14,829)
Price hedge contracts	2,469
Deferred federal income taxes	21,784
Change in operating assets and liabilities	42,541
Net Cash Provided by Operating Activities	$ 239,798

See accompanying notes to consolidated financial statements.

Pogo Producing Company and Subsidiaries

Consolidated Statements of Shareholders' Equity (Unaudited)

	For the Six Months Ended			
	2001			
	Shareholders' Equity		Compre-hensive	
	Shares	Amount	Income	Sh
	(Expressed in thousands, except			
Common Stock:				
$1.00 par-200,000,000 and 100,000,000 shares authorized, respectively				
Balance at beginning of year	40,659,591	$ 40,660		40,
Shares issued for acquisition of NORIC	12,615,816	12,615		
Stock options exercised	319,129	319		
Issued at end of period	53,594,536	53,594		40,
Additional Capital:				
Balance at beginning of year		298,885		
Shares issued for acquisition of NORIC		351,729		
Stock options exercised		6,617		
Balance at end of period		657,231		
Retained Earnings (Deficit):				
Balance at beginning of year		20,112		
Net income		70,925	$ 70,925	
Dividends ($0.06 per common share)		(2,830)		
Balance at end of period		88,207		
Accumulated Other				

Comprehensive Income (Loss):				
Balance at beginning of year		(1,062)		
Exchange gains (losses) on Canadian currency		389	389	
Cumulative effect of change in accounting principle		(2,438)	(2,438)	
Unrealized gains arising during the period on price hedge contracts		14,504	14,504	
Reclassification adjustment for losses included in net income		(1,521)	(1,521)	
Balance at end of period		9,872		
Comprehensive Income			$ 81,859	
Treasury Stock:				
Balance at beginning of year	(15,575)	(324)		
Activity during the period	-	-		
Balance at end of period	(15,575)	(324)		
Common Stock Outstanding, at the End of the Period	53,578,961			40,
Total Shareholders' Equity		$ 808,580		

See accompanying notes to consolidated financial statements.

Pogo Producing Company and Subsidiaries

Notes to Consolidated Financial Statements (Unaudited)

(1) General Information -

The consolidated financial statements included herein have been prepared by Pogo Producing Company (the "Company") without audit and include all adjustments (of a normal and recurring nature) which are, in the opinion of management, necessary forthe fair presentation of interim results which are not necessarily indicative of results for the entire year. Certain prior year amounts have been reclassified to conform with current year presentation. Refer to the Consolidated Statements of Shareholders' Equity for an analysis of Other Comprehensive Income which was $44,562,000 and $16,712,000, respectively, for the three months ended June 30, 2001 and 2000 and $81,859,000 and $25,074,000, respectively, for the six months ended June 30, 2001 and 2000. The financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Company's annual report on Form 10-K for the year ended December 31, 2000.

(2) Long-Term Debt -

Long-term debt and the amount due within one year at June 30, 2001 and December 31, 2000, consist of the following:

	June 30, 2001
	(Expressed
Senior debt -	
Bank revolving credit agreement	
LIBOR based loans, borrowings at average interest rate of 5.13%	$ 120,000
Swing Line loan, borrowing at an interest rate of 6.75%	10,000
Banker's acceptances, borrowing at an interest rate of 4.61%	19,997
Total senior debt	149,997
Subordinated debt -	
8 3/4% Senior subordinated notes due 2007 ("2007 Notes")	100,000
10 3/8% Senior subordinated notes due 2009 ("2009 Notes")	150,000
8 1/4% Senior subordinated notes due 2011 ("2011 Notes")	200,000
5 1/2% Convertible subordinated notes due 2006 ("2006 Notes")	115,000
Total subordinated debt	565,000
Long-term debt, none due within one year	$ 714,997

Refer to Note 3 in Notes to Consolidated Financial Statements included in the Company's annual report on Form 10-K for the year ended December 31, 2000, for further information on the Company's debt agreements.

On March 8, 2001, prior to the merger with NORIC Corporation ("NORIC") and the acquisition of North Central Oil Corporation ("North Central") on March 14, 2001, the Company entered into a reserve based revolving credit facility (the "Credit Facility"). The Credit Facility provides for a $515,000,000 revolving credit facility until March 7, 2006. The amount that may be borrowed may not exceed a borrowing base which is determined semi-annually and is calculated based upon substantially all of the Company's proved oil and gas properties. As of July 25, 2001, the borrowing base was established at $425,000,000. The Credit Facility is governed by various financial and other covenants, including requirements to maintain positive working capital (excluding current maturities of debt) and a fixed charge coverage ratio, creation of liens, a limitation on commodity hedging above certain specified limits, the prepayment of subordinated debt, the payment of dividends, mergers and consolidations, investments and asset dispositions. In addition, the Company has pledged the stock of North Central and its inter-company receivable with North Central as security for its obligations under the Credit Facility and is prohibited from pledging borrowing base properties as security for other debt. The Credit Facility also permits short-term "swing line" loans and the issuance of up to $50,000,000 in letters of credit. Borrowings under the Credit facility bear interest, at the Company's option, at a base (prime) rate plus a variable margin (currently none) or LIBOR plus a variable margin (currently 1.125%). The margin varies as a function of the percentage of the borrowing base utilized. A commitment fee on the unborrowed amount that is currently available under the Credit Facility is also charged based on the percentage of the borrowing base that is being utilized. As of July 25, 2001, there was $132,000,000 outstanding under the Credit Facility.

In connection with its entering into the Credit Facility, the Company's previously existing uncommitted money market line of credit with a commercial bank was terminated.

(2) Long-Term Debt (continued) -

The Master Banker's Acceptance Agreement between the Company and one of its lenders was recently modified to increase the amount which the lender has agreed to accept bank drafts from the Company up to $25,000,000. The banker's draftsare available on an uncommitted basis and the bank has no obligation to accept the Company's request for drafts. Drafts drawn under this agreement would be reflected as long-term debt on the Company's balance sheet because the Company currently has the ability and intent to reborrow such amounts under the Credit Facility. The Company's 2007 Notes, 2009 Notes, and the Company's new notes due 2011 (described below) may restrict all or a portion of the amounts that may be borrowed under the Master Banker's Acceptance Agreement as senior debt. The Master Banker's Acceptance Agreement permits either party to terminate the letter agreement at any time upon five business days notice. As of July 25, 2001 there was $24,912,000 outstanding under this agreement.

On April 10, 2001 the Company issued $200,000,000 principal amount of Senior Subordinated Notes due 2011 (the "2011 Notes"). The 2011 Notes bear interest at a rate of 8 1/4%, payable semi-annually in arrears on April 15 and October 15 of each year, commencing October 15, 2001. The 2011 Notes are general unsecured senior subordinated obligations of the Company, are subordinated in right of payment to the Company's senior indebtedness, which currently includes the Company's obligations under the Credit Facility and its banker's acceptances, are equal in right of payment to the 2007 Notes and the 2009 Notes, but are senior in right of payment to the Company's subordinated indebtedness, which currently includes the 2006 Notes. In addition, they are senior in right of payment to the liquidation preference under the Company's Trust Preferred Securities. The Company, at its option, may redeem the 2011 Notes in whole or in part, at any time on or after April 15, 2006, at a redemption price of 104.125% of their principal value and decreasing percentages thereafter. The indentures governing the 2011 Notes also imposes certain covenants on the Company that are substantially identical to the covenants contained in the indentures governing the 2007 Notes and the 2009 Notes, including covenants limiting: incurrence of indebtedness including senior indebtedness; restricted payments; the issuance and sales of restricted subsidiary capital stock; transactions with affiliates; liens; disposition of proceeds of asset sales; non-guarantor restricted subsidiaries; dividends and other payment restrictions affecting restricted subsidiaries; and mergers, consolidations and the sale of assets.

(3) Income Taxes -

The Company does not provide for U.S. income taxes on unremitted earnings of foreign subsidiaries as the Company's present intention is to reinvest the unremitted earnings in its foreign operations. Unremitted earnings of foreign subsidiaries are approximately $28,000,000 at June 30, 2001. It is not practicable to determine the amount of U.S. income taxes that would be payable upon remittance of the assets that represent those earnings.

Pogo Producing Company and Subsidiaries

Notes to Consolidated Financial Statements (Unaudited)

(4) Hedging Activities -

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities ("SFAS 133"). In June 2000, the FASB issued SFAS 138, Accounting for Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS 133, as amended, establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair market value. The statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting. The Company adopted SFAS 133 effective January 1, 2001. Based on the nature of the Company's derivative instruments currently outstanding and the historical volatility of oil and gas commodity prices, the Company expects that SFAS 133 could increase volatility in the Company's earnings and other comprehensive income for future periods.

SFAS 133, in part, allows special hedge accounting. SFAS 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings.

SFAS 133 requires that as of the date of initial adoption, the difference between the market value of derivative instruments and the previous carrying amount of theses derivatives be recorded in net income or other comprehensive income, as appropriate, as the cumulative effect of a change in accounting principle. Based on interpretive guidance issued during the first quarter of 2001, the Company determined that the cumulative effect of adopting SFAS 133 should be recorded in other comprehensive income. As such, effective January 1, 2001, the Company recorded an unrealized loss of $2,438,000, net of deferred taxes of $1,313,000, in other comprehensive income. During the first six months of 2001, the Company recognized a $2,340,000 loss as an offset to oil and gas revenues on these contracts. An immaterial amount of ineffectiveness on these hedge contracts was also recognized in other income. Unrealized gains on derivative instruments arising during the six months ended June 30, 2001 of $12,983,000, net of deferred taxes of $6,991,000, has been reflected as a component of other comprehensive income. Based on the fair market value of the hedge contracts as of June 30, 2001, the Company would reclassify additional pre-tax income of approximately $11,600,000 (approximately $7,500,000 net of taxes) from other comprehensive income (shareholders' equity) to net income during the next twelve months.

As of June 30, 2001, the Company held options to sell 70 million cubic feet of natural gas production per day for the period from July 1, 2001 through December 31, 2002. The Company has designated these contracts as cash flow hedges designed to give the Company the right, but not the obligation, to sell natural gas at a sales price of $4.25 per MMBtu for the period from July 2001 through March 2002 and $4.00 per MMBtu for the period from April 2002 through December 2002. These contracts are designed to guarantee the Company a minimum "floor" price for the contracted volumes of production without limiting the Company's participation in price increases during the covered period. As of June 30, 2001, the Company was a party to the following hedging arrangements:

Contract Period	Volume in MMBtu(a)	NYMEX Contract Price per MMBtu(a)	Fair Market Value (b)
July 2001 - March 2002	19,180	$4.25	$ 18,266,000
April 2002 - December 2002	19,250	$4.00	$ 19,511,000

(a) MMBtu means million British Thermal Units.
(b) Fair Market value is calculated using prices derived from NYMEX futures contract prices existing at June 30, 2001.

These hedging transactions are settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days or occasionally, the penultimate trading day of a particular contract month. For any particular floor transaction, the counter-party is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction. The Company is not required to make any payment in connection with the settlement of a floor transaction.

As of June 30, 2001 the Company was not a party to any commodity price hedging contracts with respect to any of its current or future crude oil and condensate production.

Pogo Producing Company and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)

(5) Business Segment Information -

Financial information by operating segment is presented below:

	Company	Oil and Gas	
		(Expressed in th	
Long-Lived Assets:			
As of June 30, 2001:			
United States	$ 1,662,453	$ 1,653,202	$
Kingdom of Thailand	331,621	328,013	
Canada and other	13,304	13,166	
Total	$ 2,007,378	$ 1,994,381	$
As of December 31, 2000:			
United States	$ 462,530	$ 454,246	$
Kingdom of Thailand	337,317	334,018	
Canada	11,807	11,576	
Total	$ 811,654	$ 799,840	$
Revenues:			
For the three months ended June 30, 2001			

United States	$ 129,618	$ 124,661	$
Kingdom of Thailand	38,077	38,067	
Canada and other	1,699	1,684	
Total	$ 169,394	$ 164,412	$
For the three months ended June 30, 2000			
United States	$ 67,977	$ 64,595	$
Kingdom of Thailand	38,998	38,913	
Canada	1,045	1,045	
Total	$ 108,020	$ 104,553	$
For the six months ended June 30, 2001			
United States	$ 249,090	$ 238,211	$
Kingdom of Thailand	86,071	86,012	
Canada and other	4,095	4,102	
Total	$ 339,256	$ 328,325	$
For the six months ended June 30, 2000			
United States	$ 134,400	$ 128,031	$
Kingdom of Thailand	72,636	72,550	
Canada	1,902	1,868	
Total	$ 208,938	$ 202,449	$
Operating Income (Loss):			
For the three months ended June 30, 2001			
United States	$ 40,730	$ 40,298	$
Kingdom of Thailand	17,027	17,017	
Canada and other	(3,270)	(3,285)	
Total	$ 54,487	$ 54,030	$
For the three months ended June 30, 2000			
United States	$ 18,973	$ 18,919	$
Kingdom of Thailand	18,136	18,051	
Canada	(374)	(374)	
Total	$ 36,735	$ 36,596	$
For the six months ended June 30, 2001			
United States	$ 99,311	$ 97,261	$
Kingdom of Thailand	40,774	40,715	
Canada and other	(8,640)	(8,633)	
Total	$ 131,445	$ 129,343	$
For the six months ended June 30, 2000			
United States	$ 31,989	$ 32,552	$
Kingdom of Thailand	29,888	29,802	
Canada	(567)	(601)	
Total	$ 61,310	$ 61,753	$

Pogo Producing Company and Subsidiaries

Notes to Consolidated Financial Statements (Unaudited)

(6) Earnings per Share -

Earnings per common share (basic earnings per share) are based on the weighted average number of shares of common stock outstanding during the periods. Earnings per share and potential common share (diluted earnings per share) consider the effect of dilutive securities as set out below. Amounts are expressed in thousands, except per share amounts.

	Three Months Ended June 30, 2001		
	Income	Shares	Per Sha
Basic earnings per share -	$ 30,979	53,575	$
Effect of dilutive securities:			
Options to purchase common shares	-	877	
2006 Notes	1,028	2,726	
Trust Preferred Securities	1,584	6,316	
Diluted earnings per share	$ 33,591	63,494	$
Antidilutive securities -			
Options to purchase common shares	-	307	$ 3

	Three Months Ended June 30, 2000		
	Income	Shares	Per Sha
Basic earnings per share -	$ 16,791	40,382	$
Effect of dilutive securities:			
Options to purchase common shares	-	628	
2006 Notes	1,028	2,726	
Trust Preferred Securities	1,584	6,316	
Diluted earnings per share	$ 19,403	50,052	$
Antidilutive securities -			
Options to purchase common shares	-	224	$ 3
2006 Notes	-	-	

(a) Represents income before cumulative effect of change in accounting principle.

	Six Months Ended June 30, 2001		
	Income	Shares	Per Sh
Basic earnings per share -	$ 70,925	48,425	$

Effect of dilutive securities:			
Options to purchase common shares	-	906	
2006 Notes	2,056	2,726	
Trust Preferred Securities	3,169	6,316	
Diluted earnings per share	$ 76,150	58,373	$
Antidilutive securities -			
Options to purchase common shares	-	307	$

	Six Months Ended June 30, 2000		
	Income (a)	Shares	Per Sh
Basic earnings per share -	$ 26,942	40,337	$
Effect of dilutive securities:			
Options to purchase common shares	-	610	
2006 Notes	-	-	
Trust Preferred Securities	3,169	6,316	
Diluted earnings per share	$ 30,111	47,263	$
Antidilutive securities -			
Options to purchase common shares	-	226	$
2006 Notes	2,056	2,726	$

(a) Represents income before cumulative effect of change in accounting principle.

(7) Acquisition -

On March 14, 2001, the previously announced merger of the Company and NORIC Corporation ("NORIC") was consummated. As a result of the merger, the Company acquired all of the outstanding capital stock of North Central Oil Corporation ("North Central"), which was the principal asset of NORIC. North Central was an independent domestic oil and gas exploration and production company. The merger was accounted for using the purchase method of accounting. Accordingly, the purchase price was allocated to the net assets acquired based upon their estimated fair market values at the date of acquisition. Such allocations are based upon preliminary information and are subject to change when final valuations are obtained. Commencing March 14, 2001, North Central's operations are consolidated with the operations of the Company. Pursuant to the merger agreement among the Company and NORIC and certain NORIC shareholders dated as of November 19, 2000, former shareholders received 12,615,816 shares of the Company's common stock and approximately $344,711,000 in cash. In addition, at the closing the Company repaid all $78,600,000 principal amount of North Central's existing bank debt. The sources of funds used in connection with the merger included cash on hand at the Company and NORIC and borrowings under the Company's new credit agreement.

The following summary presents unaudited pro form consolidated results of operations as if the acquisition had occurred at the beginning of each period presented. The pro forma results are for illustrative purposes only and include adjustments in addition to the pre-acquisition historical results of North Central, such as increased depreciation, depletion and amortization expense resulting from the allocation of fair market value to oil and gas properties acquired and increased interest expense on acquisition debt. The unaudited pro forma financial information is not necessarily indicative of the operating results that would have occurred had the acquisition been consummated at those dates, nor are they necessarily indicative of future operating results.

	2001
Revenues	$ 4
Income before cumulative effect of change in accounting principle	$
Net income	$
Earnings per share:	
Basic -	
Income before cumulative effect of change in accounting principle	$
Net income	$
Diluted -	
Income before cumulative effect of change in accounting principle	$
Net income	$

Pogo Producing Company and Subsidiaries

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

This discussion should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations included in the Company's annual report on Form 10-K for the year ended December 31, 2000. Certain statements contained herein are "Forward Looking Statements" and are thus prospective. As further discussed in the Company's annual report on Form 10-K for the year ended December 31, 2000, such forward-looking statements are subject to risks, uncertainties and other factors that could cause actual results to differ materially from future results expressed or implied by such forward-looking statements.

On March 14, 2001, the previously announced merger of Pogo Producing Company (the "Company") and NORIC Corporation ("NORIC") was consummated. As a result of the merger, the Company acquired all of the outstanding capital stock of North Central Oil Corporation ("North Central"), an independent domestic oil and gas exploration and production company, which was the principal asset of NORIC. Corporation. The merger was accounted for using the purchase method of accounting. Commencing March 14, 2001, the results of North Central's operations are consolidated with the Company's. Pursuant to the merger agreement among the Company, NORIC and certain NORIC shareholders dated as of November 19, 2000, former shareholders of NORIC received 12,615,816 shares of the Company's common stock and approximately $344,711,000 in cash. In addition, at the closing the Company repaid all $78,600,000 principal amount of North Central's existing bank debt. The sources of funds used in connection with the merger included cash on

hand at the Company and NORIC and borrowings under the Company's credit agreement.

Results of Operations

Net income

The Company reported net income for the second quarter of 2001 of $33,979,000 or $0.58 per share ($33,591,000 or $0.53 per share on a diluted basis), compared to net income for the second quarter of 2000 of $16,791,000 or $0.42 per share ($19,403,000 or $0.39 per share on a diluted basis). For the first six months of 2001, the Company reported net income of $70,925,000 or $1.46 per share ($76,150,000 or $1.31 per share on a diluted basis) compared to net income for the first six months of 2000 of $26,942,000 or $0.67 per share ($28,343,000 or $0.60 per share on a diluted basis). The increase in net income during the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, was primarily related to increased oil and gas revenues resulting from improved oil and gas production levels and increased natural gas prices. these factors were partially offset by a decrease in revenues from the sale of natural gas liquids ("NGL") and a decrease in the average prices that the Company received for its crude oil and condensate production. The net income reported in the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000 was also related to increases in pipeline sales. The net income reported in the first six months of 2001 was also positively impacted by a gain on the sale of certain non-strategic properties, all of which were recognized in the first quarter of 2001.

Earnings per common share are based on the weighted average number of common shares outstanding for the respective periods. The increase in the weighted average number of common shares outstanding for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, resulted primarily from the issuance of common stock in connection with the merger with NORIC on March 14, 2001 and, to a lesser extent the exercise of stock options pursuant to the Company's incentive plans. Earnings per share computations on a diluted basis for all periods reflect additional shares of common stock issuable upon the assumed conversion of Pogo Trust I's 6 1/2% Cumulative Quarterly Income Convertible Preferred Securities due 2029 (the "Trust Preferred Securities") and, to a much lesser extent, additional shares of common stock issuable upon the assumed exercise of options to purchase common shares under the Company's incentive plans, less treasury shares that are assumed to have been purchased by the Company from the option proceeds. Earnings per share computations for the second quarter and first six months of 2001, and the second quarter of 2000, also reflect additional shares of common stock issuable upon the assumed conversion of the Company's 5 1/2% Convertible Subordinated Notes due 2006 (the "2006 Notes").

Total Revenues

The Company's total revenues for the second quarter of 2001 were $169,394,000, an increase of approximately 57% from total revenues of $108,020,000 for the second quarter of 2000. The Company's total revenues for the first six months of 2001 were $339,256,000, an increase of approximately 62% compared to total revenues of $208,938,000 for the first six months of 2000. The increase in the Company's total revenues for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, resulted primarily from a substantial increase in oil and gas revenues and, to a much lesser extent, increased pipeline sales and, with respect to the six month

periods, an increase in gain on sales of certain non-strategic Company properties.

Oil and Gas Revenues

The Company's oil and gas revenues for the second quarter of 2001 were $164,412,000, an increase of approximately 57% from oil and gas revenues of $104,553,000 for the second quarter of 2000. The Company's oil and gas revenues for the first six months of 2001 were $328,325,000, an increase of approximately 62% from oil and gas revenues of $202,449,000 for the first six months of 2000. The following table reflects an analysis of variances in the Company's oil and gas revenues (expressed in thousands) between 2001 and 2000:

Increase (decrease) in oil and gas revenues resulting from variances in:	2/nd/ Qtr 2001 Compared to 2/nd/ Qtr 2000	1/st/ Hal Compared 1/st/ Hal
Natural gas--		
Price	$ 19,433	$63,232
Production	39,809	47,861
	59,242	111,093
Crude oil and condensate--		
Price	(1,221)	(365
Production	2,134	17,213
	913	16,848
Natural Gas Liquids	(296)	(2,065
Increase (decrease) in oil and gas revenues	$59,859	$125,876

The increase in the Company's oil and gas revenues for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, is primarily related to increases in the Company's natural gas and oil and condensate production volumes and, to a lesser extent, an increase in the price that it received for its natural gas production volumes. These factors were partially offset by a decrease in the average price the Company received for its oil and condensate production volumes and decreased production of NGL. NGL is extracted from natural gas. NGL is extracted from natural gas. Due to the relatively high price (relative to crude oil and condensate) that the Company received for its natural gas production volumes during the second quarter and first six months of 2001, the Company elected in many instances to leave the NGL in the natural gas. The Company recently resumed processing its natural gas production volumes to extract NGL for resale due to the recent decline in natural gas prices, relative to oil and condensate prices.

Comparison of Increases (Decreases) in:	2/nd/ Quarter		%
Natural Gas --	2001	2000	Change

Average prices			
North America (a)	$ 4.62	$ 3.00	54%
Kingdom of Thailand(b)	$ 2.24	$ 2.20	2%
Company-wide average price	$ 4.04	$ 2.73	48%
Average daily production volumes (MMcf per day)			
North America (a)	205.0	107.8	90%
Kingdom of Thailand	66.1	55.1	20%
Company-wide average daily production	271.1	162.9	66%

(a) North American average prices and production reflect production from the United States and Canada. "MMcf" and "Bbls" stand for million cubic feet and barrels, respectively.

(b) The Company is paid for its natural gas production in the Kingdom of Thailand in Thai Baht. The average prices are presented in U.S. dollars based on the revenue recorded in the Company's financial records.

Comparison of Increases (Decreases) in:	2/nd/ Quarter		%	1
Crude Oil and Condensate --	2001	2000	Change	
Average prices(a)				
North America	$25.84	$26.59	(3)%	
Kingdom of Thailand	$28.21	$31.16	(9)%	
Company-wide average price	$26.75	$28.68	(7)%	
Average daily production volumes (Bbls per day)				
North America	15,514	13,352	16%	
Kingdom of Thailand(b)	13,442	11,593	16%	
Company-wide average daily production	28,956	24,945	16%	
Total Liquid Hydrocarbons --				
Company-wide average daily production (Bbls per day)(b)	31,028	27,131	14%	

(a) Average prices are computed on production that is actually sold during the period. For North American average prices, this equates to actual production. However, in the Gulf of Thailand, crude oil and condensate sold may be more or less than actual production. See footnote (b).

(b) Oil and condensate production in the Gulf of Thailand is produced and stored on the FPSO and FSO pending sale and is sold in tanker loads that typically average between 300,000 and 750,000 barrels per sale. Therefore, oil and condensate sales volumes for a given period in the Gulf of Thailand may not equate to actual production. In accordance with generally accepted accounting principles, as currently

interpreted, reported revenues are based on sales volumes. However, the Company believes that actual production volumes are a more meaningful measure of the Company's operating results and therefore reports production volumes as part of its operating results. The Company produced 351,000 and 205,000 barrels more than it sold in the second quarter and first six months of 2001, respectively, and produced 33,000 and 197,000 barrels more than it sold in the second quarter and first six months of 2000, respectively.

Natural Gas

Thailand Prices. The price that the Company receives under the gas sales agreement with the Petroleum Authority of Thailand ("PTT") is based upon a formula which takes into account a number of factors including, among other items, changes in the Thai/U.S. exchange rate and fuel oil prices in Singapore. The increase in the average price that the Company received for its natural gas production in the Kingdom of Thailand for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, reflects positive adjustments under the gas sales agreement.

Production. The increase in the Company's natural gas production during the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, was primarily related to production from properties acquired in the North Central acquisition and, to a lesser extent, successful development programs on the Company's Thailand and New Mexico properties that were partially offset by natural decline at certain of the Company's other properties.

Crude Oil and Condensate

Thailand Prices. Since the inception of production from the Company's properties located in the Gulf of Thailand, crude oil and condensate have been stored on storage vessels (an FPSO in the Tantawan field and an FSO in the Benchamas field) until an economic quantity is accumulated for offloading and sale. A typical sale ranges from 300,000 to 750,000 barrels. Prices that the Company receives for its crude oil and condensate production from Thailand are based on world benchmark prices, typically as a differential to Malaysian TAPIS crude and are denominated in dollars. In addition, the Company is generally paid for its crude oil and condensate production from Thailand in dollars.

Thailand Production. The increase in the Company's crude oil and condensate production from the Gulf of Thailand during the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, resulted from increased production from the Benchamas Field. However, with respect to the quarterly comparative periods, total sales declined because of unfavorable tanker lifting schedules, resulting in an increase of 351,000 barrels in inventory stored on board the FPSO and FSO at the end of the period. Due a change in interpretation of an accounting principle, for purposes of the financial statements, the Company now records its oil production in Thailand at the time of sale, rather than when produced, as it had previously. In accordance with generally accepted accounting principles, as currently interpreted, at the end of each quarter, the crude oil and condensate stored on board the FSO and FPSO pending sale is accounted for as inventory at cost. Reported revenues are based on sales volumes. When a tanker load of oil is sold in Thailand, the entire amount will be accounted for as production sold, regardless of when it was produced. The Company believes that actual production volumes are a

more meaningful measure of the Company's operating results than sales volumes

and therefore reports production volumes as part of its operating results. The Company produced 351,000 and 205,000 barrels more than it sold in the second quarter and first six months of 2001, respectively, and produced 33,000 and 197,000 barrels more than it sold in the second quarter and first six months of 2000, respectively. As of June 30, 2001, the Company had approximately 555,000 net barrels stored on board the FPSO and FSO.

North American Production. The increase in the Company's North American crude oil and condensate production during the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, primarily related to production from properties acquired in the North Central acquisition and, to a lesser extent, successful development programs on the Company's other properties that was partially offset by natural decline at certain of the Company's properties.

NGL Production. The Company's oil and gas revenues, and its total liquid hydrocarbon production, reflect the production and sale by the Company of NGL, which are liquid products extracted from natural gas production. The decrease in NGL revenues for the second quarter and first six months of 2001, compared with the second quarter and first six months of 2000, primarily related to the decision by the Company not to extract NGL from its natural gas production due to the more favorable economics of leaving it in the natural gas stream. The Company recently resumed processing its natural gas production volumes to extract NGL for resale due to the recent decline in natural gas prices, relative to oil and condensate prices.

Costs and Expenses

	2nd Quarter		%	1/s
Comparison of Increases (Decreases) in:	2001	2000	Change	2001
Lease Operating Expenses				
North America........................	$ 22,721,000	$ 14,859,000	53%	$ 39,77
Kingdom of Thailand..................	$ 6,975,000	$ 8,658,000	(19)%	$ 15,75
Total Lease Operating Expenses....................	$ 29,696,000	$ 23,517,000	26%	$ 55,52
Pipeline Operating and Natural Gas Purchases.........................	$ 4,400,000	$ 3,156,000	39%	$ 8,42
General and Administrative Expenses.....	$ 9,650,000	$ 7,539,000	28%	$ 17,85
Exploration Expenses....................	$ 5,486,000	$ 2,114,000	160%	$ 12,43
Dry Hole and Impairment Expenses........	$ 12,277,000	$ 2,120,000	479%	$ 23,04
Depreciation, Depletion and				
Amortization (DD&A) Expenses.........	$ 53,464,000	$ 32,839,000	63%	$ 90,53
DD&A rate............................	$ 1.33	$ 1.10	21%	$
Mcfe sold (a)........................	39,509,000	29,637,000	33%	72,24
Interest--				
Charges..............................	$ (14,988,000)	$ (8,210,000)	83%	$ (26,29
Interest Income......................	$ 694,000	$ 186,000	273%	$ 1,99
Capitalized Interest Expense.........	$ 10,303,000	$ 4,604,000	124%	$ 14,82
Minority Interest - Dividends and Costs.......................	$ (2,501,000)	$ (2,559,000)	(2)%	$ (4,99
Foreign Currency Transaction Loss.......	$ (421,000)	$ (794,000)	47%	$ (1,00
Income Tax Expense......................	$ (16,529,000)	$ (13,171,000)	25%	$ (45,04

(a) "Mcfe" stands for thousands of cubic feet equivalent.

Lease Operating Expenses.

The increase in North American lease operating expenses for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, primarily related to increased severance taxes resulting from increased production from the Company's non-U.S. government owned properties (accounting for approximately $5,469,000 and $8,510,000 of the increase for the quarter and six month periods, respectively), lease operating expenses attributable to properties acquired in the North Central acquisition and generally increasing costs resulting from an industry-wide increase in demand for oil field services and equipment, that was only partially offset by decreased lease maintenance expenses. The decrease in lease operating expenses in the Kingdom of Thailand for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, primarily related to an accounting adjustment that reduced lease operating expenses attributable to crude oil and condensate held as inventory on board the FPSO and FSO. These lease operating expenses will be recognized for accounting purposes when this crude oil and condensate is sold. In addition, lease operating expenses for both 2001 periods, compared to

the 2000 periods, were positively affected by a decrease in maintenance and workover activity in the Benchamas Field. These factors were partially offset by generally increasing costs resulting from an industry-wide increase in demand for oil field services and equipment. A substantial portion of the Company's lease operating expenses in the Kingdom of Thailand relates to the lease payments made in connection with the bareboat charter of the FPSO for the Tantawan field and the FSO for the Benchamas field. Collectively, these lease payments accounted for $3,757,000, $7,472,000, $3,757,000 and $7,513,000 (net to the Company's interest) of the Company's Thailand lease operating expenses for the second quarter and first six months of 2001 and the second quarter and first six months of 2000, respectively.

Pipeline Operating and Natural Gas Purchases

Revenue from the sale of natural gas purchased for resale is reported under "Pipeline sales and other." Prior to the acquisition of the Pogo Onshore Pipeline interests, the Company did not separately report its pipeline operating expenses or revenues, nor did it purchase any natural gas for resale to customers of its pipelines. The increase in pipeline operating expenses and natural gas purchase costs for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, primarily related to increased cost of natural gas purchased for resale by the Company.

General and Administrative Expenses

The increase in general and administrative expenses for the second quarter of 2001, compared with the second quarter of 2000, related to increased expenses associated with the Company's acquisition of North Central and its employees, as well as an increase in the size of the Company's work force and normal salary and concomitant benefit expense adjustments. The decrease in general and administrative expenses for the first six months of 2001, compared with the first six months of 2000, primarily related to a $1,889,000 retroactive adjustment for the over accrual of certain payroll costs, that was partially offset by increased expenses associated with the Company's acquisition of North Central and its employees, as well as an increase in the size of the Company's work force and normal salary and concomitant benefit expense adjustments.

Exploration Expenses

Exploration expenses consist primarily of rental payments required under oil and gas leases to hold non-producing properties ("delay rentals") and exploratory geological and geophysical costs which are expensed as incurred. The increase in exploration expense for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, resulted primarily from the cost of conducting two major 3-D projects in Hungary, a payment to transfer seismic licenses used by North Central and the acquisition of 3-D data in the Company's Offshore and Western Divisions, partially offset by generally decreased geophysical acquisition costs in the Company's other operational areas.

Dry Hole and Impairment

The increase in the Company's dry hole and impairment expense for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, resulted primarily from increased dry hole costs and, with respect to the six month comparative periods, impairment expense charged to a non-operated property located in the offshore Gulf of Mexico due to unexpectedly high drilling and completion expenses.

Depreciation, Depletion and Amortization Expenses

The increase in the Company's depreciation, depletion and amortization ("DD&A") expense for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, resulted primarily from an increase in the Company's natural gas and liquid hydrocarbon production and, to a lesser extent, an increase in the Company's composite DD&A rate.

The increase in the composite DD&A rate for all of the Company's producing fields for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, resulted primarily from production from fields acquired in the North Central acquisition that, because they were valued at fair market value in connection with the acquisition, contribute a DD&A rate higher than the Company's recent historic average. The increase was partially offset by an increased percentage of the Company's production coming from certain of the Company's fields that have DD&A rates that are lower than the Company's recent historical composite rate (principally the Benchamas Field and certain Permian basin properties) and a corresponding decrease in the percentage of the Company's production coming from fields that have DD&A rates that are higher than the Company's recent historical composite DD&A rate.

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Interest

Interest Charges. The increase in the Company's interest charges for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, resulted primarily from an increase in the average amount of the Company's outstanding related to the acquisition of North Central, partially offset by a decline in the average interest rate on the outstanding debt. The increase in the Company's interest charges for the first six months of 2001, compared to the first six months of 2000, was also affected by a charge for amortization of debt issuance expense during the first quarter of 2001 related to the termination of the Company's previous credit facility in connection with the North Central acquisition.

Interest Income. The decrease in the Company's interest income for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, resulted primarily from a decrease in the amount of cash and cash equivalents temporarily invested. Except for working capital

needs, a significant portion of the Company's cash and cash and cash equivalents were used to fund the North Central acquisition.

Capitalized Interest. The increase in capitalized interest for the second quarter and first six months of 2001, compared to the second quarter and first six months of 2000, resulted primarily from an increase in the amount of capital expenditures subject to interest capitalization during the relevant periods ($359,404,000 and $401,347,000, in 2001, compared to $206,735,000 and $220,726,000 in 2000), partially offset by a decrease in the interest rate used to determine the amount of capitalized interest. A substantial percentage of the Company's capitalized interest expense resulted from capitalization of interest related to capital expenditures for the development of the Benchamas field in the Gulf of Thailand and, to a lesser extent, several development projects in the Gulf of Mexico.

Minority Interest -- Dividends and Costs Associated with Preferred Securities of a Subsidiary Trust

Pogo Trust I, a business trust in which the Company owns all of the issued common securities, issued $150,000,000 of Trust Preferred Securities on June 2, 1999. The amounts recorded for the second quarter and first six months of 2000 and 2001, respectively, under Minority Interest -- Dividends and Costs Associated with Preferred Securities of a Subsidiary Trust principally reflect cumulative unpaid dividends and, to a lesser extent, the amortization of issuance expenses related to the offering and sale of the Trust Preferred Securities.

Foreign Currency Transaction Losses

The foreign currency transaction losses reported for the second quarter and first six months of 2000 and 2001 resulted primarily from the fluctuation against the U.S. dollar of cash and other monetary assets and liabilities denominated in Thai Baht that were on the Company's subsidiary financial statements during the respective periods. The weakening of the Thai Baht against the U.S. dollar has been attributed to, among other things, the negative impact on the Thai economy of high crude oil prices and continued weakness in the banking sector. The Company cannot predict what the Thai Baht to U.S. dollar exchange rate will be in the future. As of June 30, 2001, the Company was not a party to any financial instrument that was intended to constitute a foreign currency hedging arrangement.

Income Tax Expense

The increase in the Company's tax expense for the second quarter and the first six months of 2001, compared to the second quarter and the first six months of 2000, resulted primarily from an increase in pre-tax income from the Company's North American and Kingdom of Thailand operations. The Company's effective tax rate for the second quarter and first six months of 2001 was 34.8% and 38.8%, respectively, compared to 44% and 44.1% for the second quarter and first months of 2000, respectively. The decrease in the effective tax rate in 2001 is attributable to certain tax benefits in the Kingdom of Thailand.

Liquidity and Capital Resources

Cash Flows

The Company's Condensed Consolidated Statement of Cash Flows for the first six months of 2001 reflects net cash provided by operating activities of $239,798,000. In addition to net cash provided by operating activities, the Company received $5,472,000, primarily from the exercise of stock options, and $4,348,000 from the sale of certain non-strategic properties. The Company also borrowed a net $149,997,000 under its senior debt arrangements and issued

$200,000,000 of its 8 1/4% Senior Subordinated Notes due 2011 (the "2011 Notes").

During the first six months of 2001, the Company expended $344,711,000 in partial consideration for the NORIC shares, repaid all $78,600,000 of North Central's senior indebtedness, invested $179,114,000 in capital projects, paid $8,625,000 in debt issuance expenses, paid $4,875,000 in cash distributions to holders of its Trust

Preferred Securities, paid $2,714,000 to purchase proved reserves and paid $2,830,000 ($0.03 per share) in cash dividends to holders of the Company's common stock. As of July 25, 2001, the Company's cash and cash equivalents were $84,846,000 and its long-term debt stood at $721,912,000 and it had $268,000,000 of availability under its revolving credit facility.

Future Capital Requirements

The Company's capital and exploration budget for 2001, which does not include any amounts that may be expended for the purchase of proved reserves or any interest which may be capitalized resulting from projects in progress, was recently increased by the Company's Board of Directors to $350,000,000, principally on account of the projects to be undertaken on properties acquired in the North Central acquisition. The Company currently anticipates that its available cash and cash equivalents, cash provided by operating activities and funds available under its credit agreement and banker's acceptance facility will be sufficient to fund the Company's ongoing operating, interest and general and administrative expenses, any currently anticipated costs associated with the Company's projects during 2001, and future dividend and distribution payments at current levels (including a dividend payment of $0.03 per share on its common stock to be paid on August 17, 2001 to shareholders of record on August 3, 2001). The declaration of future dividends on the Company's equity securities will depend upon, among other things, the Company's future earnings and financial condition, liquidity and capital requirements, its ability to pay dividends and distributions under certain covenants contained in its debt instruments, the general economic and regulatory climate and other factors deemed relevant by the Company's Board of Directors.

ITEM 3. Quantitative and Qualitative Disclosure about Market Risk.

The Company is exposed to market risk, including adverse changes in commodity prices, interest rates and foreign currency exchange rates. The information contained in the Company's Annual Report on Form 10-K for the year ended December 31, 2000, and should be read in conjunction with the following.

Interest Rate Risk

From time to time, the Company has entered into various financial instruments, such as interest rate swaps, to manage the impact of changes in interest rates. As of July 1, 2001, the Company has no open interest rate swap or interest rate lock agreements. Therefore, the Company's exposure to changes in interest rates primarily results from its short-term and long-term debt with both fixed and floating interest rates. The following table presents principal or notional amounts (stated in thousands) and related average interest rates by year of maturity for the Company's debt obligations and their indicated fair market value at June 30, 2001:

	2000	2001	2002	2003	2004	Thereafter	Total	
Liabilities Long-Term Debt:								
Variable Rate.................	$ 0	$ 0	$ 0	$ 0	$ 0	$ 149,997	$149,997	$1
Average Interest Rate.........	-	-	-	-	-	5.17%	5.17%	
Fixed Rate....................	$ 0	$ 0	$ 0	$ 0	$ 0	$ 565,000	$565,000	$5
Average Interest Rate.........	-	-	-	-	-	8.35%	8.35%	

Foreign Currency Exchange Rate Risk

The Company conducts business in Thai Baht, Hungarian Forint and the Canadian dollar and is therefore subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions. As of July 1, 2001, the Company is not a party to any foreign currency exchange agreement.

Current Hedging Activity

From time to time, the Company has used and expects to continue to use hedging transactions with respect to a portion of its oil and gas production to achieve a more predictable cash flow, as well as to reduce its exposure to price fluctuations. While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of hedging transactions also involves the risk that the counter-parties will be unable to meet the financial terms of such transactions. All of the Company's recent historical hedging transactions have been carried out in the over-the-counter market with investment grade institutions. In January 2001, the Company began to account for its hedging activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities ("SFAS 133"). SFAS 133, as amended, establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair market value. The statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge

accounting hedge accounting criteria are met. Special accounting for qualifying hedges allows the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instruments, if any, must be recognized currently in earnings.

Natural Gas

As of June 30, 2001, the Company held options to sell 70 million cubic feet of natural gas production per day for the period from July 1, 2001 through December 31, 2002. The Company has designated these contracts as cash flow hedges designed to give the Company the right, but not the obligation, to sell natural gas at a sales price of $4.25 per MMBtu for the period from April 2001 through March 2002 and $4.00 per MMBtu for the period from April 2002 through December 2002. These contracts are designed to guarantee a minimum "floor" price for the contracted volumes of production without limiting the Company's participation in price increases during the covered period. As of July 1, 2001,

the Company was a party to the following hedging arrangements:

Contract Period	Volume in MMBtu (a)	NYMEX Contract Price per MMBtu(a)	Fair Market Value(b)
Floor Contracts:			
July 2001 -- March 2002	19,180	$4.25	$18,266,000
April 2002 - December 2002	19,250	$4.00	$19,511,000

(a) MMBtu means million British Thermal Units.
(b) Fair Market Value is calculated using prices derived from NYMEX futures contract prices existing at June 30, 2001.

These hedging transactions are settled based upon the average of the reported settlement prices on the NYMEX for the last three trading days or, occasionally, the penultimate trading day of a particular contract month. For any particular floor transaction, the counter-party is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction. The Company is not required to make any payment in connection with the settlement of a floor transaction.

Crude Oil

As of June 30, 2001, the Company was not a party to any commodity price hedging contracts with respect to any of its current or future crude oil and condensate production.

Part II. Other Information

Item 4. Submission of Matters to a Vote of Security-Holders

The registrant held its annual meeting of stockholders in Houston, Texas on April 24, 2001. The following sets forth the items that were put to a vote of the stockholders and the results thereof concerning:

(A) election of two directors, each for a term of three years. The vote tabulation for each nominee was as follows:

Nominee	For	Withheld
William L. Fisher	48,218,901	123,341
Paul G. Van Wagenen	48,214,410	127,832

(B) a proposal to amend the Company's Restated Certificate of Incorporation, to increase the number of shares of the Company's authorized common stock from 100,000,000 to 200,000,000, with 42,786,475 shares of stock cast for approval, 5,514,314 shares against approval and 41,453 shares abstained.

(C) a proposal to amend the Company's Restated Certificate of Incorporation, to increase the number of shares of the Company's authorized preferred stock from 2,000,000 to 4,000,000, with 28,662,715 shares of stock cast for approval, 14,782,506 shares against approval and 51,370 shares abstained. In addition, 4,845,651 shares were broker

non-votes.

(D) ratification of the appointment of Arthur Andersen LLP, independent public accountants, to audit the financial statements of the registrant for the year 2001, with 48,045,572 shares of stock cast for the appointment, 279,301 against the appointment, and 17,369 shares abstained.

Item 6. Exhibits and Reports on Form 8-K

(A) Exhibits

*4.1 Indenture dated as of April 10, 2001 between Pogo Producing Company and Wells Fargo Bank Minnesota, National Association, as Trustee (Exhibit 4.2, Registration Statement on Form S-4, filed April 24, 2001, File No. 333-59426).

*Incorporated herein by reference as indicated

(B) Reports on Form 8-K

Report filed on April 6, 2001, announcing the placement of the 2011 Notes on April 4, 2001 under Item 5 and attaching one exhibit under Item 7.

Report filed on April 24, 2001, announcing the Company's quarterly and financial results and certain unaudited supplemental operating and financial information related to the Company's first quarter 2001 operating and financial results under Item 5 and attaching two exhibits under Item 7.

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.

Pogo Producing Company
(Registrant)

/s/ Thomas E. Hart

Thomas E. Hart
Vice President and Chief
Accounting Officer

/s/ James P. Ulm, II

James P. Ulm, II
Vice President and Chief
Financial Officer

Date: August 2, 2001