POGO PRODUCING CO
Form 10-Q
August 11, 2003

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, 2003

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. Employee 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 ¨

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2): Yes x No ¨

Registrant s number of common shares outstanding as of August 6, 2003: 63,529,006

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(Expressed in thousands, except per share amounts)			
Revenues:				
Oil and gas	$ 295,530	$ 185,241	$ 605,397	$ 327,538
Other	69	(856)	956	(243)
Total	295,599	184,385	606,353	327,295
Operating Costs and Expenses:				
Lease operating	31,484	29,656	64,573	58,128
General and administrative	15,054	10,828	28,426	22,370
Exploration	1,827	1,352	3,659	1,176
Dry hole and impairment	3,920	3,500	6,098	8,495
Depreciation, depletion and amortization	84,347	73,942	164,766	139,748
Production and other taxes	10,231	4,929	19,185	7,740
Accretion and other	4,820		7,896	181
Total	151,683	124,207	294,603	237,838
Operating Income	143,916	60,178	311,750	89,457
Interest:				
Charges	(12,984)	(14,500)	(26,679)	(29,088)
Income	547	534	934	912
Capitalized	4,117	6,859	8,131	13,512
Minority Interest - Dividends and costs associated with preferred securities of a subsidiary trust		(1,638)		(4,140)
Foreign Currency Transaction Gain	336	659	562	1,331
Income Before Taxes and Cumulative Effect of Change in Accounting Principle	135,932	52,092	294,698	71,984
Income Tax Expense	(56,213)	(23,474)	(122,336)	(34,341)
Income Before Cumulative Effect of Change in Accounting Principle	79,719	28,618	172,362	37,643
Cumulative Effect of Change in Accounting Principle			(4,166)	

Net Income	$ 79,719	$ 28,618	$ 168,196	$ 37,643
Earnings Per Common Share				
Basic:				
Income before cumulative effect of change in accounting principle	$ 1.29	$ 0.51	$ 2.80	$ 0.68
Cumulative effect of change in accounting principle			(0.07)	
Net income	$ 1.29	$ 0.51	$ 2.73	$ 0.68
Diluted:				
Income before cumulative effect of change in accounting principle	$ 1.24	$ 0.48	$ 2.67	$ 0.66
Cumulative effect of change in accounting principle			(0.06)	
Net income	$ 1.24	$ 0.48	$ 2.61	$ 0.66
Dividends Per Common Share	$ 0.05	$ 0.03	$ 0.10	$ 0.06
Weighted Average Number of Common Shares and Potential Common Shares Outstanding:				
Basic	61,961	56,192	61,559	54,972
Diluted	65,376	64,340	65,252	61,210

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	June 30, 2003	December 31, 2002
	(Expressed in thousands, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 229,768	$ 134,449
Accounts receivable	112,099	101,807
Other receivables	33,543	14,634
Deferred income tax		20,041
Inventories - Product	4,804	2,501
Inventories - Tubulars	8,967	9,406
Other	10,638	4,818
Total current assets	399,819	287,656
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	3,567,533	3,396,669
Unevaluated properties	133,461	141,094
Other, at cost	28,414	26,626
	3,729,408	3,564,389
Accumulated depreciation, depletion and amortization		
Oil and gas	(1,526,662)	(1,389,976)
Other	(20,022)	(15,364)
	(1,546,684)	(1,405,340)
Property and equipment, net	2,182,724	2,159,049
Other Assets:		
Deferred income tax	2,416	2,416
Debt issue costs	10,438	11,368
Foreign value added taxes receivable	15,202	13,908
Other	19,142	17,196
	47,198	44,888
	$ 2,629,741	$ 2,491,593

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	June 30, 2003	December 31, 2002
	(Expressed in thousands, except share amounts)	
Liabilities and Shareholders Equity		
Current Liabilities:		
Accounts payable - operating activities	$ 53,646	$ 41,102
Accounts payable - investing activities	59,879	68,963
Accrued interest payable	11,055	11,096
Income taxes payable	54,910	15,527
Accrued payroll and related benefits	3,116	3,011
Deferred income tax	5,324	5,324
Price hedge contracts	8,196	2,433
Other	8,688	2,229
Total current liabilities	204,814	149,685
Long-Term Debt	563,088	722,903
Deferred Income Tax	501,459	526,897
Asset Retirement Obligation	67,497	
Other Liabilities and Deferred Credits	19,401	14,324
Total liabilities	1,356,259	1,413,809
Commitments and Contingencies		
Shareholders Equity:		
Preferred stock, $1 par; 4,000,000 shares authorized		
Common stock, $1 par; 200,000,000 shares authorized, 62,365,192 and 61,061,888 shares issued, respectively	62,365	61,062
Additional capital	857,332	822,526
Retained earnings	364,187	202,155
Accumulated other comprehensive income (loss)	(8,692)	(6,249)
Treasury stock (55,359 shares), at cost	(1,710)	(1,710)
Total shareholders equity	1,273,482	1,077,784
	$ 2,629,741	$ 2,491,593

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows (Unaudited)

	Six Months Ended June 30,	
	2003	**2002**
	(Expressed in thousands)	
Cash Flows from Operating Activities:		
Cash received from customers	$ 622,061	$ 301,784
Operating, exploration, and general and administrative expenses paid	(119,795)	(96,328)
Interest paid	(25,520)	(28,156)
Income taxes paid	(75,686)	(4,059)
Income taxes received		25,884
Value added taxes paid	(1,294)	(4,498)
Price hedge contracts	(13,004)	15,683
Other	5,462	527
Net cash provided by operating activities	392,224	210,837
Cash Flows from Investing Activities:		
Capital expenditures	(157,826)	(175,673)
Proceeds from the sale of properties	8	5
Net cash used in investing activities	(157,818)	(175,668)
Cash Flows from Financing Activities:		
Borrowings under senior debt agreements	200,012	364,997
Payments under senior debt agreements	(360,000)	(390,000)
Payments of cash dividends on common stock	(6,164)	(3,240)
Payments of preferred dividends of a subsidiary trust		(4,850)
Payment of debt issue costs	(100)	(130)
Proceeds from exercise of stock options and other	26,999	14,174
Net cash used in financing activities	(139,253)	(19,049)
Effect of exchange rate changes on cash	166	86
Net increase in cash and cash equivalents	95,319	16,206
Cash and cash equivalents at the beginning of the year	134,449	94,294
Cash and cash equivalents at the end of the period	$ 229,768	$ 110,500
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 168,196	$ 37,643
Adjustments to reconcile net income to net cash provided by operating activities -		
Cumulative effect of change in accounting principle	4,166	
Minority interest		4,140
Accretion and other	7,283	(1,331)
Losses from the sales of properties	90	303

Depreciation, depletion and amortization	164,766	139,748
Dry hole and impairment	6,098	8,495
Interest capitalized	(8,131)	(13,512)
Price hedge contracts	2,506	7,685
Deferred income taxes	7,269	15,611
Change in operating assets and liabilities	39,981	12,055
Net cash provided by operating activities	$ 392,224	$ 210,837

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Shareholders Equity (Unaudited)

	For the Six Months Ended June 30,					
	2003			2002		
	Shareholders Equity		Compre-hensive	Shareholders Equity		Compre-hensive
	Shares	Amount	Income	Shares	Amount	Income
	(Expressed in thousands, except share amounts)					
Common Stock:						
$1.00 par-200,000,000 shares authorized						
Balance at beginning of year	61,061,888	$ 61,062		53,690,827	$ 53,691	
Shares issued for Trust Preferred Securities conversion				6,309,972	6,310	
Shares issued for stock options exercised and other	1,303,304	1,303		753,438	753	
Issued at end of period	62,365,192	62,365		60,754,237	60,754	
Additional Capital:						
Balance at beginning of year		822,526			659,227	
Shares issued for Trust Preferred Securities conversion					138,720	
Shares issued for stock options exercised and other		34,802			16,657	
Stock options granted		4				
Balance at end of period		857,332			814,604	
Retained Earnings:						
Balance at beginning of year		202,155			102,019	
Net income		168,196	$ 168,196		37,643	$ 37,643
Dividends ($0.10 and $0.06 per common share in 2003 and 2002, respectively)		(6,164)			(3,240)	
Balance at end of period		364,187			136,422	
Accumulated Other Comprehensive Income (Loss):						
Balance at beginning of year		(6,249)			10,272	
Change in fair value of price hedge contracts		(12,199)	(12,199)		(6,453)	(6,453)
Reclassification adjustment for losses (gains) included in net income		9,756	9,756		(5,199)	(5,199)
Balance at end of period		(8,692)			(1,380)	
Comprehensive Income			$ 165,753			$ 25,991
Treasury Stock:						
Balance at beginning of year	(55,359)	(1,710)		(15,575)	(324)	
Activity during the period						

Balance at end of period	(55,359)	(1,710)	(15,575)	(324)
Common Stock Outstanding, at the End of the Period	62,309,833		60,738,662	
Total Shareholders Equity		$ 1,273,482		$ 1,010,076

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 for the fair presentation of interim results. The interim results are not necessarily indicative of results for the entire year. Certain prior year amounts have been reclassified to conform to current year presentation. Such reclassifications had no effect on the Company s operating income, net income or shareholders equity. 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, 2002.

(2) 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 thousand, except per share amounts.

	Three Months Ended June 30, 2003			Six Months Ended June 30, 2003		
	Income	**Shares**	**Per Share**	**Income(a)**	**Shares**	**Per Share**
Basic earnings per share -	$ 79,719	61,961	$ 1.29	$ 172,362	61,559	$ 2.80
Effect of dilutive securities:						
Options to purchase common shares		689			967	
2006 Notes	1,028	2,726		2,056	2,726	
Diluted earnings per share	$ 80,747	65,376	$ 1.24	$ 174,418	65,252	$ 2.67
Antidilutive securities -						
Options to purchase common shares		10	$ 43.46		81	$ 41.23

	Three Months Ended June 30, 2002			Six Months Ended June 30, 2002		
	Income	**Shares**	**Per Share**	**Income**	**Shares**	**Per Share**
Basic earnings per share -	$ 28,618	56,192	$ 0.51	$ 37,643	54,972	$ 0.68
Effect of dilutive securities:						

Options to purchase common shares		1,005			871	
2006 Notes	1,028	2,726				
Trust Preferred Securities (b)	1,108	4,417		2,693	5,367	
Diluted earnings per share	$ 30,754	64,340	$ 0.48	$ 40,336	61,210	$ 0.66
Antidilutive securities -						
Options to purchase common shares		138	$ 38.19		173	$ 36.77
2006 Notes			$	2,056	2,726	$ 0.75

(a) Reflects income before cumulative effect of change in accounting principle.
(b) The Trust Preferred securities were converted to common stock on June 3, 2002.

(3) HEDGING ACTIVITIES -

As of June 30, 2003, the Company held various derivative instruments. During 2002 and 2003, the Company entered into natural gas and crude oil option agreements referred to as collars . Collars are designed to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The Company has designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Currently, the Company does not expect losses due to creditworthiness of its counterparties.

During the three-month and six-month periods ended June 30, 2003, the Company recognized pre-tax losses of $4,035,000 ($2,623,000 after taxes) and $14,810,000 ($9,627,000 after taxes), respectively, from its price hedge contracts which are included in oil and gas revenues. The Company also recognized a pre-tax loss of $200,000 due to ineffectiveness on these hedge contracts during the first six months of 2003. During the three-month and six-month periods ended June 30, 2002, the Company recognized a pre-tax loss of $1,011,000 ($657,000 after taxes) and a pre-tax gain of $7,998,000 ($5,199,000 after taxes), respectively, from its price hedge contracts which are included in oil and gas revenues. No ineffectiveness on these hedge contracts was recognized in income during the first six months of 2002. Unrealized losses on derivative instruments of $2,443,000, net of deferred taxes of $1,315,000, have been reflected as a

POGO PRODUCING COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Unaudited)

component of other comprehensive income for the six months ended June 30, 2003. Based on the fair market value of the hedge contracts as of June 30, 2003, the Company would reclassify additional pre-tax losses of approximately $13,372,000 (approximately $8,692,000 after taxes) from accumulated other comprehensive loss (shareholders equity) to net income during the next twelve months.

The gas hedging transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil hedging transactions are generally settled based on the average of the reporting settlement prices for West Texas Intermediate on the NYMEX for each trading day of a particular contract month. For any particular collar transaction, the counterparty 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, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of such transaction.

The estimated fair value of these transactions is based upon various factors that include closing exchange prices on the NYMEX, volatility and the time value of options. Further details related to the Company s hedging activities as of June 30, 2003 are as follows:

		NYMEX Contract Price		
Contract Period and Type of Contract	**Volume**	**Floor**	**Ceiling**	**Fair Value of Liability**
Natural Gas Contracts (MMBtu) (a)				
Collar Contracts:				
July 2003 - December 2003	7,360	$ 3.85	$ 5.00	$ (5,832,000)
July 2003 - December 2003	3,680	$ 4.25	$ 7.00	$ (316,000)
Crude Oil Contracts (Barrels)				
Collar Contracts:				
July 2003 - December 2003	1,840,000	$ 25.00	$ 30.00	$ (2,048,000)

(a) MMBtu means million British Thermal Units.

(4) CHANGE IN ACCOUNTING PRINCIPLE -

The Company adopted Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations (SFAS 143) as of January 1, 2003. SFAS 143 requires the Company to record the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. Upon adoption of SFAS 143, the Company was required to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and an asset retirement cost (ARC) was capitalized as part of the carrying value of the associated asset. Upon initial application of SFAS 143, a cumulative effect of a change in accounting principle was also required in order to recognize a liability for any existing AROs adjusted for cumulative accretion, an increase to the carrying amount of the associated long-lived asset and accumulated depreciation on the capitalized cost. Subsequent to initial measurement, liabilities are required to be accreted to their present value each period and capitalized costs are depreciated over the estimated useful life of the related assets. Upon settlement of the liability, the Company will settle the obligation against its recorded amount and will record any resulting gain or loss.

Activity related to the Company s ARO during the six months ended June 30, 2003 is as follows (in thousands):

	Six Months Ended June 30, 2003
Initial ARO as of January 1, 2003	$ 63,643
Liabilities incurred during period	1,459
Liabilities settled during period	
Accretion expense	2,395
Balance of ARO as of June 30, 2003	$ 67,497

POGO PRODUCING COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Unaudited)

For the three and six months ended June 30, 2003, the Company recognized depreciation expense related to its ARC of $972,000 and $1,028,000, respectively. As a result of the adoption of SFAS 143 on January 1, 2003, the Company recorded a $56,769,000 increase in the net capitalized cost of its oil and gas properties and recognized an after-tax charge of $4,166,000 for the cumulative effect of the change in accounting principle (net of related income tax benefit of $2,707,000).

Had the Company adopted SFAS 143 on January 1, 2002, the pro forma ARO would have been $58,187,000. Had SFAS 143 been applied retroactively during the three months and six months ended June 30, 2002, the Company s net income and earnings per share would have been as follows (expressed in thousands, except per share amounts):

	Three Months Ended June 30, 2002		Six Months Ended June 30, 2002	
	As Reported	Pro forma	As Reported	Pro forma
Net Income	$ 28,618	$ 28,343	$ 37,643	$ 37,249
Earnings per share:				
Basic	$ 0.51	$ 0.50	$ 0.68	$ 0.68
Diluted	$ 0.48	$ 0.47	$ 0.66	$ 0.65

(5) GEOGRAPHIC INFORMATION -

Financial information by geographic segment is presented below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(Expressed in thousands)			
Revenues:				
North America	$ 220,607	$ 134,188	$ 455,175	$ 235,884
Kingdom of Thailand	74,971	50,194	151,155	91,411
Other	21	3	23	
Total	$ 295,599	$ 184,385	$ 606,353	$ 327,295
Operating Income (Loss):				
North America	$ 109,322	$ 41,504	$ 236,196	$ 55,178

Kingdom of Thailand	35,483	19,114	77,204	35,234
Other	(889)	(440)	(1,650)	(955)
Total	$ 143,916	$ 60,178	$ 311,750	$ 89,457

(6) ACCOUNTING FOR STOCK-BASED COMPENSATION -

The Company s incentive plans authorize awards granted wholly or partly in common stock (including rights or options which may be exercised for or settled in common stock) to key employees and non-employee directors (collectively, Stock Awards). Prior to January 1, 2003, the Company accounted for Stock Awards using the intrinsic value recognition provisions of APB Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations. Under this method, the Company recognized no compensation expense for stock options granted when the exercise price of the options was equal to or greater than the quoted market price of the Company s common stock on the grant date. Effective January 1, 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, Accounting for Stock Based Compensation (SFAS 123), and the prospective method transition provisions of SFAS No. 148, Accounting for Stock Based Compensation Transition and Disclosure an amendment of FAS No. 123 (SFAS 148), for all Stock Awards granted, modified or settled after January 1, 2003. The Company granted Stock Awards covering 10,000 shares of common stock during the three and six-month periods ended June 30, 2003.

The following table illustrates the effect on the Company s net income and earnings per share if the fair value recognition provisions of SFAS 123 for employee stock-based compensation had been applied to all Stock Awards outstanding during the three and six-month periods ended June 30, 2003 and 2002 (in thousands of dollars, except per share amounts):

POGO PRODUCING COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
Net income, as reported	$ 79,719	$ 28,618	$ 168,196	$ 37,643
Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported	3		3	
Deduct: Total employee stock-based compensation expense, determined under fair value method for all awards, net of related tax effects	(1,540)	(1,518)	(3,063)	(2,716)
Net income, pro forma	$ 78,182	$ 27,100	$ 165,136	$ 34,927
Earnings per share:				
Basic - as reported	$ 1.29	$ 0.51	$ 2.73	$ 0.68
Basic - pro forma	$ 1.26	$ 0.48	$ 2.68	$ 0.64
Diluted - as reported	$ 1.24	$ 0.48	$ 2.61	$ 0.66
Diluted - pro forma	$ 1.21	$ 0.45	$ 2.56	$ 0.61

(7) CONVERSION OF TRUST PREFERRED SECURITIES -

Pogo Trust I, a subsidiary of the Company, called its 6½% Cumulative Quarterly Income Convertible Preferred Securities due 2029 (the Trust Preferred Securities) for redemption on June 3, 2002. Prior to their redemption, holders of 2,997,196 of the 3,000,000 outstanding Trust Preferred Securities converted their Trust Preferred Securities, representing $149,850,000 face value of Trust Preferred Securities, into 6,309,972 shares of the Company s common stock. In connection with the redemption, Pogo Trust I paid a total of $147,000 to former holders of the Trust Preferred Securities. Subsequent to June 3, 2002, there were no Trust Preferred Securities outstanding. The amounts recorded under Minority Interest Dividends and Costs Associated with Preferred Securities of a Subsidiary Trust during the three-month and six-month periods ended June 30, 2002 principally reflect cumulative dividends and, to a lesser extent, the amortization of issuance expenses related to the offering and sale of the Trust Preferred Securities.

(8) SUBSEQUENT EVENTS -

The Company gave notice on June 6, 2003 of its intent to redeem all $115,000,000 of its 5½% Convertible Subordinated Notes due 2006 (the 2006 Notes) at 101.65% of their face amount. On July 7, 2003, holders of $42,536,000 face value of the 2006 Notes converted their notes into 1,008,299 shares of the Company s common stock at the $42.185 per share conversion price. In connection with the redemption, the Company also paid a total of $73,661,000 in cash to former holders of the 2006 Notes. The cash portion of the redemption payment was funded through a combination of available cash and borrowings under the Company s existing bank credit facility. The Company will record a pre-tax loss on the redemption of the 2006 Notes of approximately $1.8 million in the third quarter of 2003.

The Company also gave notice on July 7, 2003 of its intent to redeem all $100,000,000 of its 8 3/4% Senior Subordinated Notes due 2007 (the 2007 Notes) at 102.917% of their face amount. On August 6, 2003, the Company paid $102,917,000 in cash to former holders of the 2007 Notes. The cash redemption payment was funded through a combination of available cash and borrowings under the Company s existing bank credit facility. The Company will record a pre-tax loss on the redemption of the 2007 Notes of approximately $4.1 million in the third quarter of 2003.

(9) RECENT ACCOUNTING PRONOUNCEMENT -

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities (SFAS 149). SFAS 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and hedging activities under SFAS 133. The amendments set forth in SFAS 149 require that contracts with comparable characteristics be accounted for similarly. SFAS 149 is generally effective for contracts entered into or modified after June 20, 2003 (with limited exceptions) and for hedging relationships designated after June 30, 2003. The guidance is to be applied prospectively only. The adoption of SFAS 149 is not expected to have a material effect on the Company s financial statements.

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, 2002. Some of the statements in the discussion 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, 2002, these 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.

Results of Operations

Net Income

The Company reported net income for the second quarter of 2003 of $79,719,000 or $1.29 per share ($80,747,000 or $1.24 per share on a diluted basis), compared to net income for the second quarter of 2002 of $28,618,000 or $0.51 per share ($30,754,000 or $0.48 per share on a diluted basis.) For the first six months of 2003, the Company reported net income of $168,196,000 or $2.73 per share ($174,418,000 or $2.61 per share on a diluted basis), compared to net income for the first six months of 2002 of $37,643,000 or $0.68 per share ($40,336,000 or $0.66 per share on a diluted basis). The increase in net income during the second quarter and first six months of 2003 compared to the 2002 periods, was primarily related to increased natural gas, crude oil and condensate production, in addition to increases in the average prices that the Company received for its natural gas, crude oil and condensate production volumes.

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 2003, compared to the second quarter and first six months of 2002, resulted primarily from the conversion of 2,997,196 of the 3,000,000 outstanding Trust Preferred Securities into 6,309,972 shares of the Company s common stock on June 3, 2002 and to a much lesser extent, the issuance of shares upon the exercise of stock options pursuant to the Company s stock option plans. The earnings per share computations on a diluted basis for the second quarters of 2002 and 2003 and the first six months of 2003 reflect additional shares of common stock issuable upon the assumed conversion of the Company s 5½% Convertible Subordinated Notes due 2006 (the 2006 Notes) and the elimination of related interest requirements, as adjusted for applicable federal income taxes. (The Company redeemed the 2006 Notes on July 7, 2003 for a combination of cash and common stock.) In addition, for all periods, the number of common shares outstanding in the diluted computations are adjusted to include dilutive shares that are assumed to have been issued by the Company in connection with outstanding options under its Incentive Plans, less treasury shares that are assumed to have been purchased by the Company from the option proceeds.

Total Revenues

The Company s total revenues for the second quarter of 2003 were $295,599,000, an increase of approximately 60% compared to total revenues of $184,385,000 for the second quarter of 2002. The Company s total revenues for the first six months of 2003 were $606,353,000, an increase of approximately 85% compared to total revenues of $327,295,000 for the first six months of 2002. The increase in the Company s total revenues for the second quarter and first six months of 2003, compared to the 2002 periods, resulted primarily from increased oil and gas revenues, which is attributable to higher product prices and higher natural gas, crude oil and condensate production.

Oil and Gas Revenues

The Company s oil and gas revenues for the second quarter of 2003 were $295,530,000, an increase of approximately 60% from oil and gas revenues of $185,241,000 for the second quarter of 2002. The Company s oil and gas revenues for the first six months of 2003 were $605,397,000, an increase of approximately 85% from oil and gas revenues of $327,538,000 for the first six months of 2002. The following table reflects an analysis of variances in the Company s oil and gas revenues (expressed in thousands) between 2003 and 2002.

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	2nd Qtr 2003 Compared to 2nd Qtr 2002	1st Half 2003 Compared to 1st Half 2002
Increase (decrease) in oil and gas revenues resulting in variances in:		
Natural gas -		
Price	$ 40,956	$ 87,755
Production	6,580	23,396
	47,536	111,151
Crude oil and condensate -		
Price	13,317	58,760
Production	50,815	104,006
	64,132	162,766
Natural gas liquids	(1,379)	3,942
Increase in oil and gas revenues	$ 110,289	$ 277,859

The increase in the Company s oil and gas revenues in the second quarter and first six months of 2003, compared to the second quarter and first six months of 2002, is related to increases in the average price that the Company received for its natural gas, crude oil and condensate production and an increase in the Company s natural gas, crude oil and condensate production volumes.

	2nd Quarter		%	1st Six Months		%
	2003	2002	Change	2003	2002	Change
Comparison of Increases in:						
Natural Gas						
Average prices						
North America (a)	**$ 5.33**	$ 3.21	**66%**	**$ 5.46**	$ 3.01	**81%**
Kingdom of Thailand (b)	**$ 2.48**	$ 2.12	**17%**	**$ 2.40**	$ 2.22	**8%**
Company-wide average price	**$ 4.48**	$ 2.91	**54%**	**$ 4.56**	$ 2.79	**63%**
Average daily production volumes (MMcf per day):						
North America (a)	**211.9**	206.1	**3%**	**213.8**	198.6	**8%**
Kingdom of Thailand	**89.8**	79.5	**13%**	**89.4**	76.3	**17%**
Company-wide average daily production	**301.7**	285.6	**6%**	**303.2**	274.9	**10%**

(a) North American average prices reflect the impact of the Company s price hedging activity**.** Price hedging activity reduced the average price of the Company s North American natural gas production during the second quarter and first six months of 2003 by $0.15 per Mcf and

$0.27 per Mcf, respectively. Price hedging activity decreased the average price of the Company s North American natural gas production during the second quarter of 2002 by $0.05 per Mcf and increased the average price by $0.22 per Mcf during the first six months of 2002. MMcf is an abbreviation for million cubic feet.

(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.

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	2nd Quarter			1st Six Months		
	2003	**2002**	**% Change**	**2003**	**2002**	**% Change**
Comparison of Increases in:						
Crude Oil and Condensate						
Average prices (a)						
North America	**$ 28.05**	$ 24.28	**16%**	**$ 30.08**	$ 22.39	**34%**
Kingdom of Thailand	**$ 26.28**	$ 24.32	**8%**	**$ 28.84**	$ 22.09	**31%**
Company-wide average price	**$ 27.44**	$ 24.29	**13%**	**$ 29.66**	$ 22.29	**33%**
Average daily production volumes (Bbls per day):						
North America (a)	**43,863**	30,659	**43%**	**41,937**	28,862	**45%**
Kingdom of Thailand (b)	**21,807**	15,715	**39%**	**22,446**	16,114	**39%**
Company-wide average daily production	**65,670**	46,374	**42%**	**64,383**	44,976	**43%**
Total Liquid Hydrocarbons						
Company-wide average daily production (Bbls per day)(b)	**69,137**	51,400	**35%**	**68,373**	49,299	**39%**

(a) Average prices are computed on production that is actually sold during the period and include the impact of the Company s price hedging activity. Price hedging activity reduced the average price of the Company s North American crude oil and condensate production during the second quarter and first six months of 2003 by $0.28 per barrel and $0.58 per barrel, respectively. The Company had no crude oil and condensate price hedging activity in the comparable 2002 periods. For North American average prices, sales volumes equate 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) below. Bbls is an abbreviation for barrels.

(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, reported revenues are based on sales volumes. However, the Company believes that actual production volumes also provide a meaningful measure of the Company s operating results. The Company produced 98,000 barrels less than it sold in the second quarter of 2003 and 170,000 barrels more than it sold in the first six months of 2003. The Company produced 3,000 barrels less than it sold in the second quarter of 2002 and 165,000 barrels more than it sold in the first six months of 2002.

Natural Gas

Thailand Prices. The price that the Company receives under its Gas Sales Agreement with the Petroleum Authority of Thailand (PTT) is based upon a formula that 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 contract price is also subject to adjustments for quality. An amendment to the Gas Sales Agreement provides that for certain volumes which the Company produces in excess of the base contractual amount (currently 145 MMcf per day), the price that the Company receives from PTT will be equal to 88% of the then-current price calculated under its Gas Sales Agreement.

Production. The increase in the Company s natural gas production during the second quarter and first six months of 2003, compared to the second quarter and first six months of 2002, was primarily related to successful development programs on the Company s Madden Unit, Los Mogotes and Gulf of Mexico properties, including its Main Pass 61/62 Field, and increased Thailand production from the Benchamas and Tantawan Fields, partially offset by natural production declines at other properties. In late June 2003, the operator of the Company s Madden Field announced that it had shut in the Lost Cabin gas plant to study the gathering system and make necessary repairs. The shut-in has effectively reduced the Company s net production from the Madden Field by approximately 15 MMcf per day as of June 30, 2003. The Company does not currently know when full production will be restored to the Madden Field.

Crude Oil and Condensate

Thailand Prices. Since the inception of production from the Tantawan Field, crude oil and condensate have been stored on the FPSO until an economic quantity is accumulated for offloading and sale. The first such sale of crude oil and condensate from the Tantawan Field occurred in July 1997. Commencing in July 1999 when production began from the Benchamas Field, crude oil and condensate from that field has been stored on the FSO and sold as economic quantities were accumulated. 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 U.S. dollars.

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Production. The increase in the Company s crude oil and condensate production during the second quarter and first six months of 2003, compared to the second quarter and first six months of 2002, resulted primarily from the continuing success of the Company s development program in the Main Pass Blocks 61/62 Field, its Ewing Bank Block 871 Field and its Mississippi Canyon 661/705 Field and, to a lesser extent, increased crude oil and condensate production at its Tantawan and Benchamas Fields in the Kingdom of Thailand. These increases were partially offset by natural production declines at other properties.

In accordance with generally accepted accounting principles, the Company records its oil production in the Kingdom of Thailand at the time of sale, rather than when produced. When such crude oil is sold, usually during the following month, the cost of the crude oil and the related sales revenue is recognized in the income statement. 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. As of June 30, 2003, the Company had approximately 372,000 net barrels stored on board the FPSO and FSO.

NGL Production. The Company s oil and gas revenues, and its total liquid hydrocarbon production, also 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 of 2003, compared with the second quarter of 2002, primarily related to a decrease in volumes extracted, which was only partially offset by an increase in NGL prices received ($15.49 per barrel in the second quarter of 2002 versus $18.09 per barrel in the second quarter of 2003). The increase in NGL revenues for the first six months of 2003, compared with the first six months of 2002, primarily related to an increase in NGL prices received ($13.85 per barrel in the first six months of 2002 versus $20.46 per barrel in the first six months of 2003), partially offset by a decrease in volumes extracted.

Costs and Expenses

	2nd Quarter			1st Six Months		
	2003	**2002**	**% Change**	**2003**	**2002**	**% Change**
Comparison of Increases (Decreases) in:						
Lease Operating Expenses						
North America	**$ 19,999,000**	$ 19,576,000	**2%**	**$ 43,453,000**	$ 39,531,000	**10%**
Kingdom of Thailand	**$ 11,485,000**	$ 10,080,000	**14%**	**$ 21,120,000**	$ 18,597,000	**14%**
Total Lease Operating Expenses	**$ 31,484,000**	$ 29,656,000	**6%**	**$ 64,573,000**	$ 58,128,000	**11%**
General and Administrative Expenses	**$ 15,054,000**	$ 10,828,000	**39%**	**$ 28,426,000**	$ 22,370,000	**27%**
Exploration Expenses	**$ 1,827,000**	$ 1,352,000	**35%**	**$ 3,659,000**	$ 1,176,000	**211%**
Dry Hole and Impairment Expenses	**$ 3,920,000**	$ 3,500,000	**12%**	**$ 6,098,000**	$ 8,495,000	**(28)%**
Depreciation, Depletion and Amortization (DD&A) Expenses	**$ 84,347,000**	$ 73,942,000	**14%**	**$ 164,766,000**	$ 139,748,000	**18%**
DD&A rate	**$ 1.28**	$ 1.37	**(6)%**	**$ 1.29**	$ 1.37	**(6)%**
Mcfe sold (a)	**65,790,000**	54,065,000	**22%**	**128,116,000**	102,299,000	**25%**
Production and Other Taxes	**$ 10,231,000**	$ 4,929,000	**108%**	**$ 19,185,000**	$ 7,740,000	**148%**
Accretion and Other	**$ 4,820,000**	$	**N/M**	**$ 7,896,000**	$ 181,000	**4262%**
Interest						

Charges	**$ (12,984,000)**	$ (14,500,000)	**(10)%**	**$ (26,679,000)**	$ (29,088,000)	**(8)%**
Interest Income	**$ 547,000**	$ 534,000	**2%**	**$ 934,000**	$ 912,000	**2%**
Capitalized Interest Expense	**$ 4,117,000**	$ 6,859,000	**(40)%**	**$ 8,131,000**	$ 13,512,000	**(40)%**
Minority Interest - Dividends and Costs	**$**	$ (1,638,000)	**(100)%**	**$**	$ (4,140,000)	**(100)%**
Foreign Currency Transaction Gain	**$ 336,000**	$ 659,000	**(49)%**	**$ 562,000**	$ 1,331,000	**(58)%**
Income Tax Expense	**$ (56,213,000)**	$ (23,474,000)	**139%**	**$ (122,336,000)**	$ (34,341,000)	**256%**

(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 2003, compared to the respective 2002 periods, is related primarily to new and higher production from the Company s onshore properties and additional Gulf of Mexico platforms added during 2002 and, to a lesser extent, increased expenses at the recently expanded Lost Cabin gas plant in the Madden Unit.

The increase in lease operating expenses in the Kingdom of Thailand for the second quarter and first six months of 2003, compared to the respective 2002 periods, primarily related to costs associated with operating the four additional platforms which were added to the Gulf of Thailand during the second half of 2002 and the resulting increase in operating expenses as additional wells were subsequently brought on production. In accordance with generally accepted accounting principles, the portion of lifting costs that is attributable to crude oil and condensate stored on the FPSO and FSO is treated as an inventoried cost until that crude oil and condensate is sold. At the time the

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crude oil and condensate is sold, those inventoried lifting costs are recognized as lease operating expenses. Variances in production, sales and operating costs will result in variances in the amount of lease operating expense that is currently recognized as expense and the amount recorded as product inventory to be recognized in subsequent periods. 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 charters of the FPSO for the Tantawan Field and the FSO for the Benchamas Field. Collectively, these lease payments accounted for approximately $3,625,000 and $7,211,000 (net to the Company s interest) of the Company s Thailand lease operating expenses for the second quarters and first six months, respectively, of 2003 and 2002. The Company currently expects these lease payments to remain relatively constant at approximately $14,500,000 per year (net to the Company s interest) for the next several years.

Notwithstanding the overall increase in lease operating expenses, on a per unit of production basis, the Company s total lease operating expenses have continued to decrease from an average of $0.64 per Mcfe for both the second quarter and first six months of 2002 to $0.48 per Mcfe for the second quarter and $0.50 per Mcfe for the first six months of 2003.

General and Administrative Expenses

The increase in general and administrative expenses for the second quarter and first six months of 2003 compared with the respective 2002 periods, primarily related to normal increases in compensation and concomitant benefit expense, higher pension expense resulting from lower returns on the Company s retirement plan assets and increased medical costs and, to a lesser extent, increases in professional fees and insurance costs. The Company s general and administrative expenses, on a per unit of production basis, remained steady at $0.22 per Mcfe for the first six months of 2003 and 2002. The Company s general and administrative expenses increased to $0.23 per Mcfe for the second quarter of 2003 compared to $0.20 per Mcfe for the second quarter of 2002.

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 that are expensed as incurred. The increase in exploration expenses for the first six months of 2003, compared to the first six months of 2002, resulted primarily from a rebate of a delay rental ($1,327,000 net to the Company) that was paid by the Company s Thai subsidiary to the Kingdom of Thailand, which was returned in the first quarter of 2002 when certain contractual obligations under the Company s Thai license were satisfied. There was no comparable rebate in the first six months of 2003.

Dry Hole and Impairment Expenses

Dry hole and impairment expenses relate to costs of unsuccessful exploratory wells drilled and impairment of oil and gas properties. During the second quarter and first six months of 2003, the Company drilled one and two unsuccessful exploratory wells, respectively. No unsuccessful exploratory wells were drilled in the second quarter and first six months of 2002. Generally accepted accounting principles require that if the expected future cash flows of the Company s reserves on a property fall below the related carrying value recorded on the Company s books, these properties must be impaired and written down to their respective fair value. Depending on market conditions, including the prices for oil and natural gas, and the Company s results of operations, a similar test may be conducted at any time to determine whether impairments are appropriate. Depending on the results of this test, impairment could be required on some of the Company s properties and such impairments could have a material negative non-cash impact on the Company s results of operations and financial position. During the second quarters and first six months of 2003 and 2002, the Company recognized miscellaneous impairments on various non-producing prospects and leases.

Depreciation, Depletion and Amortization (DD&A) Expenses

The Company s provision for DD&A expense is based on its capitalized costs and is determined on a cost center by cost center basis using the units of production method. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in the Gulf of Mexico and Gulf of Thailand. Generally, the Company establishes cost centers on the basis of an oil or gas trend or play for its onshore oil and gas activities. The increase in the Company s DD&A expenses for the second quarter and first six months of 2003 compared to the respective 2002 periods resulted primarily from an increase in the Company s natural gas and liquid hydrocarbon production, partially offset by a decrease in the Company s composite DD&A rate.

The decrease in the composite DD&A rate for all of the Company s producing fields for the second quarter and first six months of 2003, compared to the respective 2002 periods, resulted primarily from an increased percentage of the Company s production coming from fields that have DD&A rates lower than the Company s recent historical composite rate (principally certain Gulf of Mexico properties and the Benchamas Field) and a corresponding decrease in the percentage of the Company s production coming from fields that have DD&A rates higher than the Company s recent historical composite DD&A rate.

Production and Other Taxes

The increase in production and other taxes during the second quarter and first six months of 2003, compared to the respective 2002 periods, relates primarily to increased severance taxes due to higher onshore production volumes and prices. The increase is also related to the recognition during the second quarter and first six months of 2003 of $1,852,000 and $4,226,000, respectively, of the Special Remunitory Benefit (SRB) obligation related to the Company s Kingdom of Thailand concession. No comparable SRB expenses were incurred in 2002. SRB is a payment to the Thai government required by the Company s concession agreement after certain specified revenue, expenditure and drilling criteria have been achieved. It is currently anticipated that the Company will continue to pay SRB for the foreseeable future.

Accretion and Other

The increase in accretion and other expense during the second quarter and first six months of 2003, compared to the comparable 2002 periods, relates primarily to the inclusion of expense related to the accretion of the Company s asset retirement obligation under a new accounting standard adopted on January 1, 2003, for which no comparable expense was incurred in the second quarter or first six months of 2002. The increase in accretion and other expense during second quarter of 2003, compared to the second quarter of 2002, was also the result of increased valuation allowances on certain of the Company s receivables (including the Company s Enron receivable). The increase in accretion and other expense during the first six months of 2003, compared to the first six months of 2002, was, to a lesser extent, also the result of a write down of the value of the Company s tubular inventory stock during the first quarter of 2003 for which no comparable write down expense was incurred in the first six months of 2002.

Interest

Interest Charges. The decrease in the Company s interest charges for the second quarter and first six months of 2003, compared with the respective 2002 periods, resulted primarily from a decrease in the average amount of the Company s outstanding debt, partially offset by an increase in the average interest rate on the outstanding debt due to the repayment of approximately $160,000,000 of lower interest rate senior debt under the Credit Facility during the first six months of 2003.

Interest Income. The increase in the Company s interest income for the second quarter and first six months of 2003, compared to the comparable 2002 periods, resulted primarily from an increase in the amount of cash and cash equivalents temporarily invested. The cash and cash equivalents on the Company s balance sheet are primarily held by the Company s international subsidiaries for future investment overseas, in part due to the negative tax effects that would result from the repatriation of these funds.

Capitalized Interest. Interest costs related to financing oil and gas projects in progress are capitalized until the projects are substantially complete and ready for their intended use, provided such projects are evaluated as successful. The decrease in capitalized interest for the second quarter and first six months of 2003, compared to the comparable 2002 periods, resulted primarily from a decrease in the amount of capital expenditures subject to interest capitalization during the second quarter and first six months of 2003 (approximately $186,000,000 and $196,000,000, respectively), compared to the second quarter and first six months of 2002 (approximately $381,000,000 and $379,000,000, respectively). These changes were only partially offset by an increase in the Company s weighted average borrowing rate. The weighted average borrowing rate increased due to the Company s repayment of lower rate senior debt during the second quarter and first six months of 2003. A substantial percentage of the Company s capitalized interest relates to unevaluated properties acquired in the North Central acquisition and capital expenditures for the development of the Benchamas Field in the Gulf of Thailand, as well as several development projects in the Gulf of Mexico.

Minority Interest Dividends and Costs Associated with Mandatorily Redeemable Convertible Preferred Securities of a Subsidiary Trust

Pogo Trust I, a business trust in which the Company owned all of the issued common securities, issued $150,000,000 of Trust Preferred Securities on June 2, 1999. Pogo Trust I called the Trust Preferred Securities for redemption on June 3, 2002. Prior to their redemption, holders of 2,997,196 of the 3,000,000 outstanding Trust Preferred Securities converted their Trust Preferred Securities, representing over $149,850,000 face value of Trust Preferred Securities, into 6,309,972 shares of the Company s common stock. In connection with the redemption, Pogo Trust I paid a total of $147,000 to former holders of the Trust Preferred Securities. Subsequent to June 3, 2002, there were no Trust Preferred Securities outstanding. The amounts recorded under Minority Interest Dividends and Costs Associated with Preferred Securities of a Subsidiary Trust during the second quarter and first six months of 2002 principally reflect cumulative dividends and, to a lesser extent, the amortization of issuance expenses related to the offering and sale of the Trust Preferred Securities. No such expenses were incurred in the second quarter and first six months of 2003.

Foreign Currency Transaction Gain (Loss)

The foreign currency transaction gain reported in the second quarter and first six months of 2003 and the comparable 2002 periods, resulted primarily from the fluctuation against the U.S. dollar of cash and other monetary assets and liabilities denominated in Thai Baht related to the Company s Thai operations. During the first six months of 2003, the Thai Baht U.S. dollar daily average exchange rate fluctuated between 41.2 and 43.4 Baht to the U.S. dollar. The Company cannot predict what the Thai Baht to U.S. dollar exchange rate will be in the future. As of August 6, 2003, the Company was not a party to any financial instrument that was intended to constitute a foreign currency hedging arrangement.

Exposure from market rate fluctuations related to activities in Hungary, where the Company s functional currency is the legal tender in Hungary (currently the Forint), is not material at this time.

Income Tax Expense

Changes in the Company s income tax expense are a function of the Company s consolidated effective tax rate and its pre-tax income. The increase in the Company s tax expense for the second quarter and first six months of 2003, compared to the comparable 2002 periods, resulted primarily from increased pre-tax income during the 2003 periods, partially offset by a decrease in the Company s effective tax rate during the 2003 periods. The Company s consolidated effective tax rate for the second quarters of 2003 and 2002 was 41% and 45%, respectively. The Company s consolidated effective tax rate for the first six months of 2003 and 2002 was 42% and 48%, respectively. The lower effective tax rates are the result of a lower percentage of the Company s pre-tax income being derived from its Thailand operations in 2003, which is taxed at a rate higher than the U.S. statutory rate, relative to the percentage of its pre-tax income from U.S. operations.

Cumulative Effect of Change in Accounting Principle

The Company adopted SFAS No. 143, Accounting for Asset Retirement Obligations, (SFAS 143), as of January 1, 2003. SFAS 143 requires the Company to record the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. Upon adoption of SFAS 143, the Company was required to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and an asset retirement cost (ARC) was capitalized as part of the carrying value of the associated asset. Upon initial application of SFAS 143, the Company recorded an after-tax charge to recognize the cumulative effect of a change in accounting principle of $4,166,000. This charge was required in order to recognize a liability for any existing AROs adjusted for cumulative accretion, and also to increase the carrying amount of the associated long-lived asset for the ARC and its accumulated depreciation.

Liquidity and Capital Resources

The Company s cash flow provided by operating activities for the first six months of 2003 was $392,224,000. This compares to cash flow from operating activities of $210,837,000 in first six months of 2002. The resulting increases are attributable to the reasons described under Results of Operations above. Cash flow from operating activities in the first six months of 2003 was more than adequate to fund $157,826,000 in cash expenditures for capital and exploration projects for the six-month period ended June 30, 2003. The Company also repaid approximately $160,000,000 of net debt obligations and paid $6,164,000 of dividends on the Company s common stock during the first six months of 2003. As of June 30, 2003, the Company had cash and cash equivalents of $229,768,000 (including $153,513,000 in international subsidiaries which the Company intends to reinvest in its foreign operations) and long-term debt obligations of $565,000,000 (excluding debt discount of $1,912,000) with no repayment obligations until 2006. On July 7, 2003, the Company redeemed all $115,000,000 of its outstanding 5 $^{1}/2$% Convertible Subordinated Notes due 2006, for 1,008,299 shares of common stock and $73,661,000 in cash. On August 6, 2003, the Company redeemed all $100,000,000 of its 8 $^{3}/4$% Senior Subordinated Notes due 2007 for $102,917,000 in cash. The Company may determine to repurchase additional debt in the future, including in market transactions, privately negotiated transactions or otherwise, depending on market conditions, liquidity requirements, contractual restrictions and other factors.

Effective April 21, 2003, the Company s borrowing base under its Credit Agreement was redetermined by its lenders at $600,000,000. The available borrowing capacity under the Credit Agreement is currently $515,000,000. As of August 6, 2003, the Company had an outstanding balance of $93,000,000 under its Credit Agreement.

Future Capital and Other Expenditure Requirements

The Company s capital and exploration budget for 2003, 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, has been established by the Company s Board of Directors at $355,000,000, of which approximately $134,000,000 was incurred in the six-month period ended June 30, 2003. The Company currently anticipates that its available cash and cash investments, cash provided by operating activities and funds available under its bank credit facility will be sufficient to fund the Company s ongoing operating, interest and general and administrative expenses, its authorized capital budget, the redemption of the 2007 notes, and future dividend payments at current levels for the foreseeable future. The declaration and amount of future dividends on the Company s common stock will depend upon, among other things, the Company s future earnings and financial condition, liquidity and capital requirements, its ability to pay dividends and other payments 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.

Recent Accounting Pronouncements and Developments

In April 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities (SFAS 149). SFAS 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and hedging activities under SFAS 133. The amendments set forth in SFAS 149 require that contracts with comparable characteristics be accounted for similarly. SFAS 149 is generally effective for contracts entered into or modified after June 20, 2003 (with limited exceptions) and for hedging relationships designated after June 30, 2003. The guidance is to be applied prospectively only. The adoption of SFAS 149 is not expected to have a material effect on the Company s financial statements.

The Company has been made aware of an issue regarding the application of provisions of SFAS 141, Business Combinations and SFAS No. 142, Goodwill and Other Intangible Assets (SFAS 142) to companies in the

extractive industries, including oil and gas companies. The issue is whether SFAS 142 requires registrants to reclassify costs associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs. Historically, the Company and other oil and gas companies have included the cost of these oil and gas leasehold interests as part of oil and gas properties and provided the disclosures required by SFAS No. 69, Disclosures about Oil and Gas Producing Activities (SFAS 69). Also under consideration is whether SFAS 142 requires registrants to provide the additional disclosures prescribed by SFAS 142 for intangible assets for costs associated with mineral rights.

If it is ultimately determined that SFAS 142 requires the Company to reclassify costs associated with mineral rights from property and equipment to intangible assets, the Company currently believes that its results of operations and financial condition would not be affected, since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing successful efforts accounting rules and impairment standards. In addition, costs associated with mineral rights would continue to be characterized as oil and gas property costs in our required disclosures under SFAS 69.

At June 30, 2003, we had undeveloped leaseholds of approximately $114 million that would be classified on our balance sheet as intangible undeveloped leaseholds and developed leaseholds of approximately $961 million (net of accumulated depletion) that would be classified as intangible developed leaseholds if we applied the interpretation currently being discussed.

ITEM 3. ***Quantitative and Qualitative Disclosures About Market Risk.***

The Company is exposed to market risk, including adverse changes in commodity prices, interest rates and foreign currency exchange rates as discussed below.

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Commodity Price Risk

The Company produces and sells natural gas, crude oil, condensate and NGLs. As a result, the Company s financial results can be significantly affected as these commodity prices fluctuate widely in response to changing market forces. The Company makes limited use of a variety of derivative financial instruments, for non-trading purposes only, as a hedging strategy to manage commodity prices associated with oil and gas sales and to reduce the impact of commodity price fluctuations.

Current Hedging Activity

Natural Gas

As of June 30, 2003, the Company held various derivative instruments. The Company has entered into natural gas and crude oil option agreements referred to as collars . Collars are designed to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The Company has designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Currently, the Company does not expect losses due to creditworthiness of its counterparties.

The gas hedging transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil hedging transactions are generally settled based on the average of the reporting settlement prices on the NYMEX for each trading day of a particular contract month. For any particular collar transaction, the counterparty 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, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of such transaction.

The estimated fair value of these transactions is based upon various factors that include closing exchange prices on the NYMEX, volatility and the time value of options. Further details related to the Company s hedging activities as of June 30, 2003, are as follows:

		NYMEX Contract Price		Fair Value of
Contract Period and Type of Contract	**Volume**	**Floor**	**Ceiling**	**Liability**
Natural Gas Contracts (MMBtu) (a)				
Collar Contracts:				
July 2003 - December 2003	7,360	$ 3.85	$ 5.00	$ (5,832,000)

July 2003 - December 2003	3,680	$ 4.25	$ 7.00	$ (316,000)
Crude Oil Contracts (Barrels)				
Collar Contracts:				
July 2003 - December 2003	1,840,000	$ 25.00	$ 30.00	$ (2,048,000)

(a) MMBtu means million British Thermal Units.

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 August 6, 2003, 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, 2003:

	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Average Interest Rate								
Fixed Rate	$ 0	$ 0	$ 0	$ 115,000(a)	$ 100,000(b)	$ 350,000	$ 565,000	$ 602,398
Average Interest Rate				5.50%	8.75%	9.16%	8.34%	

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(a) The Company gave notice on June 6, 2003 of its intent to redeem all $115,000,000 of its 5½% Convertible Subordinated Notes due 2006 (the 2006 Notes) at 101.65% of their face amount. On July 7, 2003, holders of $42,536,000 face value of the 2006 Notes converted their notes into 1,008,299 shares of the Company s common stock at the $42.185 per share conversion price. In connection with the redemption, the Company also paid a total of $73,661,000 in cash to former holders of the 2006 Notes.

(b) The Company gave notice on July 7, 2003 of its intent to redeem all $100,000,000 of its 8 3/4% Senior Subordinated Notes due 2007 at 102.917% of their face amount. On August 6, 2003, the Company paid $102,917,000 in cash to former holders of the 2007 Notes. The cash redemption payment was funded through a combination of available cash and borrowings under the Company s existing bank credit facility.

Foreign Currency Exchange Rate Risk

In addition to the U.S. dollar, the Company and certain of its subsidiaries conduct their business in Thai Baht and Hungarian Forint and are therefore subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions. The Company conducts a substantial portion of its oil and gas production and sales in Southeast Asia. Southeast Asia in general, and the Kingdom of Thailand in particular, have experienced severe economic difficulties in the past, including sharply reduced economic activity, illiquidity, highly volatile foreign currency exchange rates and unstable stock markets. The economic situation in Thailand and the volatility of the Thai Baht against the dollar could have a material impact on the Company s Thailand operations and prices that the Company receives for its oil and gas production there. Although the Company s sales to PTT under the Gas Sales Agreement are denominated in Baht, because predominantly all of the Company s crude oil sales and its capital and most other expenditures in the Kingdom of Thailand are denominated in dollars, the dollar is the functional currency for the Company s operations in the Kingdom of Thailand. As of August 6, 2003, the Company is not a party to any foreign currency exchange agreement.

Exposure from market rate fluctuations related to activities in Hungary, where the Company s functional currency is the legal tender in Hungary (currently the Forint,) is not material at this time.

ITEM 4. Controls and Procedures.

The Company carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s Chairman, President and Chief Executive Officer and its Senior Vice President and Chief Financial Officer, of the effectiveness of the Company s disclosure controls and procedures pursuant to Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this quarterly report. Based upon that evaluation, the Company s Chairman, President and Chief Executive Officer and its Senior Vice President and Chief Financial Officer concluded that the Company s disclosure controls and procedures are effective in timely alerting them to material information required to be included in our periodic Securities and Exchange Commission filings.

There were no changes in the Company s internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Part II. Other Information

ITEM 4. Submission of Matters to Vote of Security Holders

The registrant held its annual meeting of stockholders in Houston, Texas on April 22, 2003. The following sets forth the items that were put to a vote of the stockholders and the results thereof concerning:

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

Nominee	For	Withheld
William L. Fisher	46,727,815	8,474,383
Gerrit W. Gong	46,729,053	8,473,145
Carroll W. Suggs	52,288,264	2,913,934

(B) a proposal to ratify the appointment of ProcewaterhouseCoopers LLP, independent accountants, to audit the financial statements of the Company for the year 2003, with 47,028,795 votes cast for ratification, 8,139,164 votes cast against ratification and 34,239 votes were cast in abstention.

POGO PRODUCING COMPANY AND SUBSIDIARIES

ITEM 6. Exhibits and Reports on Form 8-K.

(A) Exhibits

10.1	Form of Restricted Stock Award Agreement under Incentive Plans.
10.2	Form of Director s Phantom Stock Agreement.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.
32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.

(B) Reports on Form 8-K

During the quarter for which this report is filed, the following reports on Form 8-K were filed:

Report dated April 22, 2003 (Items 7, 9, and 12 (furnished material only; not filed for purposes of Section 18 of the Securities Exchange Act or any other purpose)).

Report dated July 15, 2003 (Items 7, 9, and 12 (furnished material only; not filed for purposes of Section 18 of the Securities Exchange Act or any other purpose)).

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
Senior Vice President and Chief
Financial Officer

Date: August 11, 2003