

NUEVO ENERGY CO  
Form 10-Q  
November 13, 2003

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**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

**FORM 10-Q**

(Mark One)

**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)  
OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 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 1-10537

**Nuevo Energy Company**

(Exact Name of Registrant as Specified in Its Charter)

**Delaware**

(State or other jurisdiction of  
incorporation or organization)

**76-0304436**

(I.R.S. Employer Identification No.)

**1021 Main, Suite 2100, Houston, Texas**

(Address of principal executive offices)

**77002**

(Zip Code)

Registrant's telephone number, including area code: **(713) 652-0706**

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 requirements for the past 90 days

Yes  No

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes  No

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

Common Stock, par value \$.01 per share. Shares outstanding on November 7, 2003: 19,517,614

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Below is a list of terms commonly used in the oil and gas industry.

/d	=	per day
Bbl	=	barrel of crude oil or other liquid hydrocarbons
Bcf	=	billion cubic feet of natural gas
Bcfe	=	billion cubic feet of natural gas equivalent
BOE	=	barrel of oil equivalent, converting gas to oil at the ratio of 6 Mcf of gas to 1 Bbl of oil
BOPD	=	barrel of oil per day
MBbl	=	thousand barrels
Mcf	=	thousand cubic feet of natural gas
MMBbl	=	million barrels of oil or other liquid hydrocarbons
MMcf	=	million cubic feet of natural gas
MBOE	=	thousand barrels of oil equivalent
MMBOE	=	million barrels of oil equivalent

## PART I FINANCIAL INFORMATION

## ITEM 1. FINANCIAL STATEMENTS

**NUEVO ENERGY COMPANY**  
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME**  
(In thousands, except per share data)  
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
<b>Revenues</b>				
Crude oil and liquids	\$ 74,093	\$ 71,838	\$ 237,713	\$ 206,595
Natural gas	13,614	8,897	42,352	22,551
Other	127	3,515	540	3,563
	<u>87,834</u>	<u>84,250</u>	<u>280,605</u>	<u>232,709</u>
<b>Costs and Expenses</b>				
Lease operating expenses	39,632	36,841	121,068	103,881
Exploration costs	284	2,318	1,673	3,800
Depletion, depreciation, amortization and accretion	17,349	18,018	52,447	52,724
General and administrative expenses	6,572	6,525	19,635	19,840
Loss (gain) on disposition of properties	223	(620)	(4,234)	(15,946)
Other	394	186	723	(12)
	<u>64,454</u>	<u>63,268</u>	<u>191,312</u>	<u>164,287</u>
Operating Income	23,380	20,982	89,293	68,422
Derivative gain (loss)	358	(3,371)	(1,369)	(4,304)
Interest income	16	53	319	227
Interest expense	(6,232)	(9,528)	(24,588)	(27,744)
Loss on early extinguishment of debt			(10,892)	
Dividends on TECONS	(1,653)	(1,653)	(4,959)	(4,959)
Income From Continuing Operations Before Income Tax	15,869	6,483	47,804	31,642
<b>Income Tax Expense</b>				
Current	(1,756)	1,025	324	1,025
Deferred	8,233	1,601	18,813	11,800
	<u>6,477</u>	<u>2,626</u>	<u>19,137</u>	<u>12,825</u>
Income From Continuing Operations	9,392	3,857	28,667	18,817
Income from discontinued operations, including gain/loss on disposal, net of income tax	640	2,298	5,964	5,366
Cumulative effect of a change in accounting principle, net of income tax			8,496	
Net Income	\$ 10,032	\$ 6,155	\$ 43,127	\$ 24,183

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<b>Earnings Per Share:</b>				
<b>Basic</b>				
Income from continuing operations	\$ .49	\$ .22	\$ 1.49	\$ 1.10
Income from discontinued operations, net of income tax	.03	.13	.31	.31
Cumulative effect of a change in accounting principle, net of income tax			.44	
Net income	\$ .52	\$ .35	\$ 2.24	\$ 1.41
<b>Diluted</b>				
Income from continuing operations	\$ .48	\$ .22	\$ 1.47	\$ 1.09
Income from discontinued operations, net of income tax	.03	.13	.30	.31
Cumulative effect of a change in accounting principle, net of income tax			.44	
Net income	\$ .51	\$ .35	\$ 2.21	\$ 1.40
<b>Weighted Average Shares Outstanding:</b>				
<b>Basic</b>				
	19,387	17,399	19,283	17,161
<b>Diluted</b>				
	19,635	17,502	19,472	17,308

See accompanying notes.

**NUEVO ENERGY COMPANY**  
**CONDENSED CONSOLIDATED BALANCE SHEETS**  
(In thousands, except share amounts)  
(Unaudited)

	September 30, 2003	December 31, 2002
<b>ASSETS</b>		
Current assets		
Cash and cash equivalents	\$ 1,550	\$ 5,047
Accounts receivable, net	35,765	40,945
Inventory	6,953	7,326
Assets held for sale	37,097	92,738
Deferred income taxes	8,353	7,683
Prepaid expenses and other	5,292	3,862
	<u>95,010</u>	<u>157,601</u>
Property and equipment, at cost		
Land	5,224	5,224
Oil and gas properties (successful efforts method)	1,019,631	951,258
Other property	14,769	14,303
	<u>1,039,624</u>	<u>970,785</u>
Accumulated depreciation, depletion and amortization	(339,935)	(357,072)
	<u>699,689</u>	<u>613,713</u>
Deferred income taxes	17,260	43,258
Goodwill	17,121	19,664
Other assets	12,014	20,935
	<u>841,094</u>	<u>855,171</u>
Total assets	<u>\$ 841,094</u>	<u>\$ 855,171</u>
<b>LIABILITIES AND STOCKHOLDERS EQUITY</b>		
Current liabilities		
Accounts payable	\$ 23,404	\$ 34,323
Accrued interest	10,528	5,169
Accrued drilling costs	6,351	8,035
Accrued lease operating costs	18,489	15,598
Price risk management activities	25,190	20,884
Other accrued liabilities	20,576	16,735
	<u>104,538</u>	<u>100,744</u>
Long-term debt		
Senior subordinated notes	250,000	409,577
Bank credit facility	26,325	28,700
	<u>276,325</u>	<u>438,277</u>
Total debt	<u>276,325</u>	<u>438,277</u>
Interest rate swaps fair value adjustment		2,161
Interest rate swaps termination gain	14,777	11,673
	<u>14,777</u>	<u>11,673</u>

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Long-term debt	291,102	452,111
Asset retirement obligation	101,053	
Other long-term liabilities	9,525	13,040
Company-Obligated Mandatorily Redeemable Convertible Preferred Securities of Nuevo Financing I (TECONS)	115,000	115,000
Commitments and contingencies (Note 9)		
Stockholders' equity		
Preferred stock, \$1.00 par value, 10,000,000 shares authorized; 7% cumulative convertible preferred stock, none issued		
Common stock, \$0.01 par value, 50,000,000 shares authorized, 23,090,985 and 23,048,388 shares issued and 19,473,331 and 19,110,102 shares outstanding, respectively	231	230
Additional paid-in capital	391,021	388,479
Treasury stock, at cost, 3,617,654 and 3,867,691 shares, respectively	(70,928)	(75,683)
Deferred stock compensation and other	(1,515)	(605)
Accumulated other comprehensive income (loss)	(14,072)	(11,468)
Accumulated deficit	(84,861)	(126,677)
Total stockholders' equity	219,876	174,276
Total liabilities and stockholders' equity	\$ 841,094	\$ 855,171

See accompanying notes.

**NUEVO ENERGY COMPANY**  
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**  
(In thousands)  
(Unaudited)

	Nine Months Ended September 30,	
	2003	2002
<b>Cash flows from operating activities</b>		
Net income	\$ 43,127	\$ 24,183
Adjustments to reconcile net income to net cash provided by operating activities		
Depletion, depreciation, amortization and accretion	52,447	52,724
Amortization of debt financing costs	1,576	1,899
Loss on early extinguishment of debt	10,892	
Gain on sales of assets, net	(4,234)	(15,946)
Deferred income taxes	18,813	11,800
Non-cash effect of discontinued operations	640	8,661
Cumulative effect of a change in accounting principle	(8,496)	
Other	4,155	6,647
Working capital changes, net of non-cash transactions		
Accounts receivable	5,683	5,778
Accounts payable	(6,493)	(9,198)
Accrued liabilities	(20,137)	(11,184)
Other	32,298	(7,857)
	<u>130,271</u>	<u>67,507</u>
<b>Cash flows from investing activities</b>		
Additions to oil and gas properties	(48,411)	(37,647)
Cash portion of acquisition of Athanor Resources, Inc.		(61,312)
Additions to other properties	(2,737)	(3,524)
Proceeds from sale of properties	82,001	26,968
Other investing activities	1,841	
	<u>32,694</u>	<u>(75,515)</u>
<b>Cash flows from financing activities</b>		
Payments of long-term debt	(159,577)	
Premium paid for redemption of notes	(7,505)	
Net borrowings (repayments) of credit facility	(2,375)	2,500
Proceeds from exercise of stock options	2,995	1,229
Other proceeds		1,294
	<u>(166,462)</u>	<u>5,023</u>
Increase (decrease) in cash and cash equivalents	(3,497)	(2,985)
Cash and cash equivalents		
Beginning of period	5,047	7,110
End of period	<u>\$ 1,550</u>	<u>\$ 4,125</u>

See accompanying notes.

**NUEVO ENERGY COMPANY**  
**CONDENSED CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY**  
(In thousands)  
(Unaudited)

	Nine Months Ended September 30, 2003	
	Shares	Amount
<b>Common Stock</b>		
Balance, beginning of period	19,110	\$ 230
Issuances and purchases of common stock		
Employee stock compensation and plans	363	1
	19,473	\$ 231
<b>Additional Paid-In Capital</b>		
Balance, beginning of period		\$ 388,479
Exercise of stock options		220
Employee stock compensation and plans		2,322
		\$ 391,021
<b>Accumulated Deficit</b>		
Balance, beginning of period		\$ (126,677)
Loss on issue of treasury shares		(1,311)
Net income (loss)		43,127
		\$ (84,861)
<b>Accumulated Other Comprehensive Income</b>		
Balance, beginning of period		\$ (11,468)
Other comprehensive income		(2,604)
		\$ (14,072)
<b>Treasury Stock</b>		
Balance, beginning of period		\$ (75,683)
Issuance related to employee stock compensation and plans		4,755
		\$ (70,928)
<b>Deferred Compensation and Other</b>		
Balance, beginning of period		\$ (605)
Deferred compensation		(525)
Stock acquired by benefit trust		(385)
		\$ (1,515)
<b>Total Stockholders Equity</b>		\$ 219,876

See accompanying notes.

**NUEVO ENERGY COMPANY**  
**CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)**  
(In thousands)  
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net income	\$10,032	\$ 6,155	\$ 43,127	\$ 24,183
Unrealized gains (losses) from cash flow hedging activity:				
Reclassification adjustment for settled contracts	4,861	3,586	18,153	1,985
Changes in fair value of derivative instruments during the period	(2,403)	(11,591)	(20,757)	(26,130)
Other comprehensive income (loss)	2,458	(8,005)	(2,604)	(24,145)
Comprehensive income (loss)	\$12,490	\$ (1,850)	\$ 40,523	\$ 38

See accompanying notes.

**NUEVO ENERGY COMPANY**  
**NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

**1. Basis of Presentation**

This Quarterly Report on Form 10-Q has been prepared pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ( SEC ) and does not include all disclosures required on an annual basis by accounting principles generally accepted in the United States. You should read this report along with our 2002 Annual Report on Form 10-K, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of September 30, 2003, and for the three and nine months ended September 30, 2003 and 2002, are unaudited. The balance sheet as of December 31, 2002, is derived from the audited balance sheet included in our Form 10-K. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature, to fairly present our interim period results. Information for interim periods may not necessarily indicate the results of operations for the entire year.

Our accounting policies are consistent with those discussed in our Form 10-K, except as discussed below. You should refer to our Form 10-K for a further discussion of those policies.

*Accounting for Asset Retirement Obligations.*

In August 2001, the Financial Accounting Standards Board ( FASB ) issued Statement of Financial Accounting Standards ( SFAS ) No. 143, *Accounting for Asset Retirement Obligations*. This Statement requires a liability to be recorded relating to the eventual retirement and removal of assets used in our business. The liability is discounted to its present value, with a corresponding increase to the related asset value. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. The provisions of this statement are effective for fiscal years beginning after June 15, 2002. We adopted the provisions of SFAS No. 143 on January 1, 2003 to record our asset retirement obligation to plug and abandon oil and gas wells, offshore platforms and facilities. In connection with the initial application of SFAS No. 143, we recorded a cumulative effect of change in accounting principle, net of taxes, of \$8.5 million as an increase to net income. In addition, we recorded an asset retirement obligation for oil and gas properties and equipment of \$92.7 million. The following table rolls forward our asset retirement obligation in accordance with the provisions of SFAS No. 143:

	<b>Three Months Ended September 30, 2003</b>	<b>Nine Months Ended September 30, 2003</b>
	(In thousands)	
Beginning asset retirement obligation	\$ 99,229	\$ 92,680
Liabilities incurred during period	54	2,618
Liabilities settled during period	(521)	(1,072)
Accretion expense	2,291	6,827
Ending asset retirement obligation	<u>\$ 101,053</u>	<u>\$ 101,053</u>

In addition, pro forma net income and earnings per share for the three months ended September 30, 2002 and for the nine months ended September 30, 2002 for the change in accounting had SFAS No. 143 been implemented during these periods would have been as follows:

	<b>Three Months Ended September 30, 2002</b>	<b>Nine Months Ended September 30, 2002</b>
	(In thousands, except per share data)	
Net income		
As reported	\$6,155	\$24,183
Pro forma	7,403	27,761
Net income per share - reported		
Basic	0.35	1.41
Diluted	0.35	1.40

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Net income per share - pro forma		
Basic	0.43	1.62
Diluted	0.42	1.60

*Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.*

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. SFAS No. 150 establishes standards for how an issuer classifies and measures three classes of freestanding financial instruments (mandatorily redeemable instruments, instruments with repurchase obligations, instruments with obligations to issue a variable number of shares) with characteristics of both liabilities and equity. Instruments within the scope of the statement must be classified as liabilities on the balance sheet. SFAS No. 150 is effective for all freestanding financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. We have not entered into any financial instruments within the scope of SFAS No. 150 since May 31, 2003, nor do we currently hold any significant financial instruments within the scope. SFAS No. 150 does not apply to convertible bonds, consequently our TECONS are not within the scope of SFAS No. 150.

*Guarantor s Accounting and Disclosure Requirements.*

The FASB issued Interpretation No. 45 ( FIN 45 ), *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of the Indebtedness of Others*, in November 2002, which clarifies the requirements of SFAS No. 5, *Accounting for Contingencies*, relating to a guarantor s accounting for and disclosures of certain guarantees issued. FIN 45 requires enhanced disclosures for certain guarantees. It also requires that certain guarantees issued or modified after December 31, 2002, including certain third-party guarantees, be recorded initially on the balance sheet at fair value. For guarantees issued on or before December 31, 2002, liabilities are recorded when and if payments become probable and estimable. We adopted FIN 45 effective January 1, 2003, and have included the disclosure requirements of FIN 45 in Note 9 to the condensed consolidated financial statements. The adoption of FIN 45 had no effect on our consolidated financial position, results of operations or cash flows.

*Consolidation of Variable Interest Entities.*

In January 2003, the FASB issued Interpretation No. 46 ( FIN 46 ), *Consolidation of Variable Interest Entities*, an interpretation of Accounting Research Bulletin No. 51. FIN 46 requires certain variable interest entities, or VIEs, to be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. FIN 46 is effective for all VIEs created or acquired after January 31, 2003. For VIEs created or acquired prior to February 1, 2003, the provisions of FIN 46 must be applied for the first interim or annual period beginning after June 15, 2003. We currently have no contractual relationship or other business relationship with a variable interest entity and therefore the adoption of FIN 46 had no effect on our consolidated financial position, results of operations or cash flows.

*Accounting for Costs Associated with Mineral Rights.*

The FASB issued SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets* in June 2001. We adopted the provisions of these statements on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. SFAS No. 142 addresses accounting and reporting of acquired goodwill and other intangible assets. This statement eliminates the requirement to amortize goodwill; instead, such goodwill is required to be reviewed at least annually for impairment. It also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item on the balance sheet.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 for companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, we have included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties pursuant to the provisions of SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Companies*. If it is ultimately determined that SFAS No. 142 requires these costs to be classified as a separate intangible asset line item on the balance sheet, we would be required to reclassify approximately \$92 million and \$98 million at September 30, 2003 and December 31, 2002, respectively, out of oil and gas properties into a separate intangible assets line item on the balance sheet. To calculate these amounts, we

deducted our estimate of the fair value of tangible oil and gas equipment acquired in the merger with Athanor Resources, Inc. in 2002 from the amount of the purchase price allocated to property, plant and equipment. Our results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with successful efforts accounting rules. The classification of these costs as intangible assets would not have any impact on our compliance with the covenants under our debt agreements.

## 2. Stock-Based Compensation

We account for stock compensation plans under the intrinsic value method of Accounting Principles Board Opinion ( APB ) No. 25, *Accounting for Stock Issued to Employees*. No compensation expense is recognized for stock options that had an exercise price equal to or greater than the market value of the underlying common stock on the date of grant. As permitted by SFAS No. 123, *Accounting for Stock-Based Compensation*, we have continued to apply APB No. 25 for purposes of determining net income. Had compensation expense for stock-based compensation been determined based on the fair value at the date of grant, our net income and earnings per share would have been as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands, except per share data)			
Net income as reported	\$ 10,032	\$ 6,155	\$ 43,127	\$ 24,183
Add:				
Stock based employee compensation expense included in reported net income, net of related income tax	278	276	772	583
Deduct:				
Total stock based employee compensation expense determined under fair value based method for all awards, net of related income tax	(532)	(515)	(1,534)	(1,457)
Pro forma net income	\$ 9,778	\$ 5,916	\$ 42,365	\$ 23,309
Earnings per share:				
Basic as reported	\$ 0.52	\$ 0.35	\$ 2.24	\$ 1.41
Basic pro forma	0.50	0.34	2.20	1.36
Diluted as reported	\$ 0.51	\$ 0.35	\$ 2.21	\$ 1.40
Diluted pro forma	0.50	0.34	2.18	1.35

## 3. Earnings Per Share

SFAS No. 128, *Earnings per Share*, requires a reconciliation of the numerator (income) and denominator (shares) of the basic earnings per share computation to the numerator and denominator of the diluted earnings per share computation. For the quarter and nine months ended September 30, 2003, we had 0.5 million and 1.6 million stock options which were not included in the calculation of diluted earnings per share because the option exercise price exceeded the average market price. We also have 2.3 million Term Convertible Securities, Series A ( TECONS ) that were not included in the calculation of diluted earnings per share for the quarter and nine months ended September 30, 2003, due to their anti-dilutive effect. The reconciliation is as follows:

Three Months Ended September 30,			
2003		2002	
Net Income	Shares	Net Income	Shares
(In thousands)			

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Earnings - Basic	\$ 10,032	19,387	\$ 6,155	17,399
Effect of dilutive securities				
Stock options and restricted stock		248		38
Shares held by benefit trust				65
Earnings - Diluted	\$ 10,032	19,635	\$ 6,155	17,502

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	Nine Months Ended September 30,			
	2003		2002	
	Net Income	Shares	Net Income	Shares
	(In thousands)			
Earnings - Basic	\$43,127	19,283	\$24,183	17,161
Effect of dilutive securities				
Stock options and restricted stock		189		86
Shares held by benefit trust			(8)	61
Earnings - Diluted	\$43,127	19,472	\$24,175	17,308

#### 4. Discontinued Operations

We sold our Eastern properties in 2002 and sold our Brea-Olinda, Union Island and Orcutt Hill oil and gas properties in 2003. The historical results of operations of these properties are classified as discontinued operations in our statements of income. The following table reflects revenue, gain/loss on disposition and pre-tax income for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands)			
<b>Brea-Olinda</b>				
Revenue	\$	\$4,510	\$ 3,246	\$ 11,985
Pre-tax income	(12)	2,398	2,831	5,689
<b>Union Island</b>				
Revenue		481	1,575	1,279
Gain/(loss) on disposition			7,705	
Pre-tax income		316	9,118	694
<b>Eastern Properties</b>				
Revenue		(71)		3,207
Gain/(loss) on disposition		315		315
Pre-tax income		421		1,176
<b>Orcutt Hill</b>				
Revenue	1,534	2,394	6,609	6,400
Gain/(loss) on disposition	452		(4,898)	
Pre-tax income	1,087	728	(1,994)	1,450

#### 5. Long-Term Debt

Our long-term debt consists of the following:

	September 30, 2003	December 31, 2002
	(In thousands)	
9 % Senior Subordinated Notes due 2010	\$ 150,000	\$ 150,000
9 ½ % Senior Subordinated Notes due 2008	100,000	257,210

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9 ½ % Senior Subordinated Notes due 2006		2,367
Bank credit facility (2.29% September 30, 2003, 3.11% December 31, 2002)	26,325	28,700
	<u>          </u>	<u>          </u>
Total debt	276,325	438,277
Interest rate swaps fair value adjustment		2,161
Interest rate swaps termination gain	14,777	11,673
	<u>          </u>	<u>          </u>
Total long-term debt	291,102	452,111
	<u>          </u>	<u>          </u>

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In April 2003, we redeemed in full the remaining \$2.4 million of our 9 ½% Senior Subordinated Notes due 2006. The notes were redeemed at 101.58% of the principal amount plus accrued and unpaid interest. In June 2003, we redeemed \$157.2 million of our 9 ½% Senior Subordinated Notes due 2008 at 104.75% of the principal amount plus accrued and unpaid interest. In the second quarter of 2003, we recorded a \$10.9 million loss on early extinguishment of debt consisting of a \$7.5 million call premium and a \$3.4 million deferred financing cost write-off on the notes called. We also terminated our interest rate swaps and received cash of \$4.1 million during the second quarter of 2003 (See Note 6). In October 2003, we called for redemption \$25.0 million of our 9 ½% Senior Subordinated Notes due 2008 for 104.75% of the principal amount plus accrued and unpaid interest and completed the redemption on November 5, 2003. We paid a \$1.2 million call premium and will write-off \$0.5 million of deferred financing costs related to the called Notes in the fourth quarter.

### 6. Financial Instruments

We have entered into commodity swaps, collars, put options and interest rate swaps. The commodity swaps, collars and put options are designated as cash flow hedges and the interest rate swaps are designated as fair value hedges in accordance with SFAS No. 133. Quantities covered by the crude oil commodity swaps and put options are based on West Texas Intermediate ( WTI ) barrels. The selling price for our crude oil production is expected to average 74% of WTI, as reported on NYMEX, therefore, each WTI barrel hedges 1.36 barrels of our production. We have also entered into a call spread and three-way collars that are not designated as hedges and changes in fair value are recognized in earnings.

#### *Derivative Instruments Designated as Cash Flow Hedges.*

At September 30, 2003, we had recorded \$14.1 million (net of related tax expense of \$9.7 million) of cumulative hedging losses in other comprehensive income, of which \$11.8 million (based on September 30, 2003 futures prices) is expected to be reclassified to earnings within the next 12 months. The amounts ultimately reclassified to earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

As a result of hedging transactions, oil and gas revenues were reduced by \$30.6 million and \$3.3 million in the first nine months of 2003 and 2002, respectively. There was no hedging ineffectiveness for the first nine months of 2003.

At September 30, 2003, we had outstanding the following derivatives designated as cash flow hedges:

	Crude Oil			Natural Gas		
	Bbls / day	\$ / Bbl	Index	MMbtu/day	\$/MMbtu	Index
<b>Swaps for Sales</b>						
2003						
4 <sup>th</sup> Qtr	13,500	\$ 23.79	WTI	8,000	\$ 4.94	Waha
2004						
1 <sup>st</sup> Qtr	14,500	23.76	WTI	16,500	4.93	Waha & Socal
2 <sup>nd</sup> Qtr	13,500	24.03	WTI	14,500	4.65	Waha & Socal
3 <sup>rd</sup> Qtr	11,000	23.64	WTI	10,500	4.50	Waha & Socal
4 <sup>th</sup> Qtr	8,500	23.76	WTI	14,500	4.64	Waha & Socal
2005						
1 <sup>st</sup> Qtr	11,500	24.01	WTI	10,500	4.77	Waha & Socal
2 <sup>nd</sup> Qtr	6,500	23.04	WTI	7,000	4.66	Waha
3 <sup>rd</sup> Qtr	4,500	22.14	WTI			
4 <sup>th</sup> Qtr	4,500	22.14	WTI			
<b>Collars</b>						
2003						
Full Year	10,000	22.00 28.91	WTI			
4 <sup>th</sup> Qtr				6,000	3.70 4.30	Waha
<b>Swaps for Purchases</b>						
2004				8,000	3.91	Socal
2005				8,000	3.85	Socal



*Derivative Instruments Designated as Fair Value Hedges.*

In late December 2001 and early 2002, we entered into three interest rate swap agreements with notional amounts totaling \$200.0 million to hedge the fair value of our 9 ½% Notes due 2008 and our 9 % Notes due 2010. These swaps were designated as fair value hedges and as interest rates fluctuated, the change in value of these instruments were reflected as an increase or decrease of long-term debt with an offsetting adjustment to long-term assets or liabilities.

In late August and early September 2002, we terminated our swap transactions relating to these Notes. As a result of these terminations, we received accrued interest of \$2.2 million and the present value of the swap option totaling \$9.6 million on our 9 % Notes and \$0.5 million in accrued interest and the present value of the swap option totaling \$2.5 million on our 9 ½% Notes. The gain of \$9.6 million on our 9 % Notes and \$2.5 million on our 9 ½% Notes is reflected as an increase of long-term debt and is being amortized as a periodic reduction in interest expense over the life of the Notes. During the three months ended September 30, 2003, we amortized \$0.3 million as a reduction of interest expense.

Following the termination of the three interest rate swaps referenced above, in late August and early November 2002, we entered into two new interest rate swap agreements with notional amounts totaling \$100.0 million, to hedge a portion of the fair value of our 9 % Notes due 2010. These swaps were also designated and accounted for as fair value hedges.

In May 2003, we terminated our swap transactions relating to these 9 % Notes. As a result of these terminations, we received accrued interest of \$0.4 million and the present value of the swap option of \$4.1 million. The gain of \$4.1 million on the Notes is reflected as an increase of long-term debt and is being amortized as a periodic reduction in interest expense over the life of the Notes. During the three months ended September 30, 2003, we amortized \$0.1 million as a reduction of interest expense.

*Other Derivatives Not Designated as Hedging Instruments.*

We have a call spread that is not designated as a hedging instrument and is marked-to-market with changes in fair value recognized currently as a derivative gain/loss. During the three months ended September 30, 2003 we recorded a \$0.1 million derivative loss and recorded the fair value of the remaining derivative loss at September 30, 2003 totaling \$4.6 million in accrued liabilities.

In August 2003, we entered into three-way collars that are not designated as hedging instruments and are marked-to-market with changes in fair value recognized currently as a derivative gain/loss. During the three months ended September 30, 2003 we recorded a \$0.4 million derivative gain and recorded the fair value of the derivative gain at September 30, 2003 totaling \$0.4 million as an asset.

Three-Way Collars <sup>(1)</sup>	Bbls / day	Index	Weighted Average Price
2004 (Jan Dec)	8,000	WTI	\$ 19.28-24.00-31.00

<sup>(1)</sup> A Three-Way Collar combines a sold put, a purchased put and a sold call. The purchased put and sold put establish a floating minimum price and the sold call establishes a maximum price we will receive for the volumes under contract.

**7. Segments**

We are engaged in one industry, the exploration for and production of oil and natural gas. We manage our business via two operating segments, domestic operations and international operations. Our chief operating decision-making team makes operating decisions, the foremost of these being capital investment decisions, and assesses operational performance and rates of return based principally on these two segments. Financial information by reportable segment is presented below:

## Three Months Ended September 30, 2003

	Oil and Gas Domestic	Oil and Gas Foreign <sup>(1)</sup>	Other <sup>(2)</sup>	Total
	(In thousands)			
Revenues from external customers	\$82,668	\$5,039	\$127	\$87,834
Income (loss) from continuing operations before income tax	27,829	3,036	(14,996)	15,869

## Three Months Ended September 30, 2002

	Oil and Gas Domestic	Oil and Gas Foreign <sup>(1)</sup>	Other <sup>(2)</sup>	Total
	(In thousands)			
Revenues from external customers	\$69,889	\$10,846	\$3,515	\$84,250
Income (loss) from continuing operations before income tax	25,452	2,984	(21,953)	6,483

## Nine Months Ended September 30, 2003

	Oil and Gas Domestic	Oil and Gas Foreign <sup>(1)</sup>	Other <sup>(2)</sup>	Total
	(In thousands)			
Revenues from external customers	\$249,108	\$30,957	\$540	\$280,605
Income (loss) from continuing operations before income tax	92,517	18,179	(62,892)	47,804

## Nine Months Ended September 30, 2002

	Oil and Gas Domestic	Oil and Gas Foreign <sup>(1)</sup>	Other <sup>(2)</sup>	Total
	(In thousands)			
Revenues from external customers	\$202,631	\$26,515	\$3,563	\$232,709
Income (loss) from continuing operations before income tax	81,148	9,128	(58,634)	31,642

<sup>(1)</sup> The timing of Congo crude oil liftings determines when revenues are recognized and has a significant effect on foreign results of operations.

<sup>(2)</sup> Includes corporate income and expenses.

### 8. Acquisition of Athanor Resources, Inc.

We acquired Athanor Resources, Inc. ( Athanor ) in September 2002 in a transaction valued at \$101.4 million which included the issuance of approximately 2.0 million shares of our common stock. The acquisition was accounted for using the purchase method of accounting. The following unaudited pro forma condensed income statement information has been prepared as if the acquisition had occurred at the beginning of the period presented. The historical results of operations, based on 2002 realized prices, have been adjusted to reflect the difference between Athanor's historical depletion, depreciation and amortization and the expense calculated based on the value allocated to the assets acquired. The information presented is not necessarily indicative of the results of future operations of the combined companies.



	<b>Three Months Ended September 30, 2002</b>	<b>Nine Months Ended September 30, 2002</b>
	<b>(In thousands, except per share data)</b>	
Revenues	\$ 89,742	\$ 248,266
Income from continuing operations	4,700	20,832
Net income	6,998	26,198
Earnings per share		
Basic		
Income from continuing operations	\$ 0.24	\$ 1.09
Net income	0.36	1.37
Diluted		
Income from continuing operations	\$ 0.24	\$ 1.08
Net income	0.36	1.36

## 9. Commitments and Contingencies

### *Legal Proceedings and Other Matters.*

We acquired properties from Unocal in 1996 and are obligated to make a contingent payment based on net proceeds received, less certain deductions, on oil sold through 2004 if oil prices exceed thresholds set forth in the purchase and sale agreement with Unocal. Any contingent payments paid or accrued are accounted for as a purchase price adjustment to oil and gas properties. We paid \$10.8 million to Unocal in 2002 attributable to calendar year 2001 and recorded the payment as an increase in oil and gas properties. In March 2003, we advised Unocal that we had failed to take deductions to the sales price that we believe are permitted by the agreement. Application of these deductions results in no payment due for either calendar year 2001 or 2002. Unocal disputes this position for both years. Attempts to resolve this issue through mediation were unsuccessful. We filed suit against Unocal to recover the 2001 payment, secure a declaration of the appropriate deduction methodology to be applied for 2002 through 2004 and to recover attorneys' fees. Unocal has answered and filed a counterclaim claiming breach of contract and anticipatory breach of contract seeking \$16.0 million for 2002 and a declaration of the appropriate deduction methodology and attorneys' fees. While the outcome of this matter is not presently determinable, its resolution is not expected to have a material impact on our results of operations, financial condition or liquidity.

We have asserted a claim against Torch Energy Advisors for matters arising out of our former outsourcing arrangement. Among other demands, we have requested the return of a \$2.0 million working capital advance. Torch has asserted claims for indemnity and payment of certain fees it asserts are owed to them. These outstanding issues will be arbitrated and are not expected to have a material impact on our results of operations, financial condition or liquidity.

During the second quarter of 2003, we entered into a settlement agreement with Hills for Everyone, a non-profit organization, and Orange County, California ending litigation challenging the adequacy of the environmental review of our Tonner Hills real estate project. The settlement did not have a material impact on the project or our results of operations, financial condition or liquidity.

### *Contingencies.*

In 2001, we experienced a failure of a carbon dioxide treatment vessel at the Rincon Onshore Separation Facility ( ROSF ) located in Ventura County, California. Insurance claims relating to the cost of repair and business interruption (less a 30-day waiting period) were settled in the second quarter of 2003 and we recognized income of \$2.3 million in connection with the insurance settlement.

In 1997, there was a spill of crude oil into the Santa Barbara Channel from a pipeline that connects our Point Pedernales field with shore-based processing facilities. As of September 30, 2003, all outstanding claims have been settled. We expect that the final insurance settlements related to these claims will be insignificant. We are awaiting final disposition of certain insurance claims that have been submitted to our carriers.

Our 1994 acquisition agreement to purchase the two subsidiaries owning interests in the Yombo field offshore Congo contains a provision for contingent royalty to be paid by us to the seller if certain conditions are met. Under this provision we will pay to the seller an amount equal to \$2.8 million, increased by 7% per year from 1995, if we recover from our Yombo field production an amount greater than the sum of our capital costs, our operating costs, and \$27.0 million, which entire amount increases 27% annually. We currently estimate that we could reach payout as early as 2005.

*Guarantees Related to Assets or Obligations of Third Parties.*

We have indemnified certain third parties for future environmental remediation costs that may be incurred for properties that we purchased or properties that we sold to a third party. The properties may or may not require environmental remediation and if we are determined to be responsible, our indemnities may require us, among other matters, to pay for the remediation costs. We are not able to determine the maximum potential amount, if any, of future payments that we could be required to make under these indemnifications primarily due to the following: the indefinite term of the majority of these indemnities; the unknown extent of possible contamination; the conditional nature of our responsibility under certain indemnities; uncertainties related to the timing of the remediation work; possible changes in laws governing the remediation process; the unknown number of claims that may be made and changes in remediation technology.

We have performance obligations in the ordinary course of business that are secured by surety bonds or letters of credit. These surety bonds and letters of credit are issued by financial institutions and are required to be reimbursed if drawn upon. At September 30, 2003, we had surety bonds of \$39.7 million and letters of credit of \$1.6 million.

In the ordinary course of business, we have provided indemnifications and guarantees that are not explicitly defined whose terms range in duration. We do not believe that these will have a material effect on our results of operation, financial condition or liquidity.

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

### Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements which have been prepared in accordance with accounting principles generally accepted in the United States of America ( GAAP ). The preparation of our financial statements requires us to make estimates and judgments that affect the reported amount of assets, liabilities, revenues and expenses. We believe the following critical accounting policies reflect our significant estimates and judgments used in the preparation of our financial statements:

*Revenue Recognition.* Crude oil and natural gas revenue is recognized when title passes to the purchaser. We use the entitlement method for recording sales of crude oil and natural gas from producing wells. Under the entitlement method, revenue is recorded based on our net revenue interest in production. Deliveries of crude oil and natural gas in excess of our net revenue interests are recorded as liabilities and under-deliveries are recorded as assets. Production imbalances are recorded at the lower of the sales price in effect at the time of production or the current market value. Substantially all such amounts are anticipated to be settled with production in future periods. At September 30, 2003, our imbalances were insignificant.

*Successful Efforts Accounting.* We account for our crude oil and natural gas operations using the successful efforts method of accounting. Under this method of accounting, all costs associated with oil and gas lease acquisition costs, successful exploratory wells and all development wells are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves. When a proved property is sold, ceases to produce or is abandoned, a gain or loss is recognized. When an entire interest in an unproved property is sold for cash or cash equivalent, a gain or loss is recognized, taking into consideration any recorded impairment. When a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained. Unproved leasehold costs are capitalized pending the results of exploration efforts. Exploration costs, including geological and geophysical expenses, exploratory dry holes and delay rentals, are charged to expense when incurred.

The FASB issued SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets* in June 2001. We adopted the provisions of these statements on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. SFAS No. 142 addresses accounting and reporting of acquired goodwill and other intangible assets. This statement eliminates the requirement to amortize goodwill; instead, such goodwill is required to be reviewed at least annually for impairment. It also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item on the balance sheet.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 for companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, we have included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties pursuant to the provisions of SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Companies*. If it is ultimately determined that SFAS No. 142 requires these costs to be classified as a separate intangible asset line item on the balance sheet, we would be required to reclassify approximately \$92 million and \$98 million at September 30, 2003 and December 31, 2002, respectively, out of oil and gas properties into a separate intangible assets line item on the balance sheet. To calculate these amounts, we deducted our estimate of the fair value of tangible oil and gas equipment acquired in the merger with Athanor Resources, Inc. in 2002 from the amount of the purchase price allocated to property, plant and equipment. However, the results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with successful efforts accounting rules. The classification of these costs as intangible assets would not have any impact on our compliance with the covenants under our debt agreements.

*Proved Reserve Estimates.* There are uncertainties inherent in estimating crude oil and natural gas reserve quantities, projecting future production rates and projecting the timing of future development expenditures. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. Proved reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions at the end of the respective years.

Proved developed reserves are those reserves expected to be recovered through existing equipment and operating methods.

*Impairment of Proved Oil and Gas Properties.* We review our proved properties when management determines that events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. If the carrying amount of an asset exceeds the sum of the undiscounted estimated future net cash flows, we recognize an impairment equal to the difference between the carrying value and the fair value of the asset which is estimated to be the expected present value of future net cash flows from proved reserves, utilizing a risk-free rate of return.

*Impairment of Unproved Oil and Gas Properties.* Unproved leasehold costs are reviewed periodically and a loss is recognized to the extent, if any, that the cost of the property has been impaired.

*Impairment of Goodwill.* Goodwill of a reporting unit is tested for impairment annually in the fourth quarter, and also at interim dates upon the occurrence of significant events. The fair value of each reporting unit that has goodwill is determined and compared to the carrying amount of the reporting unit. If the fair value of the reporting unit is less than the carrying amount, including goodwill, the fair value of the reporting unit's individual assets and liabilities is deducted from the fair value of the reporting unit. This difference represents the implied fair value of goodwill, which is compared to the carrying amount of the reporting unit's goodwill. We recognize an impairment of the excess of the carrying amount of goodwill over the implied fair value of goodwill.

*Asset Retirement Obligations.* The computation of our asset retirement obligations was prepared in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligation*, which requires us to record the fair value of liabilities for retirement obligations of long-lived assets. Our asset retirement obligations arise from the requirement that we must pay our share to plug and abandon our oil and gas wells and offshore platforms, and facilities. We estimated our liability based on the best information available to us at this time. Revisions to the liability could occur due to changes in the timing and actual plugging and abandonment costs.

*Derivative Financial Instruments and Price Risk Management Activities.* We use price risk management activities to manage non-trading market risks. We use derivative financial instruments such as swaps, collars and put options to hedge the impact market price risk exposures on our crude oil and natural gas production, natural gas purchases and to mitigate our exposure to interest rate risk. We account for our derivatives under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, and have designated derivative instruments that qualify for hedge accounting as cash flow hedges for commodity related contracts and fair value hedges for interest rate contracts. Derivatives that do not qualify for hedge accounting are carried on the balance sheet at fair value, and changes in fair value are recognized in earnings.

*Stock-Based Compensation.* We account for stock compensation plans under the intrinsic value method of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*. No compensation expense is recognized for stock options that had an exercise price equal to their market value of the underlying common stock on the date of grant. We disclose in both annual and interim financial statements the effect of reported results had the stock based compensation been determined based on fair value at the date of grant and expensed.

*Income Taxes.* Deferred income taxes are accounted for under the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The effect on deferred taxes of a change in tax rates is recognized in income in the period the change occurs.

### Results of Operations

Our results of operations are significantly affected by fluctuations in oil and gas prices. We sold our Brea-Olinda field, Union Island field, Orcutt Hill field and Eastern properties. The results of operations of these properties are classified as discontinued operations in our financial statements. The following table reflects our production and average prices for oil and natural gas excluding our discontinued operations for all periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
<b>Crude Oil and Liquids</b>				
Sales Volumes (MBbls/day)				
Domestic	37.6	35.0	37.3	36.2
Foreign	4.8	4.9	4.9	5.1
<b>Total</b>	<b>42.4</b>	<b>39.9</b>	<b>42.2</b>	<b>41.3</b>
Sales Prices (\$/Bbl)				
Unhedged	\$ 21.02	\$ 21.15	\$ 23.05	\$ 18.61
Hedged	18.99	19.56	20.62	18.32
Revenues (\$/thousands)				
Domestic	\$76,975	\$67,062	\$234,725	\$184,073
Foreign	5,039	10,846	30,957	26,515
Marketing Fees	(1)	(221)	(4)	(667)
Hedging	(7,920)	(5,849)	(27,965)	(3,326)
<b>Total</b>	<b>\$74,093</b>	<b>\$71,838</b>	<b>\$237,713</b>	<b>\$206,595</b>
<b>Natural Gas</b>				
Sales Volumes (MMcf/day)				
Domestic	38.3	29.7	38.0	28.8
Sales Prices (\$/Mcf)				
Unhedged	\$ 3.94	\$ 3.26	\$ 4.34	\$ 2.87
Hedged	3.86	3.26	4.08	2.87
Revenues (\$/thousands)				
Domestic	\$14,089	\$ 8,952	\$ 45,445	\$ 22,843
Marketing Fees	(197)	(55)	(443)	(292)
Hedging	(278)		(2,650)	
<b>Total</b>	<b>\$13,614</b>	<b>\$ 8,897</b>	<b>\$ 42,352</b>	<b>\$ 22,551</b>

#### Three Months Ended September 30, 2003 Compared to Three Months Ended September 30, 2002

We reported net income of \$10.0 million, or \$0.51 per diluted share and \$9.4 million, or \$0.48 per diluted share from income from continuing operations for the quarter ended September 30, 2003 as compared to net income of \$6.2 million, or \$0.35 per diluted share and income from continuing operations of \$3.9 million, or \$0.22 per diluted share in the same period of 2002. Income from continuing operations is discussed below.

*Revenues.*

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*Oil and Gas Revenues.* Oil and gas revenues of \$87.7 million for the three months ended September 30, 2003 increased \$7.0 million from \$80.7 million in the same period of 2002 due to higher crude oil and natural gas production and higher natural gas prices which was partially offset by higher hedging losses in 2003. Crude oil production increased 6% to 42.4 MBbls/day for the three months ended September 30, 2003 compared to 39.9 MBbls/day in the same period of 2002 primarily due to higher production from new wells onshore California, higher production from the Pakenham field which was acquired in September 2002 and the acquisition of an additional interest in the Point Pedernales field offshore California.

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The realized oil price for the three months ended September 30, 2003 was \$18.99 per Bbl, compared to \$19.56 per Bbl from the same period in 2002. We had crude oil hedging losses of \$7.9 million, or \$2.03 per Bbl in the three months ended September 30, 2003 compared to hedging losses of \$5.8 million, or \$1.59 per Bbl in same period of 2002. Natural gas production averaged 38.3 MMcf per day for the three months ended September 30, 2003, an increase of 8.6 MMcf per day from the same period of 2002. Increased production of 14.0 MMcf per day during the three months ended September 30, 2003 from the Pakenham field which was acquired in September 2002 was partially offset by lower production offshore California of 5.5 MMcf per day due to production declines on our Pitas Point offshore property and mechanical downtime on other California properties. The realized natural gas price for the three months ended September 30, 2003 increased 18% to \$3.86 per Mcf, including a \$0.08 per Mcf hedging loss, compared to \$3.26 per Mcf from the comparable period in 2002 that had no gas hedged.

*Other Revenue.* Other revenue was \$0.1 million in the three months ended September 30, 2003 compared to \$3.5 million in the same period of 2002. The 2002 period included \$3.0 million of business interruption recoveries.

### *Costs and Expenses.*

*Costs and Expenses.* Lease operating expense ( LOE ) for the three months ended September 30, 2003 was \$39.6 million, compared to \$36.8 million in the 2002 period. The increased LOE is due to higher steam costs in our onshore California operations (principally due to higher natural gas prices for gas purchased), higher workover and major maintenance expense in our offshore California operations, field costs in our Pakenham field which was purchased in 2002 and the acquisition of an additional interest in Point Pedernales. Exploration costs were \$0.3 million in the three months ended September 30, 2003 compared to \$2.3 million in the 2002 period which included a \$2.3 million write off of our Anaguid permit in Tunisia. Depletion, depreciation, amortization and accretion ( DD&A ) of \$17.3 million for the three months ended September 30, 2003, was \$0.7 million lower than the same period of 2002 due to a lower rate which was partially offset by higher crude oil and natural gas production and accretion expense related to the January 2003 adoption of SFAS 143.

*Derivative Gain (Loss).* The derivative gain was \$0.4 million for the three months ended September 30, 2003 compared to a loss of \$3.4 million in the same period of 2002. The derivative gain/loss is comprised of realized and unrealized gains and losses on our mark-to-market derivatives which are not accounted for as hedges and ineffectiveness of our hedges.

*Interest Expense.* Interest expense decreased 35% to \$6.2 million for the three months ended September 30, 2003 compared to \$9.5 million in the same period of 2002. Lower interest expense of \$4.0 million from the redemption of \$159.6 million of 9 ½% Notes and lower facility fees of \$0.4 million were partially offset by a lower benefit on the interest rate swaps of \$1.3 million which was due to the termination of the remaining swaps in the second quarter 2003.

*Dividends.* Dividends on the TECONS were \$1.7 million in both the three months ended September 30, 2003 and 2002. The TECONS pay dividends at a rate of 5.75%.

*Income Tax.* We had income tax expense of \$6.5 million including current tax benefit of \$1.8 million for the three months ended September 30, 2003, compared to an expense of \$2.6 million in the prior year period. Our effective income tax rate was 40.8% in 2003 and 40.5% in 2002.

*Discontinued Operations.* We had income from discontinued operations of \$0.6 million for the three months ended September 30, 2003 compared to income of \$2.3 million in same period of 2002. In 2003, we sold our Brea-Olinda, Union Island and Orcutt Hill properties located onshore California. In 2002, the income from discontinued operations consists of after-tax operating income from our Eastern properties which were sold in 2002 and operating income from the Brea-Olinda, Union Island and Orcutt Hill properties.

**Year to Date September 30, 2003 Compared to Year to Date September 30, 2002**

We reported net income of \$43.1 million, or \$2.21 per diluted share and income from continuing operations of \$28.7 million, or \$1.47 per diluted share for the nine months ended September 30, 2003 as compared to net income of \$24.2 million, or \$1.40 per diluted share and income from continuing operations of \$18.8 million, or \$1.09 per diluted share in the same period of 2002. Income from continuing operations is discussed below.

*Revenue.*

*Oil and Gas Revenues.* Oil and gas revenues increased 22% to \$280.1 million for the nine months ended September 30, 2003 from \$229.1 million in the same period of 2002 due to significantly higher realized crude oil and natural gas prices and higher crude oil and natural gas production which was partially offset by higher hedging losses in 2003. Crude oil production averaged 42.2 MBbls/day for the nine months ended September 30, 2003 compared to 41.3 MBbls/day in the same period of 2002. Higher production from the Pakenham field which was acquired in September 2002 and the acquisition of an additional interest in Point Pedernales were partially offset by lower production offshore California due to mechanical downtime. The realized oil price for the nine months ended September 30, 2003 was \$20.62 per Bbl, an increase of \$2.30 per Bbl from the same period in 2002. We had hedging losses of \$28.0 million, or \$2.43 per Bbl in the nine months ended September 30, 2003 compared to hedging losses of \$3.3 million, or \$0.30 per Bbl in same period of 2002. Natural gas production averaged 38.0 MMcf per day for the nine months ended September 30, 2003, an increase of 9.2 MMcf per day from the same period of 2002. The Pakenham field which was acquired in September 2002 averaged 15.1 MMcf per day during the nine months ended September 30, 2003 and was partially offset by production declines at Pitas Point and mechanical downtime and normal declines onshore California. The realized natural gas price for the nine months ended September 30, 2003 was \$4.08 per Mcf, including a \$0.26 per Mcf hedging loss, compared to \$2.87 per Mcf from the comparable period in 2002 that had no gas hedged.

*Other Revenue.* Other revenue was \$0.5 million for the nine months ended September 30, 2003 compared to \$3.6 million for the same period of 2002. The 2002 period included \$3.0 million of business interruption recoveries.

*Costs and Expenses.*

*Costs and Expenses.* LOE for the nine months ended September 30, 2003 totaled \$121.1 million, as compared to \$103.9 million for the 2002 period. The increased LOE is due to higher steam costs in our onshore California operations, field costs from our Pakenham field which was acquired in 2002 and the acquisition of an additional interest in the Point Pedernales field. Exploration costs were \$1.7 million in the nine months ended September 30, 2003 compared to \$3.8 million in the same period of 2002. Exploration costs in 2003 included the dry hole cost of Chott Fejaj in Tunisia while the 2002 costs included a \$2.3 million write off of our Anaguid permit in Tunisia. DD&A was \$52.4 million for the nine months ended September 30, 2003, compared to \$52.7 million in the same period of 2002. The DD&A rate was \$3.96 per BOE in the 2003 period compared to \$4.19 per BOE in 2002. The gain on disposition of properties was \$4.2 million for the nine months ended September 30, 2003 as compared to a \$15.9 million gain in 2002. The 2003 gain was due to the release of escrow related to the 2001 sale of properties. In 2002, under the terms of a settlement agreement with ExxonMobil, we conveyed to them our interest in the Santa Ynez Unit, our non-consent interest in the adjacent Pescado field and relinquished our right to participate in the Sacate field and recorded a \$14.7 million gain related to the sale of this unproved property.

*Derivative Gain (Loss).* Our derivative loss for the nine months ended September 30, 2003 was \$1.4 million compared to a loss of \$4.3 million in the same period of 2002. The derivative loss is comprised of a loss on our mark-to-market derivatives and ineffectiveness of our hedges.

*Interest Expense.* Interest expense was \$24.6 million for the nine months ended September 30, 2003 compared to interest expense of \$27.7 million in the same period of 2002. Lower interest expense of \$4.2 million from the redemption of \$159.6 million of our 9 ½% Notes, lower interest expense on our line of credit of \$0.6 million and lower facility fees of \$0.9 million were more than offset by lower benefits from our interest rate swaps.

*Loss on Early Extinguishment of Debt.* In 2003 we redeemed \$157.2 million of our 9 ½% Notes due 2008 and \$2.4 million of our 9 ½% Notes due 2006. In connection with the redemptions, we paid a premium of \$7.5 million and wrote off \$3.4 million of deferred financing costs.

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*Dividends.* Dividends on the TECONS were \$5.0 million in both the nine months ended September 30, 2003 and 2002. The TECONS pay dividends at a rate of 5.75%.

*Income Tax.* We had income tax expense of \$19.1 million including current tax of \$0.3 million for the nine months ended September 30, 2003, compared to an expense of \$12.8 million in the prior year period. Our effective income tax rate was 40.0% in 2003 and 40.5% in 2002.

*Discontinued Operations.* We had income from discontinued operations of \$6.0 million for the nine months ended September 30, 2003 compared to income of \$5.4 million in same period of 2002. In 2003, we sold our Brea-Olinda, Union Island and Orcutt Hill properties located onshore California. We recognized a \$7.7 million gain on the sale of the Union Island property and a \$5.4 million loss in connection with writing down the Orcutt Hill property to the estimated fair value less our costs to sell the property. In 2002, the income from discontinued operations consists of after-tax operating income from our Eastern properties which were sold in 2002 and operating income from the Brea-Olinda, Union Island and Orcutt Hill properties.

*Cumulative Effect of Change in Accounting Principle.* In January 2003, we adopted SFAS No. 143. In connection with the initial application, we recorded a cumulative effect of change in accounting principle, net of taxes, of \$8.5 million as an increase to income (See Note 1 to the Condensed Consolidated Financial Statements).

### **Capital Resources and Liquidity**

Our sources of cash in 2003 were net cash provided by operating activities of \$130.3 million, proceeds from the sale of properties of \$82.0 million and \$1.8 million of other investing activities. This cash, along with our cash on hand at the beginning of the year, was used to fund our oil, gas and other property capital expenditures of \$51.1 million, pay down \$2.4 million of our line of credit and to redeem \$159.6 million of our outstanding senior subordinated notes, plus a \$7.5 million call premium. The redemption of the notes will result in lower cash interest expense on our 9 ½% notes of approximately \$15.0 million per year. In October 2003, we called for redemption \$25.0 million of our 9½% Senior Subordinated Notes due 2008 for 104.75% of the principal amount plus accrued and unpaid interest and completed the redemption on November 5, 2003. We paid \$1.2 million call premium and will write-off \$0.5 million of deferred financing costs related to the called Notes.

Current assets decreased from \$157.6 million at December 31, 2002 to \$95.1 million at September 30, 2003 principally due to the sale of our Brea-Olinda and Orcutt Hill properties which were sold in the first and third quarters, respectively, and removed from assets held for sale.

We believe our working capital, cash flow from operations and available financing sources are sufficient to meet our obligations as they become due and to finance our capital budget through 2003. We have a \$200.0 million borrowing base under our Credit Agreement. Under the most restrictive covenant, the entire \$200.0 million was available at September 30, 2003 and we had \$26.3 million outstanding and letters of credit of \$1.6 million under our Credit Agreement.

### **Contingencies and Other Matters**

See Item 1, Financial Statements, Note 9, which is incorporated herein by reference.

### **New Accounting Pronouncements**

See Item 1, Financial Statements, Note 1, which is incorporated herein by reference.

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

This report contains or incorporates by reference forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical facts included in this document, including without limitation, statements in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations and covenant compliance, are forward looking statements. We can give no assurances that the assumptions upon which such forward-looking statements are based will prove to be correct. Important factors that could cause actual results to differ materially from our expectations included in the cautionary statements set forth in our annual report on Form 10-K filed with the Securities and Exchange Commission, the volatility of oil and gas prices, future production costs, future oil and gas production quantities, operating hazards, environmental conditions and statements in this document. The cautionary statements expressly qualify all subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf.

**ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

The information contained in this item updates, and should be read in conjunction with Part II, Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2002.

At September 30, 2003, we had outstanding the following derivatives designated as cash flow hedges:

	Crude Oil			Natural Gas		
	Bbls / day	\$ / Bbl	Index	MMbtu/day	\$/MMbtu	Index
Swaps for Sales						
2003						
4 <sup>th</sup> Qtr	13,500	\$ 23.79	WTI	8,000	\$ 4.94	Waha
2004						
1 <sup>st</sup> Qtr	14,500	23.76	WTI	16,500	4.93	Waha & Socal
2 <sup>nd</sup> Qtr	13,500	24.03	WTI	14,500	4.65	Waha & Socal
3 <sup>rd</sup> Qtr	11,000	23.64	WTI	10,500	4.50	Waha & Socal
4 <sup>th</sup> Qtr	8,500	23.76	WTI	14,500	4.64	Waha & Socal
2005						
1 <sup>st</sup> Qtr	11,500	24.01	WTI	10,500	4.77	Waha & Socal
2 <sup>nd</sup> Qtr	6,500	23.04	WTI	7,000	4.66	Waha
3 <sup>rd</sup> Qtr	4,500	22.14	WTI			
4 <sup>th</sup> Qtr	4,500	22.14	WTI			
Collars						
2003						
Full Year	10,000	22.00 28.91	WTI			
4 <sup>th</sup> Qtr				6,000	3.70 4.30	Waha
Swaps for Purchases						
2004						
				8,000	3.91	Socal
2005						
				8,000	3.85	Socal

	Crude Oil					
	Three-Way Collars <sup>(1)</sup>	Bbls / day	Index	Weighted Average Price		
2004						
(Jan Dec)		8,000	WTI	\$ 19.28	24.00	31.00

- <sup>(1)</sup> A Three-Way Collar combines a sold put, a purchased put and a sold call. The purchased put and sold put establish a floating minimum price and the sold call establishes a maximum price we will receive for the volumes under contract. Subsequent to September 30, 2003, we entered into the following derivatives designated as cash flow hedges:

Crude Oil		
Bbls / day	\$ / Bbl	Index

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Swaps for Sales  
2005

1 <sup>st</sup> Qtr	3,000	\$26.30	WTI
2 <sup>nd</sup> Qtr	4,000	25.78	WTI

*Derivative Instruments Designated as Fair Value Hedges.*

In late October 2003, we entered into an interest rate swap agreement with a notional amount totaling \$100.0 million to hedge the fair value of our 9 % Notes due 2010. These swaps were designated as fair value hedges and as interest rates fluctuated, the change in value of these instruments were reflected as an increase or decrease of long-term debt with an offsetting adjustment to long-term assets or liabilities.

**ITEM 4. CONTROLS AND PROCEDURES**

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, or the Exchange Act. This term refers to the controls and procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission. Our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this quarterly report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this quarterly report.

There were no changes to our internal control over financial reporting during our last fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

**PART II OTHER INFORMATION**

**ITEM 1. LEGAL PROCEEDINGS**

See Part I, Item 1, Financial Statements, Note 9, which is incorporated herein by reference.

**ITEM 2. CHANGES IN SECURITIES AND USE OF PROCEEDS**

None.

**ITEM 3. DEFAULTS UPON SENIOR SECURITIES**

None.

**ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY-HOLDERS**

None.

**ITEM 5. OTHER INFORMATION**

None.

**ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K**

**(a) Exhibits:**

- 31.1 Certification of Chief Executive Officer of Nuevo Energy Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
- 31.2 Certification of Chief Financial Officer of Nuevo Energy Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
- 32.1 Certification of Chief Executive Officer of Nuevo Energy Company pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
- 32.2 Certification of Chief Financial Officer of Nuevo Energy Company pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

**(b) Reports on Form 8-K:**

Date	Event Reported
November 12, 2003	Press release announcing third quarter 2003 earnings

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) 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.

**NUEVO ENERGY COMPANY**  
(Registrant)

Date: November 13, 2003

By: /s/ James L. Payne

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James L. Payne  
*Chairman, President and  
Chief Executive Officer*

Date: November 13, 2003

By: /s/ Janet F. Clark

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Janet F. Clark  
*Senior Vice President and  
Chief Financial Officer*

**EXHIBIT INDEX**

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